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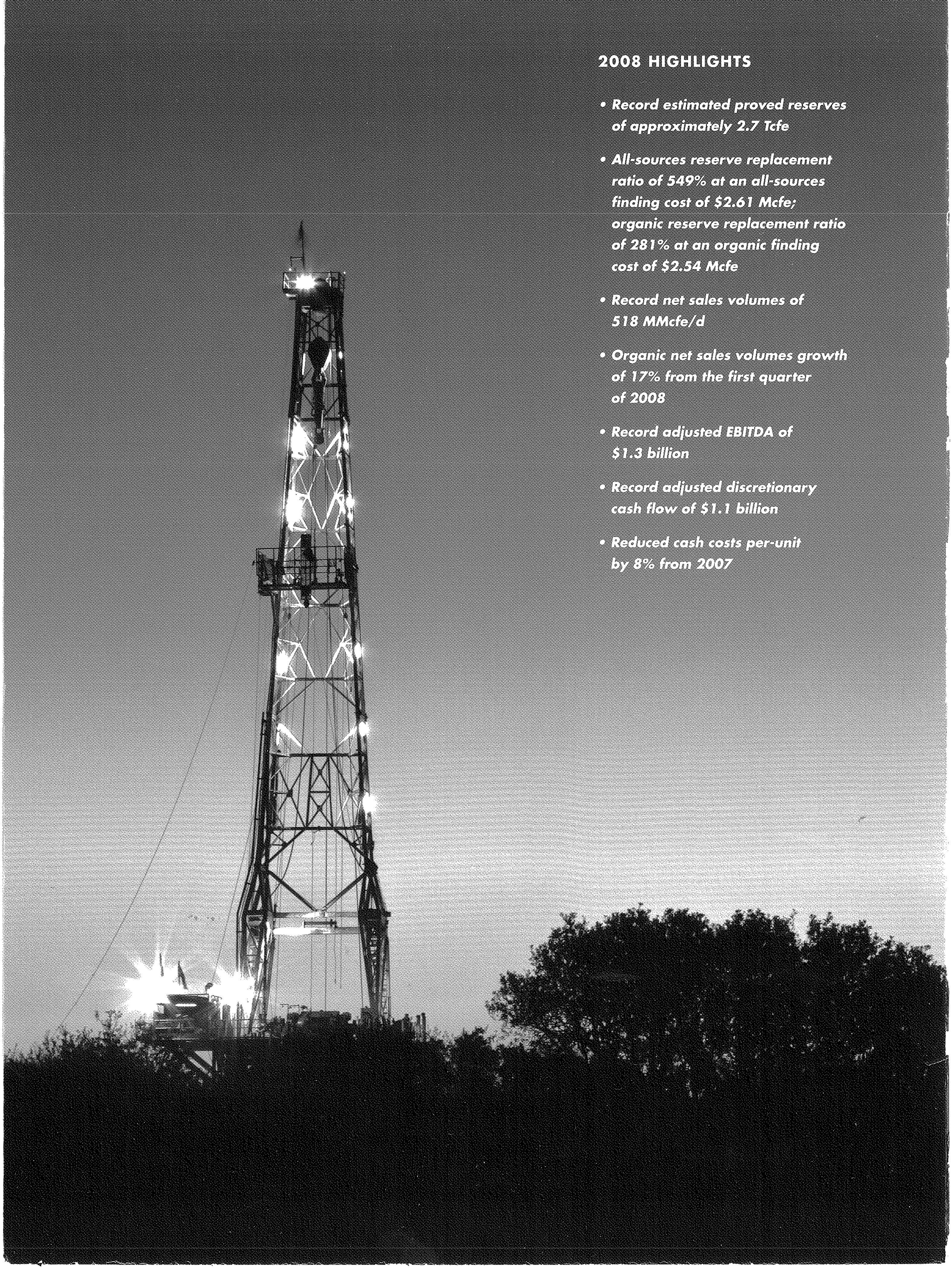
CORE STRENGTH

ANNUAL REPORT 2008



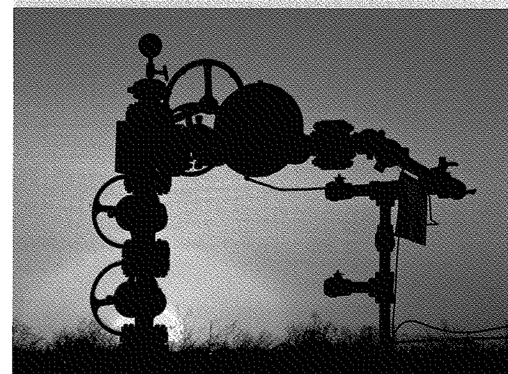
2008 HIGHLIGHTS

- *Record estimated proved reserves of approximately 2.7 Tcfe*
- *All-sources reserve replacement ratio of 549% at an all-sources finding cost of $2.61 Mcfe; organic reserve replacement ratio of 281% at an organic finding cost of $2.54 Mcfe*
- *Record net sales volumes of 518 MMcfe/d*
- *Organic net sales volumes growth of 17% from the first quarter of 2008*
- *Record adjusted EBITDA of $1.3 billion*
- *Record adjusted discretionary cash flow of $1.1 billion*
- *Reduced cash costs per-unit by 8% from 2007*

Dear Fellow Shareholders

OVERVIEW

2008 was a year like no other in the exploration and production business. The industry saw the price of commodities increase to high levels during 2008, causing a spending frenzy on conventional plays and even more so on newly developing unconventional or "resource" plays. By year-end, commodity prices had fallen dramatically, due in part to a deepening recession worldwide. However, our success never wavered in 2008 and can be attributed to five factors, which, in some cases, set us apart from our competition:

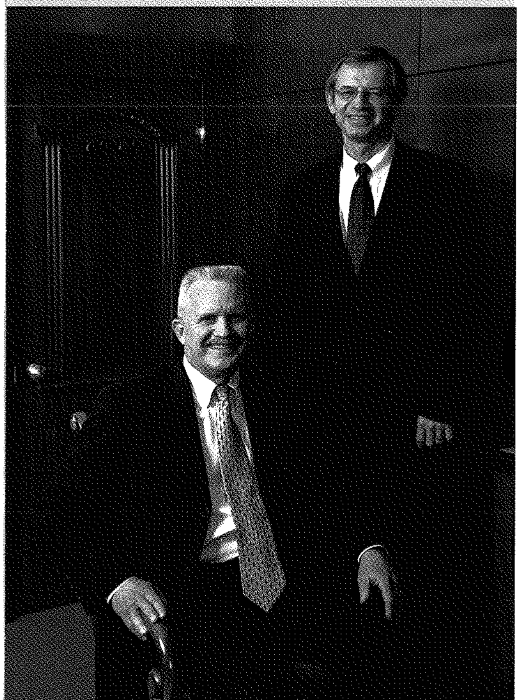


1. *Forest's culture is deeply rooted in operations, with people who are focused on extracting efficiencies from cost control and field execution. We began focusing on these "early in the game."*
2. *Forest is experienced in spending near or below our cash flow for drilling and leasehold projects. We have employed the free cash flow business model for the past five years, with the last quarter of 2008 being the only exception.*
3. *During volatile pricing periods, Forest's diverse asset portfolio allows capital expenditures to be allocated or re-allocated for the best return. While geographically diverse, we have remained committed to only two types of rock — tight-gas sands and gas shales.*
4. *Forest's acquisition and divestiture program has upgraded the asset base with each transaction. As part of each acquisition we have added attractive leasehold and infrastructure at little or no cost.*
5. *Forest has always strived to remain financially flexible. This can be seen with increasing the bank facility by $800 million during the year along with the senior note issuance and divestitures. All assuring our financial strength for the future.*

These *core strengths* enable us to be among the most efficient operators in some of the highest quality plays in North America.

2008 RESULTS

Many records were set for the Company in 2008 including estimated proved reserves, net sales volumes, adjusted net earnings, adjusted EBITDA and adjusted discretionary cash flow. The most impressive statistics are the significant organic growth in production and reserves while spending near our cash flow. Focusing our efforts in a limited number of Core Areas with similar geology provides for greater efficiencies in our knowledge base and economies of scale. The efficiencies we gain are tangible as we again decreased cash costs in 2008, an eight percent reduction per-unit from 2007. Our superior performance is evidenced in metrics for cost control, finding costs and reserve replacement performance. These metrics are a testament to our *core strengths* and the quality of the asset portfolio. Margins and efficiencies matter at Forest Oil, and should matter to those with assets considered resource plays.



James D. Lightner Chairman of the Board

H. Craig Clark President and CEO

In 2008, Forest quietly and efficiently added valuable leasehold in East Texas, including the Haynesville/Bossier Shale, and the Texas Panhandle. Our enviable low cost of entry is a result of recent acquisitions and spending discipline. Our operational execution after establishing our foothold, especially in horizontal drilling applications, was exceptional, which gives us the confidence going forward in resource plays or shales. Our *core strength* may even be Forest's intention to add value through margin extraction and use of new technology. You can see these themes throughout our 2008 highlights.

2008 ACQUISITIONS AND DIVESTITURES

Forest upgraded its asset portfolio through acquisitions and divestitures. We again sold non-core properties at higher reserve cost metrics than the new assets we purchased. Forest completed two significant bolt-on acquisitions in 2008 that enhanced our two biggest Core Areas in the East Texas/North Louisiana and Greater Buffalo Wallow Areas. The first transaction, which was announced at our 2008 Analyst Conference in April, added assets in East Texas and North Louisiana and included Cotton Valley/Travis Peak development locations and undeveloped acreage in the Haynesville/Bossier Shale trend. In fact, our first Haynesville horizontal well was drilled on some of this acreage. The net production from the acquisition at announcement was 13 MMcfe/d. The Haynesville horizontal well initially produced 14 MMcfe/d, more than the entire property base a year earlier. The second acquisition, announced in August, provided significant leasehold with drilling opportunities in East Texas and Buffalo Wallow. These two areas are the most important to the Company as they constitute over 30% of the producing assets and a significant portion of the Company's future drilling portfolio. We are one of the top producers and drillers in both areas. On the divestiture side, we sold our Gabon assets and most of our Rockies assets in the fourth quarter of 2008.

2009 PLAN

We intend to concentrate our *core strengths* on our major Core Assets in 2009. This will result in efficient, repeatable exploitation of our tight-gas sand and shale gas plays. Our 2009 capital program has been reduced significantly from 2008, designed to live within cash flow while maintaining our valuable leasehold and reserve base. Our current 2009 budget is designed to spend $500–$600 million, with approximately 70% in our Core Areas and almost half within the Eastern Business Unit. Based on the success we have seen in 2008, we will increase our horizontal drilling activity to one-third of our total drilling program. All of our horizontal projects are economic at very low commodity prices and our Haynesville Shale play will occupy an increasing role in our drilling program. Our 2009 plan is also focused on cost cutting, specifically, reducing average drilling costs throughout the year.

Our company-operated rig fleet allows us to be free from long term, expensive rig contracts, and thus we are able to extract efficiencies to reduce drilling costs going forward.

OUR PORTFOLIO

Forest has amassed a very significant portfolio of tight-gas sand and shale gas assets located within North America. These have continuously been referred to by the industry as resource plays. These types of resource plays are the future of the North American industry and certainly the future of Forest Oil. Looking back on our 2006–07 divestiture activity, we essentially traded the Gulf of Mexico and Alaska for our resource plays with huge potential in onshore North America. These plays will be enhanced with technology, but will only be economic if cost extraction and operational efficiencies are gained as they mature. These "new oilfields" are working for us, as can be seen in our 2008 results. Our results validate the quality of our asset base and provide confidence in our future execution. We continue to be proactive and "walk the walk" on these type of plays in terms of our discipline to enter them, spend material capital and add value to them over time. In order to properly exploit our assets and maximize returns we will focus on:

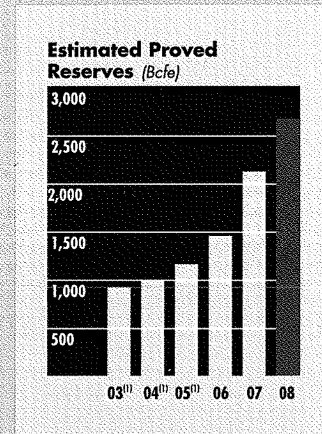
- *Cost of entry*
- *Up front integration of data before drilling*
- *Mechanical success*
- *Cost and extraction efficiency*

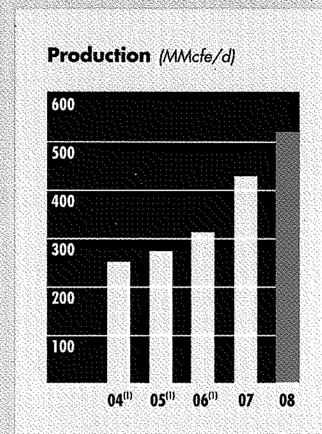
Our portfolio and *core strengths* align perfectly with these points.

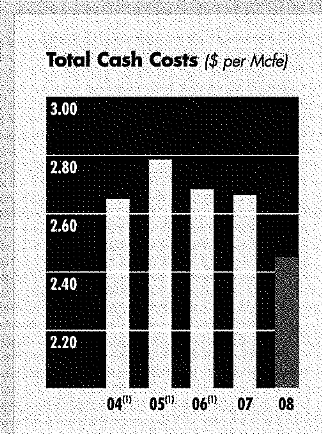
In closing, we want to first thank Mr. Bill Britton who is retiring at our upcoming shareholder meeting in May. Mr. Britton has served honorably on the Forest Oil Board of Directors since 1996 and has been critical to our Canadian operations over the years. We also want to thank our shareholders and employees for their share ownership and tenure. The management and employees are committed to creating shareholder value. We remain loyal to our shareholders and employees. Our employees all share in the benefits. They are always hard working and are all shareholders themselves.

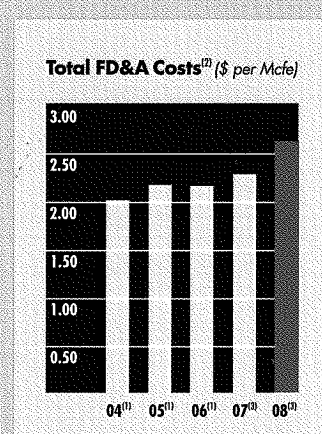
JAMES D. LIGHTNER
Chairman of the Board

H. CRAIG CLARK
President and Chief Executive Officer

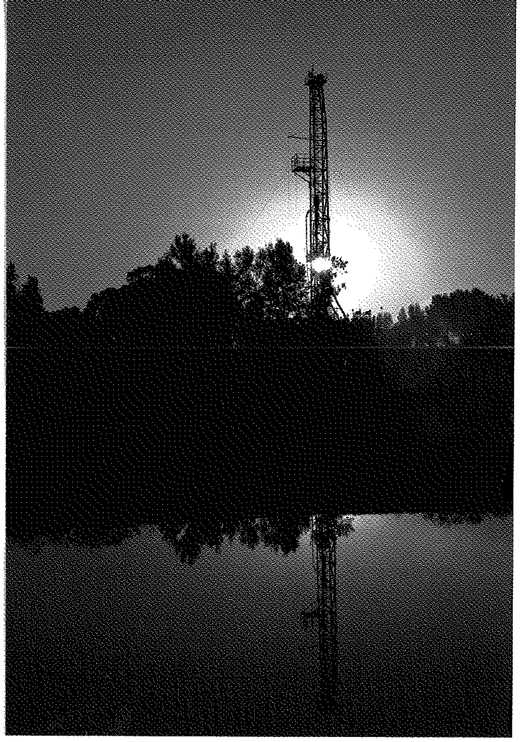








(1) Pro forma for the spin-off of the Gulf of Mexico operations and includes reserve revisions
(2) Does not include tax gross-up amounts
(3) Does not include effect of Alaska properties during 2007 or reserve revisions



Operations

Play extensions, the application of horizontal drilling and strategic acquisitions marked a successful 2008 for Forest, further solidifying Forest's strength in its five Core Areas. The Core Areas include East Texas/North Louisiana; the Greater Buffalo Wallow Area in the Texas Panhandle; the Arkoma Basin in Western Arkansas; South Texas; and the Deep Basin of Alberta in Canada.
Forest drilled 437 net wells, increased production 22% and closed two significant acquisitions in 2008. The Company significantly expanded its existing production and leasehold positions in the East Texas/North Louisiana corridor and in the Greater Buffalo Wallow Area where Forest plans to deploy its exploitation expertise to the newly acquired properties. Along with Forest's 2008 acquisition activity, the Company has tested acreage offsetting its Core Areas, expanding each of the areas outside of its previous boundaries and expanding the size and scope of the plays to both existing and new production horizons. The expansion of the plays has further potential with the application of horizontal drilling technology which allows the Company to target the best zone within a wellbore and perform multiple fractures within that zone. Success achieved in 2008 allows the Company the ability to fine-tune its inventory while focusing on the properties that provide the best rates of return to the organization.

DECEMBER 2008	
GROSS ACREAGE POSITION	210,000
NET ACREAGE POSITION	161,000
FULLY DEVELOPED PROJECT INVENTORY (LOCATIONS)*	3,506
NET UNRISKED POTENTIAL (BCFE)*	7,071

EAST TEXAS/NORTH LOUISIANA

Forest's *core strength* improved significantly in the East Texas/North Louisiana corridor in 2008 with the expansion of its acreage position through two strategic acquisitions. These acquisitions added a significant component of prospective Haynesville/Bossier Shale acreage to Forest's portfolio without significant cost. The acquisitions added additional drilling locations and production to the portfolio to make Forest a major player in the region with approximately 210,000 gross acres and net production of approximately 86 MMcfe/d. From a geologic perspective, the opportunities in East Texas/North Louisiana expanded significantly with successful completions in shallower Travis Peak intervals, further application of horizontal drilling in the Cotton Valley Sands and lastly with the emergence of the highly prolific Haynesville/Bossier Shale. To further assess this area's potential, Forest will test the James Lime in 2009, adding additional serendipity to Forest's position in East Texas/North Louisiana. The Haynesville/Bossier trend on our acreage was first delineated from a vertical perspective in 2008 to identify the limits of the play. Based on that drilling, Forest believes it has rights covering approximately 127,000 net acres in the Haynesville/Bossier Shale. The geotechnical information gathered during 2008 led us to begin horizontal development of this play. Forest intends to operate two horizontal drilling rigs in 2009 to exploit this shale. Along with the horizontal Haynesville/Bossier program, Forest will continue its successful horizontal Cotton Valley program in 2009.

DECEMBER 2008	
GROSS ACREAGE POSITION	120,000
NET ACREAGE POSITION	91,000
FULLY DEVELOPED PROJECT INVENTORY (LOCATIONS)*	2,514
NET UNRISKED POTENTIAL (BCFE)*	2,387

GREATER BUFFALO WALLOW AREA

The Greater Buffalo Wallow Area was significantly expanded in 2008 through both an acquisition and a step-out exploratory drilling program on offset acreage. The Cordillera Acquisition added high quality acreage to the core operating area in both the northern and southeastern sections of the play. The added acreage to the north gives Forest an opportunity to exploit shallower zones that could be enhanced with horizontal drilling applications. Field expansions onto our southeastern acreage bolts-on to legacy acreage. Drilling in this area resulted in wells with initial production rates in 2008 as high as 10 MMcfe/d. A total of 14 previously undrilled sections had successful wells completed during 2008, resulting in an expanded inventory of drilling locations and production growth potential. At year end, the Greater Buffalo Wallow Area's gross acreage position was approximately 120,000 acres. Forest expects 2009 will see a continued expansion by the Company in both the core and offsetting acreage, utilizing two rigs to drill approximately 21 wells throughout the year. Forest will continue its attractive exploitation efforts, using multiple slick-water fracture technology both vertically and horizontally to again expand the *core strength* of this play.

ARKOMA BASIN

The multiple stacked gas pays in the Arkoma Basin of Western Arkansas continued to provide production growth in 2008. Net production increased to approximately 50 MMcfe/d as a result of a successful multi-rig drilling program. The low drilling and operating costs in this area yield attractive rates of return while generating significant cash flow. Forest expanded its *core strength* in this area in 2008 through the utilization of horizontal drilling. Forest expects to continue to target the Atoka Sands with its 2009 drilling program, but anticipates expanding its horizontal campaign in 2009 based on success from 2008.

DECEMBER 2008	
GROSS ACREAGE POSITION	74,000
NET ACREAGE POSITION	44,000
FULLY DEVELOPED PROJECT INVENTORY (LOCATIONS)*	817
NET UNRISKED POTENTIAL (BCFE)*	199

SOUTH TEXAS

Generating strong cash flow and step-out exploratory drilling marked Forest's *core strength* in South Texas during 2008. After a slow down in activity in 2007, Forest interpreted seismic data and refocused operations to match Forest's *core strengths*. Activity was then ramped back up in the area in 2008. After a thorough review of the region, Forest identified prolific opportunities both on legacy and offsetting acreage. The South Texas assets are expected to continue to generate significant cash flow for Forest in 2009, but also provide opportunities to explore offsetting acreage in Wilcox and Vicksburg trends, as well as opportunity to explore shales that have previously been untouched.

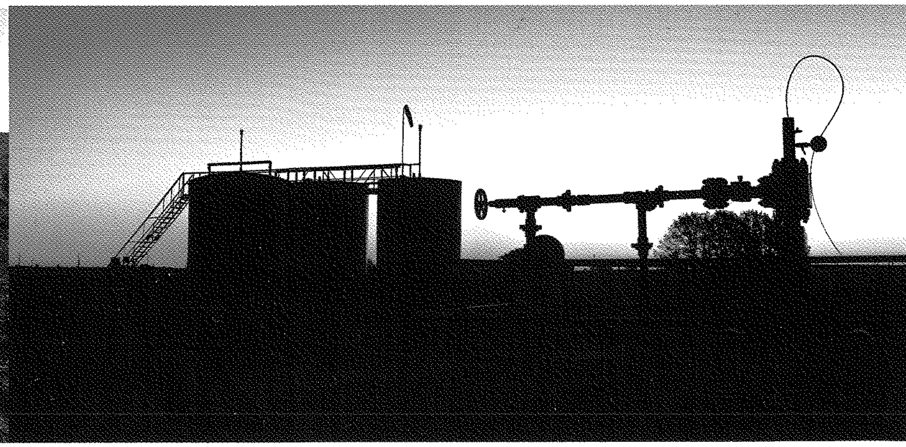
DECEMBER 2008	
GROSS ACREAGE POSITION	124,000
NET ACREAGE POSITION	108,000
FULLY DEVELOPED PROJECT INVENTORY (LOCATIONS)*	465
NET UNRISKED POTENTIAL (BCFE)*	448

DEEP BASIN

The Deep Basin contains numerous multiple-zone pay completion opportunities. Wild River and Sundance/Ansell share similar geologic pay horizons, allowing Forest to benefit from its successful four and a half year drilling program that has seen the Deep Basin net production increase from 9 MMcfe/d to 44 MMcfe/d. The play was expanded in 2008 through the finalization of a field study that supported an increase in the drilling density in Wild River to six wells per section from four. Forest has received regulatory approval that would allow down-spacing to six wells per section in a part of Wild River. Furthermore, Forest began horizontal drilling in the field, targeting low permeable zones in the basin that, based on encouraging results, will be expanded in 2009. Sundance/Ansell wells, like Wild River, are completed with multi-layer fracture stimulated completions that made the Wild River Field so successful. The Company expects it to follow Wild River in many respects, including production growth. With over 250 potential wells to drill in the Deep Basin, not including proved undeveloped locations, Forest has plenty of opportunity to expand the play, while further exploiting uphole potential through recompletion opportunities.

DECEMBER 2008	
GROSS ACREAGE POSITION	73,000
NET ACREAGE POSITION	33,000
FULLY DEVELOPED PROJECT INVENTORY (LOCATIONS)*	259
NET UNRISKED POTENTIAL (BCFE)*	240

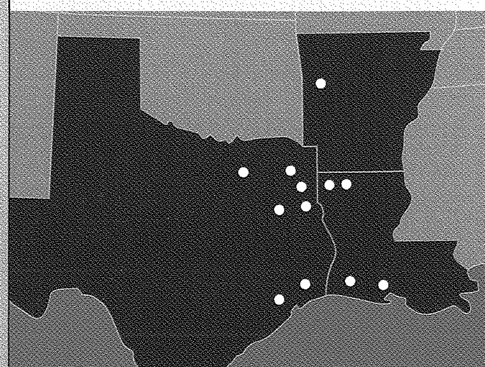
* Does not include estimated proved reserves or locations associated with estimated proved reserves



Operational Fact Sheet

Eastern

	2008	2007	2006
NET PRODUCTION			
Gas (MMcf/d)	103.4	66.0	36.2
Liquids (MBbls/d)	5.4	4.1	3.0
ESTIMATED PROVED RESERVES			
Gas (Bcf)	727.5	470.7	232.4
Liquids (MMBbls)	24.8	21.6	17.6
Equivalent (Bcfe)	876.1	600.3	338.1
DEVELOPED ACREAGE			
Gross	271,061	172,633	184,475
Net	187,641	113,557	102,385
UNDEVELOPED ACREAGE			
Gross	205,949	282,298	252,482
Net	120,132	139,101	124,252
GROSS WELL COUNT			
Gas	1,421	898	441
Oil	398	350	345
CAPITAL EXPENDITURES In thousands			
	$489,384	$375,581	$412,803



2008 HIGHLIGHTS

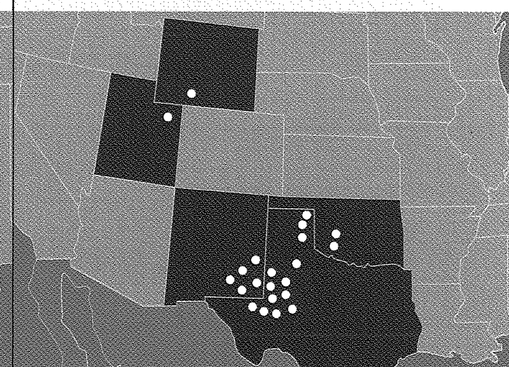
- Increased reserves 46% to 876 Bcfe at an all-in reserve replacement ratio of 556%
- Increased net sales volumes 51% to 136 MMcfe/d in 2008 from 90 MMcfe/d in 2007
- Record net production of 86 MMcfe/d in the East Texas/North Louisiana Area in the fourth quarter of 2008
- 98% success rate in the East Texas/North Louisiana Area with initial production rates as high as 9.9 MMcfe/d through the utilization of horizontal drilling on large undeveloped acreage blocks
- Completed 14 vertical Haynesville/Bossier Shale wells in the East Texas/North Louisiana Area
- Added 47,000 acres in the East Texas/North Louisiana Area increasing total gross acreage to 210,000 acres
- Net production of 49 MMcfe/d in the conventional Arkoma Basin in the fourth quarter of 2008 achieved through horizontal drilling

FUTURE STRATEGY

- 2009 drilling program for the Eastern Business Unit calls for approximately 73 wells and a continued high pace of additional projects
- Plan to drill approximately 67 wells in 2009 in the East Texas/North Louisiana Area and the Arkoma Basin with a total of 4,323 non-proved future locations identified
- Move to horizontal applications to exploit the Haynesville/Bossier Shale in the East Texas/North Louisiana Area
- Continue to leverage on the Lantern Drilling rigs as a tool to keep costs in check

Western

	2008	2007	2006
NET PRODUCTION			
Gas (MMcf/d)	91.3	77.4	71.0
Liquids (MBbls/d)	11.3	10.7	10.2
ESTIMATED PROVED RESERVES			
Gas (Bcf)	575.0	408.7	339.0
Liquids (MMBbls)	68.9	59.9	60.9
Equivalent (Bcfe)	988.2	767.9	704.1
DEVELOPED ACREAGE			
Gross	384,511	353,754	262,461
Net	230,680	217,814	154,267
UNDEVELOPED ACREAGE			
Gross	416,240	1,128,547	207,190
Net	272,101	789,494	103,820
GROSS WELL COUNT			
Gas	943	3,663	3,091
Oil	1,945	2,251	2,674
CAPITAL EXPENDITURES In thousands			
	$375,581	$278,701	$299,398



2008 HIGHLIGHTS

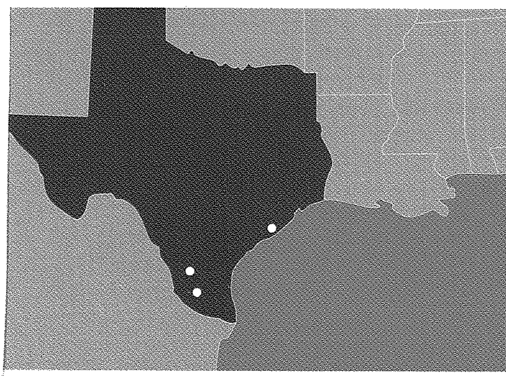
- Increased reserves 29% to 988 Bcfe at an all-in reserve replacement ratio of 378%
- Increased net sales volumes 13% to 159 MMcfe/d in 2008 from 141 MMcfe/d in 2007
- Record net production of 87 MMcfe/d in the Greater Buffalo Wallow Area in the fourth quarter of 2008
- 100% success rate in the Greater Buffalo Wallow Area with initial production rates as high as 10 MMcfe/d due to continued improvement of slick-water fracture technology and deeper pay completions
- Added 71,000 acres in the Greater Buffalo Wallow Area increasing total gross acreage to 120,000 acres
- Divested non-core assets in the Rockies to concentrate portfolio
- Utilized Lantern Drilling rigs

FUTURE STRATEGY

- 2009 drilling program for the Western Business Unit calls for approximately 22 wells and a continued high pace of additional projects
- Plan to drill approximately 21 wells in 2009 in the Greater Buffalo Wallow Area with a total of 2,514 non-proved future locations identified
- Continue to leverage on the Lantern Drilling rigs as a tool to keep costs in check

Southern

	2008	2007	2006
NET PRODUCTION			
Gas (MMcf/d)	128.0	80.3	N/A
Liquids (MBbls/d)	2.2	1.6	N/A
ESTIMATED PROVED RESERVES			
Gas (Bcf)	417.1	408.5	N/A
Liquids (MMBbls)	6.7	5.7	N/A
Equivalent (Bcfe)	457.0	442.6	N/A
DEVELOPED ACREAGE			
Gross	175,091	192,752	N/A
Net	127,572	135,852	N/A
UNDEVELOPED ACREAGE			
Gross	54,943	73,843	N/A
Net	40,090	34,208	N/A
GROSS WELL COUNT			
Gas	1,268	1,429	N/A
Oil	36	23	N/A
CAPITAL EXPENDITURES In thousands			
	$281,836	$103,614	N/A



2008 HIGHLIGHTS

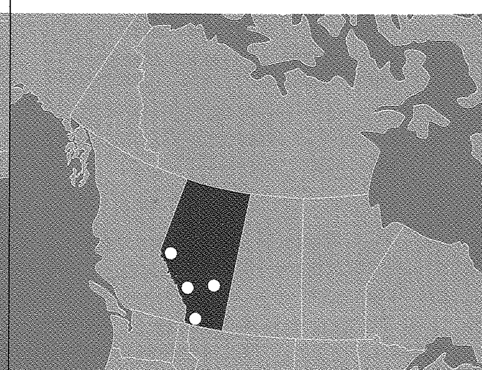
- Increased reserves 3% to 457 Bcfe at an all-in reserve replacement ratio of 27%
- Increased net sales volumes 57% to 141 MMcfe/d in 2008 from 90 MMcfe/d in 2007
- Net production of 130 MMcfe/d in South Texas in the fourth quarter of 2008
- 89% success rate in South Texas with initial production rates as high as 8 MMcfe/d
- Added acreage in South Texas increasing total gross acreage to 124,000 gross acres

FUTURE STRATEGY

- 2009 drilling program for the Southern Business Unit calls for 22 wells and a continued high pace of additional projects
- Plan to drill approximately 17 wells in 2009 in South Texas with a total of 465 non-proved future locations identified
- Exploratory drilling is planned in areas near Charco for deeper objectives utilizing 3-D seismic
- Continue to leverage on the Lantern Drilling rigs as a tool to keep costs in check

Canada

	2008	2007	2006
NET PRODUCTION			
Gas (MMcf/d)	63.7	68.7	66.7
Liquids (MBbls/d)	3.0	2.9	3.1
ESTIMATED PROVED RESERVES			
Gas (Bcf)	237.5	208.2	197.9
Liquids (MMBbls)	8.8	7.3	5.7
Equivalent (Bcfe)	290.5	252.1	232.1
DEVELOPED ACREAGE			
Gross	297,238	286,016	267,157
Net	161,687	157,737	151,645
UNDEVELOPED ACREAGE			
Gross	822,662	852,704	1,082,504
Net	344,504	375,398	581,746
GROSS WELL COUNT			
Gas	668	626	572
Oil	356	341	329
CAPITAL EXPENDITURES In thousands			
	$200,884	$173,212	$150,955



2008 HIGHLIGHTS

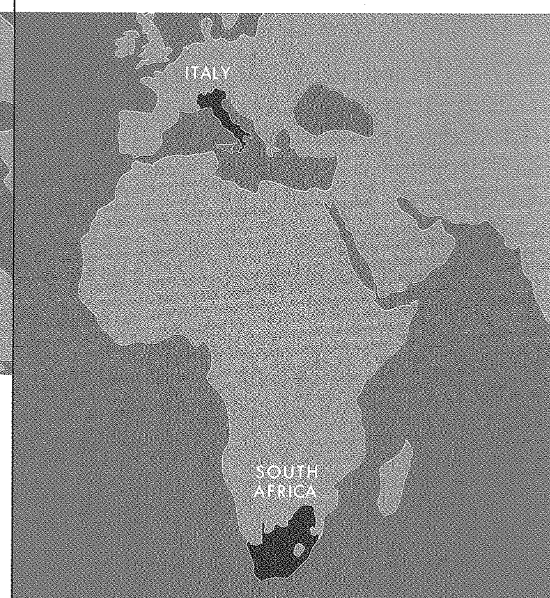
- Increased reserves 15% to 291 Bcfe at an all-in reserve replacement ratio of 130%
- Net sales volumes of 82 MMcfe/d in 2008
- Net production of 44 MMcfe/d in the Deep Basin in the fourth quarter of 2008
- 100% success rate in the Deep Basin with initial production rates as high as 7.2 MMcfe/d through the utilization of slick-water fracture technology
- 73,000 gross acres in the Deep Basin
- Drilled three horizontal wells in Quebec in the St. Lawrence Lowlands proving the ability to successfully drill the wells horizontally and pump multi-stage slick-water fracture jobs without major operational issues

FUTURE STRATEGY

- 2009 drilling program for the Canada Business Unit calls for 10 wells and an active recompletion program
- Test recompletion opportunities uphole in the Wild River Field in the Falher, Viking, Notikewin, Dunvegan and Cardium formations
- Additional drilling in Narraway targeting the Nikanassin
- Continue to test the completed wells in Quebec

International

	2008	2007	2006
NET PRODUCTION			
Gas (MMcf/d)	–	–	–
Liquids (MBbls/d)	–	–	–
ESTIMATED PROVED RESERVES			
Gas (Bcf)	56.3	56.3	–
Liquids (MMBbls)	–	–	–
Equivalent (Bcfe)	56.3	56.3	–
DEVELOPED ACREAGE			
Gross	2,500	2,500	–
Net	2,250	2,250	–
UNDEVELOPED ACREAGE			
Gross	3,060,238	5,469,514	5,835,867
Net	1,762,453	2,967,091	3,333,194
GROSS WELL COUNT			
Gas	2	2	–
Oil	–	–	–
CAPITAL EXPENDITURES In thousands			
	$6,949	$15,853	$6,984



2008 HIGHLIGHTS

- Successfully divested Gabon assets for $20 million with no associated reserves or production
- Prepared formal production license application in Italy to commence production from Forest's Monte Pallano property that tested at a combined 22 MMcfe/d rate without fracture stimulation

FUTURE STRATEGY

- Continue progress towards achieving production licenses in Forest's concessions in Italy
- Continue progress in securing Ibhubesi Production Right and associated gas contracts in South Africa

Executive Officers

H. CRAIG CLARK, 52
President and
Chief Executive Officer
Years of Service: 8

DAVID H. KEYTE, 52
Executive Vice President
and Chief Financial Officer
Years of Service: 21

J.C. RIDENS, 53
Executive Vice President
and Chief Operating Officer
Years of Service: 5

CECIL N. COLWELL, 58
Senior Vice President,
Worldwide Drilling
Years of Service: 20

LEONARD C. GURULE, 52
Senior Vice President
Years of Service: 6

CYRUS D. MARTER IV, 45
Senior Vice President,
General Counsel and Secretary
Years of Service: 7

GLEN J. MIZENKO, 46
Senior Vice President, Business
Development and Engineering
Years of Service: 8

MARK E. BUSH, 49
Vice President, Eastern Region
Years of Service: 11

STEPHEN T. HARPHAM, 47
Vice President, Western Region
Years of Service: 7

RONALD C. NUTT, 51
Vice President, Southern Region
Years of Service: 2

VICTOR A. WIND, 35
Corporate Controller
Years of Service: 4

Board of Directors

WILLIAM L. BRITTON, age 74, has been a director since 1996. Mr. Britton has served as Chairman Emeritus of the law firm of Bennett Jones LLP since 2005. He served as a partner of Bennett Jones LLP from 1962 until December 2004, and was Managing Partner and Chairman from 1981 to 1997. Mr. Britton serves as Chairman of Hanzell Vineyards, Ltd. and Geary-Market Investment Company of California. He is a director of ATCO Ltd., Akita Drilling Ltd., Barking Power Limited, and The Denver Broncos Football Club. Mr. Britton is a member of our Nominating and Corporate Governance Committee.

LOREN K. CARROLL, age 65, has been a director since November 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 returned in October 1992. Mr. Carroll is a director of Smith International, Inc., Fleetwood Enterprises, Inc., a producer of recreational vehicles and manufactured homes, CGG-Veritas, a geophysical services and equipment company, and KBR, Inc., an engineering and construction company. Mr. Carroll is a member of our Compensation Committee and is the Chairman of the Nominating and Corporate Governance Committee.

H. CRAIG CLARK, age 52, has served as our President and Chief Executive Officer, and 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.

DOD A. FRASER, age 58, has been a director since 2000. Mr. Fraser is President of Sackett Partners Incorporated, a consulting company, and 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 is a board member of Smith International, Inc., an oilfield service company, and Terra Industries, Inc., a nitrogen-based fertilizer company. Mr. Fraser serves as Chairman of our Audit Committee and is a member of our Nominating and Corporate Governance Committee.

JAMES H. LEE, age 60, 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 firm, since 1984. Mr. Lee is a director of Frontier Oil Corporation, a crude oil refining and wholesale marketing company. He is a member of our Audit Committee and our Executive Committee.

JAMES. D. LIGHTNER, age 56, became a director in 2004 and has served as our non-executive Chairman of the Board since May 2008. Mr. Lightner has been a Partner and Chief Executive Officer of Orion Energy Partners, an oil and gas exploration and production company, since its inception in August 2004. 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. Mr. Lightner had been a director since November 2004 of W-H. Energy Services Inc., an oil field services company, until its sale to Smith International in July 2008. Mr. Lightner has been a director of Cornerstone E&P Company LP, a private oil and gas exploration and production company since August 2006. Mr. Lightner serves as Chairman of our Executive Committee and is a member of our Compensation Committee.

PATRICK R. MCDONALD, age 51, became a director in 2004. Mr. McDonald has served as Chief Executive Officer, President and Director of Nytis Exploration Company, an oil and gas exploration company, since April 2003. 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. Prior to 1988, he served as Chairman, Chief Executive Officer, and President of Interenergy Corporation, a natural gas gathering, processing, and marketing company. Mr. McDonald is a member of our Audit Committee and serves as Chairman of the Compensation Committee.

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, 2008

or

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

Received SEC
MAR 2 0 2009
Washington, DC 20549

For the transition period from to

Commission File Number: 1-13515

FOREST OIL CORPORATION

(Exact Name of Registrant as Specified in Its Charter)

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

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

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

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

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

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

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 definition 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 by Rule 12b-2 of the Exchange Act). Yes ☐ No ☒

The aggregate market value of the voting stock held by non-affiliates of the registrant as of June 30, 2008, the last business day of the registrant's most recently completed second fiscal quarter, was $6,631,228,312 (based on the closing price of such stock on the New York Stock Exchange Composite Tape).

There were 97,034,743 shares of the registrant's common stock, par value $.10 per share, outstanding as of February 20, 2009.

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, 2008 are incorporated by reference into Part III of this Form 10-K.

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PART I

Item 1. Business.

General

Forest Oil Corporation ("Forest") is an independent oil and gas company engaged in the acquisition, exploration, development, and production of natural gas and 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. Throughout this Form 10-K we use the terms "Forest," "Company," "we," "our," and "us" to refer to Forest Oil Corporation and its subsidiaries.

We currently conduct our operations in three geographical segments and five business units. The geographical segments are: the United States, Canada, and International. The business units are: Western, Eastern, Southern, Canada, and International. We conduct exploration and development activities in each of our geographical segments; however, substantially all of our estimated proved reserves and all of our producing properties are located in North America. Forest's total estimated proved reserves as of December 31, 2008 were approximately 2,668 Bcfe. At December 31, 2008, approximately 87% of our estimated proved oil and gas reserves were in the United States, approximately 11% were in Canada, and approximately 2% were in Italy. See Note 15 to the Consolidated Financial Statements for additional segment information.

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 and Section 21E of the Securities Exchange Act of 1934. See "Forward-Looking Statements," below, for more details. We also use a number of terms used in the oil and gas industry. See the heading "Glossary of Oil and Gas Terms," below, for the definition of certain terms.

Strategy

Over the last several years, we have implemented a strategy directed at transforming Forest from a predominantly Gulf of Mexico oil and gas producer with international frontier exploration emphasis to a North American onshore development company with numerous lower risk opportunities for production and reserve growth. As part of this transformation, we have made several key acquisitions of properties in our core operational areas while divesting certain non-core assets, including our offshore Gulf of Mexico properties in 2006 and our Alaska properties in 2007. Since the beginning of 2004, we have acquired oil and gas assets that included approximately 1,682 Bcfe of estimated proved reserves. In general, our acquisition program has focused on acquisitions of properties that have substantial development drilling opportunities and undeveloped acreage. Our drilling and recompletion activities have added 1,282 Bcfe of estimated proved reserves over the last five years, and our inventory of future drilling locations is at an all time high as of December 31, 2008. Since 2004, we have also divested non-core oil and gas properties with estimated proved reserves of 705 Bcfe. The following table sets forth changes in our estimated proved reserves over the last five years.

	Estimated Proved Reserves
	(Bcfe)
Beginning balance, January 1, 2004	1,296
Purchases of proved reserves	1,682
Extensions and discoveries	1,282
Sales of proved reserves	(705)
Production	(804)
Revisions of previous estimates	(83)
Ending balance, December 31, 2008	2,668

Due to the recent downturn in the global economy as well as the dramatic decrease in oil and natural gas prices, we have chosen to significantly reduce our capital expenditures and drilling activity in 2009. Our goal in 2009 will be to keep our exploration and development capital expenditures within our cash flow from operations, while maintaining our estimated proved reserve base and production, protecting against lease expirations and non-consent penalties, and continuing to focus on cost control. We plan to devote over one-third of our capital spending in 2009 to horizontal drilling in the Ark-La-Tex and Greater Buffalo Wallow core areas (see discussion of our core areas in "Business Unit Activities" below). We expect this horizontal drilling to generate rates of return acceptable to us in the current price and cost environment. We also plan to rely almost exclusively on our drilling subsidiary, Lantern Drilling Company ("Lantern"), to drill our wells rather than employing third-party drilling rigs whenever possible.

We have a divestiture program with an announced intention to sell $450 million to $750 million of oil and gas assets outside our core areas. Due to the current economic conditions, this program has been delayed. We hope to complete these divestitures by the end of 2010, assuming market conditions and property valuations improve, but cannot predict whether we will be able to complete any asset divestitures. If divestitures are completed, we intend to use the proceeds to reduce debt.

By keeping our 2009 capital spending within our cash flow from operations, we hope to maintain financial flexibility and sufficient liquidity to maintain our assets and operations until margins on oil and gas production improve. In order to preserve significant borrowing capacity and flexibility under our bank credit facilities, we recently issued $600 million in senior notes due 2014 and used the net proceeds to pay down borrowings on the facilities. See "Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Bank Credit Facilities," for a discussion of our bank credit facilities.

Acquisition and Divestiture Activities

We pursue acquisitions that meet our criteria for investment returns and that are consistent with our low-risk development focus, and 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 prowess, technical expertise, and existing land and infrastructure positions.

In September 2008, we acquired producing oil and natural gas properties located in our Greater Buffalo Wallow and Ark-La-Tex core areas from Cordillera Texas, L.P. We paid to the seller approximately $570 million in cash, subject to customary post-closing adjustments to reflect an economic effective date of July 1, 2008, and issued 7.25 million shares of Forest's common stock, valued at approximately $360 million (based on a September 30, 2008 closing price), for the acquired assets. As of the closing date of the acquisition, the assets included approximately 350 Bcfe of estimated proved reserves and 118,000 gross acres (85,000 net acres).

In May 2008, we acquired producing oil and natural gas properties located primarily in our core Ark-La-Tex region in East Texas and North Louisiana. We paid approximately $284 million for the assets, as adjusted to reflect an economic effective date of April 1, 2008. As of the closing date of the acquisition, the assets included approximately 110 Bcfe of estimated proved reserves and 69,000 gross acres (47,000 net acres).

In June 2007, we acquired The Houston Exploration Company ("Houston Exploration") in a cash and stock transaction totaling approximately $1.5 billion and the assumption of Houston Exploration's debt. Houston Exploration was an independent natural gas and oil producer engaged in the exploration, development, exploitation, 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 common shares, valued at $30.28 per share.

In August 2007, we sold all of our assets located in Alaska (the "Alaska Assets") to Pacific Energy Resources Ltd. ("PERL"). Forest estimated the proved reserves associated with the Alaska Assets at closing to be 173 Bcfe. The total consideration received for the Alaska Assets included $400 million in cash, 10 million shares of PERL common stock, and a zero coupon senior subordinated note from PERL due 2014 in the principal amount at stated maturity of $60.8 million.

In March 2006, we acquired oil and natural gas properties located primarily in the Cotton Valley trend in East Texas for approximately $255 million in cash, as adjusted to reflect an economic effective date of February 1, 2006. As of the closing date of the acquisition, the assets included approximately 110 Bcfe of estimated proved reserves and approximately 26,000 net acres.

Also in March 2006, we completed the spin-off of our offshore Gulf of Mexico operations by means of a special dividend, which consisted of a pro rata spin-off (the "Spin-off") of all outstanding shares of Forest Energy Resources, Inc. (hereinafter known as Mariner Energy Resources, Inc. or "MERI"), a total of approximately 50.6 million shares of common stock, to holders of record of Forest common stock as of the close of business on February 21, 2006. Immediately following the Spin-off, MERI was merged with a subsidiary of Mariner Energy, Inc. ("Mariner") (the "Mariner Merger"). 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.

Business Unit Activities

Western

The Western business unit's operations are located primarily in the Texas Panhandle and West Texas. Western's core area of focus is in the Greater Buffalo Wallow area located primarily in Hemphill, Roberts, and Wheeler Counties in the Texas Panhandle. Wells drilled in the Greater Buffalo Wallow area primarily target the Granite Wash, Atoka, and Morrow formations at depths between approximately 10,000 feet and 18,000 feet.

Eastern

The Eastern business unit's operations are located primarily in East Texas, Arkansas, and Louisiana. The business unit's core area of focus is the Ark-La-Tex region including the Cotton Valley/Haynesville trends in East Texas and North Louisiana and the Arkoma Basin in western Arkansas. Since focusing operations in East Texas in 2006, we primarily have targeted tight-gas sands in the Cotton Valley trend at depths ranging from 9,500 feet to 11,000 feet through both vertical and horizontal wells. Based on our success in 2008, we expect to expand the business unit's horizontal drilling activity beyond tight-gas sands. In February 2009, we announced the initial production rates from our first horizontal Haynesville Shale well and are planning to complete 12 to 15 horizontal tests in 2009 in the Haynesville Shale. Of the approximately 161,000 net acres we have leased in the Cotton Valley trend, approximately 127,000 net acres also include rights to the Haynesville formation. The Eastern business unit's operations in the Arkoma Basin provide for low-risk, low-cost repeatable drilling opportunities targeting the Bashum and Borum sands at depths ranging between 6,000 feet to 7,000 feet. We also initiated a horizontal drilling program in the Arkoma Basin in 2008 and, given its success, plan to drill between three and five horizontal wells there in 2009.

Southern

The Southern business unit's operations are located in South Texas and the upper Texas Gulf Coast. The business unit's core areas of focus include the Charco and Rincon fields acquired from Houston Exploration in 2007 as well as the Katy and McAllen Ranch fields, which are legacy Forest properties. The primary producing zones targeted in South Texas include the Wilcox and Vicksburg trends at depths ranging between 7,000 feet and 13,000 feet.

Canada

The Canada business unit's operations are located primarily in Alberta and its core area of focus is in the Deep Basin in central Alberta. Wells drilled in the Deep Basin target multi-zone Cretaceous reservoirs at depths of approximately 10,000 feet. The business unit has also accumulated nearly 340,000 gross acres in the Utica Shale play in the St. Lawrence Lowlands in Quebec. We drilled and completed three horizontal wells in the Utica Shale in 2008 and plan additional evaluation and testing in 2009. Our Quebec licenses have ten-year terms with various expiration dates, ranging from 2012 to 2019.

International

The International business unit's operations are located in Italy and South Africa. The International business unit sold all of its interests in Gabon during 2008 for approximately $24 million. In 2007, the International business unit drilled and completed two wells in Italy, which established estimated proved reserves of approximately 56 Bcfe as of December 31, 2008. We are in the process of procuring required permits in Italy to allow us to commence production after 2009.

Reserves

The following table shows our estimated quantities of proved reserves as of December 31, 2008 and 2007. Substantially all of our estimated proved reserves are currently located in North America.

See Note 17 to the Consolidated Financial Statements for additional information regarding estimated proved reserves.

	December 31,	
	2008	2007
Proved developed:		
Natural gas (MMcf)	1,260,078	1,092,075
Liquids (MBbls)	69,841	66,597
Total (MMcfe)	1,679,124	1,491,657
Proved undeveloped:		
Natural gas (MMcf)	753,328	460,301
Liquids (MBbls)	39,279	27,879
Total (MMcfe)	989,002	627,575
Total proved:		
Natural gas (MMcf)	2,013,406	1,552,376
Liquids (MBbls)	109,120	94,476
Total (MMcfe)	2,668,126	2,119,232

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 and gas that cannot be measured in an exact manner, and the accuracy of any reserve 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 and gas quantities ultimately recovered will vary from reserve estimates. See Part I, Item 1A—"Risk Factors," for a description of some of the risks and uncertainties associated with our business and reserves.

Forest annually files estimates of its oil and gas reserves with the U.S. Department of Energy ("DOE"). During 2008, we filed estimates of our oil and gas reserves as of December 31, 2007 with the DOE, which were consistent with the reserve data reported for the year ended December 31, 2007 in Note 17 to the Consolidated Financial Statements.

Independent Audit of Reserves

For financial reporting purposes, including this Form 10-K, Forest uses reserve estimates prepared by its internal staff of engineers. We engage independent reserve engineers to audit a substantial portion of our reserves. Our reserve audit procedures require the independent reserve engineers to prepare their own independent estimates of proved reserves for fields comprising at least 80% of the aggregate net present value of our year-end proved reserves, discounted at 10% per annum, for each country in which we own fields for which proved reserves have been recorded. The fields selected for audit comprise at least the top 80% of Forest's fields based on the discounted present value of such fields and a minimum of 80% of the value added during the year through discoveries, extensions, and acquisitions. Forest may also include fields that fall outside of the top 80% that represent material volumes of proved reserves, have experienced material revisions to prior estimates of proved reserve volumes or value, or have experienced changes as a result of new operational activity. The procedures prohibit exclusions of any fields, or any part of a field, that comprises part of the top 80%. The independent reserve engineers then compare their estimates to those prepared by Forest. The independent reserve audits prepared for Forest are not financial audits and are not performed in accordance with the established generally accepted financial audit procedures. Instead, a reserve audit is conducted based on reserve definition and cost and price parameters specified by the Securities and Exchange Commission ("SEC").

For the years ended December 31, 2008, 2007, and 2006, we engaged DeGolyer and MacNaughton, an independent petroleum engineering firm, to perform reserve audit services. For the year ended December 31, 2008, DeGolyer and MacNaughton independently audited estimates relating to properties constituting approximately 88% of our reserves, as of December 31, 2008, based on reserve values. When compared on a field-by-field basis, some of Forest's estimates of net proved reserves were greater and some were less than the estimates prepared by DeGolyer and MacNaughton. However, there was no material difference, in the aggregate, between Forest's internal estimates of total net proved reserves and the estimates prepared by DeGolyer and MacNaughton for the fields subject to the audit.

Drilling Activities

During 2008, we drilled a total of 714 gross wells, of which 85 were classified as exploration and 629 were classified as development. Our 2008 drilling program achieved a 97% success rate. The following table summarizes the number of wells drilled during 2008, 2007, and 2006, 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, 2008, we had 47 gross (33 net) wells in progress in the United States and 9 gross (7 net) wells in progress in Canada.

	Year Ended December 31,					
	2008		2007		2006	
	Gross	Net	Gross	Net	Gross	Net
Development wells, completed as:						
Gas wells	570	322	392	210	210	52
Oil wells	44	40	34	29	13	11
Non-productive[1]	15	11	17	14	1	1
Total	629	373	443	253	224	64
Exploratory wells, completed as:						
Gas wells	76	56	41	28	135	68
Oil wells	6	6	6	2	15	9
Non-productive[1]	3	2	5	3	8	5
Total	85	64	52	33	158	82

(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).

Productive Wells

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, 2008, Forest owned interests in 493 gross wells containing multiple completions. The following table summarizes our productive wells as of December 31, 2008, all of which are located in the United States, Canada, and Italy:

	United States				Canada				Italy				Total	
	Operated Wells		Non-operated Wells		Operated Wells		Non-operated Wells		Operated Wells		Non-operated Wells		Operated and Non-operated Wells	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Gas	2,923	2,571	709	182	398	313	270	78	2	2	—	—	4,302	3,146
Oil	2,010	1,849	369	95	259	234	97	21	—	—	—	—	2,735	2,199
Total	4,933	4,420	1,078	277	657	547	367	99	2	2	—	—	7,037	5,345

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, 2008 and 2007. A majority of our developed acreage in the United States and Canada is subject to mortgage liens securing our bank credit facilities. 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.

	December 31,							
	2008				2007			
	Developed Acreage		Undeveloped Acreage[1]		Developed Acreage		Undeveloped Acreage	
Location	Gross	Net	Gross	Net	Gross	Net	Gross	Net
United States:								
Western	384,511	230,680	416,240	272,101	353,754	217,814	1,128,547	789,494
Eastern	274,326	189,089	195,558	119,126	172,633	113,557	282,298	139,101
Southern	175,091	127,572	54,943	40,090	192,752	135,852	73,843	34,208
	833,928	547,341	666,741	431,317	719,139	467,223	1,484,688	962,803
Canada	297,238	161,687	822,662	344,504	286,016	157,737	852,704	375,398
International:								
South Africa	—	—	2,771,695	1,474,542	—	—	2,771,695	1,474,542
Italy	2,500	2,250	288,543	287,911	2,500	2,250	288,543	287,911
Gabon[2]	—	—	—	—	—	—	2,409,276	1,204,638
	2,500	2,250	3,060,238	1,762,453	2,500	2,250	5,469,514	2,967,091
Total	1,133,666	711,278	4,549,641	2,538,274	1,007,655	627,210	7,806,906	4,305,292

(1) The decrease in undeveloped acreage from 2007 to 2008 is a result of selling non-core oil and gas properties located primarily in the Western business unit.
(2) The Gabon assets were sold in August 2008.

At December 31, 2008, approximately 12%, 12%, and 19% of our net undeveloped acreage in the United States and Canada was held under leases that will expire in 2009, 2010, and 2011, respectively, if not extended by exploration or production activities. The South African national government implemented new legislation in 2004 that revised the regulations and process pursuant to which it grants petroleum exploration and production licenses. Under the new regulations, we have applied to the government to convert one existing prospecting sublease into an exploration right and have applied for a production right covering the geographic area of our other existing prospecting sublease. The government has not taken final action on these applications. Because the regulations implementing the new legislation are not final and the potential work obligations that could be imposed pursuant to any new rights, when and if they are granted, are still uncertain, we cannot predict whether these rights will meet our economic or operational requirements. If the rights do not meet our internal requirements, we may choose to relinquish these leases. See "Our international operations may be adversely affected by currency fluctuations and economic and political developments" in Part I, Item 1A—"Risk Factors", for further details.

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, 2008, 2007, and 2006.

	United States			Canada			Total Company		
	2008	2007	2006	2008	2007	2006	2008	2007	2006
Natural Gas:									
Sales price received (per Mcf)	$ 7.54	5.95	6.21	6.98	5.29	5.07	7.45	5.79	5.83
Effects of energy swaps and collars (per Mcf)[1]	—	—	(.37)	—	—	—	—	—	(.25)
Average sales price (per Mcf)[1]	$ 7.54	5.95	5.84	6.98	5.29	5.07	7.45	5.79	5.58
Natural gas sales volumes (MMcf)	118,120	82,963	48,674	23,313	25,079	24,350	141,433	108,042	73,024
Liquids:									
Oil and Condensate:									
Sales price received (per Bbl)	$ 96.85	67.91	62.18	86.68	58.05	50.89	95.07	66.44	60.79
Effects of energy swaps and collars (per Bbl)[1]	—	—	(4.94)	—	—	—	—	—	(4.34)
Average sales price (per Bbl)[1]	$ 96.85	67.91	57.24	86.68	58.05	50.89	95.07	66.44	56.45
Natural gas liquids:									
Average sales price (per Bbl)	$ 44.54	39.32	32.02	60.71	43.54	41.40	45.94	39.75	33.85
Total liquids:									
Average sales price (per Bbl)[1]	$ 73.06	58.02	51.22	79.61	54.40	47.55	73.96	57.54	50.70
Liquids sales volumes (MBbls)	6,929	6,885	6,887	1,102	1,060	1,139	8,031	7,945	8,026
Average sales price (per Mcfe)[1]	**$ 8.75**	**7.18**	**7.08**	**8.37**	**6.05**	**5.69**	**8.69**	**6.96**	**6.72**
Total sales volumes (MMcfe)	**159,694**	**124,273**	**89,996**	**29,925**	**31,439**	**31,184**	**189,619**	**155,712**	**121,180**
Production costs (per Mcfe):									
Lease operating expenses	$ .83	1.09	1.41	1.21	1.00	.91	.89	1.08	1.28
Production and property taxes	.49	.42	.40	.12	.11	.10	.43	.35	.32
Transportation and processing costs	.06	.08	.13	.32	.33	.32	.10	.13	.18
Total production costs (per Mcfe)	**$ 1.38**	**1.59**	**1.94**	**1.65**	**1.44**	**1.32**	**1.42**	**1.56**	**1.78**

(1) Includes the effects of hedging under cash flow hedge accounting in 2006. See Part II, Item 7—"Management's Discussion and Analysis of Financial Condition and Results of Operations," concerning our hedging activities and the effects of energy swaps and collars not accounted for under cash flow hedge accounting.

Marketing and Delivery Commitments

Our natural gas production is typically sold on a month-to-month basis in the spot market, priced in reference to published indices. Our oil production is typically sold under short-term contracts at prices based upon refinery postings 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 25, 2009.

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, acquire new producing properties, and acquire additional leases and prospects for future development and exploration. Factors that affect our ability to acquire properties include, among others, availability of desirable acquisition targets, staff and resources to identify and evaluate properties, available funds, and internal standards for minimum projected return on investment. 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. See Part I, Item 1A—*"Risk Factors—Competition within our industry is intense and may adversely affect our operations"* below.

Regulation

Our oil and gas operations are subject to various United States federal, state, and local laws and regulations and foreign laws and regulations.

United States

Various aspects of our oil and natural gas operations are subject to regulation by state and federal agencies. All of the jurisdictions in which we own or operate producing crude oil and natural gas properties have adopted laws regulating the exploration for and production of crude oil and natural gas, including laws requiring permits for the drilling of wells, imposing bonding requirements in order to drill or operate wells, and providing authority for regulation relating to the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, and the plugging and abandonment of wells. 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, the number of wells which may be drilled in an area, and the unitization or pooling of crude oil and natural gas properties. In addition, state conservation laws sometimes establish maximum rates of production from crude oil and natural gas wells, generally prohibit the venting or flaring of natural gas, and impose certain requirements regarding the ratability or fair apportionment of production from fields and individual wells.

Certain of our operations are conducted on federal land pursuant to oil and gas leases administered by the Bureau of Land Management ("BLM"). These leases contain relatively standardized terms and require compliance with detailed BLM regulations and orders (which are subject to change by the BLM). In addition to permits required from other agencies, lessees must obtain a permit from the BLM prior to the commencement of drilling and comply with regulations governing, among other things, engineering and construction specifications for production facilities, safety procedures, the valuation of production, and the removal of facilities. Under certain circumstances, the BLM or the Minerals Management Service, as applicable, 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.

In August 2005, Congress enacted the Energy Policy Act of 2005 ("EPAct 2005"). Among other matters, EPAct 2005 amends the Natural Gas Act ("NGA") to make it unlawful for "any entity," including otherwise non-jurisdictional producers such as Forest, to use any deceptive or manipulative device or contrivance in connection with the purchase or sale of natural gas or the purchase or sale of transportation services subject to regulation by the Federal Energy Regulatory Commission ("FERC"), in contravention of rules prescribed by the FERC. EPAct 2005 also gives the FERC authority to impose civil penalties for violations of the NGA up to $1,000,000 per day per violation. The new anti-manipulation rule does not apply to activities that relate only to intrastate or other non-jurisdictional sales or gathering, but does apply to activities of otherwise non-jurisdictional entities to the extent the activities are conducted "in connection with" gas sales, purchases or transportation subject to FERC jurisdiction. It therefore reflects a significant expansion of the FERC's enforcement authority. We do not anticipate we will be affected any differently than other producers of natural gas.

In December 2007, the FERC issued rules requiring that any market participant, including a producer such as Forest, that engages in physical sales for resale or purchases for resale of natural gas that equal or exceed 2.2 million MMBtus during a calendar year must annually report such sales or purchases to the FERC, beginning on May 1, 2009. These rules are intended to increase the transparency of the wholesale natural gas markets and to assist the FERC in monitoring such markets and in detecting market manipulation. On September 18, 2008 the FERC issued its order on rehearing, which largely approved the existing rules, except the FERC exempted from the reporting requirement certain types of purchases and sales, including purchases and sales of unprocessed gas and bundled sales of gas made pursuant to state regulated retail tariffs. Also, the FERC clarified that other end use purchases and sales are not exempt from the reporting requirements. The monitoring and reporting required by the new rules will likely increase our administrative costs. Forest does not anticipate it will be affected any differently than other producers of natural gas.

Additional proposals and proceedings that might affect the oil and gas industry are regularly considered by Congress, the states, the FERC, and the courts. We cannot predict when or whether any such proposals 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.

Canada

The oil and natural gas industry in Canada is subject to extensive controls and regulations imposed by various levels of government. Federal authorities do not regulate the price of oil and gas in export trade. Legislation exists, however, that regulates the quantities of oil and natural gas which may be removed from the provinces and exported from Canada in certain circumstances. Regulatory requirements also exist related to licensing for drilling of wells, the method and ability to produce wells, surface usage, transportation of production from wells, and conservation matters. We do not expect that any of these controls and regulations will affect Forest in a manner significantly different from other oil and natural gas companies of similar size with operations in Canada.

The provinces in which we operate have legislation and regulation which govern land tenure, royalties, production rates and taxes, environmental protection, and other matters under their respective jurisdictions. The royalty regime in the provinces in which we operate is a significant factor in the profitability of our production. Crown royalties are determined by government regulation and are typically calculated as a percentage of the value of production. The value of the production and the rate of royalties payable depend on prescribed reference prices, well productivity, geographical location, and the type or quality of the product produced. Any royalties payable on production from privately owned lands are determined by negotiations between Forest and the landowners.

The majority of our Canadian operations are located in the Province of Alberta. The Alberta Government implemented a new oil and gas royalty framework effective January 2009. The new framework establishes new royalties for conventional oil, natural gas and bitumen that are linked to price and production levels and apply to both new and existing conventional oil and gas activities and oil sands projects. Under the new framework, the formula for conventional oil and natural gas royalties uses a sliding rate formula, dependant on the market price and production volumes, and well depths in the case of gas wells. Royalty rates for conventional oil range from 0% to 50%. Natural gas royalty rates range from 5% to 50%. In comparison, under the prior royalty regime, royalty rates ranged from 10% to 35% for conventional oil and from 5% to 35% for natural gas.

In November 2008, the Alberta Government announced that companies drilling new natural gas and conventional oil wells at depths between 1,000 meters and 3,500 meters (or 3,281 feet and 11,483 feet), which are drilled between November 19, 2008 and December 31, 2013, will have a one-time option of selecting new transitional royalty rates or the new royalty framework rates. The transition option provides lower royalties in the initial years of a well's life. For example, under the transition option, royalty rates for natural gas wells will range from 5% to 30%. However, if we elect to apply the transitional royalty rates, the well will not qualify for either of the two new royalty programs for deeper wells that also went into effect in January 2009 (see the "DOEP" and "NGDDP" discussion below). The election must be made before the well is drilled. Re-entry wells that are given a new drill date are also eligible for the transition option. All wells using the transitional royalty rates must shift to the new royalty framework rates on January 1, 2014.

Our drilling programs in Alberta have included, and in the future may include, deeper wells. On January 1, 2009, two new royalty programs impacting deep drilling activities went into effect, including the Deep Oil Exploration Program ("DOEP") and the Natural Gas Deep Drilling Program ("NGDDP"). These programs provide upfront royalty adjustments to new wells. To qualify for such royalty adjustments under the DOEP, exploration wells must have a vertical depth greater than 2,000 meters (6,562 feet) with a Crown interest and must be drilled after January 1, 2009. Oil wells in this category qualify for a royalty exemption on either the first $1,000,000 of royalty or the first 12 months of production and the oil well royalty rate minimum will be 0% until the entire credit has been applied. The NGDDP applies to wells producing at a true vertical depth greater than 2,500 meters (8,202 feet). The NGDDP will have an escalating royalty credit in line with progressively deeper wells from $625 per meter ($191 per foot) to a maximum of $3,750 per meter ($1,143 per foot) and there are additional benefits for the deepest wells, and the gas well royalty rate will be 5% until the entire credit has been applied. Both the DOEP and the NGDDP are five year programs. Any wells drilled after December 31, 2013, or any wells that choose the transition option, will not qualify under either program. No royalty adjustments will be granted under either the DOEP or the NGDDP after December 31, 2018. The majority of our drilling activities and wells in Alberta will be subject to the new royalty framework or, at our election, the transitional rules. As a result, wells that we drill in the future may be subject to the new higher royalty rates, which may be partially offset by credits for deep wells, while our existing production base will be subject to lower royalty rates. Overall, we do not currently believe the new regime will have a significant impact on our financial results and operations.

Environmental Regulation

As an operator of oil and natural gas properties in the United States and Canada, we are subject to stringent federal, state, provincial, and local laws and regulations relating to environmental protection as well as controlling the manner in which various substances, including 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 capital or increased operating costs to comply with governmental standards, and even injunctions that limit or prohibit exploration and production activities or that constrain the disposal of substances generated by oilfield 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 closure or other actions of a remedial nature to prevent future contamination. We believe that it is reasonably likely that the trend in environmental legislation and regulation will continue toward stricter standards. See Part I, Item 1A—*"Risk Factors—Our oil and gas operations are subject to various environmental and other governmental laws and regulations that materially affect our operations"* below, for a discussion of greenhouse gas emission regulatory developments.

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, Canada, 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, 2008, we had 814 employees. None of our employees is currently represented by a union for collective bargaining purposes.

Geographical Data

Forest operates in one industry segment. For information relating to our geographical operating segments, see Note 15 to the Consolidated Financial Statements of this Form 10-K.

Offices

Our corporate office is located in leased space at 707 17th Street, Denver, Colorado 80202. We maintain offices in Houston, Texas and Calgary, Alberta, Canada, 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 facilities, 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 insure that production from our properties, if obtained, will be salable for the account of Forest.

Glossary of Oil and Gas Terms

The terms defined in this section are used throughout this 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)(2-4) 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. The number of acres which are allocated or 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 and produce oil or gas reserves not classified as proved, to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir, or to extend a known reservoir.

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.

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.

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.

NYMEX. New York Mercantile Exchange.

Productive wells. Producing wells and wells that are capable of production, including injection wells, salt water disposal wells, service wells, and wells that are shut-in.

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

Proved reserves. Estimated quantities of crude oil, natural gas, and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known oil and gas reservoirs under existing economic and operating 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 ad valorem taxes, future capital costs, and operating expenses, but before deducting any estimates of U.S. federal income taxes. The estimated future net revenues are discounted at an annual rate of 10%, in accordance with the SEC's practice, to determine their "present value." The present value is shown to indicate the effect of time on the value of the revenue stream and should not be construed as being the fair market value of the properties. Estimates of future net revenues are made using oil and natural gas prices and operating costs at the estimation date and held constant for the life of the reserves.

Tcfe. Trillion cubic feet equivalent, determined using the ratio of six Mcf of natural gas to one bbl of crude oil, condensate, or natural gas liquids.

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

In June 2008, we submitted to the NYSE the certification of the Chief Executive Officer of Forest required by Section 303A.12 of the NYSE Listed Company Manual, relating to Forest's compliance with the NYSE's corporate governance listing standards with no qualifications. Also, we have included the certifications of the Principal Executive Officer and Principal Financial Officer of Forest required by Section 302 of the Sarbanes-Oxley Act of 2002 and related rules, relating to the quality of Forest's public disclosure, in this Form 10-K as Exhibits 31.1 and 31.2.

Forward-Looking Statements

The information in this Form 10-K includes "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. Forward-looking statements are statements other than statements of historical facts 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," variations of such words, and similar expressions identify forward-looking statements. These forward-looking statements are based on our current expectations and assumptions about future events and are based on currently available information as to the outcome and timing of future events.

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;
- estimates of future capital expenditures;
- 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 gas prices;
- the amount, nature, and timing of the completion of any planned asset-monetization transactions;
- the amount, nature, and timing of future capital expenditures, including future development costs;
- our outlook on the current financial crisis and our ability to access the capital markets to fund capital and other expenditures;
- our assessment of our counterparty risks and the ability of our counterparties to perform their future obligations;
- our estimates as to the amount, nature, and timing of any synergies and other benefits expected to result from acquisitions; 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 and forecasts 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 can be affected by inaccurate assumptions and 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. When considering forward-looking statements, you should keep in mind the risk factors and other cautionary statements described under the heading "Risk Factors" included in this Form 10-K. These risks include, but are not limited to, the following:

- the volatility of oil and natural gas prices;
- the availability of capital on economic terms to fund our significant capital expenditures and acquisitions;
- our level of our indebtedness;
- our ability to replace and sustain production;
- the impact of the current financial crisis on our business operations, financial condition, and ability to raise capital;
- the ability of financial counterparties to perform or fulfill their obligations under existing agreements;
- a lack of available drilling and production equipment, and related services and labor;
- unsuccessful exploration and development drilling activities;
- regulatory and environmental risks associated with drilling and production activities;
- declines in the value of our oil and natural gas properties resulting in a decrease in our borrowing base under our bank credit facilities and ceiling test write-downs;
- the adverse effects of changes in applicable tax, environmental and other regulatory legislation;
- a deterioration in the demand for our products;
- the risks and uncertainties inherent in estimating proved oil and natural gas reserves and in projecting future rates of production and the timing of expenditures;

- the risks of conducting exploratory drilling operations in new or emerging plays;
- intense competition with companies with more capital and larger staffs; and
- the risks of conducting operations outside of the United States and impact of fluctuations in currency exchange rates and political developments on the financial results of our operations.

Should one or more of the risks or uncertainties described above or elsewhere in this Form 10-K occur, or should underlying assumptions prove incorrect, our actual results and plans could differ materially from those expressed in any 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 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. Recent declines in commodity prices have adversely affected, and in the future will adversely affect, our financial condition and results of operations, cash flows, access to the capital markets, and ability to grow.

Our financial condition, operating results, and future rate of growth depend upon the prices that we receive for our oil and natural gas. Prices also affect our cash flow available for capital expenditures and our ability to access funds under our bank credit facilities and through the capital markets. The amount available for borrowing under our bank credit facilities is subject to a global borrowing base, which is determined by our lenders taking into account our estimated proved reserves and is subject to periodic redeterminations based on pricing models determined by the lenders at such time. The recent decline in oil and natural gas prices has adversely impacted the value of our estimated proved reserves and, in turn, the market values used by our lenders to determine our global borrowing base. If commodity prices continue to decline in 2009, it will have similar adverse effects on our reserves and global borrowing base. Further, because we have elected to use the full-cost accounting method, we must perform each quarter a "ceiling test" that is impacted by declining prices. Significant price declines could cause us to take one or more ceiling test write-downs, which would be reflected as non-cash charges against current earnings. For example, as a result of the dramatic declines in oil and natural gas prices in the second half of 2008, we recorded a non-cash ceiling test impairment of approximately $2.4 billion ($1.5 billion after-tax) for the three months and year ended December 31, 2008. The impairment resulted in a charge to net earnings and the recording of a net loss in 2008. See *"—Lower oil and gas prices and other factors have resulted, and in the future may result, in ceiling test write-downs and other impairments of our asset carrying values."*

In addition, significant or extended price declines may also adversely affect the amount of oil and natural gas that we can produce economically. A reduction in production could result in a shortfall in our expected cash flows and require us to reduce our capital spending or borrow funds to cover any such shortfall. Any of these factors could negatively impact our ability to replace our production and our future rate of growth.

The markets for oil and natural gas have been volatile historically and are likely to remain volatile in the future. Oil spot prices reached historical highs in July 2008, peaking at more than $145 per barrel, and natural gas spot prices reached near historical highs in July 2008, peaking at more than $13 per MMBtu. These prices have declined significantly since that time and may continue to fluctuate widely in the future. The prices we receive for our oil and natural gas depend upon factors beyond our control, including among others:

- domestic and global supplies, consumer demand for oil and natural gas, and market expectations regarding supply and demand;
- domestic and worldwide economic conditions;
- the impact of the U.S. dollar exchange rate on oil and natural gas prices;
- the proximity, capacity, cost, and availability of oil and natural gas pipelines, processing, gathering, and other transportation facilities;
- weather conditions;
- political instability and armed conflicts in oil-producing and gas-producing regions;
- actions by the Organization of Petroleum Exporting Countries directed at maintaining prices and production levels;
- the price and availability of imports of oil and natural gas;
- the impact of energy conservation efforts and the price and availability of alternative fuels; and
- domestic and foreign governmental regulations and taxes.

These factors make it very difficult to predict future commodity price movements with any certainty. We sell the majority of our oil and natural gas production at current prices rather than through fixed-price contracts. However, we do enter into derivative instruments to reduce our exposure to fluctuations in oil and natural gas prices. See "*—Our use of hedging transactions could result in financial losses or reduce our income.*" Further, oil prices and natural gas prices do not necessarily fluctuate in direct relation to each other. Approximately 75% of our estimated proved reserves at December 31, 2008 were natural gas, and, as a result, our financial results will be more sensitive to fluctuations in natural gas prices.

We require substantial capital expenditures to conduct our operations, engage in acquisition activities, and replace our production, and we may be unable to obtain needed financing on satisfactory terms necessary to execute our operating strategy.

We require substantial capital expenditures to conduct our exploration, development, and production operations, engage in acquisition activities, and replace our production. Historically, we have funded our capital expenditures through a combination of our cash flows from operations, our bank credit facilities, and debt and equity issuances. We also engage in asset sale transactions to fund capital expenditures when market conditions permit us to complete transactions on terms we find acceptable. In 2008, 2007, and 2006, we spent approximately $2.8 billion, $3.0 billion, and $943 million on capital expenditures, respectively, including approximately $1.4 billion, $2.2 billion, and $316 million on property acquisitions, respectively. Our exploration and development capital expenditures budget for 2009 is approximately $500 million to $600 million, which reflects our intention to finance our capital expenditures using cash flow from operations. Our lower level of planned capital expenditures in 2009, compared with 2008, reflects our expectations of lower future commodity prices and declining service costs in 2009. In addition, we may seek advances under our bank credit facilities to fund some of our 2009 capital and operating expenses depending on the timing of our cash flows and capital requirements. For any large acquisitions or other exceptional expenditures, we expect we would need to access the public or private capital markets or complete additional asset sales. If our revenues and cash flows decrease in the future as a result of a continuation of the decline in commodity prices, however, and we are unable to obtain additional debt or equity financing in the private or public capital markets or access alternative sources of funds in 2009, we may be required to reduce the level of our capital expenditures and may lack the capital necessary to replace our reserves or maintain our production at current levels.

Our future revenues, cash flows, and spending levels are subject to a number of factors, including commodity prices, the level of production from existing wells, and our success in developing and producing new wells. Further, our ability to access funds under our bank credit facilities is based on a global borrowing base, which is subject to periodic redeterminations based on our estimated proved reserves and prices that will be determined by our lenders using the prices prevailing at such time. If the prices for oil and natural gas decline, or if we have a downward revision in estimates of our proved reserves, the global borrowing base may be reduced. See Part II, Item 7—"Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Bank Credit Facilities" below, for more details.

Our ability to access the private and public debt and equity markets and complete future asset monetization transactions is also dependent upon oil and natural gas prices, in addition to a number of other factors, some of which are outside our control. These factors include, among others:

- the value and performance of our debt and equity securities;
- the credit ratings assigned to our debt by independent rating agencies;
- domestic and global economic conditions; and
- conditions in the domestic and global financial markets.

The continuing financial crisis may impact our business and financial condition. We may not be able to obtain funding in the capital markets on terms we find acceptable, or obtain funding under our current bank credit facilities because of the deterioration of the capital and credit markets and our global borrowing base.

The current credit crisis and related turmoil in the global financial systems have had an impact on our business and our financial condition, and we may face challenges if economic and financial market conditions do not improve. Historically, we have used our cash flow from operations and borrowings under our bank credit facilities to fund our capital expenditures and have relied on the capital markets and asset monetization transactions to provide us with additional capital for large or exceptional transactions or to refinance debt obligations. A continuation of the economic crisis could further reduce the demand for oil and natural gas and continue to put downward pressure on the prices for oil and natural gas, which have declined significantly since oil prices reached historic highs and natural gas prices reached near historic highs in July 2008. These price declines have negatively impacted our revenues and cash flows.

We currently have existing bank credit facilities with lender commitments totaling $1.8 billion and a global borrowing base set at $1.62 billion. The global borrowing base is determined by the lenders periodically and is based on the estimated value of our oil and gas properties using pricing models determined by the lenders at such time. Also, under the terms of our bank credit facilities, our global borrowing base will be immediately reduced by an amount equal to $0.30 for every $1.00 principal amount of senior notes issued in the future (excluding any senior notes that Forest may issue to refinance senior notes outstanding on May 9, 2008). For example, our borrowing base was recently lowered by $180 million to $1.62 billion as a result of a $600 million senior notes issuance on February 17, 2009. In the future, we may not be able to access adequate funding under our bank credit facilities as a result of (i) a decrease in our global borrowing base due to the outcome of a subsequent borrowing base redetermination, or (ii) an unwillingness or inability on the part of our lending counterparties to meet their funding obligations. The recent declines in commodity prices, or a continuing decline in these prices, could result in a determination to lower the global borrowing base in the future and, in such case, we could be required to repay any indebtedness in excess of the global borrowing base. The turmoil in the financial markets has adversely impacted the stability and solvency of a number of large global financial institutions.

Although we were recently able to issue $600 million in senior notes, the current credit crisis has made it more difficult to obtain funding in the public and private capital markets. In particular, the cost of raising money in the debt and equity capital markets has increased substantially while the availability of funds from those markets generally has diminished significantly. Also, as a result of concerns about the general stability of financial markets and the solvency of specific counterparties, the cost of obtaining money from the credit markets has increased as many lenders and institutional investors have increased interest rates, imposed tighter lending standards, refused to refinance existing debt at maturity on terms similar to existing debt or at all, and reduced or, in some cases, ceased to provide any new funding.

The credit crisis also has impacted the level of activity in the oil and gas property sales market. The lack of available credit and access to capital has limited and will likely continue to limit the parties interested in any proposed asset transactions and will likely reduce the values we could realize in those transactions. We were unable to complete all of our planned asset divestitures in the second half of 2008 due to the distressed market conditions, and we believe that it will be difficult to complete any asset monetization transactions in 2009 on economically attractive terms. While we hope to complete our planned asset divestitures by the end of 2010, there is no assurance that we will be able to complete these planned divestitures.

The distressed economic conditions also may adversely affect the collectibility of our trade receivables. For example, our accounts receivable, which totaled $157 million at December 31, 2008, are primarily from purchasers of our oil and natural gas production and other exploration and production companies which own working interests in the properties that we operate. This industry concentration could adversely impact our overall credit risk, because our customers and working interest owners may be similarly affected by changes in economic and financial market conditions, commodity prices, and other conditions. Further, the credit crisis and turmoil in the financial markets could cause our commodity derivative instruments to be ineffective in the event a counterparty were unable to perform its obligations or seek bankruptcy protection.

Due to these factors, we cannot be certain that funding, if needed, will be available to the extent required, or on acceptable terms. If we are unable to access funding when needed on acceptable terms, we may not be able to fully implement our business plans, complete new property acquisitions to replace our reserves, take advantage of business opportunities, respond to competitive pressures, or refinance our debt obligations as they come due, any of which could have a material adverse effect on our operations and financial results.

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

As of December 31, 2008, the principal amount of our outstanding consolidated debt was approximately $2.7 billion, which amount included approximately $1.3 billion outstanding under our combined U.S. and Canadian credit facilities. Our level of indebtedness has 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 pay principal and interest on the debt, which will reduce the amount available to fund working capital, capital expenditures, and other general corporate purposes;
- 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 due to changes in our debt level or our financial condition;
- 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;
- limit our flexibility in planning for and reacting to changes in our business as covenants and restrictions contained in our existing and possible future debt arrangements may require that we meet certain financial tests and place restrictions on the incurrence of additional indebtedness;
- place us at a disadvantage compared to similar companies in our industry that have less debt; and
- make us more vulnerable to economic downturns and adverse developments in our business.

We may incur more debt in the future. In February 2009, for example, we issued $600 million of 8½% senior notes due 2014. The net proceeds from this offering were used to repay a portion of the outstanding borrowings under our U.S. credit facility.

Our credit and debt agreements contain various restrictive covenants. A failure on our part to comply with the financial and other restrictive covenants contained in our bank credit facilities and the indentures pertaining to our outstanding senior notes could result in a default under these agreements. Any default under our bank credit facilities or indentures could adversely affect our business and our financial condition and results of operations, and would impact our ability to obtain financing in the future. In addition, the global borrowing base included in our bank credit facilities is subject to periodic redetermination by our lenders. A lowering of our global borrowing base could require us to repay indebtedness in excess of the borrowing base.

A higher level of debt will increase the risk that we may default on our financial obligations. Our ability to meet our debt obligations and other expenses will depend on our future performance. Our future performance will be affected by oil and natural gas prices, financial, business, domestic and global economic conditions, governmental regulations and environmental regulations, and other factors, many of which we are unable to control. If our cash flow is not sufficient to service our debt, we may be required to refinance the debt, sell assets, or sell shares of our stock on terms that we do not find attractive, if it can be done at all.

Our use of hedging transactions could result in financial losses or reduce our income.

To reduce our exposure to fluctuations in oil and natural gas prices, we have entered into and expect in the future to enter into derivative instruments (or hedging agreements) for a portion of our oil and natural gas production. Our commodity hedging agreements are limited in duration, usually for periods of two years or less; however, in conjunction with acquisitions, we sometimes enter into or acquire hedges for longer periods. As of February 25, 2009, we had hedged, via commodity swaps and collar instruments, approximately 83 Bcfe of our 2009 production and 40 Bcfe of our 2010 production. Our hedging transactions expose us to certain risks and financial losses, including, among others:

- the risk that we may be limited in receiving the full benefit of increases in oil and natural gas prices as a result of these transactions;
- the risk that we may hedge too much or too little production depending on how oil and natural gas prices fluctuate in the future;
- the risk that there is a change to the expected differential between the underlying price and the actual price received; and
- the risk that a counterparty to a hedging arrangement may default on its obligations to Forest.

Our hedging transactions will impact our earnings in various ways. Due to the volatility of oil and natural gas prices, we may be required to recognize mark-to-market gains and losses on derivative instruments as the estimated fair value of our commodity derivative instruments is subject to significant fluctuations from period to period. The amount of any actual gains or losses recognized will likely differ from our period to period estimates and will be a function of the actual price of the commodities on the settlement date of the derivative instrument. For example, for the first two quarterly periods in 2008, we reported unrealized losses on our commodity derivative instruments of $137 million and $329 million, respectively. In contrast, for the third and fourth quarters of 2008, we reported unrealized gains on our commodity derivative instruments of $498 million and $185 million, respectively. We expect that commodity prices will continue to fluctuate in the future and, as a result, our periodic financial results will continue to be subject to fluctuations related to our derivative instruments.

Currently, all of our outstanding commodity derivative instruments are with certain lenders or affiliates of the lenders under our bank credit facilities. As of February 25, 2009, our primary derivative counterparties included the following lenders and their affiliates: BMO Capital Markets Financing, Inc. ("BMO"), BNP Paribas, Barclays Bank PLC ("Barclays"), Credit Suisse, Deutsche Bank AG New York Branch ("Deutsche Bank"), Fortis Capital Corp. ("Fortis"), The Bank of Nova Scotia, Toronto Dominion (Texas) LLC and The Toronto-Dominion Bank (collectively, "Toronto Dominion"), and Wells Fargo Bank, N.A. ("Wells Fargo"). As of February 25, 2009, our derivative transactions with BMO, Credit Suisse, Fortis, The Bank of Nova Scotia, BNP Paribas and Toronto Dominion accounted for approximately 73 Bcfe, or 88% of our 2009 hedged production, and 32 Bcfe, or 82% of our 2010 hedged production. Our obligations under our existing derivative agreements with our lenders are secured by the security documents executed by the parties under our bank credit facilities.

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

We use the full cost method of accounting to report our oil and gas operations. Under this method, we capitalize the cost to acquire, explore for, and develop oil and gas properties. Under full cost accounting rules, the net capitalized costs of proved oil and gas properties may not exceed a "ceiling limit," which is based upon the present value of estimated future net cash flows from proved reserves, discounted at 10%. If net capitalized costs of proved oil and gas properties exceed the ceiling limit, we must charge the amount of the excess to earnings. This is called a "ceiling test write-down." Under the accounting rules, we are required to perform a ceiling test each quarter. A ceiling test write-down would not impact cash flow from operating activities, but it would reduce our shareholders' equity. See "Management's Discussion and Analysis of Financial Condition and Results of Operations—Critical Accounting Policies, Estimates, Judgments, and Assumptions—Full Cost Method of Accounting" below, for further details.

Investments in unproved properties, including capitalized interest costs, are also assessed periodically to ascertain whether impairment has occurred. Unproved properties whose costs are individually significant are assessed individually by considering the primary lease terms of the properties, the holding period of the properties, and geographic and geologic data obtained relating to the properties. The amount of impairment assessed, if any, is added to the costs to be amortized, or is reported as a period expense, as appropriate. If an impairment of unproved properties results in a reclassification to proved oil and gas properties, the amount by which the ceiling limit exceeds the capitalized costs of proved oil and gas properties would be reduced.

We also assess the carrying amount of goodwill in the second quarter of each year and at other periods when events occur that may indicate an impairment exists. These events include, for example, a significant decline in oil and gas prices or a decline in our market capitalization.

The risk that we will be required to write-down the carrying value of our oil and gas properties, our unproved properties, or goodwill increases when oil and gas prices are low or volatile. In addition, write-downs may occur if we experience substantial downward adjustments to our estimated proved reserves or our unproved property values, or if estimated future development costs increase. For example, oil and natural gas prices declined significantly during the second half of 2008. At December 31, 2008, the spot prices for oil and natural gas were $44.60 per barrel and $5.71 per MMBtu, respectively. Based on these prices, we recorded a non-cash ceiling test impairment of approximately $2.4 billion ($1.5 billion after-tax) for the three months and year ended December 31, 2008. The impairment is reflected as a charge to net earnings. Additional write-downs of the full cost pools in the United States and Canada may be required in 2009 if oil and natural gas prices stay at their current levels or decline further, unproved property values decrease, estimated proved reserve volumes are revised downward or costs incurred in exploration, development, or acquisition activities in the respective full cost pools exceed the discounted future net cash flows from the additional reserves, if any, attributable to each of the cost pools. Based on current prices, as of February 25, 2009, we believe it is likely we will record an additional ceiling test impairment in the first quarter of 2009.

Our proved reserves are estimates and depend on many assumptions. Any material inaccuracies in these assumptions could cause the quantity and value of our oil and gas reserves, and our revenue, profitability, and cash flow, to be materially different from our estimates.

The proved oil and gas reserve information and the related future net revenues information contained in this report represent only estimates, which are prepared by our internal staff of engineers. Estimating quantities of proved oil and natural gas reserves is a subjective, complex process and depends on a number of variable factors and assumptions. To prepare estimates of economically recoverable oil and natural gas reserves and future net cash flows:

- we analyze historical production from the area and compare it to production rates from other producing areas;
- we analyze available technical data, including geological, geophysical, production, and engineering data, and the extent, quality, and reliability of this data can vary; and
- we must make various economic assumptions, including assumptions about oil and natural gas prices, drilling, operating, and production costs, severance and excise taxes, capital expenditures, workover and remedial costs, and the availability of funds.

As a result, these estimates are inherently imprecise. Ultimately, actual production, revenues, taxes, expenses, and expenditures relating to our reserves will vary from our estimates. Any significant inaccuracies in our assumptions or changes in operating conditions could cause the estimated quantities and net present value of the reserves contained in this Form 10-K to be different from our estimates. In addition, we may adjust our estimates of proved reserves to reflect production history, actual results, prevailing commodity prices, and other factors, many of which are beyond our control.

Further, you should not assume that any present value of future net cash flows from our producing reserves contained in this Form 10-K represents the market value of our estimated oil and natural gas reserves. We base the estimated discounted future net cash flows from our proved reserves on oil and natural gas prices and costs as of the date of the estimate. Actual future prices and costs may be materially higher or lower. Actual future net revenues will be affected by factors such as the amount and timing of actual development expenditures, the rate and timing of production, and changes in governmental regulations and, or taxes. At December 31, 2008, approximately 37% of our estimated proved reserves (by volume) were undeveloped. Recovery of undeveloped reserves generally requires significant capital expenditures and successful drilling operations. Our reserve 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. In addition, the 10% discount factor that we use to calculate the net present value of future net revenues and cash flows may not necessarily be the most appropriate discount factor based on our cost of capital in effect from time to time and the risks associated with our business and the oil and gas industry in general.

Our failure to replace our reserves could result in a material decline in our reserves and production, which could adversely affect our financial condition.

In general, our proved reserves decline when oil and natural gas is produced, unless we are able to conduct successful exploitation, exploration, and development activities, or acquire additional properties containing proved reserves, or both. Our future performance, therefore, is highly dependent upon our ability to find, develop, and acquire additional oil and natural gas reserves that are economically recoverable. Exploring for, developing, or acquiring reserves is capital intensive and uncertain. We may not be able to economically find, develop, or acquire additional reserves, or may not be able to make the necessary capital investments if our cash flows from operations decline or external sources of capital become limited or unavailable. We cannot assure you that our future exploitation, exploration, development, and acquisition activities will result in additional proved reserves or that we will be able to drill productive wells at acceptable costs. Further, the current economic crisis has adversely impacted our ability to obtain financing to fund acquisitions and has lowered the level of activity and depressed values in the oil and natural gas property sales market. See *"—The continuing financial crisis may impact our business and financial condition. We may not be able to obtain funding in the capital markets on terms we find acceptable, or obtain funding under our current bank credit facilities because of the deterioration of the capital and credit markets and our global borrowing base,"* for a discussion of the impact of financial market conditions on our access to financing.

Drilling is a high-risk activity and may not result in commercially productive reserves.

We do not always encounter commercially productive reservoirs through our drilling operations. The seismic data and other technologies that we use when drilling wells do not allow us to conclusively determine prior to drilling a well whether oil or natural gas is present or can be produced economically. As a result, we may drill new wells or participate in new wells that are dry wells or are productive but not commercially productive and, as a result, we may not recover all or any portion of our investment in the wells we drill or in which we participate.

The costs and expenses of drilling, completing, and operating wells are often uncertain. The presence of unanticipated pressures or irregularities in formations, miscalculations, or accidents may cause our drilling costs to be significantly higher than expected or cause our drilling activities to be unsuccessful or result in the total loss of our investment. Also, our drilling operations may be shortened, delayed, or canceled as a result of a variety of factors, many of which are beyond our control, including, among others:

- unexpected drilling conditions;

- geological irregularities or pressure in formations;
- mechanical difficulties and equipment failures or accidents;
- increases in the costs of, or shortages or delays in the availability of, drilling rigs and related equipment;
- shortages in labor;
- adverse weather conditions;
- compliance with environmental and other governmental requirements;
- fires, explosions, blow-outs, or surface cratering; and
- restricted access to land necessary for drilling or laying pipelines.

We conduct our drilling activities through a wholly owned drilling subsidiary that 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 the factors described above, and the risks associated with conducting drilling activities. Among other things, these risks include the risk of natural gas leaks, oil spills, pipeline ruptures, and discharges of toxic gases, any of which could result in substantial losses, personal injuries or loss of life, severe damage to or destruction of property, natural resources, and equipment, extensive pollution or other environmental damage, clean-up responsibilities, regulatory investigations, and administrative, civil, and criminal penalties, and injunctions resulting in the suspension of our operations. If any of these risks occur, we could sustain substantial losses.

Competition within our industry is intense and may adversely affect our operations.

We operate in a highly competitive environment. We compete with major and independent oil and gas companies in acquiring desirable oil and gas properties and in obtaining the equipment and labor required to develop and operate such properties. We also compete with major and independent oil and gas companies in the marketing and sale of oil and natural gas. Many of these competitors are larger, including some of the fully integrated companies, have financial, staff, and other resources substantially greater than ours and, or are less leveraged than we are. As a result, these companies may have more access to capital and may be able to pay more for development prospects and producing properties, or evaluate and bid for a greater number of properties and prospects than our financial and staffing resources permit. Also, from time to time, we have to compete with financial investors in the property acquisition market, including private equity sponsors with more funds and access to additional liquidity. Factors that affect our ability to acquire properties include availability of desirable acquisition targets, staff and resources to identify and evaluate properties, available funds, and internal standards for minimum projected return on investment. Oil prices increased to historic levels and natural gas prices increased to near historic levels in 2008, before declining significantly. As commodity prices increased, so did the cost of equipment, service, and labor in the industry as well as the cost of properties available for acquisition. While commodity prices have dropped significantly, the costs of obtaining necessary equipment, services, and labor have not declined in a corresponding fashion, which impacts our cash flows and places us at a disadvantage with companies with greater cash flows and liquidity. In addition, oil and gas producers are increasingly facing competition from providers of non-fossil energy, and government policy may favor those competitors in the future. Many of these competitors have financial and other resources substantially greater than ours. We can give no assurance that we will be able to compete effectively in the future and that our financial condition and results of operations will not suffer as a result.

Our growth depends partly on our ability to acquire oil and gas properties on a profitable basis.

Acquisition of producing oil and gas properties has historically been a key element of maintaining and growing our reserves and production. Competition for these assets has been and will continue to be intense, and we have curtailed our acquisition efforts at the present time. The success of any acquisition will depend on a number of factors, including, among others:

- the acquisition price;
- future oil and gas prices;
- our ability to reasonably estimate or assess the recoverable volumes of reserves;
- rates of future production and future net revenues attainable from reserves;
- future operating and capital costs;
- our ability to promptly integrate the new operations with Forest's operations;
- results of future exploitation, exploration, and development activities on the acquired properties; and
- future abandonment and possible future environmental liabilities.

There are numerous uncertainties inherent in estimating quantities of proved oil and gas reserves, future production rates, and associated costs and potential liabilities with respect to prospective acquisition targets. Actual results from an acquisition may vary substantially from those assumed in the purchase analysis, and acquired properties may not produce as expected; or there may be conditions that subject us to increased costs and liabilities, including environmental liabilities. See "*—The continuing financial crisis may impact our business and financial condition. We may not be able to obtain funding in the capital markets on terms we find acceptable, or obtain funding under our current bank credit facilities because of the deterioration of the capital and credit markets and our global borrowing base,*" for a discussion of the impact of the financial market conditions on our access to financing.

Our international operations may be adversely affected by currency fluctuations and economic and political developments.

We currently have oil and gas properties and operations in Canada, Italy, and South Africa. As a result, we are exposed to the risks of international operations, including political and economic developments, royalty and tax increases, changes in laws or policies affecting our exploration and development activities, and currency exchange risks, as well as changes in the policies of the United States affecting trade, taxation, and investment in other countries.

We have significant operations in Canada. In 2008, the revenues and expenses of such operations represented approximately 15% of our consolidated oil and gas revenues and 18% of our consolidated production costs. The revenues and expenses of these operations are denominated in Canadian dollars. As a result, the profitability of our Canadian operations is subject to the risk of fluctuation in the exchange rates between the U.S. dollar and Canadian dollar. In addition, our Canadian operations may be adversely affected by recent regulatory developments.

The majority of our Canadian operations are located in Alberta, Canada, and in October 2007, the Alberta Government announced a new oil and gas royalty framework. The new framework went into effect on January 1, 2009. Under the new Alberta framework, royalties for conventional oil, natural gas, and bitumen are linked to price and production levels that apply to both new and existing conventional oil and gas activities and oil sands projects. The new framework applies a sliding rate formula to determine conventional oil and natural gas royalties, which are dependent on market prices and production volumes. Royalty rates for conventional oil will range from 0% to 50%. New natural gas royalty rates will range from 5% to 50%. In comparison, under the prior royalty regime, royalty rates ranged from 10% to 35% for conventional oil and from 5% to 35% for natural gas.

We currently conduct drilling and related exploration and development activities in Italy and are conducting related types of activities in South Africa. These activities may be adversely affected by political, economic, and regulatory developments, changes in the local royalty and tax regimes, and currency fluctuations.

Part of our strategy includes drilling in new or emerging plays. As a result, our drilling in these areas is subject to greater risk and uncertainty.

We have an internal group that is responsible for identifying and exploiting exploratory drilling in new or emerging plays. These activities are more uncertain than drilling in areas that are developed and have established production. Because emerging plays and new formations have limited or no production history, we are less able to use past drilling results to help predict future results. The lack of historical information may result in not being able to fully execute our expected drilling programs in these areas, or the return on investment in these areas may turn out not be as attractive as anticipated. We cannot assure you that our future drilling activities in Quebec or other emerging plays will be successful or, if successful, will achieve the resource potential levels that we currently anticipate based on the drilling activities that have been completed or will achieve the anticipated economic returns based on our current cost models.

Our oil and gas operations are subject to various environmental and other governmental laws and regulations that materially affect our operations.

Our oil and gas operations are subject to various U.S. federal, state, and local laws and regulations, Canadian federal, provincial, and local laws and regulations, and local and federal 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 governmental regulation include the discharge or other release into the environment of wastes and other substances in connection with drilling and production activities, bonds 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, and taxation. Failure to comply with these laws and regulations 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, Canada, 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. We may not be able to recover some or any of these costs from insurance.

Canada and Italy are signatories to the United Nations Framework Convention on Climate Change and have ratified the Kyoto Protocol established thereunder to set legally binding targets to reduce nation-wide emissions of carbon dioxide, methane, nitrous oxide and other greenhouse gases ("GHG"). In response to the Kyoto Protocol, the Canadian federal government introduced the Regulatory Framework for Air Emissions (the "Regulatory Framework") for regulating GHG emissions by establishing mandatory emissions reduction requirements on a sector basis. Sector-specific regulations are expected to come into force in 2010, but the Regulatory Framework is expected to allow emissions trading, which would enable regulated sources of GHG emissions to purchase emissions allowances or emission reduction credits from other sources. Similar GHG emission reduction requirements apply to our operations in Italy. Additionally, GHG regulation can take place at the provincial and municipal level. For example, Alberta introduced the Climate Change and Emissions Management Act, which provides a framework for managing GHG emissions by reducing specified gas emissions, relative to gross domestic product, to an amount that is equal to or less than 50% of 1990 levels by December 31, 2020 and which imposes duties to report. The accompanying regulation, the Specified Gas Emitters Regulation, effective July 1, 2007, requires mandatory emissions reductions through the use of emissions intensity targets. The Canadian federal government proposes to enter into equivalency agreements with provinces that establish a regulatory regime to ensure consistency with the federal plan. The success of any such plan appears to be doubtful in the current political climate, leaving multiple overlapping levels of regulation. The direct and indirect costs of these regulations may adversely affect our operations and financial results.

In addition, the U.S. Congress is considering legislation to reduce emissions of GHGs, and more than one-third of the states, either individually or through multi-state initiatives, already have begun implementing legal measures to reduce emissions of GHGs. Also, the U.S. Supreme Court's holding in its 2007 decision, Massachusetts, et al. v. EPA, that carbon dioxide may be regulated as an "air pollutant" under the federal Clean Air Act could result in future regulation of GHG emissions from stationary sources, even if Congress does not adopt new legislation specifically addressing emissions of GHGs. In July 2008, the United States Environmental Protection Agency released an "Advance Notice of Proposed Rulemaking" regarding possible future regulation of GHG emissions under the Clean Air Act. Although the notice did not propose any specific, new regulatory requirements for GHGs, it indicates that federal regulation of GHG emissions could occur in the near future. While it is not possible at this time to predict how legislation or new regulations that may be adopted in the United States to address GHG emissions would impact our business, any such future laws and regulations could result in increased compliance costs or additional operating restrictions, and could have an adverse effect on demand for the oil and natural gas that we produce.

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

The marketability of our production depends in part upon the availability, proximity, and capacity of pipelines, natural gas gathering systems, and processing facilities. Any significant change in market factors affecting these infrastructure facilities, as well as delays in the construction of new infrastructure facilities, could harm our business. 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 or access to gathering systems that impact a substantial amount of our production, it could temporarily have an adverse impact on our cash flow.

We may not be insured against all of the operating risks to which our businesses are exposed.

The exploration, development, and production of oil and natural gas and the activities performed by our drilling subsidiary and gas gathering subsidiary involve risks. These operating risks include the risk of fire, explosions, blow-outs, pipe failure, damaged drilling and oil field equipment, abnormally pressured formations, and environmental hazards. Environmental hazards include oil spills, gas leaks, pipeline ruptures, or discharges of toxic gases. If any of these industry operating risks occur, we could have substantial losses. 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. In accordance with industry practice, 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 Restated Certificate of Incorporation and Bylaws have provisions that discourage corporate takeovers.

Certain provisions of our Restated Certificate of Incorporation and Bylaws and provisions of the New York Business Corporation Law may have the effect of delaying or preventing a change in control. Our directors are elected to staggered terms. Also, our Restated Certificate of Incorporation authorizes our board of directors to issue preferred stock without shareholder approval and to set the rights, preferences, and other designations, including voting rights of those shares as the board may determine. Additional provisions include restrictions on business combinations, the availability of authorized but unissued common stock, and notice requirements for shareholder proposals and director nominations. Also, our board of directors has adopted a shareholder rights plan. If activated, this plan would cause extreme dilution to any person or group that attempts to acquire a significant interest in Forest without advance approval of our board of directors. The provisions contained in our Bylaws and Restated Certificate of Incorporation, alone or in combination with each other and with the shareholder rights plan, may discourage transactions involving actual or potential changes of control.

Item 1B. Unresolved Staff Comments.

As of December 31, 2008, we did not have any SEC staff comments that have been unresolved for more than 180 days.

Item 2. Properties.

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

Item 3. Legal Proceedings.

We are a party to various 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 in the reporting periods in which any such actions are resolved.

Item 4. Submission of Matters to a Vote of Security Holders.

No matter was submitted to a vote of our shareholders during the fourth quarter of the fiscal year ended December 31, 2008.

Item 4A. Executive Officers of Forest.

The following persons were serving as executive officers of Forest as of February 25, 2009.

Name	Age	Years with Forest	Office[1]
H. Craig Clark	52	8	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.
David H. Keyte	52	21	Executive Vice President and Chief Financial Officer since November 1997. Mr. Keyte served as our Vice President and Chief Financial Officer from December 1995 to November 1997 and our Vice President and Chief Accounting Officer from December 1993 until December 1995.
J.C. Ridens	53	5	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 most recently 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	58	20	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.
Leonard C. Gurule	52	6	Senior Vice President since September 2003. From 1987 to 2000, he served in various capacities at Atlantic Richfield Co. Before joining Forest, Mr. Gurule served on the boards of several local community and non-profit organizations and managed his own portfolio.
Cyrus D. Marter IV	45	7	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 of the law firm of Susman Godfrey L.L.P. in Houston, Texas.
Glen J. Mizenko	46	8	Senior Vice President, Business Development and Engineering since May 2007. 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. 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.
Mark E. Bush	49	11	Vice President, Eastern Region since April 2007. Mr. Bush joined Forest in June 1997 as Production Engineer in the Gulf of Mexico Region and was subsequently promoted to Offshore Production Engineering Manager and Production Engineering Manager, both in the Gulf Coast Region and its successor, the Eastern Region. Prior to joining Forest Oil, he worked for Oryx Energy Company (formerly Sun E&P) in various production engineering assignments in the Gulf of Mexico and South Texas.
Stephen T. Harpham	47	7	Vice President, Western Region since November 2007. Mr. Harpham joined Forest in January 2002 and served as a Reservoir Engineer and subsequently Reservoir Engineering Manager. Prior to joining Forest, Mr. Harpham was a Technical Advisor with Ensign Oil & Gas Inc.
Ronald C. Nutt	51	2	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.

Name	Age	Years with Forest	Office[1]
Victor A. Wind	35	4	Corporate Controller since 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.

(1) Officers are elected to serve for one-year terms at meetings 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 20, 2009, our Common Stock was held by 1,150 holders of record. The number of holders does not include the shareholders for whom shares are held in a "nominee" or "street" name.

The table below reflects the high and low intraday sales prices per share of the Common Stock on the New York Stock Exchange composite tape. There were no cash dividends declared on the Common Stock in 2007 or 2008. On February 25, 2009, the closing price of Forest Common Stock was $14.45.

		Common Stock	
		High	Low
2007	First Quarter	$34.25	28.84
	Second Quarter	45.05	33.26
	Third Quarter	44.72	37.43
	Fourth Quarter	52.25	42.78
2008	First Quarter	$52.22	40.85
	Second Quarter	76.20	47.26
	Third Quarter	83.10	45.31
	Fourth Quarter	49.10	12.00

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 8% senior notes due 2011, Forest's 7¾% senior notes due 2014, Forest's 8½% senior notes due 2014, and Forest's 7¼% senior notes due 2019, and (iv) Forest's United States and Canadian bank credit facilities dated as of June 6, 2007, as amended. The provisions in the indentures pertaining to these senior notes and in the bank credit facilities 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; 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. See Note 2 to the Consolidated Financial Statements for more details concerning the special stock dividend on March 2, 2006. For further information regarding our equity securities and our ability to pay dividends on our Common Stock, see Notes 4 and 6 to the Consolidated Financial Statements.

For equity compensation plan information, see Part III, Item 12—"Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters."

Issuer Purchases of Equity Securities

The table below sets forth information regarding repurchases of our Common Stock during the quarter and year ended December 31, 2008. The shares repurchased represent shares of our Common

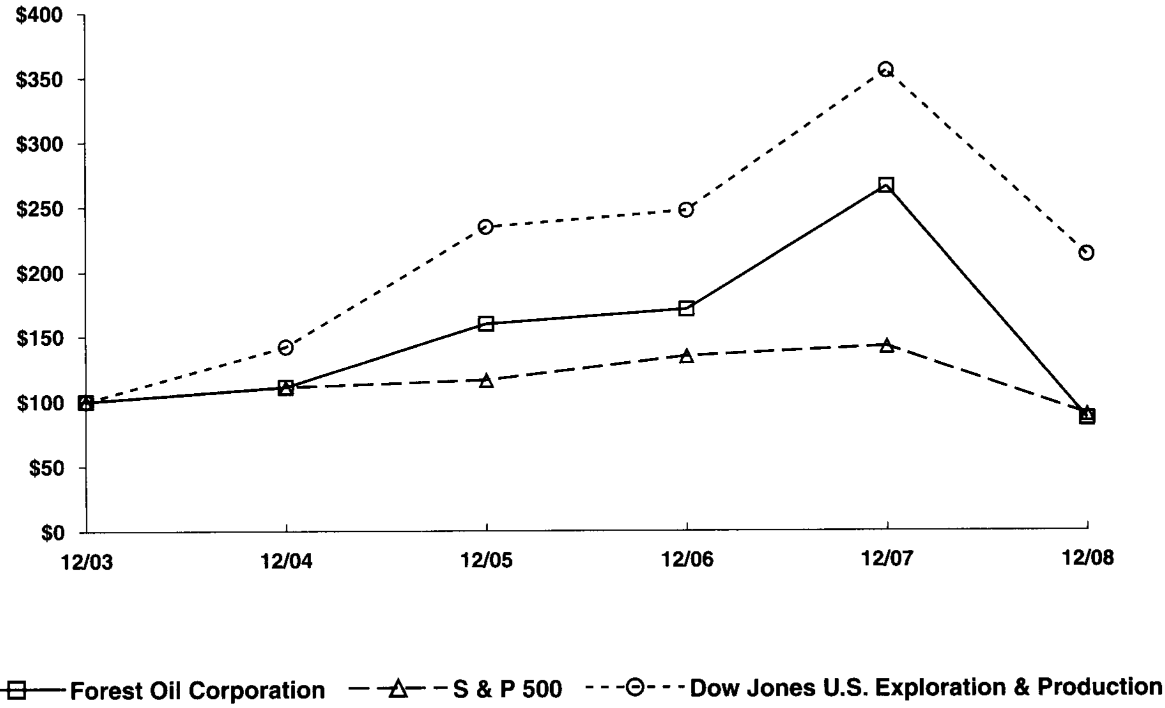
Stock that employees elected to surrender to Forest to satisfy their tax withholding obligations upon the vesting of shares of restricted stock. Forest does not consider this a share buyback program.

Period	Total # of Shares Purchased	Average Price Per Share	Total # of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum # (or Approximate Dollar Value) of Shares that May yet be Purchased Under the Plans or Programs
January 2008	11,560	$46.05	—	—
February 2008	—	—	—	—
March 2008	—	—	—	—
April 2008	1,804	56.81	—	—
May 2008	1,644	64.45	—	—
June 2008	932	71.27	—	—
July 2008	150	68.18	—	—
August 2008	1,741	52.40	—	—
September 2008	99	53.05	—	—
October 2008	—	—	—	—
November 2008	1,380	22.35	—	—
December 2008	152,885	17.77	—	—
Fourth Quarter Total	154,265	17.81	—	—
2008 Total	172,195	21.26	—	—

Stock Performance Graph

The graph below shows the cumulative total shareholder return assuming the investment of $100 on December 31, 2003 (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 U.S. Exploration & Production Index



*$100 Invested on 12/31/03 in stock or index-including reinvestment of dividends. Fiscal year ending December 31.

The information in this 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 Securities Exchange Act of 1934, as amended.

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, 2008. 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. On June 6, 2007, Forest completed the acquisition of The Houston Exploration Company. On August 27, 2007, we sold all of our Alaska assets. On March 2, 2006, Forest completed the spin-off of its offshore Gulf of Mexico operations. See Note 2 to the Consolidated Financial Statements.

	Year Ended December 31,				
	2008	2007	2006	2005	2004
	(In Thousands, Except Per Share Amounts, Volumes, and Prices)				
FINANCIAL DATA					
Revenues	$ 1,647,163	1,083,892	819,992	1,072,045	912,898
Earnings (loss) from continuing operations	(1,026,323)	169,306	166,080	151,568	123,126
Income (loss) from discontinued operations, net of tax[1]	—	—	2,422	—	(575)
Net earnings (loss)	$(1,026,323)	169,306	168,502	151,568	122,551
Basic earnings (loss) per share:					
Earnings (loss) from continuing operations	$ (11.46)	2.22	2.67	2.47	2.16
Income (loss) from discontinued operations, net of tax	—	—	.04	—	(.01)
Basic earnings (loss) per common share	$ (11.46)	2.22	2.71	2.47	2.15
Diluted earnings (loss) per share:					
Earnings (loss) from continuing operations	$ (11.46)	2.18	2.62	2.41	2.12
Income (loss) from discontinued operations, net of tax	—	—	.04	—	(.01)
Diluted earnings (loss) per common share	$ (11.46)	2.18	2.66	2.41	2.11
Total assets	$ 5,282,798	5,695,548	3,189,072	3,645,546	3,122,505
Long-term debt	$ 2,735,661	1,503,035	1,204,709	884,807	888,819
Shareholders' equity	$ 1,672,912	2,411,811	1,434,006	1,684,522	1,472,147
OPERATING DATA					
Annual production:					
Gas (MMcf)	141,433	108,042	73,024	101,833	107,366
Liquids (MBbls)	8,031	7,945	8,026	10,568	10,837
Average sales price[2]:					
Gas (per Mcf)	$ 7.45	5.79	5.58	6.36	5.34
Liquids (per Bbl)	$ 73.96	57.54	50.70	39.23	31.05

(1) Discontinued operations relate to the sale of the business assets of our Canadian marketing subsidiary on March 1, 2004.

(2) Includes the effects of hedging under cash flow hedge accounting in 2004 to 2006.

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 Form 10-K. Historical statements made herein are accurate only as of the date of filing of this 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.

Overview

Forest is an independent oil and gas company engaged in the acquisition, exploration, development, and production of natural gas and 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. We currently conduct our operations in three geographical segments and five business units. The geographical segments are: the United States, Canada, and International. The business units are: Western, Eastern, Southern, Canada, and International. We conduct exploration and development activities in each of our geographical segments; however, substantially all of our estimated proved reserves and all of our producing properties are located in North America. Forest's total estimated proved reserves as of December 31, 2008 were approximately 2,668 Bcfe. At December 31, 2008, approximately 87% of our estimated proved oil and gas reserves were in the United States, approximately 11% were in Canada, and approximately 2% were in Italy.

2008 Highlights

Forest's 2008 highlights were as follows:

- Oil and gas production in 2008 increased 22% to 190 Bcfe from 156 Bcfe in 2007 and oil and natural gas revenues increased 52% to $1.6 billion from $1.1 billion in 2007.
- Forest's year-end estimated proved reserves were a record 2,668 Bcfe, 26% higher than 2007's year-end estimated proved reserves of 2,119 Bcfe, as a result of current year acquisitions and additional discoveries despite negative reserve revisions of 213 Bcfe due primarily to significantly lower year-end spot prices. The significant decline in year-end spot prices triggered a non-cash $2.4 billion ($1.5 billion after-tax) ceiling test write-down as of December 31, 2008.
- Completed several key acquisitions of oil and gas properties in our existing core areas in the Texas Panhandle, East Texas, North Louisiana, and South Texas. In total, we acquired 512 Bcfe of estimated proved reserves for approximately $1.4 billion during 2008. See Note 2 to the Consolidated Financial Statements for more information on our recent acquisition program.
- Sold non-core oil and gas properties with estimated proved reserves of 93 Bcfe for cash proceeds of $310 million, including $24 million for our unproven oil and gas properties in Gabon.

2009 Strategy and Outlook

Due to the recent downturn in the global economy as well as the dramatic decrease in oil and natural gas prices, we have chosen to significantly reduce our capital expenditures and drilling activity in 2009. Our goal in 2009 will be to keep our exploration and development capital expenditures within our cash flow from operations, while maintaining our estimated proved reserve base and production, protecting against lease expirations and non-consent penalties, and continuing to focus on cost control.

We plan to devote over one-third of our capital spending in 2009 to horizontal drilling in our Ark-La-Tex and Greater Buffalo Wallow core areas. We expect this horizontal drilling to generate rates of return acceptable to us in the current price and cost environment. We also plan to rely almost exclusively on our drilling subsidiary, Lantern, to drill our wells rather than employing third-party drilling rigs whenever possible.

We have a divestiture program which was commenced in 2008 with an announced intention to sell $450 million to $750 million of oil and gas assets that are considered non-core to Forest. Due to the current economic conditions, this program has been delayed. We hope to complete these divestitures by the end of 2010, assuming market conditions and property valuations improve, but cannot predict whether we will be able to complete any asset divestitures. If divestitures are completed, we intend to use the proceeds to reduce debt.

By keeping our 2009 capital spending within our cash flow from operations, we hope to maintain financial flexibility and sufficient liquidity to maintain our assets and operations until margins on oil and gas production improve. In order to preserve significant borrowing capacity and flexibility under our bank credit facilities, we recently issued $600 million in senior notes due 2014 and used the net proceeds to pay down borrowings on the facilities.

Due to the decline in the market price for oil and natural gas, Forest believes that our 2009 earnings and operating cash flow will decrease significantly compared to 2008. We also expect equipment, service, and fuel costs to decrease, but not enough to offset the decline in oil and natural gas revenues.

Results of Operations

For the year ended December 31, 2008, Forest reported a net loss of $1.0 billion, or a loss of $11.46 per basic share, compared to net earnings of $169 million, or earnings of $2.22 per basic share, in 2007. The decrease in net earnings in 2008 compared to 2007 was due to a $2.4 billion ($1.5 billion after-tax) non-cash ceiling test impairment we recorded in the fourth quarter 2008, which was caused by the significant decline in year-end spot commodity prices. The ceiling test impairment offset significant increases in revenues, which had resulted from higher volumes at increased oil and natural gas prices.

For each of the years ended December 31, 2007 and 2006, Forest reported net earnings of $169 million, or $2.22 per basic share in 2007 and $2.71 per basic share in 2006. Earnings from operations were $388 million for the year ended December 31, 2007 as compared to $273 million for the year ended December 31, 2006. Earnings from operations in 2007 were $115 million higher than in 2006 primarily due to higher revenues attributable mainly to the acquisition of Houston Exploration in June 2007.

Discussion of the components of the changes in our annual results follows. Comparability between 2008 and 2007, as well as between 2007 and 2006, was significantly impacted by our acquisition of Houston Exploration in June 2007 and the sale of the Alaska assets in August 2007. Details for the acquisition and divestiture transactions are included in Note 2 to the Consolidated Financial Statements.

Oil and Gas Production and Revenues

Oil and gas production volumes, revenues, and weighted average sales prices, by product and location for the years ended December 31, 2008, 2007, and 2006, are set forth in the table below. This table does not include miscellaneous marketing and processing revenues of $1 million and $6 million for the years ended December 31, 2007 and 2006, respectively.

	Year Ended December 31,											
	2008				2007				2006			
	Gas (MMcf)	Oil (MBbls)	NGLs (MBbls)	Total (MMcfe)	Gas (MMcf)	Oil (MBbls)	NGLs (MBbls)	Total (MMcfe)	Gas (MMcf)	Oil (MBbls)	NGLs (MBbls)	Total (MMcfe)
Production volumes:												
United States	118,120	3,778	3,151	**159,694**	82,963	4,504	2,381	**124,273**	48,674	5,243	1,644	**89,996**
Canada	23,313	802	300	**29,925**	25,079	793	267	**31,439**	24,350	739	400	**31,184**
Totals	141,433	4,580	3,451	**189,619**	108,042	5,297	2,648	**155,712**	73,024	5,982	2,044	**121,180**
Revenues (In Thousands):												
United States	$ 890,417	365,913	140,339	**1,396,669**	493,321	305,873	93,624	**892,818**	302,050	326,024	52,636	**680,710**
Canada	162,769	69,520	18,213	**250,502**	132,601	46,037	11,625	**190,263**	123,408	37,605	16,559	**177,572**
Total before hedging	1,053,186	435,433	158,552	**1,647,171**	625,922	351,910	105,249	**1,083,081**	425,458	363,629	69,195	**858,282**
Less hedging effects[1]	—	—	—	**—**	—	—	—	**—**	(17,893)	(25,920)	—	**(43,813)**
Totals	$1,053,186	435,433	158,552	**1,647,171**	625,922	351,910	105,249	**1,083,081**	407,565	337,709	69,195	**814,469**
Average sales price:												
United States	$ 7.54	96.85	44.54	**8.75**	5.95	67.91	39.32	**7.18**	6.21	62.18	32.02	**7.56**
Canada	6.98	86.68	60.71	**8.37**	5.29	58.05	43.54	**6.05**	5.07	50.89	41.40	**5.69**
Combined	7.45	95.07	45.94	**8.69**	5.79	66.44	39.75	**6.96**	5.83	60.79	33.85	**7.08**
Less hedging effects[1]	—	—	—	**—**	—	—	—	**—**	(.25)	(4.34)	—	**(.36)**
Totals	$ 7.45	95.07	45.94	**8.69**	5.79	66.44	39.75	**6.96**	5.58	56.45	33.85	**6.72**

(1) Commodity swaps and collars accounted for as cash flow hedges. See Part II, Item 7A—"Quantitative and Qualitative Disclosures about Market Risk" below concerning our hedging activities.

Production Volumes and Oil and Gas Revenues

Net oil and gas production in 2008 was 189.6 Bcfe, or an average of 518 MMcfe per day, a 22% increase from 155.7 Bcfe, or an average of 427 MMcfe per day, in 2007. The net increase in oil and gas production in 2008 was primarily attributable to continued drilling and acquisition activity, partially offset by normal production declines on existing wells and the sale of the Alaska assets in August 2007. Oil and natural gas revenues in 2008 were $1.6 billion, a 52% increase as compared to $1.1 billion in 2007. The increase in oil and natural gas revenues of $564 million was due to the 22% increase in production and a 25% increase in the average realized sales price, which increased to $8.69 per Mcfe in 2008 from $6.96 per Mcfe in 2007.

Net oil and gas production in 2007 was 155.7 Bcfe, or an average of 427 MMcfe per day, a 28% increase from 121.2 Bcfe, or an average of 332 MMcfe per day, in 2006. The net increase in oil and gas production was primarily attributable to the additional production from drilling activities and from the Houston Exploration acquisition in June 2007, which was partially offset by the spin-off of our offshore Gulf of Mexico properties in early March 2006, the sale of the Alaska assets in August 2007, and normal production declines on existing wells. Oil and natural gas revenues before hedging effects in 2007 were $1.1 billion, a 26% increase as compared to $858 million in 2006. The increase in oil and natural gas revenues before hedging effects of $225 million was due to the 28% increase in production, offset by a 2% decrease in the average realized sales price (before the effects of hedging), to $6.96 per Mcfe in 2007 from $7.08 per Mcfe in 2006.

Hedge Effects

The table above also presents the effects of the derivative instruments (e.g., commodity swaps and collars) that we designated as cash flow hedges in 2006. Beginning in March 2006, we elected to discontinue the use of cash flow hedge accounting for all of our commodity derivatives. Accordingly, gains or losses recognized (i.e., cash settlements) in connection with hedging activities for the majority of 2006 and all of 2007 and 2008 are reflected in "Realized and unrealized gains and losses on derivative instruments" under Other income and expense in our Consolidated Statements of Operations rather than being included as part of Revenues. See *Realized and Unrealized Gains and Losses—Derivative Instruments* below for information on gains and losses recognized on derivative instruments not designated as cash flow hedges during the last three years.

Oil and Gas Production Expense

The table below sets forth the detail of oil and gas production expense for the years ended December 31, 2008, 2007, and 2006:

	Year Ended December 31,		
	2008	2007	2006
	(In Thousands, Except per Mcfe Data)		
Production expense:			
Lease operating expenses	$167,830	167,473	154,874
Production and property taxes	82,147	55,264	39,041
Transportation and processing costs	19,472	20,200	21,876
Production expense	$269,449	242,937	215,791
Production expense per Mcfe:			
Lease operating expenses	$ .89	1.08	1.28
Production and property taxes	.43	.35	.32
Transportation and processing costs	.10	.13	.18
Production expense per Mcfe	$ 1.42	1.56	1.78

Lease Operating Expenses

Lease operating expenses in 2008 were consistent with 2007 levels despite a 22% increase in production volumes. On a per-Mcfe basis, lease operating expenses decreased 18% to $.89 per Mcfe in 2008 from $1.08 per Mcfe in 2007. Lease operating expenses were $167 million in 2007, an increase of 8% compared to $155 million in 2006. On a per-Mcfe basis, lease operating expenses decreased 16% to $1.08 per Mcfe in 2007 from $1.28 per Mcfe in 2006. The decrease in lease operating expenses on a per-Mcfe basis for each period was primarily due to lower average per-unit lease operating expenses from the assets acquired from Houston Exploration in June 2007, the divestiture of the Alaska assets in August 2007, and cost control initiatives.

Production and Property Taxes

Production and property taxes, which primarily consist of severance taxes paid on the value of the oil and gas produced, generally fluctuate proportionately to our oil and gas revenues. As a percentage of oil and natural gas revenue, excluding hedging losses included as a reduction of oil and natural gas revenues in 2006, production and property taxes were 5.0%, 5.1%, and 4.5% for the years ended December 31, 2008, 2007, and 2006, respectively. Normal fluctuations will occur between periods based on the approval of incentive tax credits in Texas, changes in tax rates, and changes in the assessed values of property and equipment for purposes of ad valorem taxes.

Transportation and Processing Costs

Transportation and processing costs were $19 million, or $.10 per Mcfe, in 2008 compared to $20 million, or $.13 per Mcfe, in 2007. The per-unit decrease was primarily due to lower per-unit transportation costs recognized in 2008 as a result of the sale of the Alaska assets in August 2007. Transportation and processing costs were $20 million, or $.13 per Mcfe, in 2007 compared to $22 million, or $.18 per Mcfe, in 2006. The decrease of $.05 on a per-Mcfe basis in 2007 was due primarily to lower per-unit transportation costs incurred in Alaska in 2007 compared to the prior year and due to the sale of the Alaska assets in August 2007.

General and Administrative Expense

The following table summarizes the components of general and administrative expense incurred during the periods indicated:

	Year Ended December 31,		
	2008	2007	2006
	(In Thousands, Except Per Mcfe Data)		
Stock-based compensation costs	$ 27,012	17,681	22,048
Other general and administrative costs	95,002	89,697	58,108
General and administrative costs capitalized	(47,282)	(43,627)	(31,848)
General and administrative expense	$ 74,732	63,751	48,308
General and administrative expense per Mcfe	$ .39	.41	.40

General and administrative expense increased approximately $11 million to $75 million in 2008 from $64 million in 2007. The 17% increase in general and administrative expense was primarily related to increased stock-based compensation as well as increased employee salary and benefit costs and rent expense associated with having a full-year of additional personnel which were added as a result of the acquisition of Houston Exploration in June 2007. The increase in general and administrative expense of $15 million in 2007 compared to 2006 was also due to the increased employee salary and benefit costs resulting from the acquisition of Houston Exploration in June 2007, offset by a reduction to stock-based compensation costs. The percentage of general and administrative costs capitalized under the full cost method of accounting remained relatively constant between the three years, ranging between 39% and 41%.

Forest recorded stock-based compensation cost in the amount of $27 million in 2008, $18 million in 2007, and $22 million in 2006, of which approximately $10 million in 2006 was attributed to a partial settlement of Forest's restricted stock awards and phantom stock unit awards in connection with the Spin-off. The increase in stock-based compensation of $9 million in 2008 from 2007 was primarily due to stock-based awards granted in 2008. The decrease in stock-based compensation of $4 million in 2007 from 2006 was due to the $10 million partial settlement in 2006, partially offset by the recognition of stock-based compensation associated with restricted stock and stock options granted in 2007.

Depreciation and Depletion; Undeveloped Properties

	Year Ended December 31,		
	2008	2007	2006
	(In Thousands, Except Per Mcfe Data)		
Depreciation and depletion expense	$532,181	390,338	266,881
Depreciation and depletion expense per Mcfe	$ 2.81	2.51	2.20

Depreciation, depletion, and amortization expense ("DD&A") increased $.30 per Mcfe in 2008 compared to 2007 primarily due to price-related negative reserve revisions during 2008 caused by a decrease in oil and gas prices at December 31, 2008 compared to December 31, 2007 as well as the acquisition of Houston Exploration in June 2007. The increase of $.31 per Mcfe in 2007 compared to 2006 was primarily due to the acquisition of Houston Exploration. DD&A on a per-unit basis is expected to be lower in 2009 due to the $2.4 billion non-cash ceiling test impairment recorded in the fourth quarter of 2008.

The following costs of unproved properties were not subject to depletion at the periods indicated:

December 31,	United States	Canada	International	Total
		(In Thousands)		
2008	$834,596	69,248	60,183	964,027
2007	445,949	63,951	58,610	568,510
2006	149,687	53,034	58,538	261,259

The increase in the total unproved properties of $395 million to $964 million in 2008 from $569 million in 2007 is attributable to the several acquisitions made during 2008 with significant undeveloped acreage positions. The increase in the total unproved properties of $308 million in 2007 from $261 million in 2006 is primarily attributable to the Houston Exploration acquisition completed in 2007. See Note 2 to the Consolidated Financial Statements for additional information on acquisitions and divestitures.

Accretion of Asset Retirement Obligations

Accretion expense of $8 million in 2008, $6 million in 2007, and $7 million in 2006 was related to the accretion of Forest's asset retirement obligations pursuant to Statement of Financial Accounting Standards ("SFAS") No. 143, *Accounting for Asset Retirement Obligations*. SFAS No. 143 requires entities to record the fair value of a liability for an asset retirement obligation in the period in which it is incurred and 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. See Note 1 to the Consolidated Financial Statements for additional information on our asset retirement obligations.

Impairment of Oil and Gas Properties

In the fourth quarter of 2008, Forest recorded a ceiling test impairment of its U.S. oil and gas properties pursuant to the ceiling test limitation prescribed by the SEC for companies using the full cost method of accounting. The write-down totaled $2.4 billion ($1.5 billion after-tax) and was primarily a result of a significant decline in oil and gas prices in the fourth quarter of 2008. Additional write-downs of the full cost pools in the United States and Canada may be required in 2009 if oil and gas prices continue to decline, unproved property values decrease, estimated proved reserve volumes are revised downward or costs incurred in exploration, development, or acquisition activities in the respective full cost pools exceed the discounted future net cash flows from the additional reserves, if any, attributable to each of the cost pools. The December 31, 2008 NYMEX spot prices for natural gas and oil were $5.71 per MMBtu and $44.60 per barrel, respectively, and spot prices have declined since then. Based on current prices as of February 25, 2009, it is likely we will record an additional ceiling test impairment in the first quarter of 2009.

Forest also recorded impairments related to its international properties of $4 million in 2006, including $2 million related to a dry hole drilled in Gabon and $2 million related to expired concessions in Italy.

Gain on Sale of Assets

In 2008, Forest recognized a $21 million gain on the sale of all of its unproven oil and gas properties in Gabon for net proceeds of $24 million. In 2007, Forest sold its overriding royalty interests in Australia for net proceeds of $7 million, which resulted in a gain on the sale of $7 million.

Interest Expense

The following table summarizes interest expense incurred during the periods indicated.

	Year Ended December 31,		
	2008	2007	2006
	(In Thousands)		
Interest costs	$143,534	127,063	75,508
Interest costs capitalized	(17,855)	(13,901)	(3,721)
Interest expense	$125,679	113,162	71,787

Interest expense in 2008 totaled $126 million compared to $113 million 2007. The $13 million increase in interest expense was primarily due to increased interest expense on the credit facilities, which was caused by higher average borrowings throughout the year, offset somewhat by lower interest rates. Interest expense also increased given the fact that the $750 million of senior notes that were issued in June 2007 in conjunction with the Houston Exploration acquisition were outstanding for all of 2008; however, this increase was offset by decreased interest expense associated with Alaska credit agreements which were paid off in August 2007. Interest capitalization increased by $4 million due to higher interest costs and larger investments in unproved properties in 2008 as compared to 2007. Interest costs related to significant unproved properties that are under development are capitalized to oil and gas properties under the full cost method of accounting.

Interest expense in 2007 totaled $113 million compared to $72 million 2006. The $41 million increase in interest in 2007 from 2006 is primarily due to the $750 million of senior notes that we issued in June 2007 and the Alaska credit agreements, which were entered into in December 2006 and were paid off in August 2007. The increase in interest capitalized in 2007 from 2006 is due to the acquisition of Houston Exploration, which also included a large investment in unproved properties.

Realized and Unrealized Gains and Losses

Derivative Instruments

The table below sets forth realized and unrealized gains and losses on derivatives recognized under Other income and expense in our Consolidated Statements of Operations for the periods indicated. Since March 2006, when Forest elected to discontinue cash flow hedge accounting for all of its derivative instruments, Forest has recognized all unrealized mark-to-market gains and losses as a gain or loss on derivative instruments in Other income and expense in the Consolidated Statements of Operations. In addition, cash settlements, or realized gains and losses, on derivative instruments are also recorded as a gain or loss on derivative instruments in Other income and expense in the Consolidated Statements of Operations. The amounts shown in the table below for 2006 represent amounts related to ineffective hedges or derivatives that did not meet the criteria to qualify for cash flow hedge accounting prior to our discontinuance of cash flow hedge accounting. See Note 9 and Note 10 to the Consolidated Financial Statements for more information on our derivative instruments.

	Year Ended December, 31		
	2008	2007	2006
	(In Thousands)		
Realized losses (gains) on derivatives, net:			
Oil[1]	$ 71,198	(2,587)	29,743
Gas[2]	(16,126)	(72,904)	(5,879)
Interest	889	(474)	—
Subtotal realized	55,961	(75,965)	23,864
Unrealized (gains) losses on derivatives, net:			
Oil	(118,151)	123,099	(36,953)
Gas	(98,618)	(10,321)	(46,676)
Interest	(4,721)	4,721	—
Subtotal unrealized	(221,490)	117,499	(83,629)
Realized and unrealized (gains) losses on derivatives, net	$(165,529)	41,534	(59,765)

(1) Includes total proceeds of $7 million received in 2007 upon termination of two oil swaps, which collectively covered 1,000 Bbl per day for 2009 and 500 Bbl per day for 2010.

(2) Includes total proceeds of $19 million received in 2008 upon termination of two gas swaps and one gas collar, which collectively covered 40 Bbtu per day for 2009.

Foreign Currency Exchange

Realized and unrealized foreign currency exchange gains and losses relate to the outstanding intercompany indebtedness between Forest Oil Corporation and our Canadian subsidiary. Since the intercompany debt is denominated in U.S. dollars, the strengthening of the U.S. dollar in 2008 and 2006 resulted in an unrealized foreign exchange loss in those years. Conversely, the weakening of the U.S. dollar in 2007 resulted in unrealized foreign currency exchange gains in 2007. Realized foreign currency exchange gains and losses relate to repayments of the indebtedness to Forest Oil Corporation by our Canadian subsidiary. The table below shows the components of realized and unrealized foreign currency exchange for the years ended December 31, 2008, 2007, and 2006.

	Year Ended December, 31		
	2008	2007	2006
	(In Thousands)		
Realized foreign currency exchange losses (gains)	$ 959	(7,721)	(315)
Unrealized foreign currency exchange losses (gains)	19,481	(7,694)	3,931
Realized and unrealized foreign currency exchange losses (gains), net	$20,440	(15,415)	3,616

Other Investments

Unrealized losses on other investments totaled $34 million and $5 million for the years ended December 31, 2008 and 2007, respectively. The unrealized losses on other investments relate to fair value adjustments to the shares of Pacific Energy Resources, Ltd. common stock and a zero-coupon senior subordinated note due 2014 from Pacific Energy Resources, Ltd. that were each received as a portion of the total consideration for the sale of our Alaska assets. See Note 2 and Note 9 to the Consolidated Financial Statements for more information on these investments.

Other Income and Expense

The components of other income and expense for the years ended December 31, 2008, 2007, and 2006 were as follows:

	Year Ended December 31,		
	2008	2007	2006
	(In Thousands)		
Franchise taxes	$1,612	2,322	1,410
Share of income of equity method investee	—	(275)	(2,334)
Debt extinguishment costs	97	12,215	—
Other, net	(133)	(2,214)	1,135
Total other expense, net	$1,576	12,048	211

Franchise taxes are taxes paid to various states based on capital investment deployed in those states, determined by apportioning total capital as defined by statute. Forest's share of income of equity method investee related to our 40% ownership of a pipeline company that transports crude oil in Alaska, which was included in the sale of the Alaska assets in August 2007. Debt extinguishment costs in 2007 related to the complete repayment of the Alaska Credit Agreements and included $5 million in prepayment premiums and $7 million of unamortized debt issue costs.

Income Tax

The table below sets forth Forest's total income tax from continuing operations and effective tax rates for the periods presented:

	Year Ended December 31,		
	2008	2007	2006
	(In Thousands, Except Percentages)		
Current income tax	$ 11,139	5,999	2,126
Deferred income tax	(585,817)	56,396	88,777
Total income tax	$(574,678)	62,395	90,903
Effective tax rate	36%	27%	35%

Our combined U.S. and Canadian effective tax rate generally approximates 35% to 36% but will fluctuate based on the percentage of pre-tax income generated in the U.S. versus Canada. Our effective rate in 2007 was 27% due to a reduction in income taxes of approximately $21 million related to statutory rate reductions enacted in Canada, the release of valuation allowances, and a lower apportioned effective state income tax rate. See Note 5 to the Consolidated Financial Statements for a reconciliation of our income taxes at the statutory rate to income taxes at our effective rate for each period presented.

Results of Discontinued Operations

On March 1, 2004, the assets and business operations of our Canadian marketing subsidiary were sold and the subsidiary's results of operations were reported as discontinued operations in the Consolidated Statements of Operations. In 2006, Forest received an additional $3.6 million contingent payment ($2.4 million net of tax) from the buyer, which is also reflected as income from discontinued operations in the Consolidated Statements of 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 facilities as our primary sources of liquidity. To fund large and other exceptional 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 and natural gas directly impact our level of cash flow generated from operations. Currently, natural gas accounts for approximately 75% of our estimated proved reserves and, as a result, our operations and cash flow are more sensitive to fluctuations in the price for natural gas. We employ a hedging strategy in order to try to minimize the adverse effects of wide fluctuations in commodity prices on our cash flow. As of February 25, 2009, we had hedged, via commodity swaps and collar instruments, approximately 83 Bcfe of our 2009 production and 40 Bcfe of our 2010 production. 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 2009 and 2010. In the future, we may determine to increase or decrease our hedging positions. As of February 25, 2009, all of our derivatives counterparties were commercial banks that are parties to our credit facilities, or their affiliates. See Part II, Item 7A, "Quantitative and Qualitative Disclosures About Market Risk—Commodity Price Risk" below for further details concerning our hedging activities.

The other primary sources of liquidity include our U.S. credit facility and our Canadian credit facility, which had combined commitments totaling $1.8 billion as of December 31, 2008. These facilities are used to fund daily operations and to fund acquisitions and refinance debt, as needed and if available. The credit facilities are secured by our assets and mature in June 2012. See the heading *"Bank Credit Facilities"* below for further details.

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, on February 17, 2009, we issued $600 million principal amount of 8½% senior notes due 2014 in a private offering, and in 2008, we issued $250 million principal amount of additional 7¼% senior notes in a private offering. Our ability to access the debt and equity capital markets on economical 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. Notwithstanding that we recently completed a $600 million issuance of senior notes, the continuing economic crisis and distressed financial markets have impacted our business and limited our ability to access the capital markets on economical terms as funding from these markets has diminished significantly. For example, during the fourth quarter of 2008, the capital markets were essentially frozen and not available to Forest on terms we found acceptable; however, in February 2009 we were able to issue $600 million of new senior notes in a private offering. We cannot be certain that funding will be available to us in the debt and equity markets in the future, if needed, nor can we be certain that such funding will be available on acceptable terms.

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 2008, we sold certain non-strategic assets for total proceeds of approximately $310 million. However, due to significant declines in oil and natural gas prices and the turmoil in the financial and credit markets over the last year, the level of activity in the market for oil and gas properties has greatly diminished, as has the pool of available buyers. We intend to pursue asset dispositions in the future, including our previously announced intention to sell $450 million to $750 million of non-core properties. Due to the current economic conditions, however, this program has been delayed. We hope to complete these divestitures by year end 2010, assuming market conditions and property valuations improve, but cannot predict whether we will be able to complete any asset divestitures.

We believe that our cash flow provided by operating activities and funds available under our credit facilities will be sufficient to fund our operating and capital expenditures budget, and our short-term contractual obligations during 2009. However, if our revenue and cash flow decrease in the future as a result of further deterioration in domestic and global economic conditions and a continuation of declining commodity prices, we may have to reduce further our spending levels. We believe that this financial flexibility to adjust our spending levels will provide us with sufficient liquidity to meet our financial obligations should economic conditions not improve during 2009. 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 Facilities

As of December 31, 2008, we had syndicated bank revolving credit agreements with total lender commitments of $1.8 billion. The commitments under the credit agreements consisted of a $1.65 billion U.S. credit facility through a syndicate of banks led by JPMorgan Chase Bank, N.A. (the "U.S. Credit Facility") and a $150 million Canadian credit facility through a syndicate of banks led by JPMorgan Chase Bank, N.A., Toronto Branch (the "Canadian Credit Facility," and together with the U.S. Credit Facility, the "Credit Facilities"). The Credit Facilities will mature in June 2012.

Forest's availability under the Credit Facilities is governed by a borrowing base (the "Global Borrowing Base"). The determination of the Global Borrowing Base is made by the lenders, applying their own assumptions in their sole discretion, 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 Global Borrowing Base is redetermined semi-annually, and the available borrowing amount could be increased or decreased as a result of such redeterminations. In addition to the semi-annual redeterminations, Forest and the lenders each have discretion at any time, but not more often than once during any calendar year, to have the Global Borrowing Base redetermined. Because the process for determining the Global Borrowing Base involves evaluating the estimated value of our oil and gas properties using pricing models determined by the lenders at that time, the recent decline in oil and gas commodity prices, or a further decline in those prices, could result in a determination to decrease the Global Borrowing Base in the future.

The Global Borrowing Base is also subject to change in the event (i) we issue senior notes, in which case the Global Borrowing Base will immediately be reduced by an amount equal to $0.30 for every $1.00 principal amount of any newly issued senior notes, excluding any senior notes that we may issue to refinance senior notes that were outstanding on May 9, 2008, or (ii) if we sell oil and natural gas properties included in the Global Borrowing Base having a fair market value in excess of 10% of the Global Borrowing Base then in effect. The Global Borrowing Base is subject to other automatic adjustments under the facilities. As a result of issuing $600 million of 8½% senior notes due 2014 in February 2009, our borrowing base was lowered from $1.8 billion to $1.62 billion effective February 17, 2009. As a result of the adjustment to the Global Borrowing Base, we reallocated amounts under the U.S. Credit Facility and Canadian Credit Facility and currently have allocated $1.47 billion to the U.S. Credit Facility and $150 million to the Canadian Credit Facility. A lowering of the Global Borrowing Base could require us to repay indebtedness in excess of the Global Borrowing Base in order to cover the deficiency. The automatic lowering of the Global Borrowing Base on February 17, 2009 did not result in any deficiency, and therefore we did not have to repay any amounts.

Borrowings under the U.S. Credit Facility bear interest at one of two rates as may be elected by Forest. Loans will bear interest at a rate that is based on interest rates applicable to dollar deposits in the London interbank market ("LIBO Rate"), or a rate based on the greater of the prime rate announced by the global administrative agent or the federal funds rate plus ½ of 1%. Loans under the Canadian Credit Facility will bear interest at a rate that may be based on the base rate announced by the Canadian administrative agent, the LIBO Rate, a rate based on the greater of the rate for U.S. dollar denominated loans made by the Canadian administrative agent and the federal funds rate plus ½ of 1%, or a banker's acceptance rate.

The Credit Facilities include various covenants and restrictive provisions 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 include financial covenants. If we were to fail to perform our obligations under these covenants or other covenants and obligations, it could cause an event of default and the Credit Facilities could be terminated and amounts outstanding could be declared immediately due and payable by the lenders, subject to notice and cure periods in certain cases. Such events of default include non-payment, breach of warranty, non-performance of financial covenants, default on other indebtedness, certain pension plan events, certain adverse judgments, change of control, a failure of the liens securing the Credit Facilities, and an event of default under the Canadian Credit Facility. In addition, 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 Facilities. An acceleration of our indebtedness under the Credit Facilities could in turn result in an event of default under the indentures for our senior notes, which in turn could result in the acceleration of the senior notes. For example, the indentures for our 8% senior notes due 2011 and our 7¾% senior notes due 2014 include as events of default, among others, a default on indebtedness that results in the acceleration of indebtedness in an amount greater than $10 million; each of the indentures for our 8½% senior notes due 2014 and our 7¼% senior notes due 2019 include a similar event of default if the amount involved is greater than $25 million.

The Credit Facilities are collateralized by a portion of our assets. We are required to mortgage and grant a security interest in the greater of 75% of the present value of our consolidated proved oil and gas properties, or 1.875 multiplied by the allocated U.S. borrowing base. We also have pledged the stock of several subsidiaries to the lenders to secure the Credit Facilities. Under certain circumstances, we could be obligated to pledge additional assets as collateral. If Forest's corporate credit ratings assigned by Moody's and S&P improve and meet pre-established levels, the collateral requirements would not apply and, at our request, the banks would release their liens and security interests on our properties. In addition to these collateral requirements, one of our subsidiaries, Forest Oil Permian Corporation, is a subsidiary guarantor of the Credit Facilities.

The lending group under our U.S. Credit Facility includes the following institutions: JPMorgan Chase Bank, N.A. ("JPMorgan Chase"), Bank of America, N.A. ("Bank of America"), Citibank, N.A. ("Citibank"), BNP Paribas, BMO Capital Markets Financing, Inc. ("BMO"), Credit Suisse, Cayman Islands Branch ("Credit Suisse"), Deutsche Bank AG New York Branch ("Deutsche Bank"), U.S. Bank National Association, The Bank of Nova Scotia ("Bank of Nova Scotia"), Fortis Capital Corp. ("Fortis"), Bank of Scotland plc, UBS Loan Finance LLC, Compass Bank, Wells Fargo Bank, N.A. ("Wells Fargo"), Mizuho Corporate Bank, Ltd., Toronto Dominion (Texas) LLC, Barclays Bank PLC ("Barclays"), Bank of Oklahoma N.A., Export Development Canada, Guaranty Bank and Trust Company, Union Bank of California, N.A., and ABN Amro Bank N.V. The lenders under our Canadian Credit Facility include: JPMorgan Chase Bank, N.A., Toronto Branch ("JPM Toronto", with JPMorgan Chase, collectively "JPMorgan"), Bank of Montreal, The Toronto-Dominion Bank (together with Toronto Dominion (Texas) LLC, "Toronto Dominion"), Bank of America, N.A., Canada Branch, and Citibank, N.A., Canadian Branch. Of the $1.8 billion total commitments under the Credit Facilities, JPMorgan, Bank of America, BNP Paribas, Credit Suisse, Deutsche Bank, Bank of Nova Scotia, Toronto Dominion, and Wells Fargo hold approximately 62% of the total commitments, with each of these eight lenders holding an equal share. With respect to the other 38% of the total commitments, no single lender holds more than 4.2% of the total commitments.

From time to time, we engage in other transactions with a number of the lenders under the Credit Facilities. Such lenders or their affiliates may serve as underwriter or initial purchaser of our debt and equity securities, act as agent or directly purchase our production, or serve as counterparties to our commodity and interest rate derivative agreements. As of February 25, 2009, our primary derivative counterparties included the following lenders and their affiliates: BMO, BNP Paribas, Barclays, Credit Suisse, Deutsche Bank, Fortis, Bank of Nova Scotia, Toronto Dominion, and Wells Fargo. As of February 25, 2009, our derivative transactions with BMO, Credit Suisse, Fortis, Bank of Nova Scotia, BNP Paribas, and Toronto Dominion account for approximately 73 Bcfe, or 88% of our 2009 hedged production, and 32 Bcfe, or 82% of our 2010 hedged production. Our obligations under our existing derivative agreements with our lenders are secured by the security documents executed by the parties under our Credit Facilities. See Item 7A—"Quantitative and Qualitative Disclosures about Market Risk—Commodity Price Risk," below for additional details concerning our derivative arrangements.

At December 31, 2008, there were outstanding borrowings of $1.2 billion under the U.S. Credit Facility at a weighted average interest rate of 2.2%, and there were outstanding borrowings of $94.4 million under the Canadian Credit Facility at a weighted average interest rate of 3.0%. We also had used the Credit Facilities for approximately $2.7 million in letters of credit, leaving an unused borrowing amount under the Credit Facilities of approximately $512.8 million at December 31, 2008. At March 2, 2009, there were outstanding borrowings of $753.0 million under the U.S. Credit Facility at a weighted average interest rate of 1.8%, and there were outstanding borrowings of $97.6 million under the Canadian Credit Facility at a weighted average interest rate of 2.3%. We also had used the Credit Facilities for approximately $2.7 million in letters of credit, leaving an unused borrowing amount under the Credit Facilities of approximately $766.7 million at March 2, 2009.

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 Facilities include 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 credit facilities 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, net cash used by investing activities, and net cash provided by financing activities for the years ended December 31, 2008, 2007, and 2006 were as follows:

	Year Ended December 31,		
	2008	2007	2006
	(In Thousands)		
Net cash provided by operating activities	$ 1,070,040	708,245	422,478
Net cash used by investing activities	(2,093,493)	(1,093,221)	(909,891)
Net cash provided by financing activities	1,016,258	359,552	513,832

Cash flows provided by operating activities are primarily affected by production volumes and commodity prices, net of the effects of settlements of our derivative contracts, and changes in working capital. The increases in net cash provided by operating activities of $362 million in 2008 as compared to 2007 and $286 million in 2007 as compared to 2006 were primarily due to higher production volumes and commodity prices in each of the periods being compared.

Cash flows used by investing activities are primarily comprised of the acquisition, exploration, and development of oil and gas properties net of dispositions of oil and gas properties. The increase in net cash used by investing activities in 2008 as compared to 2007 was primarily due to increased acquisition, exploration, and development expenditures in 2008 and decreased proceeds from asset sales in 2008. Cash used by investing activities also increased in 2007 as compared to 2006 primarily due to an increase in cash used for acquisitions, exploration, and development of oil and gas properties in 2007, offset by an increase in proceeds from the sale of oil and gas properties in 2007. The major components of cash used by investing activities for the years ended December 31, 2008, 2007, and 2006 were as follows:

	Year Ended December 31,		
	2008	2007	2006
	(In Thousands)		
Acquisition, exploration, and development of oil and gas properties	$(2,338,488)	(1,563,100)	(894,448)
Proceeds from sale of assets	309,940	502,048	6,507
Acquisition of other fixed assets	(66,005)	(32,169)	(21,950)
Other	1,060	—	—
Net cash used by investing activities	$(2,093,493)	(1,093,221)	(909,891)

Net cash provided by financing activities in 2008 included net bank proceeds of $1.0 billion, the issuance of additional 7¼% senior notes due 2019 for net proceeds of $247 million, proceeds from the exercise of stock options and the employee stock purchase plan of $18 million, and the redemption of our 8% senior notes due 2008 of $265 million. Net cash provided by financing activities of $360 million in 2007 included the issuance of the 7¼% senior notes due 2019 for net proceeds of $739 million, net bank proceeds of $171 million, and proceeds from the exercise of stock options and from the employee stock purchase plan of $13 million, offset by the repayment of the Alaska credit agreements of $375 million and repayment of Houston Exploration's bank debt of $177 million. Net cash provided by financing activities in 2006 of $514 million included net bank proceeds of $130 million, proceeds from the Alaska credit agreements (net of issuance costs) of $368 million, $22 million of proceeds from the Spin-off, and proceeds from the exercise of stock options and from the employee stock purchase plan of approximately $7 million.

Capital Expenditures

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

	Year Ended December 31,		
	2008	2007	2006
	(In Thousands)		
Property acquisitions:			
Proved properties	$ 804,616	1,744,093	262,534
Unproved properties	566,952	449,346	53,788
	1,371,568	2,193,439	316,322
Exploration:			
Direct costs	329,897	137,475	250,344
Overhead capitalized	18,304	10,722	12,121
	348,201	148,197	262,465
Development:			
Direct costs	1,017,362	622,466	344,725
Overhead capitalized	28,978	32,905	19,727
	1,046,340	655,371	364,452
Total capital expenditures(1)	$2,766,109	2,997,007	943,239

(1) Total capital expenditures include cash expenditures, accrued cash expenditures, and non-cash capital expenditures including the value of common stock issued in conjunction with property acquisitions and stock-based compensation capitalized under the full cost method of accounting. (See Note 2 to the Consolidated Financial Statements for information on property acquisitions.) Total capital expenditures also include estimated discounted asset retirement obligations of $15 million, $38 million, and $2 million related to assets placed in service during the years ended December 31, 2008, 2007, and 2006, respectively.

Due to significant changes in the overall economy as well as the price for oil and natural gas, we have chosen to significantly reduce our capital expenditures and drilling activity in 2009 compared with 2008. We intend to keep our exploration and development capital spending within our cash flows from operations and have established a capital budget of approximately $500 million to $600 million for the year ending December 31, 2009. Some of the factors impacting the level of capital expenditures in 2009 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, 2008:

	2009	2010	2011	2012	2013	After 2013	Total
				(In Thousands)			
Bank debt(1)	$ 29,334	29,334	29,334	1,297,126	—	—	1,385,128
Senior notes(2)	107,003	107,003	391,053	84,203	85,273	1,549,636	2,324,171
Operating leases(3)	17,557	17,228	17,026	16,281	15,298	14,026	97,416
Unconditional purchase obligations(4)	44,614	7,419	772	278	—	—	53,083
Other liabilities(5)	9,919	10,621	11,394	8,966	9,581	84,997	135,478
Derivative liabilities(6)	1,284	2,600	—	—	—	—	3,884
Total contractual obligations	$209,711	174,205	449,579	1,406,854	110,152	1,648,659	3,999,160

(1) Bank debt consists of the outstanding balances under our U.S. and Canadian credit facilities as of December 31, 2008 and the anticipated interest payments due under the terms of the credit facilities using the interest rates in effect and debt balances at December 31, 2008.

(2) Senior notes consist of the principal obligations on our senior notes and senior subordinated notes and anticipated interest payments due on each.

(3) Operating leases consist of leases for drilling rigs, office facilities, office equipment, and vehicles.

(4) Unconditional purchase obligations consist primarily of firm commitments for drilling rigs, pipeline capacity, and seismic and tubular purchases.

(5) Other liabilities represent current and noncurrent liabilities that are comprised of 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.

(6) Derivative liabilities represent the fair value of liabilities for commodity derivatives as of December 31, 2008. 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.

Forest also makes 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 total maximum commitment under these leases, through 2016, totaled approximately $12 million as of December 31, 2008.

Off-balance Sheet Arrangements

From time-to-time, we enter into off-balance sheet arrangements and transactions that can give rise to off-balance sheet obligations. As of December 31, 2008, the off-balance sheet arrangements and transactions that we have entered into include (i) undrawn letters of credit, (ii) operating lease agreements, (iii) drilling commitments, and (iv) contractual obligations for which the ultimate settlement amounts are not fixed and determinable, such as gas transportation commitments and derivative contracts that are sensitive to future changes in commodity prices. Forest does not believe that any of these arrangements are reasonably likely to materially affect its 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 25, 2009, we had obtained surety bonds from a number of insurance and bonding institutions covering certain of our operations in the United States and Canada in the aggregate amount of approximately $13 million. See Part I, Item 1—"Business—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 our 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 prospectively in the depletion calculations. Assuming consistent production year over year, our depletion expense will be significantly higher or lower if we significantly decrease or increase our estimates of remaining proved reserves.

Investments in unproved properties are not depleted pending the determination of the existence of proved reserves. Unproved properties are assessed periodically to ascertain whether impairment has occurred. Unproved properties whose costs are individually significant are assessed individually by considering 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 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 in the appropriate full cost pool, or reported as impairment expense in the Consolidated Statements of Operations, as applicable.

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. The full cost ceiling test is an impairment test prescribed by SEC Regulation S-X Rule 4-10. The ceiling test is performed each quarter on a country-by-country basis. 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 crude oil and natural gas reserves, as adjusted for asset retirement obligations and the effect of cash flow hedges. 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 $2.4 billion ($1.5 billion after-tax) ceiling test impairment in the fourth quarter of 2008. The December 31, 2008 NYMEX spot prices for natural gas and oil were $5.71 per MMBtu and $44.60 per barrel, respectively, and spot prices have declined since then. Based on current prices as of February 25, 2009, it is likely we will record an additional ceiling test impairment in the first quarter of 2009.

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. 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. An impairment of unproved property costs may be indicated through evaluation of drilling results, relinquishment of drilling rights, or other information.

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 at least 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 each reporting unit, which we have determined to be our geographic operating segments, and compare the fair value with the carrying value of the net assets assigned to each 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 were 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 each of our reporting units, 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 2008, nor as a result of the non-recurring test we performed in the fourth quarter of 2008. However, there can be no assurance that our goodwill will not be impaired at any time in the future.

Oil and Gas Reserve Estimates

Our estimates of proved reserves are based on the quantities of oil and gas that geological and engineering data demonstrate, with reasonable certainty, to be recoverable in future years from known reservoirs under existing economic and operating conditions. The accuracy of any reserve 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 also changes. Any significant variance in these assumptions could materially affect the estimated quantity and value of our reserves. Despite the inherent imprecision 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 17 to the Consolidated Financial Statements.

Reference should be made to "*Independent Audit of Reserves*" under Part I, Item 1—"Business," and "*Our proved reserves are estimates and depend on many assumptions. Any material inaccuracies in these assumptions could cause the quantity and value of our oil and gas reserves, and our revenue, profitability, and cash flow, to be materially different from our estimates*," under Part I, Item 1A—"Risk Factors," in this Form 10-K.

Accounting for Derivative Instruments

We follow the provisions of SFAS No. 133, "*Accounting for Derivative Instruments and Hedging Activities*" ("SFAS 133"). SFAS 133 requires the accounting recognition of all derivative instruments as either assets or liabilities at fair value. Under the provisions of SFAS 133, we may or may not elect to designate a derivative instrument as a hedge against changes in the fair value of an asset or a liability (a "fair value hedge") or against exposure to variability in expected future cash flows (a "cash flow hedge"). 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 offsets 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. Since March 2006, we have elected not to use hedge accounting. Accordingly, after March 2006, all changes in the fair values of our derivative instruments have been and will continue to be 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.

The estimated fair values of our derivative instruments require substantial judgment. We use the income approach in determining the fair value of our derivative instruments, utilizing present value techniques for valuing our swaps and basis swaps and option-pricing models for valuing our collars. 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 actual results, changes in market conditions, or other factors, many of which are beyond our control.

Due to the volatility of oil and natural gas prices, the estimated fair values of our commodity derivative instruments are subject to large fluctuations from period to period. For example, a hypothetical 10% increase in the forward oil and natural gas prices used to calculate the fair values of our commodity derivative instruments at December 31, 2008 would decrease the net fair value of our commodity derivative instruments at December 31, 2008 by approximately $53 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, 2008 and will depend exclusively on the price of the commodities on the specified settlement dates provided by the derivative contracts.

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 generally 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 operations 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 value of deferred tax assets, management considers whether it is more likely than not that some portion or all of the deferred tax assets will not be realized. The ultimate realization of deferred tax assets is dependent upon future taxable income during the periods in which related temporary differences become deductible. Management considers the scheduled reversal of deferred tax liabilities, projected future taxable income, and tax planning strategies in making this assessment. Based upon the amount of deferred tax liabilities, historical taxable income, and projections for future taxable income over the periods for which the deferred tax assets will reverse, management believes it is more likely than not that we will realize the benefits of these deferred tax assets, net of the existing valuation allowances at December 31, 2008. The amount of the deferred tax asset considered realizable, however, could be reduced in the near term if estimates of future taxable income during relevant periods are reduced.

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 are constantly changing, as are regulatory, political, environmental, safety, and public relations considerations.

Inherent in the calculation of the present value of our asset retirement obligations ("ARO") under SFAS No. 143 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 in the Consolidated Statements of Operations.

Impact of Recently Issued Accounting Pronouncements

In December 2007, the Financial Accounting Standards Board ("FASB") issued SFAS No. 141 (Revised), *Business Combinations* ("SFAS 141(R)"), which significantly changes the financial accounting and reporting of business combination transactions. SFAS 141(R) establishes principles and requirements for how an acquirer in a business combination: (i) recognizes and measures in its financial statements the identifiable assets acquired, the liabilities assumed, and any noncontrolling interest in the acquiree, (ii) recognizes and measures the goodwill acquired in the business combination or a gain from a bargain purchase, and (iii) determines what information to disclose to enable users of the financial statements to evaluate the nature and financial effects of the business combination. SFAS 141(R) applies prospectively to business combinations that are completed or close on or after the beginning of the first annual reporting period that begins on or after December 15, 2008. Accordingly, we have adopted this pronouncement as of January 1, 2009. This pronouncement may have a material impact on the accounting for any acquisition we may make after January 1, 2009.

In February 2008, the FASB issued FASB Staff Position No. 157-2, *Effective Date of FASB Statement No. 157* ("FSP 157-2"). FSP 157-2 delayed the effective date of SFAS No. 157, *Fair Value Measurements*, for one year to fiscal years beginning after November 15, 2008, and interim periods within those fiscal years, for nonfinancial assets and nonfinancial liabilities, except for items that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually). Accordingly, we have adopted this pronouncement as of January 1, 2009. We do not expect the adoption of this pronouncement to have a material impact on our financial position or results of operations.

In March 2008, the FASB issued SFAS No. 161, *Disclosures about Derivative Instruments and Hedging Activities—an amendment of FASB Statement No. 133* ("SFAS 161"). SFAS 161 requires qualitative disclosures about objectives and strategies for using derivatives, quantitative disclosures about fair value amounts of and gains and losses on derivative instruments, and disclosures about credit-risk-related contingent features in derivative agreements. This statement is effective for fiscal years and interim periods beginning after November 15, 2008. Accordingly, we have adopted this pronouncement as of January 1, 2009. The adoption of this pronouncement will have no impact on our financial position or results of operations, but may require expanded disclosures about derivative instruments.

In June 2008, the FASB issued FASB Staff Position No. EITF 03-6-1, *Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities* ("FSP EITF 03-6-1"), which addresses 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 basic earnings per share under the two-class method described in SFAS No. 128, *Earnings per Share*. All prior period earnings per share data presented shall be adjusted retrospectively to conform with the provisions of this pronouncement. FSP EITF 03-6-1 is effective for financial statements issued for fiscal years beginning after December 15, 2008 and interim periods within those years. Accordingly, we have adopted this pronouncement as of January 1, 2009. We do not expect the adoption of FSP EITF 03-6-1 to have a material impact on our financial position or results of operations. We are currently evaluating the impact that the adoption of this pronouncement will have on our earnings per share calculations, but in general believe that our basic earnings per share will decrease as earnings will now be attributable to both common stock and share-based payment participating securities.

In December 2008, the SEC adopted revisions to its oil and gas disclosure requirements that are intended to align them with current practices and changes in technology. Key changes brought about by the amendments include:

- The replacement of the single-day year-end pricing assumption with a twelve-month average pricing assumption for both disclosure and full cost accounting purposes;
- Permitting voluntary disclosure of probable and possible reserves;
- Expanding the range of acceptable technologies used to establish the reasonable certainty of reserves;
- Easing the standard for inclusion of proved undeveloped reserves ("PUDs") by replacing the "certainty" standard for areas beyond one offsetting drilling unit from a productive well with a "reasonable certainty" standard;
- Requiring narrative disclosures regarding PUDs, including material changes in PUDs during the year, investments and progress made during the year to convert PUDs to proved developed reserves, and discussion regarding the Company's plans for development of its PUDs;
- Requiring disclosure of the qualifications of the technical person primarily responsible for preparing the reserves estimates or conducting the reserves audit and a discussion of the internal controls used to assure objectivity in the reserve estimation process;
- Requiring the filing of the independent reserve engineers' summary report if a reserves audit has been performed; and
- Permitting the disclosure of an optional reserves sensitivity analysis table to illustrate the impact of different price and/or cost assumptions on reserves, provided the price and/or cost assumptions are disclosed.

The amendments provide that companies must begin complying with these new requirements for registration statements filed on or after January 1, 2010, and for annual reports on Form 10-K for fiscal years ending on December 31, 2009, with early adoption prohibited. We are currently evaluating the impact that the adoption of this pronouncement will have on our financial position, results of operations, and disclosures.

In December 2008, the FASB issued FASB Staff Position No. FAS 132(R)-1, *Employers' Disclosures About Postretirement Benefit Plan Assets* ("FSP FAS 132(R)-1"), which provides guidance on an employer's disclosures about plan assets of a defined benefit pension or other postretirement benefit plan. FSP FAS 132(R)-1 states that disclosures concerning plan assets should provide users of financial statements with an understanding of: investment policies and strategies; categories of plan assets; fair value measurements of plan assets; and significant concentrations of risk. The disclosures required by FSP FAS 132(R)-1 shall be provided for fiscal years ending after December 15, 2009. We are currently evaluating the impact that the adoption of this pronouncement will have on our plan asset disclosures.

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

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

Commodity Price Risk

We produce and sell natural gas, crude oil, and natural gas liquids for our own account in the United States and Canada. As a result, our financial results are affected when prices for these commodities fluctuate. Such effects can be significant.

Hedging Program

In order to reduce the impact of fluctuations in commodity prices, or to protect the economics of property acquisitions, we make use of an oil and gas hedging strategy. Under our hedging strategy, we enter into commodity swaps, collars, and other financial instruments with counterparties who, in general, are participants in our credit facilities. These arrangements, which are 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, 2008, we had entered into the following swaps:

	Swaps					
	Natural Gas (NYMEX HH)			Oil (NYMEX WTI)		
	Bbtu Per Day[1]	Weighted Average Hedged Price per MMBtu	Fair Value (In Thousands)	Barrels Per Day	Weighted Average Hedged Price per Bbl	Fair Value (In Thousands)
Calendar 2009	160	$8.24	$118,494	4,500	$69.01	$23,436
Calendar 2010	—	—	—	1,500	72.95	4,608

(1) 10 Bbtu per day is subject to a $6.00 written put.

Costless Collars

Forest also enters into collar agreements with third parties. A collar agreement is similar to a swap agreement, except that we receive the difference between the floor price and the index price only if the index price is below the floor price; and we pay the difference between the ceiling price and the index price only if the index price is above the ceiling price. As of December 31, 2008, we had entered into the following collars:

	Costless Collars		
	Natural Gas (NYMEX HH)		
	Bbtu Per Day	Weighted Average Hedged Floor and Ceiling Price per MMBtu	Fair Value (In Thousands)
Calendar 2009	40	$7.31/9.76	$21,820

Basis Swaps

Forest also uses basis swaps in connection with natural gas swaps in order to fix the price differential between the NYMEX price and the index price at which the natural gas production is sold. As of December 31, 2008, we had entered into the following basis swaps:

	Basis Swaps	
	Bbtu per Day	Fair Value (In Thousands)
Calendar 2009	185	$ 4,353
Calendar 2010	90	(2,600)

The fair value of all our commodity derivative instruments based on various inputs, including published forward prices, at December 31, 2008 was a net asset of approximately $170.1 million.

In January and February 2009, Forest entered into the following additional gas swaps and basis swaps:

	Swaps		Basis Swaps
	Natural Gas (NYMEX HH)		
	Bbtu Per Day	Weighted Average Hedged Price per MMBtu	Bbtu Per Day
February – December 2009	—	$ —	20
Calendar 2010	100	6.52	—

Interest Rate Swaps

Forest may enter into interest rate swap agreements in an attempt to normalize the mix of fixed and floating interest rates within its debt portfolio. In June 2008, Forest terminated all of its outstanding interest rate swaps for a net gain of $.4 million. In February 2009, the Company entered into an interest rate swap intended to exchange the 8.5% fixed interest rate on $100.0 million of the Company's 8½% senior notes for a variable rate based on one-month LIBOR plus 6% over the term of the 8½% senior notes.

Fair Value Reconciliation

The table below sets forth the changes that occurred in the fair values of our open derivative contracts during the year ended December 31, 2008, beginning with the fair value of our derivative contracts on December 31, 2007. Due to the volatility of oil and natural gas prices, the estimated fair values of our commodity derivative instruments are subject to large fluctuations from period to period. It has been our experience that commodity prices are subject to large fluctuations, and we expect this volatility to continue. Actual gains and losses recognized related to our commodity derivative instruments will likely differ from those estimated at December 31, 2008 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, 2007	$(76,119)	(4,721)	(80,840)
Settlements of acquired derivatives	29,461	—	29,461
Net increase in fair value	161,697	3,832	165,529
Net contract losses recognized	55,072	889	55,961
As of December 31, 2008	$170,111	—	170,111

Foreign Currency Exchange Risk

We conduct business in several foreign currencies and thus are subject to foreign currency exchange rate risk on cash flows related to sales, expenses, financing, and investing transactions. In the past, 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, as have cash proceeds related to property sales and farmout arrangements. Substantially all of our Canadian revenues and costs are denominated in Canadian dollars. While the value of the Canadian dollar does fluctuate in relation to the U.S. dollar, we believe that any currency risk associated with our Canadian operations would not have a material impact on our results of operations.

Interest Rate Risk

The following table presents principal amounts and related interest rates by year of maturity for Forest's debt obligations at December 31, 2008:

	2011	2012	2013	2014	2019	Total
		(Dollar Amounts in Thousands)				
Bank credit facilities:						
Variable rate	$ —	1,284,415	—	—	—	1,284,415
Average interest rate[(1)]	—	2.28%	—	—	—	2.28%
Long-term debt:						
Fixed rate	$285,000	—	1,112	150,000	1,000,000	1,436,112
Coupon interest rate	8.00%	—	7.00%	7.75%	7.25%	7.45%
Effective interest rate[(2)]	7.71%	—	7.00%	6.56%	7.25%	7.27%

(1) As of December 31, 2008.

(2) The effective interest rate on the 8% senior notes due 2011 and the 7¾% senior notes due 2014 is reduced from the coupon rate as a result of amortization of gains related to the termination of related interest rate swaps.

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, 2008 and 2007, and the related consolidated statements of operations, shareholders' equity, and cash flows for each of the three years in the period ended December 31, 2008. 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 as of December 31, 2008 and 2007, and the consolidated results of their operations and their cash flows for each of the three years in the period ended December 31, 2008, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Forest Oil Corporation's internal control over financial reporting as of December 31, 2008, 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 26, 2009 expressed an unqualified opinion thereon.

Ernst & Young LLP

Denver, Colorado
February 26, 2009

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

	December 31, 2008	December 31, 2007
ASSETS		
Current assets:		
Cash and cash equivalents	$ 2,205	9,685
Accounts receivable	157,226	201,617
Derivative instruments	169,387	30,006
Deferred income taxes	—	23,854
Other investments	2,327	34,694
Inventory	78,683	9,486
Other current assets	63,221	52,032
Total current assets	473,049	361,374
Property and equipment, at cost:		
Oil and gas properties, full cost method of accounting:		
Proved, net of accumulated depletion of $5,502,782 and $2,742,539	3,449,510	4,414,710
Unproved	964,027	568,510
Net oil and gas properties	4,413,537	4,983,220
Other property and equipment, net of accumulated depreciation and amortization of $37,260 and $30,011	99,627	42,595
Net property and equipment	4,513,164	5,025,815
Goodwill	253,646	265,618
Derivative instruments	4,608	—
Other assets	38,331	42,741
	$5,282,798	5,695,548
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable and accrued liabilities	$ 424,941	361,089
Accrued interest	7,143	7,693
Derivative instruments	1,284	72,675
Deferred income taxes	54,583	—
Current portion of long-term debt	—	266,002
Asset retirement obligations	5,852	2,562
Other current liabilities	27,608	28,361
Total current liabilities	521,411	738,382
Long-term debt	2,735,661	1,503,035
Asset retirement obligations	91,139	87,943
Derivative instruments	2,600	38,171
Deferred income taxes	185,587	853,427
Other liabilities	73,488	62,779
Total liabilities	3,609,886	3,283,737
Commitments and contingencies (Note 12)		
Shareholders' equity:		
Preferred stock, none issued and outstanding	—	—
Common stock, 97,039,751 and 88,379,409 shares issued and outstanding	9,704	8,838
Capital surplus	2,354,903	1,966,569
(Accumulated deficit) retained earnings	(729,293)	306,062
Accumulated other comprehensive income	37,598	130,342
Total shareholders' equity	1,672,912	2,411,811
	$5,282,798	5,695,548

See accompanying Notes to Consolidated Financial Statements.

FOREST OIL CORPORATION
CONSOLIDATED STATEMENTS OF OPERATIONS

	Year Ended December 31,		
	2008	2007	2006
	(In Thousands, Except Per Share Amounts)		
Revenues	$ 1,647,163	1,083,892	819,992
Operating expenses:			
Lease operating expenses	167,830	167,473	154,874
Production and property taxes	82,147	55,264	39,041
Transportation and processing costs	19,472	20,200	21,876
General and administrative (including stock-based compensation)	74,732	63,751	48,308
Depreciation and depletion	532,181	390,338	266,881
Accretion of asset retirement obligations	7,602	6,064	7,096
Impairment of oil and gas properties	2,369,055	—	3,668
Gain on sale of assets	(21,063)	(7,176)	—
Spin-off costs	—	—	5,416
Total operating expenses	3,231,956	695,914	547,160
Earnings (loss) from operations	(1,584,793)	387,978	272,832
Other income and expense:			
Interest expense	125,679	113,162	71,787
Realized and unrealized (gains) losses on derivative instruments, net	(165,529)	41,534	(59,765)
Realized and unrealized foreign currency exchange losses (gains), net	20,440	(15,415)	3,616
Unrealized losses on other investments, net	34,042	4,948	—
Other expense, net	1,576	12,048	211
Total other income and expense	16,208	156,277	15,849
Earnings (loss) before income taxes and discontinued operations	(1,601,001)	231,701	256,983
Income tax:			
Current	11,139	5,999	2,126
Deferred	(585,817)	56,396	88,777
Total income tax	(574,678)	62,395	90,903
Earnings (loss) from continuing operations	(1,026,323)	169,306	166,080
Income from discontinued operations, net of tax	—	—	2,422
Net earnings (loss)	$(1,026,323)	169,306	168,502
Basic earnings (loss) per common share:			
Earnings (loss) from continuing operations	$ (11.46)	2.22	2.67
Income from discontinued operations, net of tax	—	—	.04
Basic earnings (loss) per common share	$ (11.46)	2.22	2.71
Diluted earnings (loss) per common share:			
Earnings (loss) from continuing operations	$ (11.46)	2.18	2.62
Income from discontinued operations, net of tax	—	—	.04
Diluted earnings (loss) per common share	$ (11.46)	2.18	2.66

See accompanying Notes to Consolidated Financial Statements.

FOREST OIL CORPORATION
CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY

	Common Stock		Capital Surplus	Retained Earnings (Accumulated Deficit)	Accumulated Other Comprehensive (Loss) Income	Treasury Stock	Total Shareholders' Equity
				(In Thousands)			
Balances at January 1, 2006	64,548	$6,455	1,529,102	217,293	(18,220)	(50,108)	1,684,522
Exercise of stock options	289	28	6,019	(8)	—	27	6,066
Tax benefit of stock options exercised	—	—	25	—	—	—	25
Employee stock purchase plan	28	4	741	—	—	—	745
Restricted stock issued, net of forfeitures	(6)	(1)	—	—	—	—	(1)
Retirement of treasury stock	(1,861)	(186)	(49,895)	—	—	50,081	—
Amortization of stock-based compensation	—	—	20,158	—	—	—	20,158
Tax benefit of acquired net operating losses	—	—	8,337	—	—	—	8,337
Pro rata distribution of MERI common stock to shareholders (Note 2)	—	—	(298,827)	(247,991)	7,549	—	(539,269)
Comprehensive earnings:							
Net earnings	—	—	—	168,502	—	—	168,502
Reclassification of hedges to earnings, net of tax	—	—	—	—	50,581	—	50,581
Change in fair value of hedges, net of tax	—	—	—	—	30,873	—	30,873
Decrease in unfunded postretirement benefits, net of tax	—	—	—	—	2,333	—	2,333
Foreign currency translation	—	—	—	—	1,134	—	1,134
Total comprehensive earnings							253,423
Balances at December 31, 2006	62,998	6,300	1,215,660	137,796	74,250	—	1,434,006
Acquisition of Houston Exploration	23,990	2,399	724,013	—	—	—	726,412
Exercise of stock options	652	65	11,720	—	—	—	11,785
Employee stock purchase plan	33	3	1,057	—	—	—	1,060
Restricted stock issued, net of cancellations	736	74	(74)	—	—	—	—
Amortization of stock-based compensation	—	—	15,504	—	—	—	15,504
Adoption of FIN 48	—	—	—	(1,040)	—	—	(1,040)
Restricted stock redeemed and other	(30)	(3)	(1,311)	—	—	—	(1,314)
Comprehensive earnings:							
Net earnings	—	—	—	169,306	—	—	169,306
Decrease in unfunded postretirement benefits, net of tax	—	—	—	—	1,295	—	1,295
Foreign currency translation	—	—	—	—	54,797	—	54,797
Total comprehensive earnings							225,398
Balances at December 31, 2007	88,379	8,838	1,966,569	306,062	130,342	—	2,411,811
Acquisition of Texas properties	7,250	725	358,875	—	—	—	359,600
Exercise of stock options	784	78	16,279	—	—	—	16,357
Employee stock purchase plan	45	5	1,378	—	—	—	1,383
Restricted stock issued, net of cancellations	684	68	(68)	—	—	—	—
Amortization of stock-based compensation	—	—	26,770	—	—	—	26,770
Adoption of EITF 06-4 and EITF 06-10 (Note 8)	—	—	—	(9,032)	—	—	(9,032)
Adjustment to pro rata distribution of MERI common stock (Note 2)	—	—	(12,385)	—	—	—	(12,385)
Restricted stock redeemed and other	(102)	(10)	(2,515)	—	—	—	(2,525)
Comprehensive loss:							
Net loss	—	—	—	(1,026,323)	—	—	(1,026,323)
Increase in unfunded postretirement benefits, net of tax	—	—	—	—	(8,007)	—	(8,007)
Foreign currency translation	—	—	—	—	(84,737)	—	(84,737)
Total comprehensive loss							(1,119,067)
Balances at December 31, 2008	97,040	$9,704	2,354,903	(729,293)	37,598	—	1,672,912

See accompanying Notes to Consolidated Financial Statements.

FOREST OIL CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2008	2007	2006
	(In Thousands)		
Operating activities:			
Net earnings (loss)	$(1,026,323)	169,306	168,502
Adjustments to reconcile net earnings (loss) to net cash provided by operating activities:			
Depreciation and depletion	532,181	390,338	266,881
Unrealized (gains) losses on derivative instruments, net	(221,490)	117,499	(83,629)
Deferred income tax	(585,817)	56,396	90,004
Impairment of oil and gas properties	2,369,055	—	3,668
Stock-based compensation expense	17,171	10,895	13,240
Accretion of asset retirement obligations	7,602	6,064	7,096
Gain on sale of assets	(21,063)	(7,176)	—
Unrealized foreign currency exchange loss (gain)	19,481	(7,694)	3,931
Unrealized losses on other investments, net	34,042	4,948	—
Other, net	(2,549)	1,402	5,899
Changes in operating assets and liabilities, net of effects of acquisitions and divestitures:			
Accounts receivable	42,854	353	(640)
Other current assets	(80,214)	1,557	(39,860)
Accounts payable and accrued liabilities	15,796	(9,592)	9,200
Accrued interest and other current liabilities	(30,686)	(26,051)	(21,814)
Net cash provided by operating activities	1,070,040	708,245	422,478
Investing activities:			
Capital expenditures for property and equipment:			
Acquisition of Houston Exploration, net of cash acquired (Note 2)	—	(775,365)	—
Exploration, development, and other acquisition costs	(2,338,488)	(787,735)	(894,448)
Other fixed assets	(66,005)	(32,169)	(21,950)
Proceeds from sales of assets	309,940	502,048	6,507
Other, net	1,060	—	—
Net cash used by investing activities	(2,093,493)	(1,093,221)	(909,891)
Financing activities:			
Proceeds from bank borrowings	3,203,360	1,536,526	1,562,778
Repayments of bank borrowings	(2,195,101)	(1,365,178)	(1,432,574)
Issuance of 7¼% senior notes, net of issuance costs	247,188	739,176	—
Redemption of 8% senior notes	(265,000)	—	—
Repurchases of 7% senior subordinated notes	(4,710)	—	—
Repayments of Alaska Credit Agreements	—	(375,000)	—
Repayments of bank debt assumed in acquisition	—	(176,885)	—
Proceeds from Alaska Credit Agreements, net of issuance costs	—	—	367,706
Proceeds from Spin-off	—	—	21,670
Proceeds from the exercise of options and from employee stock purchase plan	17,740	12,845	6,811
Other, net	12,781	(11,932)	(12,559)
Net cash provided by financing activities	1,016,258	359,552	513,832
Effect of exchange rate changes on cash	(285)	1,945	(486)
Net (decrease) increase in cash and cash equivalents	(7,480)	(23,479)	25,933
Cash and cash equivalents at beginning of year	9,685	33,164	7,231
Cash and cash equivalents at end of year	$ 2,205	9,685	33,164
Cash paid during the year for:			
Interest	$ 141,993	125,276	76,979
Income taxes	2,530	6,445	5,590

See accompanying Notes to Consolidated Financial Statements.

(1) SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES:

Description of the Business

Forest Oil Corporation ("Forest") is an independent oil and gas company engaged in the acquisition, exploration, development, and production of natural gas and 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 is active in several of the major exploration and producing areas in the United States and in Canada and has exploratory and development interests in two other foreign countries.

Basis of Presentation and Principles of Consolidation

The consolidated financial statements include the accounts of Forest Oil Corporation and its consolidated subsidiaries (collectively, "Forest" or the "Company"). Significant intercompany balances and transactions are eliminated. The Company consolidates all subsidiaries in which it controls over 50% of the voting interests. Entities in which the Company does not have a direct or indirect majority voting interest are generally accounted for using the equity method. Under the equity method, the initial investment in the affiliated entity is recorded at cost and subsequently increased or reduced to reflect the Company's share of gains or losses or dividends received from the affiliate. The Company's share of the income or losses of the affiliate is included in the Company's reported net earnings.

Certain amounts in prior years' financial statements have been reclassified to conform to the 2008 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, revenue, 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. Assumptions, judgments, and estimates are also required in determining impairments of investments in unproved properties, valuing deferred tax assets and goodwill, and estimating fair values of derivative instruments.

Cash Equivalents

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

Property and Equipment

The Company uses the full cost method of accounting for oil and gas properties. Separate cost centers are maintained for each country in which the Company has operations. During the periods presented, the Company's primary oil and gas operations were conducted in the United States and Canada. 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, 2008, 2007, and 2006, Forest capitalized $47.3 million, $43.6 million, and $31.8 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 2008, 2007, and 2006, the Company capitalized $17.9 million, $13.9 million, and $3.7 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, and geographic and geologic data obtained relating to the properties. 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.

Pursuant to full cost accounting rules, the Company must perform a ceiling test each quarter on its proved oil and gas assets within each separate cost center. The ceiling test provides that capitalized costs less related accumulated depletion and deferred income taxes for each cost center may not exceed the sum of (1) the present value of future net revenue from estimated production of proved oil and gas reserves using current prices, excluding the future cash outflows associated with settling asset retirement obligations that have been accrued on the balance sheet, at a discount factor of 10%; plus (2) the cost of properties not being amortized, if any; plus (3) the lower of cost or estimated fair value of unproved properties included in the costs being amortized, if any; less (4) income tax effects related to differences in the book and tax 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 impairment charge would be recognized to the extent of the excess capitalized costs. As a result of this limitation on capitalized costs, the accompanying financial statements included a provision for a ceiling test impairment of oil and gas property costs in 2008 of $2.4 billion in the United States. Based on current prices as of February 25, 2009, it is likely we will record an additional ceiling test impairment in the first quarter of 2009.

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. Furniture and fixtures, leasehold improvements, computer hardware and software, and other equipment are depreciated on the straight-line or declining balance method, based upon estimated useful lives of the assets ranging from three to fifteen years.

Asset Retirement Obligations

Forest records estimated future asset retirement obligations pursuant to the provisions of Statement of Financial Accounting Standards ("SFAS") No. 143, *Accounting for Asset Retirement Obligations* ("SFAS 143"). SFAS 143 requires entities to record 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 for the years ended December 31, 2008 and 2007:

	Year Ended December 31, 2008	Year Ended December 31, 2007
	(In Thousands)	
Asset retirement obligations at beginning of period	$90,505	64,102
Accretion expense	7,602	6,064
Liabilities incurred	10,375	5,195
Liabilities settled	(5,867)	(2,512)
Disposition of properties	(7,262)	(17,476)
Liabilities assumed	2,747	36,424
Revisions of estimated liabilities	1,836	(3,843)
Impact of foreign currency exchange rate	(2,945)	2,551
Asset retirement obligations at end of period	96,991	90,505
Less: current asset retirement obligations	(5,852)	(2,562)
Long-term asset retirement obligations	$91,139	87,943

Financial Instruments

The Company's financial instruments that are exposed to concentrations of credit risk consist primarily of cash equivalents, derivative instruments, and accounts receivable. The Company's cash equivalents and derivative instruments are placed with major financial institutions. The Company attempts to minimize credit risk exposure to purchasers of the Company's oil and natural gas through formal credit policies, monitoring procedures, and letters of credit when considered necessary.

The Company used various assumptions and methods in estimating fair value disclosures for financial instruments. The carrying amounts of cash and cash equivalents and accounts receivable approximated their fair value due to the short maturity of these instruments. The fair values of derivative instruments were based on published forward prices, volatilities, and credit risk considerations, including the incorporation of published interest rates and credit spreads. The carrying amount of the Company's credit facilities approximated fair value, because the interest rates on the credit facilities are variable. The fair values of the Company's senior notes and senior subordinated notes were estimated based on quoted market prices, if available, or quoted market prices of comparable instruments. The carrying values and fair values of the Company's debt instruments (other than its credit facilities) are summarized below for the periods presented:

	December 31, 2008		December 31, 2007	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(In Thousands)			
8% Senior Notes due 2008	$ —	—	266,002	267,650
8% Senior Notes due 2011	291,350	256,500	293,482	296,400
7% Senior Subordinated Notes due 2013	1,087	912	5,664	5,618
7¾% Senior Notes due 2014	158,219	123,000	159,763	152,250
7¼% Senior Notes due 2019	1,000,590	780,000	750,000	753,750

Revenues

Oil and Gas 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 seller'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, 2008 and 2007, the Company had gas imbalance payables of $9.8 million and $8.4 million, respectively, and gas imbalance receivables of $8.1 million and $9.2 million, respectively.

In 2008, sales to two purchasers were approximately 13% and 12% of the Company's total revenue. In 2006, sales to two purchasers were approximately 14% and 13% of the Company's total revenue. In 2007, there were no purchasers who exceeded 10% of the Company's total revenue.

Marketing, Processing, and Other

"Marketing, processing, and other" primarily consists of marketing fees earned from third-party marketing arrangements and fees earned attributable to volumes processed on behalf of third parties through Company-owned gas processing plants.

Accounts Receivable

The components of accounts receivable include the following:

	December 31, 2008	December 31, 2007
	(In Thousands)	
Oil and gas sales	$ 94,911	150,258
Joint interest billings	46,357	44,810
Other	16,376	7,011
Allowance for doubtful accounts	(418)	(462)
Total accounts receivable	$157,226	201,617

Forest's accounts receivable are primarily from purchasers of the Company's oil and natural gas production 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 and gas 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 believes that the loss of one or more of the Company's current oil and gas 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.

Income Taxes

The Company accounts for income taxes in accordance with the provisions of SFAS No. 109, *Accounting for Income Taxes* ("SFAS 109"). Under SFAS 109, deferred tax liabilities and assets are recognized 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. Management believes that it could implement tax planning strategies to prevent certain of these carryforwards from expiring.

Foreign Currency Translation

The functional currency of Canadian Forest Oil Ltd. ("Canadian Forest"), the Company's wholly-owned Canadian subsidiary, is the Canadian dollar. Assets and liabilities related to Canadian Forest are generally translated at end-of-period exchange rates, and related translation adjustments are generally reported as a component of shareholders' equity in accumulated other comprehensive income. Statement of operations accounts are translated at the average of the exchange rates for the period.

During 2008, 2007, and 2006, Forest realized approximately $1.0 million, $(7.7) million, and $(.3) million, respectively, of foreign currency exchange losses (gains) in connection with the repayment of intercompany debt owed to Forest Oil Corporation by Canadian Forest. During 2008, 2007, and 2006, Forest recorded approximately $19.5 million, $(7.7) million, and $3.9 million, respectively, of unrealized losses (gains) related to the intercompany debt since it is denominated in U.S. dollars.

Discontinued Operations

On March 1, 2004, the assets and business operations of our Canadian marketing subsidiary were sold and the subsidiary's results of operations were reported as discontinued operations in the Consolidated Statements of Operations. In 2006, Forest received an additional $3.6 million contingent payment ($2.4 million net of tax) from the buyer, which is also reflected as income from discontinued operations in the Consolidated Statements of Operations.

Earnings per Share

Basic earnings (loss) per share is computed by dividing net earnings (loss) attributable to common stock by the weighted average number of common shares outstanding during each period. Diluted earnings (loss) per share is computed by adjusting the average number of common shares outstanding for the dilutive effect, if any, of stock options, unvested restricted stock grants, and unvested phantom stock units. Stock options, unvested restricted stock grants, and unvested phantom stock units were not included in the calculation of diluted loss per share for the year ended December 31, 2008 as their

(1) SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES: (Continued)

inclusion would have an antidilutive effect. The following sets forth the calculation of basic and diluted earnings (loss) per share.

	Year Ended December 31,		
	2008	2007	2006
	(In Thousands, Except Per Share Amounts)		
Earnings (loss) from continuing operations	$(1,026,323)	169,306	166,080
Income from discontinued operations, net of tax	—	—	2,422
Net earnings (loss)	$(1,026,323)	169,306	168,502
Weighted average common shares outstanding during the period	89,591	76,101	62,226
Add dilutive effects of stock options, unvested restricted stock grants, and unvested phantom stock units	—	1,650	1,205
Weighted average common shares outstanding during the period, including the effects of dilutive securities	89,591	77,751	63,431
Basic earnings (loss) per common share:			
From continuing operations	$ (11.46)	2.22	2.67
From discontinued operations	—	—	.04
Basic earnings (loss) per common share	$ (11.46)	2.22	2.71
Diluted earnings (loss) per common share:			
From continuing operations	$ (11.46)	2.18	2.62
From discontinued operations	—	—	.04
Diluted earnings (loss) per common share	$ (11.46)	2.18	2.66

Stock-Based Compensation

The Company accounts for stock-based compensation under SFAS No. 123 (Revised), *Share-Based Payment* ("SFAS 123(R)"). Under this method, compensation cost is recorded for all unvested stock options, restricted stock, and phantom stock units beginning in the period of adoption, and prior period financial statements are not restated. Under the fair value recognition provisions of SFAS 123(R), stock-based compensation is measured at the grant date based on the value of the awards, and the value is recognized on a straight-line basis over the requisite service period (usually the vesting period).

Accounting for Derivative Instruments

The Company follows the provisions of SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities* ("SFAS 133"). SFAS 133 requires the accounting recognition of all derivative instruments as either assets or liabilities at fair value. Under the provisions of SFAS 133, the Company may or may not elect to designate a derivative instrument as a hedge against changes in the fair value of an asset or a liability (a "fair value hedge") or against exposure to variability in expected future cash flows (a "cash flow hedge").

Treasury Stock

In May 2006, Forest retired its treasury stock. The Company had historically accounted for treasury stock acquisitions using the cost method. Under this method, for reissuance of treasury stock, to the extent that the reissuance price was more than the cost, the excess was recorded as an increase to capital surplus. If the reissuance price was less than the cost, the difference was also recorded to capital surplus to the extent there was a cumulative treasury stock paid in capital balance.

Debt Issue Costs

Included in other assets are costs associated with the issuance of our senior notes and our revolving bank credit facilities. The remaining unamortized debt issue costs at December 31, 2008 and 2007 totaled \$23.5 million and \$19.7 million, respectively, and are being amortized over the life of the respective debt instruments. The increase in 2008 includes the debt issue costs associated with the May 2008 issuance of the \$250 million 7¼% senior notes due 2019.

Inventory

Inventories were comprised of \$78.7 million and \$9.5 million of materials and supplies as of December 31, 2008 and 2007, respectively. The Company's materials and supplies inventory, which is acquired for use in future drilling or repair operations, is primarily comprised of oil and gas drilling or repair items such as tubing, casing, operating supplies, and ordinary maintenance materials and parts.

Goodwill

The Company accounts for goodwill in accordance with SFAS No. 142, *Goodwill and Other Intangible Assets*, and is required to make an annual impairment assessment 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 reserve 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, 2008, 2007, and 2006.

A portion of our goodwill is assigned to the Canadian geographical business segment, and normal fluctuations will occur between periods based upon changes in foreign currency exchange rates. Forest recognized \$168.0 million of goodwill associated with the Houston Exploration acquisition, which occurred in June 2007, as discussed in Note 2.

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 include: foreign currency gains (losses) related to the translation of the assets and liabilities of the Company's Canadian operations; changes in the unfunded postretirement benefits; and unrealized gains (losses) related to the changes in fair value of derivative instruments designated as cash flow hedges.

(1) SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES: (Continued)

The components of accumulated other comprehensive earnings (loss) for the years ended December 31, 2008, 2007, and 2006 are as follows:

	Foreign Currency Translation	Unfunded Postretirement Benefits[1]	Unrealized Gain (Loss) on Derivative Instruments, Net[1]	Accumulated Other Comprehensive Income (Loss)
		(In Thousands)		
Balance at January 1, 2006	$ 79,413	(8,630)	(89,003)	(18,220)
2006 activity	1,134	2,333	89,003	92,470
Balance at December 31, 2006	80,547	(6,297)	—	74,250
2007 activity	54,797	1,295	—	56,092
Balance at December 31, 2007	135,344	(5,002)	—	130,342
2008 activity	(84,737)	(8,007)	—	(92,744)
Balance at December 31, 2008	$ 50,607	(13,009)	—	37,598

(1) Net of tax.

Impact of Recently Issued Accounting Pronouncements

In December 2007, the Financial Accounting Standards Board ("FASB") issued SFAS No. 141 (Revised), *Business Combinations* ("SFAS 141(R)"), which significantly changes the financial accounting and reporting of business combination transactions. SFAS 141(R) establishes principles and requirements for how an acquirer in a business combination: (i) recognizes and measures in its financial statements the identifiable assets acquired, the liabilities assumed, and any noncontrolling interest in the acquiree, (ii) recognizes and measures the goodwill acquired in the business combination or a gain from a bargain purchase, and (iii) determines what information to disclose to enable users of the financial statements to evaluate the nature and financial effects of the business combination. SFAS 141(R) applies prospectively to business combinations that are completed or close on or after the beginning of the first annual reporting period that begins on or after December 15, 2008. Accordingly, the Company has adopted this pronouncement as of January 1, 2009. This pronouncement may have a material impact on the accounting for any acquisition the Company may make after January 1, 2009.

In February 2008, the FASB issued FASB Staff Position No. 157-2, *Effective Date of FASB Statement No. 157* ("FSP 157-2"). FSP 157-2 delayed the effective date of SFAS No. 157, *Fair Value Measurements*, for one year to fiscal years beginning after November 15, 2008, and interim periods within those fiscal years, for nonfinancial assets and nonfinancial liabilities, except for items that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually). Accordingly, the Company has adopted this pronouncement as of January 1, 2009. The Company does not expect the adoption of this pronouncement to have a material impact on its financial position or results of operations.

(1) SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES: (Continued)

In March 2008, the FASB issued SFAS No. 161, *Disclosures about Derivative Instruments and Hedging Activities—an amendment of FASB Statement No. 133* ("SFAS 161"). SFAS 161 requires qualitative disclosures about objectives and strategies for using derivatives, quantitative disclosures about fair value amounts of and gains and losses on derivative instruments, and disclosures about credit-risk-related contingent features in derivative agreements. This statement is effective for fiscal years and interim periods beginning after November 15, 2008. Accordingly, the Company has adopted this pronouncement as of January 1, 2009. The adoption of this pronouncement will have no impact on the Company's financial position or results of operations, but may require expanded disclosures about derivative instruments.

In June 2008, the FASB issued FASB Staff Position No. EITF 03-6-1, *Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities* ("FSP EITF 03-6-1"), which addresses 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 basic earnings per share under the two-class method described in SFAS No. 128, *Earnings per Share*. All prior period earnings per share data presented shall be adjusted retrospectively to conform with the provisions of this pronouncement. FSP EITF 03-6-1 is effective for financial statements issued for fiscal years beginning after December 15, 2008 and interim periods within those years. Accordingly, the Company has adopted this pronouncement as of January 1, 2009. The Company does not expect the adoption of FSP EITF 03-6-1 to have a material impact on its financial position or results of operations. The Company is currently evaluating the impact that the adoption of this pronouncement will have on its earnings per share calculations, but in general believes that its basic earnings per share will decrease as earnings will now be attributable to both common stock and share-based payment participating securities.

In December 2008, the Securities and Exchange Commission ("SEC") adopted revisions to its oil and gas disclosure requirements that are intended to align them with current practices and changes in technology. Key changes brought about by the amendments include:

- The replacement of the single-day year-end pricing assumption with a twelve-month average pricing assumption for both disclosure and full cost accounting purposes;
- Permitting voluntary disclosure of probable and possible reserves;
- Expanding the range of acceptable technologies used to establish the reasonable certainty of reserves;
- Easing the standard for inclusion of proved undeveloped reserves ("PUDs") by replacing the "certainty" standard for areas beyond one offsetting drilling unit from a productive well with a "reasonable certainty" standard;
- Requiring narrative disclosures regarding PUDs, including material changes in PUDs during the year, investments and progress made during the year to convert PUDs to proved developed reserves, and discussion regarding the Company's plans for development of its PUDs;
- Requiring disclosure of the qualifications of the technical person primarily responsible for preparing the reserves estimates or conducting the reserves audit and a discussion of the internal controls used to assure objectivity in the reserve estimation process;
- Requiring the filing of the independent reserve engineers' summary report if a reserves audit has been performed; and

(1) SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES: (Continued)

- Permitting the disclosure of an optional reserves sensitivity analysis table to illustrate the impact of different price and/or cost assumptions on reserves, provided the price and/or cost assumptions are disclosed.

The amendments provide that companies must begin complying with these new requirements for registration statements filed on or after January 1, 2010, and for annual reports on Form 10-K for fiscal years ending on December 31, 2009, with early adoption prohibited. The Company is currently evaluating the impact that the adoption of this pronouncement will have on the Company's financial position, results of operations, and disclosures.

In December 2008, the FASB issued FASB Staff Position No. FAS 132(R)-1, *Employers' Disclosures About Postretirement Benefit Plan Assets* ("FSP FAS 132(R)-1"), which provides guidance on an employer's disclosures about plan assets of a defined benefit pension or other postretirement benefit plan. FSP FAS 132(R)-1 states that disclosures concerning plan assets should provide users of financial statements with an understanding of: investment policies and strategies; categories of plan assets; fair value measurements of plan assets; and significant concentrations of risk. The disclosures required by FSP FAS 132(R)-1 shall be provided for fiscal years ending after December 15, 2009. The Company is currently evaluating the impact that the adoption of this pronouncement will have on the Company's plan asset disclosures.

(2) ACQUISITIONS AND DIVESTITURES:

Acquisitions

Texas Properties Acquisition

On September 30, 2008, Forest acquired producing oil and natural gas properties located in its Greater Buffalo Wallow and Ark-La-Tex core areas from Cordillera Texas, L.P. Forest paid approximately $570 million in cash, subject to customary post-closing adjustments to reflect an economic effective date of July 1, 2008, and issued 7.25 million shares of Forest's common stock, valued at approximately $360 million (based on a September 30, 2008 closing price), to the seller for the acquired assets. Forest funded the cash component of the purchase price primarily using advances under its credit facilities.

Ark-La-Tex Properties Acquisition

On May 2, 2008, Forest acquired producing oil and natural gas properties located primarily in its core Ark-La-Tex region in East Texas and North Louisiana. Forest paid approximately $284 million, as adjusted to reflect an economic effective date of April 1, 2008, for the assets using funds advanced under its credit facilities.

Acquisition of Houston Exploration

On June 6, 2007, Forest completed the acquisition of The Houston Exploration Company ("Houston Exploration") in a cash and stock transaction totaling approximately $1.5 billion and the assumption of Houston Exploration's debt. Houston Exploration was an independent natural gas and oil producer engaged in the exploration, development, exploitation, and acquisition of natural gas and oil reserves in North America. Houston Exploration had operations in four producing regions within the United States: South Texas, East Texas, the Arkoma Basin of Arkansas, and the Uinta and DJ Basins in the Rocky Mountains. 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 common shares, valued at $30.28 per share. The cash component of the merger consideration was financed from a private placement of $750 million of 7¼% senior notes due 2019 and borrowings under the Company's credit facilities. Immediately following the completion of the merger, Forest repaid all of Houston Exploration's outstanding bank debt totaling $177 million.

The acquisition, which was accounted for using the purchase method of accounting, has been included in Forest's Consolidated Financial Statements since June 6, 2007, the date the acquisition closed. The following table represents the allocation of the total purchase price of Houston Exploration to the acquired assets and liabilities of Houston Exploration as of December 31, 2008. The allocation represents the estimated fair values assigned to each of the assets acquired and liabilities assumed.

	(In Thousands)
Fair value of Houston Exploration's net assets:	
Net working capital, including cash of $3.5 million	$ (809)
Proved oil and gas properties	1,741,823
Unproved oil and gas properties	448,100
Goodwill	168,043
Other assets	14,537
Derivative instruments	(45,170)
Long-term debt	(182,532)
Asset retirement obligations	(36,424)
Deferred income taxes	(584,049)
Other liabilities	(18,210)
Total fair value of net assets	$1,505,309
Consideration paid for Houston Exploration's net assets:	
Forest common stock issued	$ 726,412
Cash consideration paid	749,694
Aggregate purchase consideration paid to Houston Exploration stockholders	1,476,106
Plus:	
Cash settlement for Houston Exploration stock options	20,075
Direct merger costs incurred	9,128
Total consideration paid	$1,505,309

Goodwill of $168.0 million was recognized to the extent that the consideration paid exceeded the fair value of the net assets acquired and has been assigned to the U.S. geographical business segment. Goodwill is not expected to be deductible for tax purposes. The principal factors that contributed to the recognition of goodwill include the mix of complementary high-quality assets in certain of our existing core areas, lower-risk exploitation opportunities, expected increased cash flow from operations available for investing activities, and opportunities for cost savings through administrative and operational synergies.

Included in the working capital assumed at the acquisition date was a severance accrual of $28.9 million for costs to involuntarily terminate employees of Houston Exploration. Management determined it would be necessary to eliminate certain overlapping positions to achieve cost savings through administrative and operational synergies. Management has finalized its termination plan as a result of the acquisition and all severance payments have been made. The following table summarizes the activity in the severance accrual through December 31, 2008 since the acquisition date.

	(In Thousands)
Severance accrual at June 6, 2007	$ 28,850
Cash payments[(1)]	(11,519)
Net adjustment[(2)]	(1,694)
Severance accrual at December 31, 2007	15,637
Cash payments[(1)]	(15,286)
Net adjustment[(2)]	(351)
Severance accrual at December 31, 2008	$ —

(1) Represents cash severance and excise tax payments to involuntarily terminated employees of Houston Exploration as well as the related employer tax payments paid by the Company.

(2) Represents the net adjustment made to the accrual as the Company continued to finalize the termination plan. This net adjustment was made to the cost of the acquired company.

The following summary pro forma combined statement of operations data of Forest for the years ended December 31, 2007 and 2006 has been prepared to give effect to the merger as if the merger had occurred on January 1, 2007 and 2006, respectively. The pro forma financial information is not necessarily indicative of the results that might have occurred had the transaction taken place on January 1, 2007 and 2006, and is not intended to be a projection of future results. Future results may vary significantly from the results reflected in the following pro forma financial information because of normal production declines, changes in commodity prices, future acquisitions and divestitures, future development and exploration activities, and other factors. The pro forma financial information also gives pro forma effect to Forest's spin-off of its offshore Gulf of Mexico operations completed in March 2006 and Houston Exploration's sale of substantially all of its offshore Gulf of Mexico operations completed in June 2006, as though each disposition occurred on January 1, 2006.

	Year Ended December 31,	
	2007	2006
	(In Thousands, Except Per Share Amounts)	
Revenues	$1,304,849	1,220,447
Earnings from continuing operations	181,591	172,101
Net earnings	181,591	174,523
Basic earnings per common share:		
From continuing operations	$ 2.09	2.00
Basic earnings per common share	2.09	2.02
Diluted earnings per common share:		
From continuing operations	$ 2.06	1.98
Diluted earnings per common share	2.06	2.00

Cotton Valley Acquisition

On March 31, 2006, Forest completed the acquisition of oil and natural gas properties located primarily in the Cotton Valley trend in East Texas. Forest paid approximately $255 million, as adjusted to reflect an economic effective date of February 1, 2006. Forest funded this acquisition utilizing its bank credit facilities.

(2) ACQUISITIONS AND DIVESTITURES: (Continued)

Divestitures

Miscellaneous Divestitures

During the year ended December 31, 2008, Forest sold various non-core U.S. and international oil and natural gas properties for total proceeds of $309.9 million. These divestitures included the sale of all of Forest's properties in Gabon for net proceeds of $23.9 million that resulted in a gain on the sale of $21.1 million in the third quarter. During the year ended December 31, 2007, Forest sold various properties for total proceeds of $39.4 million, including an overriding royalty interest in Australia for net proceeds of $7.2 million that resulted in a gain on the sale of $7.2 million. In addition, in August 2007, the Company entered into a sale-leaseback transaction whereby the Company sold its drilling rigs for cash proceeds of $62.6 million and simultaneously entered into an operating lease with the buyer which provides for monthly rental payments of $.9 million for a term of seven years. A deferred gain of $33.3 million resulted from the sale of the drilling rigs and is being amortized over the term of the lease.

Sale of Alaska Assets

On August 27, 2007, Forest sold all of its assets located in Alaska (the "Alaska Assets") to Pacific Energy Resources Ltd. ("PERL"). The total consideration received for the Alaska Assets included $400 million in cash, 10 million shares of PERL common stock (subject to certain restrictions) (the "PERL Shares"), and a zero coupon senior subordinated note from PERL due 2014 in the principal amount at stated maturity of $60.8 million (the "PERL Note"). A portion of the cash consideration, $269 million, was applied to prepay all amounts due under the Alaska credit agreements, including accrued interest and prepayment premiums. Consideration received by Forest in the form of the PERL common stock and the zero coupon senior subordinated note are being held in other investments within the Consolidated Balance Sheet. Forest accounts for these investments as trading securities in accordance with SFAS No. 115, *Accounting for Certain Investments in Debt and Equity Securities*. Investments in debt and equity securities classified as trading securities are recorded at fair value with unrealized gains and losses recognized in "Other income and expense" in the Consolidated Statements of Operations. See Note 9 to the Consolidated Financial Statements.

Spin-off and Merger of Offshore Gulf of Mexico Operations

On March 2, 2006, Forest completed the spin-off of its offshore Gulf of Mexico operations by means of a special dividend, which consisted of a pro rata spin-off (the "Spin-off") of all outstanding shares of Forest Energy Resources, Inc. (hereinafter known as Mariner Energy Resources, Inc. or "MERI"), a total of approximately 50.6 million shares of common stock, to holders of record of Forest common stock as of the close of business on February 21, 2006. Immediately following the Spin-off, MERI was merged with a subsidiary of Mariner Energy, Inc. ("Mariner") (the "Mariner Merger"). Mariner's common stock commenced trading on the New York Stock Exchange on March 3, 2006.

The Spin-off was a tax-free transaction for federal income tax purposes. Prior to the Mariner Merger, as part of the Spin-off, MERI paid Forest $176.1 million. The $176.1 million was drawn on a newly created bank credit facility established by MERI immediately prior to the Spin-off. This credit facility and associated liability were included in the Spin-off. Subsequent to the closing, in 2006, Forest received additional net cash proceeds of $21.7 million from MERI for a total of $197.8 million. In accordance with the transaction agreements, Forest and MERI had submitted post-closing adjustments from which Forest paid MERI a total of $5.8 million during 2007. Additional adjustments were made to the cash component of the Spin-off based on the resolution of certain matters that were the subject of arbitration, which concluded in January 2009, between Forest and MERI. These adjustments resulted

(2) ACQUISITIONS AND DIVESTITURES: (Continued)

in a net amount paid to MERI of $16.6 million, of which $12.4 million is represented as an adjustment to the pro rata distribution in shareholders' equity.

The table below sets forth the assets and liabilities included in the Spin-off as of the date of the distribution (in thousands):

Working capital	$ (12,383)
Proved oil and gas properties, net of accumulated depletion	1,033,289
Unproved oil and gas properties	38,523
Other assets	7,919
Derivative instruments	(17,087)
MERI credit facility	(176,102)
Asset retirement obligations	(150,182)
Deferred income taxes	(184,483)
Other liabilities	(225)
Accumulated other comprehensive income	7,549
Net decrease to capital surplus and retained earnings	$ 546,818

The following table presents the revenues and direct operating expenses of the offshore Gulf of Mexico operations reported in the Consolidated Statements of Operations for the period presented. As the Spin-off of the offshore Gulf of Mexico operations was concluded in 2006, the Company did not have operating activity from offshore Gulf of Mexico operations during 2007 or 2008.

	Year Ended December 31, 2006
	(In Thousands)
Revenues	$46,289
Oil and gas production expense:	
Lease operating expenses	18,296
Transportation and processing costs	344
Production and property taxes	151
Revenues in excess of direct operating expenses	$27,498

(3) PROPERTY AND EQUIPMENT:

Net property and equipment at December 31, 2008 and 2007 consists of the following:

	2008	2007
	(In Thousands)	
Oil and gas properties:		
Proved	$ 8,952,292	7,157,249
Unproved	964,027	568,510
Accumulated depletion	(5,502,782)	(2,742,539)
Net oil and gas properties	4,413,537	4,983,220
Other property and equipment:		
Furniture and fixtures, computer hardware and software, and other equipment	136,887	72,606
Accumulated depreciation and amortization	(37,260)	(30,011)
Net other property and equipment	99,627	42,595
Total net property and equipment	$ 4,513,164	5,025,815

The following table sets forth a summary of oil and gas property costs not being depleted at December 31, 2008, by the year in which such costs were incurred:

	Total	2008	2007	2006	2005 and Prior
			(In Thousands)		
United States:					
Acquisition costs	$683,107	519,915	137,881	21,930	3,381
Exploration costs	151,489	100,268	16,688	28,805	5,728
Total United States	834,596	620,183	154,569	50,735	9,109
Canada:					
Acquisition costs	16,090	—	—	—	16,090
Exploration costs	53,158	29,546	13,339	7,380	2,893
Total Canada	69,248	29,546	13,339	7,380	18,983
International:					
Acquisition costs	740	—	—	—	740
Exploration costs	59,443	4,808	1,552	2,822	50,261
Total International	60,183	4,808	1,552	2,822	51,001
Total	$964,027	654,537	169,460	60,937	79,093

The majority of the United States and Canada unproved oil and gas property costs, or those not being depleted, relate to oil and gas property acquisitions discussed in Note 2 as well as work-in-progress on various exploration projects. The Company expects that substantially all of its unproved property costs in the U.S. and Canada as of December 31, 2008 will be reclassified to proved properties within five years. Forest also holds interests in various projects located outside North America. Costs related to these international interests of $60.2 million are not being depleted pending determination of the existence of proved reserves. Forest's exploration project in South Africa accounts for the majority of the international costs not being amortized. In 2008, the Company continued to pursue commercial development of the Ibhubesi field discovery in South Africa. The Company also completed ancillary documents as part of the production right application filed in 2007 and continued efforts toward securing gas contracts for the Ibhubesi field.

(4) DEBT:

Components of debt are as follows:

	December 31, 2008				December 31, 2007			
	Principal	Unamortized Premium (Discount)	Other[3]	Total	Principal	Unamortized Premium (Discount)	Other[3]	Total
				(In Thousands)				
U.S. Credit Facility	$1,190,000	—	—	1,190,000	165,000	—	—	165,000
Canadian Credit Facility	94,415	—	—	94,415	129,126	—	—	129,126
8% Senior Notes due 2008[1]	—	—	—	—	265,000	(48)	1,050	266,002
8% Senior Notes due 2011	285,000	3,875	2,475	291,350	285,000	5,167	3,315	293,482
7% Senior Subordinated Notes due 2013[2]	1,112	(25)	—	1,087	5,822	(158)	—	5,664
7¾% Senior Notes due 2014	150,000	(1,273)	9,492	158,219	150,000	(1,512)	11,275	159,763
7¼% Senior Notes due 2019[1]	1,000,000	590	—	1,000,590	750,000	—	—	750,000
Total debt	2,720,527	3,167	11,967	2,735,661	1,749,948	3,449	15,640	1,769,037
Less: current portion of long-term debt	—	—	—	—	(265,000)	48	(1,050)	(266,002)
Long-term debt	$2,720,527	3,167	11,967	2,735,661	1,484,948	3,497	14,590	1,503,035

(1) The 8% senior notes due 2008 became due and payable on June 15, 2008. In May 2008, the Company issued an additional $250 million in principal amount of 7¼% senior notes due 2019 at 100.25% of par for proceeds of $247.2 million (net of related offering costs) and used the net proceeds and borrowings under its credit facilities to redeem the $265 million in principal amount outstanding of 8% senior notes that matured on June 15, 2008. The Company had previously issued $750 million in principal amount of 7¼% senior notes due 2019 at par in connection with the Houston Exploration acquisition in June 2007.

(2) In May 2008, the Company repurchased $3.0 million in principal amount of 7% senior subordinated notes due 2013 at 99.9375% of par value. In September 2008, the Company repurchased an additional $1.8 million in principal amount of 7% senior subordinated notes due 2013 at 99.0000% of par value.

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

Bank Credit Facilities

As of December 31, 2008, the Company had syndicated bank revolving credit agreements with total lender commitments of $1.8 billion. The credit agreements consisted of a $1.65 billion U.S. credit facility through a syndicate of banks led by JPMorgan Chase Bank, N.A. (the "U.S. Credit Facility") and a $150 million Canadian credit facility through a syndicate of banks led by JPMorgan Chase Bank, N.A., Toronto Branch (the "Canadian Credit Facility," and together with the U.S. Credit Facility, the "Credit Facilities"). The Credit Facilities will mature in June 2012.

Forest's availability under the Credit Facilities is governed by a borrowing base (the "Global Borrowing Base"). The determination of the Global Borrowing Base is made by the lenders, applying their own assumptions in their sole discretion, 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 Global Borrowing Base is redetermined semi-annually, and the available borrowing amount could be increased or decreased as a result of such redeterminations. In addition to the semi-annual redeterminations, Forest and the lenders each have discretion at any time, but not more often than once during any calendar year, to have the Global Borrowing Base redetermined. Because the process for determining the Global Borrowing Base involves evaluating the estimated value of Forest's oil and gas properties using pricing models determined by the lenders at that time, the recent decline in oil and gas commodity prices, or a further decline in those prices, could result in a determination to decrease the Global Borrowing Base in the future.

(4) DEBT: (Continued)

The Global Borrowing Base is also subject to change in the event (i) the Company issues senior notes, in which case the Global Borrowing Base will immediately be reduced by an amount equal to \$0.30 for every \$1.00 principal amount of any newly issued senior notes, excluding any senior notes that the Company may issue to refinance senior notes that were outstanding on May 9, 2008, or (ii) if the Company sells oil and natural gas properties included in the Global Borrowing Base having a fair market value in excess of 10% of the Global Borrowing Base then in effect. The Global Borrowing Base is subject to other automatic adjustments under the facilities. As a result of issuing \$600 million of 8½% senior notes due 2014 in February 2009, Forest's borrowing base was lowered from \$1.8 billion to \$1.62 billion effective February 17, 2009. As a result of the adjustment to the Global Borrowing Base, the Company reallocated amounts under the U.S. Credit Facility and Canadian Credit Facility and currently have allocated \$1.47 billion to the U.S. Credit Facility and \$150 million to the Canadian Credit Facility. A lowering of the Global Borrowing Base could require the Company to repay indebtedness in excess of the Global Borrowing Base in order to cover the deficiency. The automatic lowering of the Global Borrowing Base on February 17, 2009 did not result in any deficiency, and therefore the Company did not have to repay any amounts.

Borrowings under the U.S. Credit Facility bear interest at one of two rates as may be elected by Forest. Loans will bear interest at a rate that is based on interest rates applicable to dollar deposits in the London interbank market ("LIBO Rate"), or a rate based on the greater of the prime rate announced by the global administrative agent or the federal funds rate plus ½ of 1%. Loans under the Canadian Credit Facility will bear interest at a rate that may be based on the base rate announced by the Canadian administrative agent, the LIBO Rate, a rate based on the greater of the rate for U.S. dollar denominated loans made by the Canadian administrative agent and the federal funds rate plus ½ of 1%, or a banker's acceptance rate.

The Credit Facilities include various covenants and restrictive provisions 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 include financial covenants. If the Company were to fail to perform its obligations under these covenants or other covenants and obligations, it could cause an event of default and the Credit Facilities could be terminated and amounts outstanding could be declared immediately due and payable by the lenders, subject to notice and cure periods in certain cases. Such events of default include non-payment, breach of warranty, non-performance of financial covenants, default on other indebtedness, certain pension plan events, certain adverse judgments, change of control, a failure of the liens securing the Credit Facilities, and an event of default under the Canadian Credit Facility. In addition, 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 Facilities. An acceleration of the Company's indebtedness under the Credit Facilities could in turn result in an event of default under the indentures for the Company's senior notes, which in turn could result in the acceleration of the senior notes. For example, the indentures for our 8% senior notes due 2011 and our 7¾% senior notes due 2014 include as events of default, among others, a default on indebtedness that results in the acceleration of indebtedness in an amount greater than \$10 million; each of the indentures for our 8½% senior notes due 2014 and our 7¼% senior notes due 2019 include a similar event of default if the amount involved is greater than \$25 million.

The Credit Facilities are collateralized by a portion of the Company's assets. The Company is required to mortgage and grant a security interest in the greater of 75% of the present value of our consolidated proved oil and gas properties, or 1.875 multiplied by the allocated U.S. borrowing base. The Company also has pledged the stock of several subsidiaries to the lenders to secure the Credit Facilities. Under certain circumstances, the Company could be obligated to pledge additional assets as

(4) DEBT: (Continued)

collateral. If Forest's corporate credit ratings assigned by Moody's and S&P improve and meet pre-established levels, the collateral requirements would not apply and, at the Company's request, the banks would release their liens and security interests on the Company's properties. In addition to these collateral requirements, one of the Company's subsidiaries, Forest Oil Permian Corporation, is a subsidiary guarantor of the Credit Facilities.

The lending group under the Company's U.S. Credit Facility includes the following institutions: JPMorgan Chase Bank, N.A. ("JPMorgan Chase"), Bank of America, N.A. ("Bank of America"), Citibank, N.A. ("Citibank"), BNP Paribas, BMO Capital Markets Financing, Inc. ("BMO"), Credit Suisse, Cayman Islands Branch ("Credit Suisse"), Deutsche Bank AG New York Branch ("Deutsche Bank"), U.S. Bank National Association, The Bank of Nova Scotia ("Bank of Nova Scotia"), Fortis Capital Corp. ("Fortis"), Bank of Scotland plc, UBS Loan Finance LLC, Compass Bank, Wells Fargo Bank, N.A. ("Wells Fargo"), Mizuho Corporate Bank, Ltd., Toronto Dominion (Texas) LLC, Barclays Bank PLC ("Barclays"), Bank of Oklahoma N.A., Export Development Canada, Guaranty Bank and Trust Company, Union Bank of California, N.A., and ABN Amro Bank N.V. The lenders under the Company's Canadian Credit Facility include: JPMorgan Chase Bank, N.A., Toronto Branch ("JPM Toronto", with JPMorgan Chase, collectively "JPMorgan"), Bank of Montreal, The Toronto-Dominion Bank (together with Toronto Dominion (Texas) LLC, "Toronto Dominion"), Bank of America, N.A., Canada Branch, and Citibank, N.A., Canadian Branch. Of the $1.8 billion total commitments under the Credit Facilities, JPMorgan, Bank of America, BNP Paribas, Credit Suisse, Deutsche Bank, Bank of Nova Scotia, Toronto Dominion, and Wells Fargo hold approximately 62% of the total commitments, with each of these eight lenders holding an equal share. With respect to the other 38% of the total commitments, no single lender holds more than 4.2% of the total commitments.

At December 31, 2008, there were outstanding borrowings of $1.2 billion under the U.S. Credit Facility at a weighted average interest rate of 2.2%, and there were outstanding borrowings of $94.4 million under the Canadian Credit Facility at a weighted average interest rate of 3.0%. The Company also had used the Credit Facilities for approximately $2.7 million in letters of credit, leaving an unused borrowing amount under the Credit Facilities of approximately $512.8 million at December 31, 2008.

7¼% Senior Notes Due 2019

On May 22, 2008, Forest issued an additional $250 million in principal amount of 7¼% senior notes due 2019 (the "7¼% Notes") at 100.25% of par for net proceeds of $247.2 million, after deducting initial purchaser discounts. The additional 7¼% Notes were used to redeem a portion of the Company's 8% senior notes due 2008 that matured on June 15, 2008. The additional 7¼% Notes were issued under an existing indenture (the "Indenture") dated as of June 6, 2007 among Forest, Forest Oil Permian Corporation, a wholly-owned subsidiary of Forest ("Forest Permian"), as subsidiary guarantor, and U.S. Bank National Association, as trustee. Forest previously issued an aggregate principal amount of $750 million in 7¼% Notes under the Indenture, and there is now a total of $1 billion in 7¼% Notes outstanding. The 7¼% Notes are jointly and severally guaranteed by Forest Permian on an unsecured basis. Interest is payable on June 15 and December 15 of each year. The 7¼% Notes will mature on June 15, 2019.

Forest may redeem up to 35% of the 7¼% Notes at any time prior to June 15, 2010, on one or more occasions, with the proceeds from certain equity offerings at a redemption price equal to 107.25% of the principal amount, plus accrued but unpaid interest. 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.

Forest and its restricted subsidiaries are subject to certain negative covenants under the Indenture governing the 7¼% Notes. The Indenture limits the ability of Forest and each of its restricted subsidiaries to, among other things: incur additional indebtedness, create certain liens, make certain types of "restricted payments," make investments, sell assets, enter into agreements that restrict dividends or other payments from its subsidiaries to itself, consolidate, merge or transfer all or substantially all of its assets, engage in transactions with affiliates, and pay dividends or make other distributions on capital stock or subordinated indebtedness.

8% Senior Notes Due 2011

In December 2001, Forest issued $160 million in principal amount of 8% senior notes due 2011 (the "8% Notes Due 2011") at par for proceeds of $157.5 million (net of related offering costs). In July 2004, Forest issued an additional $125 million in principal amount of 8% Notes Due 2011 at 107.75% of par for proceeds of $133.3 million (net of related offering costs). The 8% Notes due 2011 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. Interest is payable on June 15 and December 15 of each year.

7% Senior Subordinated Notes Due 2013

In connection with the acquisition of Houston Exploration, Forest assumed $5.8 million of 7% senior subordinated notes due 2013 (the "7% Notes") originally issued by Houston Exploration in June 2003. The 7% Notes may be redeemed at the option of the Company, in whole or in part, at any time on or after June 15, 2008 at a price equal to 100% of the principal amount plus accrued but unpaid interest, if any, plus a specified premium that decreases yearly from 3.5% in 2008 to 0% in 2011 and thereafter. On May 22, 2008, Forest repurchased $3.0 million in principal amount of the 7% Notes at 99.9375% of par value. On September 3, 2008, Forest repurchased an additional $1.8 million in principal amount of the 7% Notes at 99.0000% of par value. Interest is payable on June 15 and December 15 of each year.

7¾% Senior Notes Due 2014

In April 2002, Forest issued $150 million in principal amount of 7¾% senior notes due 2014 (the "7¾% Notes") at 98.09% of par for proceeds of $146.8 million (net of related offering costs). The 7¾% Notes are redeemable, at the Company's option, at any time on or after May 1, 2007, at the approximate redemption rates set forth below, plus accrued and unpaid interest. Interest is payable on May 1 and November 1 of each year.

	Redemption Rate
2009	101.3%
2010 and thereafter	100.0%

Alaska Credit Agreements

On December 8, 2006, Forest, through its wholly-owned subsidiaries, Forest Alaska Operating LLC and Forest Alaska Holding LLC (together "Forest Alaska"), issued, on a non-recourse basis to Forest, term loan financing facilities in the aggregate principal amount of $375 million. The issuance was comprised of two term loan facilities, including a $250 million first lien credit agreement and a $125 million second lien credit agreement (together the "Alaska Credit Agreements"). The loan proceeds were used to fund a $350 million distribution to Forest, which Forest used to pay down its U.S. credit facility, and to provide Forest Alaska working capital for its operations and pay transaction fees and expenses.

During the year ended December 31, 2007, Forest Alaska made scheduled repayments of $1.3 million and a voluntary prepayment of $110.0 million on the first lien credit agreement. In conjunction with the sale of the Alaska Assets on August 27, 2007, Forest used a portion of the $400 million of cash proceeds to repay the remaining $263.7 million principal balance outstanding under the Alaska Credit Agreements. During the year ended December 31, 2007, Forest recognized debt extinguishment costs of $12.2 million associated with payments on the Alaska Credit Agreements. The debt extinguishment costs included $5.0 million in prepayment premiums on the Alaska Credit Agreements and $7.2 million of unamortized debt issuance costs.

8% Senior Notes Due 2008

On June 15, 2008, Forest redeemed $265 million in principal amount of 8% senior notes due in 2008 (the "8% Notes due 2008") that matured as of that date. The Company used net proceeds received from the issuance of additional 7¼% Notes and borrowings under its credit facilities to fund the redemption of the 8% Notes due 2008.

Principal Maturities

Principal maturities of the Company's debt at December 31, 2008 are as follows (in thousands):

	Principal Maturities
2011	$ 285,000
2012	1,284,415
2013	1,112
Thereafter	1,150,000

Subsequent Event—8½% Senior Notes Due 2014

On February 17, 2009, Forest issued $600 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. Proceeds from the 8½% Notes were used to pay down outstanding balances on the Company's U.S. Credit Facility. The 8½% Notes are jointly and severally guaranteed by Forest Permian

(4) **DEBT: (Continued)**

on an unsecured basis. Interest is payable on February 15 and August 15 of each year, beginning August 15, 2009. The 8½% Notes will mature on February 15, 2014. Forest may redeem up to 35% of the 8½% Notes at any time prior to February 15, 2012, on one or more occasions, with the proceeds from certain equity offerings at a redemption price equal to 108.5% of the principal amount, plus accrued but unpaid interest.

Forest may also redeem the 8½% Notes in whole or in part and at any time, at a "make-whole" redemption price equal to the greater of (i) 100% of the principal amount of the 8½% Notes to be redeemed or (ii) the sum of the remaining scheduled payments of principal and interest on the 8½% Notes discounted to the date of redemption at an applicable Treasury yield rate plus 0.50%, plus, in either case, accrued but unpaid interest.

(5) 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,		
	2008	2007	2006
	(In Thousands)		
Current:			
Federal	$ 3,979	3,503	1,341
Foreign	3,381	(1,798)	140
State	3,779	4,294	645
	11,139	5,999	2,126
Deferred:			
Federal	(590,078)	58,536	77,445
Foreign	23,312	(2,098)	3,643
State, net	(19,051)	(42)	7,689
	(585,817)	56,396	88,777
	$(574,678)	62,395	90,903

The Company's current income tax expense for the periods presented was due primarily to federal alternative minimum tax, and to Texas state income taxes in 2008 and 2007 and Alaska state income taxes in 2007 and 2006. Deferred income taxes generally result from recognizing income and expenses at different times for financial and tax reporting. In the U.S., the largest differences are the tax effects of book recognition of the ceiling test impairment in 2008, unrealized gains and losses with respect to derivative instruments, and the capitalization of certain development, exploration, and other costs under the full cost method of accounting. In Canada, differences result in part from accelerated cost recovery of oil and gas capital expenditures for tax purposes.

(5) INCOME TAXES: (Continued)

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

	Year Ended December 31,		
	2008	2007	2006
	(In Thousands)		
United States Federal	$(1,673,671)	177,999	211,785
Foreign	72,670	53,702	45,198
	$(1,601,001)	231,701	256,983

A reconciliation of income tax computed by applying the United States statutory federal income tax rate is as follows:

	Year Ended December 31,		
	2008	2007	2006
	(In Thousands)		
Federal income tax at 35% of income before income taxes and discontinued operations	$(560,364)	81,095	89,944
State income taxes, net of federal income tax benefits	(18,895)	2,960	7,616
Change in the valuation allowance for deferred tax assets	1,956	(1,831)	(1,464)
Effect of differing tax rates in Canada	(3,971)	(1,517)	(160)
Effect of Canadian statutory rate reductions	(4,455)	(16,815)	(12,292)
Effect of state statutory rate reductions	(1,940)	(2,397)	(5,706)
Effects related to the Spin-off	—	—	7,209
Effect of state and foreign tax on permanent differences	7,353	277	(252)
Effect of foreign withholding	1,981	—	—
Other	3,657	623	6,008
Total income tax	$(574,678)	62,395	90,903

(5) INCOME TAXES: (Continued)

Net Deferred Tax Liabilities

The components of the net deferred tax liability by geographical segment at December 31, 2008 and 2007 are as follows:

	December 31, 2008		
	United States	Canada	Total
	(In Thousands)		
Deferred tax assets:			
Allowance for doubtful accounts	$ 441	—	441
Investment in PERL common stock and Note	14,536	—	14,536
Accrual for post retirement benefits	7,903	261	8,164
Stock-based compensation accruals under SFAS 123(R)	9,071	227	9,298
Net operating loss carryforwards	37,579	—	37,579
Capital loss carryforward	—	2,408	2,408
Depletion carryforward	7,301	—	7,301
Alternative minimum tax credit carryforward	34,093	—	34,093
Other	10,875	1,265	12,140
Total gross deferred tax assets	121,799	4,161	125,960
Less valuation allowance	(1,075)	(2,767)	(3,842)
Net deferred tax assets	120,724	1,394	122,118
Deferred tax liabilities:			
Property and equipment	(207,215)	(93,614)	(300,829)
Unrealized gains on derivative contracts, net	(61,459)	—	(61,459)
Total gross deferred tax liabilities	(268,674)	(93,614)	(362,288)
Net deferred tax liabilities	$(147,950)	(92,220)	(240,170)

(5) INCOME TAXES: (Continued)

	December 31, 2007		
	United States	Canada	Total
	(In Thousands)		
Deferred tax assets:			
Allowance for doubtful accounts	$ 443	—	443
Investment in PERL common stock and Note	1,776	—	1,776
Accrual for post retirement benefits	4,703	—	4,703
Stock-based compensation accruals under SFAS 123(R)	7,755	—	7,755
Net operating loss carryforwards	142,436	238	142,674
Capital loss carryforward	—	3,004	3,004
Depletion carryforward	7,137	—	7,137
Alternative minimum tax credit carryforward	10,352	—	10,352
Unrealized losses on derivative contracts, net	29,394	—	29,394
Other	15,537	1,817	17,354
Total gross deferred tax assets	219,533	5,059	224,592
Less valuation allowance	(27,036)	(811)	(27,847)
Net deferred tax assets	192,497	4,248	196,745
Deferred tax liabilities:			
Property and equipment	(932,508)	(92,401)	(1,024,909)
Other	—	(1,409)	(1,409)
Total gross deferred tax liabilities	(932,508)	(93,810)	(1,026,318)
Net deferred tax liabilities	$(740,011)	(89,562)	(829,573)

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

	December 31, 2008		
	United States	Canada	Total
	(In Thousands)		
Current deferred tax liabilities	$ (54,583)	—	(54,583)
Non-current deferred tax liabilities	(93,367)	(92,220)	(185,587)
Net deferred tax liabilities	$(147,950)	(92,220)	(240,170)

	December 31, 2007		
	United States	Canada	Total
	(In Thousands)		
Current deferred tax assets	$ 23,854	—	23,854
Non-current deferred tax liabilities	(763,865)	(89,562)	(853,427)
Net deferred tax liabilities	$(740,011)	(89,562)	(829,573)

(5) INCOME TAXES: (Continued)

The net changes in the total valuation allowance for the years ended December 31, 2008, 2007, and 2006 were as follows:

	2008	2007	2006
	(In Thousands)		
Net decrease in the valuation allowance for deferred tax assets attributable to reassessment of the amount of tax losses of acquired subsidiary expected to be utilized	$ —	—	(8,337)
Decrease in the valuation allowance for net expiring operating loss carryforwards	(25,960)	—	(9,967)
Other increases (decreases) in the valuation allowance for deferred tax assets	1,956	(1,831)	(1,465)
Net decrease in the valuation allowance	$(24,004)	(1,831)	(19,769)

The decrease in the valuation allowance for 2008 of $24.0 million relates to a decrease of $26.0 million of tax loss carryforwards of an acquired subsidiary that expired unused, offset by increases for Canadian foreign exchange translation losses and other Canadian tax loss carryforwards. The decrease in the valuation allowance for 2007 of $1.8 million relates to adjustments to Canadian tax loss carryforwards. In 2006, $18.4 million of the decrease in the valuation allowance relates to tax loss carryforwards of an acquired subsidiary which were previously provided against. Of this amount, $10.0 million relates to tax loss carryforwards that expired unused in 2006. In 2006, the Company determined that it was more likely than not that $8.3 million would be realized in the future, and this amount was released with a corresponding adjustment to capital surplus. The other decreases in the valuation allowance of $1.5 million relate to adjustments to state and Canadian tax loss carryforwards.

The Company has a net deferred tax asset of $1.4 million in international locations. The Company has, in prior years, established a valuation allowance equal to the $1.4 million net deferred tax asset as the Company currently does not have production in the related international locations.

Tax Attributes

Net Operating Losses

U.S. federal net operating loss carryforwards at December 31, 2008 were approximately $152.7 million. Of this amount, approximately $37.2 million relates to excess stock compensation that will not give rise to a financial statement benefit. The Company's federal net operating losses are scheduled to expire in years 2018 through 2027.

The Company's ability to use some of its net operating loss carryforwards and certain other tax attributes to reduce current and future U.S. federal taxable income is subject to limitations under the Internal Revenue Code. In particular, the Company's ability to utilize such carryforwards is limited due to the occurrence of "Ownership Changes" within the meaning of Section 382 of the Internal Revenue Code. The Company has established a valuation allowance against its net operating loss carryforwards in the amount of $1.1 million, recognizing the effects of Section 382 on its ability to ever realize these carryforwards.

The statute of limitations is closed for the Company's U.S. federal income tax returns for years ending on or before December 31, 2004. Pre-acquisition returns of acquired businesses are also closed for tax years ending on or before December 31, 2004, except for those related to Houston Exploration which have been held open until September 14, 2009. However, the Company has utilized, and will continue to utilize, net operating losses ("NOLs") (including NOLs of acquired businesses) in its open tax years. The earliest available NOLs were generated in the tax year beginning January 1, 1998, but

(5) INCOME TAXES: (Continued)

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 adjustments is the tax year ending December 31, 1991. The Company's most recent Canadian income tax return that is closed to potential audit adjustments is the tax year ended December 31, 2003.

In accordance with SFAS 123(R), windfall deductions from the exercise of stock-based compensation awards that do not result in a reduction in income taxes payable, should not be recorded. The Company uses the "with and without method" for realization of the tax benefits of the windfall deductions. As a result, net operating losses related to the windfall deductions of $37.2 million will be recorded in capital surplus when realized as a reduction of income taxes payable.

Alternative Minimum Tax Credits

The Alternative Minimum Tax ("AMT") credit carryforward available to reduce future U.S. federal regular taxes equaled an aggregate amount of $34.1 million at December 31, 2008, including $23.3 million acquired in conjunction with the Houston Exploration acquisition. This amount may be carried forward indefinitely.

Canadian Tax Pools

Canadian tax pools relating to the exploration, development, and production of oil and natural gas that are available to reduce future Canadian federal income taxes equaled an aggregate amount of approximately $273.4 million ($333.0 million CDN) at December 31, 2008. The Canadian tax pools include approximately $29.4 million ($35.8 million CDN) acquired from predecessor companies that are limited in use to income derived from assets acquired. These tax pool balances are deductible on a declining balance basis ranging from 4% to 100% of the balance annually, and are composed of costs incurred for oil and gas properties, and developmental and exploration expenditures, as follows:

	2008	2007
	(In Thousands of Canadian Dollars)	
Canadian exploration expense (deductible at 100% annually)	$ 3,805	8,481
Canadian development expense (deductible at 30% annually)	165,277	146,927
Canadian oil and gas property expense (deductible at 10% annually)	51,545	47,941
Canadian capital cost allowance (deductible at 4% - 45% annually)	112,374	100,652
	$333,001	304,001

Other Canadian tax pools and loss carryforwards available to reduce future Canadian federal income taxes were approximately $10.4 million ($13.0 million CDN) at December 31, 2008, which may be carried forward indefinitely.

Undistributed Earnings from Canadian Operations

The Company's Canadian operations generated book income (after tax) of approximately $49.1 million during 2008. As of December 31, 2008, the Company's Canadian operations had reported accumulated undistributed book earnings of approximately $188.7 million. The Company has not provided deferred tax liabilities with respect to U.S. income tax or Canadian withholding taxes related to these undistributed earnings. During 2008, all cash flow generated in Canada was reinvested in Canadian capital expenditures. Based on its current plans, the Company intends that future cash flows generated by Canadian operations will continue to be reinvested in Canadian exploration, development, or acquisition activities or utilized to satisfy external and intercompany debt of the Canadian operations. Should the Company distribute Canadian earnings, we may be subject to U.S. income taxes

(5) **INCOME TAXES: (Continued)**

and Canadian withholding taxes. It is not practicable to estimate the amount of such taxes that may be payable if such a distribution occurs. The Company currently has no foreign tax credits to offset such taxes.

Accounting for Uncertainty in Income Taxes

The Company adopted FASB Interpretation No. 48, "Accounting for Uncertainty in Income Taxes", an interpretation of SFAS 109, *"Accounting for Income Taxes"* ("FIN 48"), on January 1, 2007. As a result of the implementation of FIN 48 the Company recognized a liability for uncertain tax benefits of approximately $1.0 million, which was accounted for as a reduction to the January 1, 2007 balance of retained earnings. The adoption of FIN 48 increased the Company's previously recognized liability for uncertain tax benefits of $.5 million to $1.5 million. The $1.5 million liability does not relate to uncertainties about the timing of items of income or deduction and would affect the Company's effective tax rate if recognized in the Company's income tax provision. 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 recognized no significant interest or penalties at the date of its adoption of FIN 48.

In conjunction with the Houston Exploration acquisition, Forest assumed an additional liability for uncertain tax benefits of $1.6 million. There was no change in the amount of unrecognized tax benefits during the year ended December 31, 2008 and the Company does not expect any significant change in the total amounts of unrecognized tax benefits within the twelve months ending December 31, 2009.

A reconciliation of the beginning and ending balances of the total amounts of gross unrecognized tax benefits is as follows (in thousands):

	Year Ended December 31,	
	2008	**2007**
Gross unrecognized tax benefits at beginning of period	$3,167	487
Increases in tax positions for prior years	—	1,040
Increases in tax positions for acquired entities	—	1,640
Gross unrecognized tax benefits at end of period	$3,167	3,167

The total amount of unrecognized tax benefits that, if recognized, would affect the effective tax rate is $3.2 million, net of estimated accrued interest and penalties.

(6) **SHAREHOLDERS' EQUITY:**

Common Stock

At December 31, 2008, the Company had 200.0 million shares of Common Stock, par value $.10 per share, authorized and 97.0 million shares outstanding.

Rights Agreement

In October 1993, the Board of Directors adopted a shareholders' rights plan and entered into the Rights Agreement. The Company distributed one Preferred Share Purchase Right (the "Rights") for each outstanding share of the Company's Common Stock. The Rights 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. In October 2003, the Board of Directors of Forest entered into the First Amended and Restated Rights Agreement and issued rights

(6) SHAREHOLDERS' EQUITY: (Continued)

that will expire on October 29, 2013, unless earlier exchanged or redeemed, that entitle the holder thereof to purchase 1/100th of a preferred share at an initial purchase price of $120.

(7) STOCK-BASED COMPENSATION:

The table below sets forth total stock-based compensation recorded during the years ended December 31, 2008, 2007, and 2006 under the provisions of SFAS 123(R), and the remaining unamortized amounts and the weighted average amortization period remaining as of December 31, 2008.

	Stock Options	Restricted Stock	Phantom Stock Units	Total[1]
		(In Thousands)		
Year ended December 31, 2008:				
Total stock-based compensation costs	$ 2,677	23,565	242	26,484
Less: stock-based compensation costs capitalized	(1,171)	(8,546)	(124)	(9,841)
Stock-based compensation costs expensed	$ 1,506	15,019	118	16,643
Unamortized stock-based compensation costs as of December 31, 2008	$ 2,400	46,884	1,589[2]	50,873
Weighted average amortization period remaining	1.6 years	2.1 years	2.0 years	2.1 years
Year ended December 31, 2007:				
Total stock-based compensation costs	$ 5,006	10,142	2,177	17,325
Less: stock-based compensation costs capitalized	(1,485)	(3,920)	(1,381)	(6,786)
Stock-based compensation costs expensed	$ 3,521	6,222	796	10,539
Year ended December 31, 2006:				
Total stock-based compensation costs	$ 5,348	14,551	1,890	21,789
Less: stock-based compensation costs capitalized	(1,645)	(5,279)	(1,194)	(8,118)
Stock-based compensation costs expensed	$ 3,703	9,272	696	13,671

(1) The Company also maintains an employee stock purchase plan (which is not included in the table above) under which $.5 million, $.4 million, and $.3 million of compensation cost was recognized for the years ended December 31, 2008, 2007, and 2006, respectively, under the provisions of SFAS 123(R).

(2) Based on the closing price of the Company's Common Stock on December 31, 2008.

Equity Incentive Plans

In 2007, the Company adopted the Forest Oil Corporation 2007 Stock Incentive Plan (the "2007 Plan") under which qualified and non-qualified stock options, restricted stock, 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 2.7 million shares. The exercise price of an option shall not be less than the fair market value of one share of Common Stock on the date of grant. Options granted under the 2007 Plan generally vest in increments of 25% on each of the first four anniversary dates of the date of grant and have a term of ten years. Restricted stock awards generally vest three years from the date of the grant.

(7) STOCK-BASED COMPENSATION: (Continued)

As of December 31, 2008, the Company had 1,478,603 shares available to be issued under the 2007 Plan.

In 2001, the Company adopted the Forest Oil Corporation 2001 Stock Incentive Plan (the "2001 Plan") under which qualified and non-qualified stock options, restricted stock, and other awards may be granted to employees, consultants, and non-employee directors. In 2003, the Company amended the 2001 Plan to increase the number of shares reserved for issuance. The aggregate number of shares of Common Stock that the Company may issue under the 2001 Plan may not exceed 5.0 million shares. The exercise price of an option shall not be less than the fair market value of one share of Common Stock on the date of grant. Options under the 2001 Plan generally vest in increments of 25% on each of the first four anniversary dates of the date of grant and have a term of ten years. Restricted stock awards generally vest three years from the date of the grant. As of December 31, 2008, the Company had 104,292 shares available to be issued under the 2001 Plan. As a result of the Spin-off, outstanding stock options and the shares available for grant for all employees under the 2001 Plan were adjusted to reflect the economic effect of the Spin-off.

Stock Options

The following table summarizes stock option activity in the Company's stock-based compensation plans for the years ended December 31, 2008, 2007, and 2006. During 2006 the number of shares and the exercise price of the outstanding stock options were adjusted so that the fair value of each award was the same immediately before and after the Spin-off, in accordance with anti-dilution provisions of the incentive plans.

	Number of Shares	Weighted Average Exercise Price	Aggregate Intrinsic Value (In Thousands)[1]	Number of Shares Exercisable
Outstanding at January 1, 2006	2,578,235	$27.78	$45,889	1,348,599
Granted	—	—		
Exercised	(58,337)	28.71	1,255	
Cancelled	(98,587)	30.91		
Outstanding at March 2, 2006	2,421,311	27.63	55,723	
Adjustment to give effect to Spin-off	1,176,804	—		
Granted	55,000	36.61		
Exercised	(231,470)	18.96	3,536	
Cancelled	(93,366)	20.94		
Outstanding at December 31, 2006	3,328,279	18.80	46,279	2,338,751
Granted	666,655	42.16		
Exercised	(652,220)	18.07	15,610	
Cancelled	(401,208)	40.07		
Outstanding at December 31, 2007	2,941,506	21.35	87,816	2,275,314
Granted	—	—		
Exercised	(788,641)	21.14	30,372	
Cancelled	(55,598)	32.88		
Outstanding at December 31, 2008	2,097,267	21.13	376	1,898,316

(1) The intrinsic value of a stock option is the amount by which the current market value of the underlying stock exceeds the exercise price of the option.

(7) STOCK-BASED COMPENSATION: (Continued)

Stock options are granted at the fair market value of one share of Common Stock on the date of grant. Options granted to non-employee directors vest immediately and options granted to officers and other employees vest ratably over four years. All outstanding options had a term of ten years at the date of grant.

The fair value of each option granted in 2007 and 2006 was estimated using the Black-Scholes option pricing model. The following assumptions were used to compute the weighted average fair market value of options granted during the periods presented:

	2007	2006
Expected life of options	5.4 years	10 years
Risk free interest rates	4.65% - 5.13%	4.64% - 5.13%
Estimated volatility	32%	45%
Dividend yield	0.0%	0.0%
Weighted average fair market value of options granted during the year	$16.14	$23.35

The following table summarizes information about options outstanding at December 31, 2008:

	Stock Options Outstanding				Stock Options Exercisable		
Range of Exercise Prices	Number of Options	Weighted Average Remaining Contractual Life (Years)	Weighted Average Exercise Price	Aggregate Intrinsic Value (In Thousands)	Number Exercisable	Weighted Average Exercise Price	Aggregate Intrinsic Value (In Thousands)
$10.01 - 16.10	424,817	4.20	$15.22	$376	424,817	$15.22	$376
16.11 - 16.85	514,371	4.49	16.84	—	514,371	16.84	—
16.88 - 20.47	308,394	2.82	18.83	—	306,908	18.82	—
20.60 - 20.60	454,825	5.74	20.60	—	454,825	20.60	—
20.71 - 42.41	394,860	7.28	35.46	—	197,395	31.13	—
$10.01 - 42.41	2,097,267	4.98	$21.13	$376	1,898,316	$19.18	$376

(7) STOCK-BASED COMPENSATION: (Continued)

Restricted Stock and Phantom Stock Units

The following table summarizes the restricted stock and phantom stock unit activity for the years ended December 31, 2008, 2007, and 2006. The grant date fair value of the restricted stock and phantom stock units was determined by reference to the average of 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.

	Restricted Stock		Phantom Stock Units	
	Number of Shares	Weighted Average Grant Date Fair Value	Number of Shares	Weighted Average Grant Date Fair Value
Unvested at January 1, 2006	634,000	$43.58	72,350	$46.07
Awarded	38,200	39.24	13,900	36.24
Vested	(200)	46.07	—	—
Forfeited	(44,550)	45.95	(8,300)	46.07
Unvested at December 31, 2006	627,450	43.15	77,950	44.32
Awarded	784,700	42.17	90,700	41.01
Vested	(82,450)	30.26	—	—
Forfeited	(48,700)	42.20	(4,150)	44.17
Unvested at December 31, 2007	1,281,000	43.41	164,500	42.50
Awarded	759,295	62.55	84,754	61.73
Vested	(473,800)	45.66	(70,300)	45.06
Forfeited	(75,700)	46.14	(15,000)	45.15
Unvested at December 31, 2008	1,490,795	52.31	163,954	51.10

The restricted stock and phantom stock units generally vest on the third anniversary of the date of the award, but may vest earlier upon a qualifying disability, death, retirement, or a change in control of the Company in accordance with the term of the underlying agreement. The phantom stock units can be settled in cash, shares of Common Stock, or a combination of both. The phantom stock units have been accounted for as a liability within the consolidated financial statements.

Employee Stock Purchase Plan

The Company has a 1999 Employee Stock Purchase Plan (the "ESPP"), under which it is authorized to issue up to 300,000 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, 2008, the Company had 83,835 shares available for issuance under the ESPP.

(7) STOCK-BASED COMPENSATION: (Continued)

The fair value of each stock purchase right granted under the ESPP during 2008, 2007, and 2006 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:

	2008	2007	2006
Expected option life	3 months	3 months	3 months
Risk free interest rates	0.85% - 1.96%	3.92% - 5.07%	4.16% - 5.08%
Estimated volatility	76%	26%	21%
Dividend yield	0.0%	0.0%	0.0%
Weighted average fair market value of purchase rights granted	$11.72	$10.88	$9.38

(8) 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"). The Wiser Pension Plan was curtailed and all benefit accruals were suspended effective December 11, 1998. In October 2000, the Wiser Pension Plan was amended to provide additional benefits by implementing a cash balance plan for the then current employees of Wiser. In December 2004, all benefit accruals under the Wiser Pension Plan were suspended. In conjunction with the Houston Exploration acquisition in June 2007, Forest assumed a non-qualified unfunded supplementary retirement plan (the "Houston Exploration SERP" 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 employees in the U.S. and Canada, their beneficiaries, and covered dependents. These benefits, which consist primarily of medical benefits payable on behalf of retirees in the U.S. and Canada, are referred to as "Postretirement Benefits" throughout this Note. The postretirement benefits in Canada are closed to new participants.

(8) EMPLOYEE BENEFITS: (Continued)

Investments of the Plans

The weighted average asset allocations of the Forest Pension Plan and Wiser Pension Plan at December 31, 2008 and 2007 are set forth in the following table:

	Forest Pension Plan		Wiser Pension Plan	
	2008	2007	2008	2007
Fixed income securities	39%	33%	38%	29%
Equity securities	59%	66%	61%	70%
Other	2%	1%	1%	1%
	100%	100%	100%	100%

The overall investment goal for pension plan assets is to achieve an investment return that allows plan 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 Stock Index.

The 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 each of the Plans. Generally, the strategy includes allocating the 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.

Expected Benefit Payments

In the future, 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 other postretirement benefits plans in 2009 through 2013 and in the aggregate for the years 2014 through 2018 in the following amounts:

	2009	2010	2011	2012	2013	2014-2018
			(In Thousands)			
Forest Pension Plan[1]	$2,467	2,447	2,413	2,359	2,366	10,801
SERP	159	155	151	147	142	629
Wiser Pension Plan[1]	836	835	827	817	812	4,093
Postretirement benefits (U.S.)	556	555	560	540	533	2,625
Postretirement benefits (Canada)	49	59	61	64	66	363

(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 2009 totaling $.2 million to the Plans and $.5 million for the Postretirement Benefit plans, net of retiree contributions and expected Medicare reimbursements, as applicable.

The following tables set forth the estimated benefit obligations, the fair value of the assets, and the funded status of the Plans and the Postretirement Benefit plans at December 31, 2008 and 2007.

(8) EMPLOYEE BENEFITS: (Continued)

Amounts for the Forest Pension Plan, the SERP, and the Wiser Pension Plan are combined in the "Pension Benefits" columns.

Benefit Obligations

	Pension Benefits		Postretirement Benefits	
	2008	2007	2008	2007
	(In Thousands)			
Benefit obligation at the beginning of the year	$40,421	40,556	8,576	8,457
Acquisition	—	1,064	(585)	585
Service cost	—	—	518	467
Interest cost	2,277	2,247	495	453
Actuarial loss (gain)	399	(164)	(599)	(1,210)
Benefits paid	(3,317)	(3,282)	(679)	(520)
Medicare reimbursements	—	—	59	57
Retiree contributions	—	—	68	67
Impact of foreign currency exchange rate	—	—	(234)	220
Benefit obligation at the end of the year	$39,780	40,421	7,619	8,576

Fair Value of Plan Assets

	Pension Benefits		Postretirement Benefits	
	2008	2007	2008	2007
	(In Thousands)			
Fair value of plan assets at beginning of the year	$ 37,831	37,615	—	—
Actual return on plan assets	(10,652)	2,875	—	—
Retiree contributions	—	—	68	67
Medicare reimbursements	—	—	59	57
Employer contribution	589	623	552	396
Benefits paid	(3,317)	(3,282)	(679)	(520)
Fair value of plan assets at the end of the year	$ 24,451	37,831	—	—

Funded Status

	Pension Benefits		Postretirement Benefits	
	2008	2007	2008	2007
	(In Thousands)			
Excess of benefit obligation over plan assets	$(15,329)	(2,590)	(7,619)	(8,576)
Unrecognized actuarial loss (gain)	22,026	9,169	(1,932)	(1,326)
Net amount recognized	$ 6,697	6,579	(9,551)	(9,902)
Amounts recognized in the balance sheet consist of:				
Accrued benefit liability—noncurrent	$(15,329)	(2,590)	(7,619)	(8,576)
Accumulated other comprehensive income—net actuarial loss (gain)	22,026	9,169	(1,932)	(1,326)
Net amount recognized	$ 6,697	6,579	(9,551)	(9,902)

(8) EMPLOYEE BENEFITS: (Continued)

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,	
	2008	2007
	(In Thousands)	
Projected benefit obligation	$39,780	40,421
Accumulated benefit obligation	39,780	40,421
Fair value of plan assets	24,451	37,831

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 for the years ended December 31, 2008, 2007, and 2006:

	Pension Benefits			Postretirement Benefits		
	2008	2007	2006	2008	2007	2006
				(In Thousands)		
Service cost	$ —	—	—	518	467	580
Interest cost	2,277	2,247	2,192	495	453	453
Curtailment gain[(1)]	—	—	—	—	—	(1,851)
Expected return on plan assets	(2,534)	(2,562)	(2,430)	—	—	—
Recognized actuarial loss (gain)	726	778	899	(91)	(35)	—
Amortization of prior service cost	—	—	10	—	—	—
Total net periodic expense (benefit)	$ 469	463	671	922	885	(818)
Assumptions used to determine net periodic expense:						
Discount rate	5.77%	5.64% & 5.90%	5.32%	5.39% & 6.02%	3.98% & 5.75%	4.72% & 5.46%
Expected return on plan assets	7%	7%	7% & 8%	n/a	n/a	n/a
Assumptions used to determine benefit obligations:						
Discount rate	5.84%	5.77%	5.64%	6.12% & 6.74%	5.39% & 6.02%	3.98% & 5.75%

(1) Forest recognized a $1.9 million curtailment gain in connection with the Spin-off on March 2, 2006. This gain was recorded as a reduction in general and administrative expense for the year ended December 31, 2006.

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 other postretirement benefit obligations and the duration of the Moody's Aa index.

The Company estimates that net periodic expense for the year ended December 31, 2009, will include expense of $1.8 million resulting from the amortization of its related accumulated actuarial loss included in accumulated other comprehensive income at December 31, 2008.

For measurement purposes, the annual rate of increase in the per capita cost of covered health care benefits for the U.S. Postretirement Benefits was held constant at 5.5% during 2008 and thereafter. The annual rate of increase in the per capita cost of covered health care benefits for the Canadian Postretirement Benefits was assumed to be 4% per year for the dental plan; and 10% in 2009, 9.5% in 2010, 9% in 2011, 8.5% in 2012, 8% in 2013, and 7.5% thereafter for the medical plan.

(8) **EMPLOYEE BENEFITS: (Continued)**

Assumed health care cost trend rates have a significant effect on the amounts reported for postretirement benefits. A one-percentage-point change in assumed health care cost trend rates would have the following effects for 2008:

	Postretirement Benefits	
	1% Increase	1% Decrease
	(In Thousands)	
Effect on service and interest cost components	$ 176	(124)
Effect on postretirement benefit obligation	1,143	(911)

Employee Retirement Savings Plans

Forest sponsors a qualified tax-deferred savings plan ("Retirement Savings Plan") for its employees in the U.S. in accordance with the provisions of Section 401(k) of the Internal Revenue Code. Employees may defer up to 80% of their compensation, subject to certain limitations. From January 1, 2004 through December 31, 2007, the Company matching percentage was 7% of eligible employee compensation. Effective January 1, 2008, the Company matching percentage increased to 8%. Expenses associated with the Company's contributions to the Retirement Savings Plan totaled $3.2 million in 2008, $2.2 million in 2007, and $1.9 million in 2006. In each of these years, the Company matched employee contributions in cash.

Canadian Forest provides a savings plan ("Canadian Savings Plan") that is available to all of its employees. Employees may contribute up to 9% of their compensation, subject to certain limitations, with Canadian Forest matching 4% of the eligible employee compensation. The expense associated with Canadian Forest's contributions to the plan was approximately $.2 million in 2008, $.3 million in 2007, and $.2 million in 2006. All employees of Canadian Forest also participate in a defined contribution pension plan (the "Defined Contribution Pension Plan"). The expense associated with the contributions made by Canadian Forest to the Defined Contribution Pension Plan was $.3 million in both 2008 and 2007, and $.2 million in 2006.

Deferred Compensation Plan

Forest has an Executive Deferred Compensation Plan (the "Executive Plan") pursuant to which certain officers may participate and defer a portion of their compensation after contributing the maximum allowable amount to the Retirement Savings Plan. The expense associated with the Company's matching contributions to the Executive Plan and interest was $.2 million in both 2008 and 2007, and $.3 million in 2006. The Executive Plan provides for the participants to designate how deferred amounts are deemed to be invested under several investment options. As a result, the liability recorded with respect to the deferred amounts fluctuates based on gains and losses associated with investment options selected by the participants. Total amounts deferred (including the related investment gains and losses) under the Executive Plan were approximately $3.1 million at both December 31, 2008 and 2007, respectively.

In conjunction with the Houston Exploration acquisition, Forest assumed Houston Exploration's deferred compensation plan (the "Houston Exploration Plan"). The Houston Exploration Plan was frozen to new employees, and all deferrals into the plan (including matching contributions) were suspended on January 1, 2008. The assets of the Houston Exploration Plan are held by a grantor trust and are invested, at the direction of the employee, in various investment funds. The assets held in the trust (the main component of which is trust-owned life insurance policies) were $4.3 million and $10.5 million at December 31, 2008 and 2007, respectively. The expense associated with the Company's matching contributions to the Houston Exploration Plan was $.1 million in 2007. Total amounts deferred under the Houston Exploration Plan were $3.1 million and $7.4 million at December 31, 2008 and 2007.

Split Dollar Life Insurance

The Company 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. On January 1, 2008, the Company adopted Emerging Issues Task Force ("EITF") Issue No. 06-4, *Accounting for Deferred Compensation and Postretirement Benefit Aspects of Endorsement Split-Dollar Life Insurance Arrangements* ("EITF 06-4"), and EITF Issue No. 06-10, *Accounting for Collateral Assignment Split-Dollar Life Insurance Arrangements* ("EITF 06-10"). Pursuant to these pronouncements, the Company recognized a liability for the estimated cost of maintaining the insurance policies during the postretirement periods of the retirees and former executives in accordance with SFAS No. 106, *Employers' Accounting for Postretirement Benefits Other Than Pensions* ("SFAS 106"). Upon adoption, Forest recorded a $9.0 million liability as a change in accounting principle through a cumulative effect adjustment to retained earnings. The weighted average discount rate used to determine the initial postretirement benefit obligation and accretion expense for 2008 was 5.55%. The weighted average discount rate used to determine the postretirement benefit obligation as of December 31, 2008 was 5.64%. The Company's estimate of costs expected to be paid in 2009 to maintain these life insurance policies is $.9 million. Accretion of the discounted life insurance obligations totaled $.5 million during 2008. As of December 31, 2008, the Consolidated Balance Sheet includes a liability associated with the life insurance policies of $6.8 million and an asset of $2.6 million, with the asset representing the estimated cash surrender value of the life insurance policies.

(9) FAIR VALUE MEASUREMENTS:

In September 2006, the FASB issued SFAS No. 157, *Fair Value Measurements* ("SFAS 157"). This statement clarifies the definition of fair value, establishes a framework for measuring fair value, and expands disclosures about fair value measurements. The Company adopted the provisions of SFAS 157 as of January 1, 2008 for all financial and nonfinancial assets and liabilities recognized or disclosed at fair value on a recurring basis. The Company has also adopted SFAS 157 as it relates to all nonfinancial assets and liabilities that are not recognized or disclosed on a recurring basis as of January 1, 2009 pursuant to the provisions of FASB Staff Position No. FAS 157-2, *Effective Date of FASB Statement No. 157*. The adoption of SFAS 157 did not materially impact the Company's financial position, results of operations, or cash flow.

SFAS 157 establishes a three-tier fair value hierarchy, which prioritizes the inputs used to measure fair value. These tiers include: 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.

As of December 31, 2008, the Company held certain financial assets and liabilities that are required to be measured at fair value on a recurring basis, including: (i) the Company's commodity derivative instruments and (ii) other investments, which are comprised of the PERL Note and the PERL Shares discussed in Note 2 to these Consolidated Financial Statements.

At December 31, 2008, the Company used the market approach in determining the fair value of the PERL Shares, which are included within the Level 1 fair value hierarchy. Because the PERL Shares were initially restricted and not registered for public sale, they could not be valued within the

Level 1 fair value hierarchy prior to the lapsing of the restriction in August 2008. The PERL Shares were instead included within the Level 2 fair value hierarchy during this time, with the Company using the income approach in determining their fair value, utilizing an option-pricing model.

The Company used the income approach in determining the fair value of its derivative instruments, utilizing present value techniques for valuing its swaps and basis swaps and option-pricing models for valuing its collars. 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 these inputs are observable, either directly or indirectly; therefore, the Company's derivative instruments are included within the Level 2 fair value hierarchy.

The Company also used the income approach, utilizing present value techniques, in determining the fair value of its PERL Note. Inputs to this valuation technique include various premiums that take into account specific risks related to the issuer of the PERL Note. These inputs include both observable and unobservable inputs that are significant to the valuation, with the unobservable inputs reflecting the Company's own assumptions about the assumptions that market participants would use in pricing the PERL Note; therefore, the PERL Note is included within the Level 3 fair value hierarchy.

The Company's assets and liabilities measured and carried at fair value on a recurring basis at December 31, 2008, were as follows:

Description	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)		
Assets:				
Derivative instruments	$ —	173,995	—	173,995
Other investments	657	—	1,670	2,327
Liabilities:				
Derivative instruments	—	(3,884)	—	(3,884)

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, 2008.

	Other Investments
	(In Thousands)
Balance at December 31, 2007	$ 15,023
Total gains or (losses) (realized/unrealized):	
Included in earnings	(13,353)
Included in other comprehensive income	—
Purchases, sales, issuances, and settlements (net)	—
Transfers in and/or out of Level 3	—
Balance at December 31, 2008	$ 1,670
The amount of total gains or (losses) for the period included in earnings attributable to the change in unrealized gains or losses relating to assets still held at December 31, 2008	$(15,027)

(9) FAIR VALUE MEASUREMENTS: (Continued)

Gains and 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 year ended December 31, 2008 are reported in the Consolidated Statements of Operations as follows:

	Unrealized Losses on Other Investments, Net	Other Expense, Net[1]
	(In Thousands)	
Total (gains) or losses included in earnings for the period	$15,027	(1,674)
Change in unrealized (gains) or losses relating to assets still held at December 31, 2008	$15,027	—

(1) Represents imputed interest income on the PERL Note.

(10) DERIVATIVE INSTRUMENTS:

Commodity Derivatives

Forest periodically enters into derivative instruments such as swap, basis swap, and collar agreements in order to provide a measure of stability to Forest's cash flows in an environment of volatile oil and gas prices 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, the Company has elected not to account for the derivatives as cash flow hedges. As such, the Company recognizes all changes in fair value of its derivative instruments in earnings rather than deferring such amounts in accumulated other comprehensive income included in shareholders' equity, as would be done if cash flow hedge accounting were utilized. Forest is exposed to risks associated with swap and collar agreements arising from movements in the prices of oil and natural gas and from non-performance by the counterparties to the swap and collar agreements.

The tables below set forth Forest's outstanding commodity swaps and collars as of December 31, 2008. Subsequent to December 31, 2008 through February 25, 2009, the Company entered into additional natural gas swaps covering 100 Bbtu per day for Calendar 2010 at a weighted average hedged price per MMBtu of $6.52.

	Natural Gas (NYMEX HH)		Oil (NYMEX WTI)	
	Bbtu Per Day[1]	Weighted Average Hedged Price per MMBtu	Barrels Per Day	Weighted Average Hedged Price per Bbl
Swaps:				
Calendar 2009	160	$ 8.24	4,500	$69.01
Calendar 2010	—	—	1,500	72.95
Costless Collars:				
Calendar 2009	40	$7.31/9.76[2]	—	—

(1) 10 Bbtu per day is subject to a $6.00 written put.

(2) Represents weighted average hedged floor and ceiling price per MMBtu.

Forest also uses basis swaps in connection with natural gas swaps in order to fix the price differential between the NYMEX price and the index price at which the natural gas production is sold. As of December 31, 2008, the Company had basis swaps outstanding covering 185 Bbtu and 90 Bbtu per day for 2009 and 2010, respectively. Subsequent to December 31, 2008, through February 25, 2009, the Company entered into additional basis swaps covering 20 Bbtu per day for February 2009 through December 2009.

At December 31, 2008, the fair values of Forest's commodity derivative instruments are presented within the Consolidated Balance Sheet as assets of $174.0 million, of which $169.4 million is classified as current, and liabilities of $3.9 million, of which $1.3 million is classified as current. 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.

The table below summarizes the realized and unrealized gains and losses Forest incurred related to its commodity derivative instruments for the periods indicated.

	Year Ended December 31,		
	2008	2007	2006
	(In Thousands)		
Realized losses (gains) on derivatives not designated as cash flow hedges[1][2]	$ 55,072	(75,491)	23,864
Realized losses on derivatives designated as cash flow hedges[3]	—	—	43,813
Unrealized (gains) losses on derivatives not designated as cash flow hedges[1]	(216,769)	112,778	(78,056)
Ineffectiveness recognized on derivatives designated as cash flow hedges[1]	—	—	(5,573)
Realized and unrealized (gains) losses on commodity derivatives, net	$(161,697)	37,287	(15,952)

(1) Included in "Other income and expense" in the Consolidated Statement of Operations.

(2) The years ended December 31, 2008 and 2007 include proceeds of $19.2 million and $6.9 million, respectively, received upon termination of certain oil and gas swaps and collars.

(3) Included in "Revenues" in the Consolidated Statement of Operations. Realized gains or losses on derivatives that had previously been designated as cash flow hedges at the time the Company elected to discontinue hedge accounting were required to be included as part of "Revenues."

Interest Rate Derivatives

The Company may enter into interest rate swap agreements in an attempt to normalize the mix of fixed and floating interest rates within its debt portfolio. In June 2008, the Company terminated all of its outstanding interest rate swaps for a net gain of $.4 million. In February 2009, the Company entered into an interest rate swap intended to exchange the 8.5% fixed interest rate on $100.0 million of the 8½% Notes for a variable rate based on one-month LIBOR plus 6% over the term of the 8½% Notes.

The table below summarizes the realized and unrealized gains and losses Forest incurred related to its interest rate swaps for the periods indicated.

	Year Ended December 31,		
	2008	2007	2006
	(In Thousands)		
Realized losses (gains)[1][2]	$ 889	(474)	—
Unrealized (gains) losses[1]	(4,721)	4,721	—
Realized and unrealized (gains) losses on interest rate swaps, net	$(3,832)	4,247	—

(1) Included in "Other income and expense" in the Consolidated Statements of Operations.

(2) The year ended December 31, 2008 includes $.4 million of net proceeds received upon termination of the interest rate swaps.

(11) RELATED PARTY TRANSACTIONS:

Beginning in 1995, the Company consummated certain transactions with The Anschutz Corporation ("Anschutz") pursuant to which Anschutz acquired a significant ownership position in the Company. As of December 31, 2008, Anschutz owned approximately 8.1% of Forest's outstanding common stock. Based on reports filed with the SEC, as of January 15, 2009, Anschutz has entered into forward sales contracts covering a portion of its Forest common stock, although Anschutz retains voting rights for these shares through the settlement dates.

In 1998, Forest purchased certain oil and gas assets from Anschutz, including two concessions in South Africa. Over the years, the parties have entered into agreements concerning the development of these concession blocks. In March 2003, Forest entered into a Participation Agreement regarding the development of offshore South Africa acreage, including the Ibhubesi Gas Field, with The Petroleum Oil and Gas Corporation of South Africa (Pty) Limited ("PetroSA") and Anschutz Overseas South Africa (Pty) Limited ("Anschutz Overseas"). As of February 25, 2009, the parties' interests in the concessions were as follows: Forest 53.2%, Anschutz Overseas 22.8%, and PetroSA 24.0%. Forest is the operator of these concession blocks and is reimbursed by the partners for exploration expenditures and general, technical, and administrative overhead.

(12) COMMITMENTS AND CONTINGENCIES:

The table below shows the Company's future rental payments and unconditional purchase obligations as of December 31, 2008.

	2009	2010	2011	2012	2013	After 2013	Total
			(In Thousands)				
Operating leases[1]	$17,557	17,228	17,026	16,281	15,298	14,026	97,416
Unconditional purchase obligations[2]	44,614	7,419	772	278	—	—	53,083
	$62,171	24,647	17,798	16,559	15,298	14,026	150,499

(1) Includes future rental payments for office facilities, office equipment, drilling rigs, and vehicles under the remaining terms of non-cancelable operating leases.

(2) Includes unconditional purchase obligations for drilling rigs, pipeline capacity, and seismic and tubular purchases

Net rental payments under non-cancelable operating leases applicable to exploration and development activities and capitalized to oil and gas properties were $15.4 million in 2008, $8.0 million in 2007, and $2.2 million in 2006. Net rental payments under non-cancelable operating leases charged to expense amounted to $5.4 million in 2008, $4.5 million in 2007, and $3.5 million in 2006. The Company has no leases that are accounted for as capital leases.

Forest, in the ordinary course of business, is a party to various lawsuits, claims, and proceedings. While the Company believes that the amount of any potential loss upon resolution of these matters would not be material to our 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 in the reporting periods in which any such actions are resolved. Forest is also involved in a number of governmental proceedings in the ordinary course of business, including environmental matters.

(13) OTHER INCOME AND EXPENSE:

The components of other income and expense for the years ended December 31, 2008, 2007, and 2006 were as follows:

	Year Ended December 31,		
	2008	2007	2006
	(In Thousands)		
Franchise taxes	$1,612	2,322	1,410
Share of income of equity method investee	—	(275)	(2,334)
Debt extinguishment costs	97	12,215	—
Other, net	(133)	(2,214)	1,135
Total other expense, net	$1,576	12,048	211

(14) SELECTED QUARTERLY FINANCIAL DATA (unaudited):

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(In Thousands, Except Per Share Amounts)			
2008				
Revenue	$376,530	515,182	474,160	281,291
Net earnings (loss)[1]	$ (4,732)	(68,018)	429,007	(1,382,580)
Basic earnings (loss) per share	$ (.05)	(.78)	4.88	(14.50)
Diluted earnings (loss) per share	(.05)	(.78)	4.77	(14.50)
2007				
Revenue	$182,609	254,669	313,025	333,589
Net earnings[1]	$ 6,891	76,799	57,987	27,629
Basic earnings per share	$ .11	1.11	.67	.32
Diluted earnings per share	.11	1.08	.65	.31

(1) Net earnings have been subject to large fluctuations due to Forest's election not to use cash flow hedge accounting as discussed in Note 10.

(15) GEOGRAPHICAL SEGMENTS:

Segment information has been prepared in accordance with SFAS No. 131, *Disclosures About Segments of an Enterprise and Related Information.* At December 31, 2008, Forest conducted operations in one industry segment, that being the oil and gas exploration and production industry, and had three reportable geographical business segments: United States, Canada, and International. Forest's remaining activities are not significant and therefore are not reported as a separate segment, but are included as a reconciling item in the information below. The segments were determined based upon the

(15) GEOGRAPHICAL SEGMENTS: (Continued)

geographical location of operations in each business segment. The segment data presented below was prepared on the same basis as the Consolidated Financial Statements.

	Oil and Gas Operations			
	Year Ended December 31, 2008			
	United States	Canada	International	Total Company
	(In Thousands)			
Revenue	$ 1,396,669	250,502	—	1,647,171
Expenses:				
Lease operating expenses	131,756	36,074	—	167,830
Production and property taxes	78,488	3,659	—	82,147
Transportation and processing costs	9,866	9,606	—	19,472
Depletion	437,952	85,859	—	523,811
Impairment of oil and gas properties	2,369,055	—	—	2,369,055
Accretion of asset retirement obligations	6,387	1,130	85	7,602
Earnings (loss) from operations	$(1,636,835)	114,174	(85)	(1,522,746)
Capital expenditures[1]	$ 2,560,940	197,953	7,216	2,766,109
Goodwill	$ 239,420	14,226	—	253,646

(1) Includes estimated discounted asset retirement obligations of $15.0 million related to assets placed in service during the year ended December 31, 2008.

A reconciliation of segment earnings (loss) from operations to consolidated earnings (loss) before income taxes is as follows:

	(In Thousands)
Earnings (loss) from operations for reportable segments	$(1,522,746)
Marketing, processing, and other	(8)
General and administrative expense (including stock-based compensation)	(74,732)
Administrative asset depreciation	(8,370)
Interest expense	(125,679)
Realized and unrealized gains on derivative instruments, net	165,529
Realized and unrealized foreign currency exchange losses	(20,440)
Unrealized losses on other investments, net	(34,042)
Gain on sale of assets	21,063
Other expense, net	(1,576)
Earnings (loss) before income taxes	$(1,601,001)

(15) GEOGRAPHICAL SEGMENTS: (Continued)

	Oil and Gas Operations			
	Year Ended December 31, 2007			
	United States	Canada	International	Total Company
	(In Thousands)			
Revenue	$ 892,818	190,263	—	1,083,081
Expenses:				
Lease operating expenses	135,983	31,490	—	167,473
Production and property taxes	51,822	3,442	—	55,264
Transportation and processing costs	9,729	10,471	—	20,200
Depletion	301,048	84,181	—	385,229
Accretion of asset retirement obligations	5,111	903	50	6,064
Earnings (loss) from operations	$ 389,125	59,776	(50)	448,851
Capital expenditures[1]	$2,807,936	173,218	15,853	2,997,007
Goodwill	$ 248,138	17,480	—	265,618

(1) Includes estimated discounted asset retirement obligations of $37.8 million related to assets placed in service during the year ended December 31, 2007.

A reconciliation of segment earnings from operations to consolidated earnings before income taxes is as follows:

	(In Thousands)
Earnings from operations for reportable segments	$ 448,851
Marketing, processing, and other	811
General and administrative expense (including stock-based compensation)	(63,751)
Administrative asset depreciation	(5,109)
Interest expense	(113,162)
Realized and unrealized losses on derivative instruments, net	(41,534)
Unrealized foreign currency exchange gains	15,415
Unrealized losses on other investments, net	(4,948)
Gain on sale of assets	7,176
Other expense, net	(12,048)
Earnings before income taxes	$ 231,701

(15) GEOGRAPHICAL SEGMENTS: (Continued)

	Oil and Gas Operations			
	Year Ended December 31, 2006			
	United States	Canada	International	Total Company
	(In Thousands)			
Revenue	$636,897	177,572	—	814,469
Expenses:				
Lease operating expenses	126,647	28,227	—	154,874
Production and property taxes	36,060	2,981	—	39,041
Transportation and processing costs	11,941	9,935	—	21,876
Depletion	188,073	75,366	—	263,439
Accretion of asset retirement obligations	6,046	1,004	46	7,096
Impairment of oil and gas properties	—	—	3,668	3,668
Earnings (loss) from operations	$268,130	60,059	(3,714)	324,475
Capital expenditures[(1)]	$784,250	152,005	6,984	943,239
Goodwill	$ 71,377	14,869	—	86,246

(1) Includes estimated discounted asset retirement obligations of $2.4 million related to assets placed in service during the year ended December 31, 2006.

A reconciliation of segment earnings from operations to consolidated earnings before income taxes and discontinued operations is as follows:

	(In Thousands)
Earnings from operations for reportable segments	$324,475
Marketing, processing, and other	5,523
General and administrative expense (including stock-based compensation)	(48,308)
Administrative asset depreciation	(3,442)
Interest expense	(71,787)
Spin-off costs	(5,416)
Realized and unrealized gains on derivative instruments, net	59,765
Realized and unrealized foreign currency exchange losses, net	(3,616)
Other expense, net	(211)
Earnings before income taxes and discontinued operations	$256,983

Forest had revenue from two purchasers, which is reported in the United States segment, that exceeded 10% of Forest's consolidated revenue in 2008. These purchasers represented $213.8 million and $196.2 million of consolidated revenue, respectively. Forest had revenue from two purchasers that exceeded 10% of Forest's consolidated revenue in 2006. One of these purchasers represented $112.5 million of consolidated revenue, which was reported in the United States segment, and the other purchaser represented $102.9 million of consolidated revenue, which was reported in both the United States and Canada segments. There were no such purchasers in 2007.

(15) GEOGRAPHICAL SEGMENTS: (Continued)

The following tables set forth information regarding the Company's total assets by segment and long-lived assets by geographic area. Long-lived assets include net property and equipment and goodwill.

	Total Assets		
	December 31,		
	2008	2007	2006
	(In Thousands)		
United States	$4,476,489	4,828,582	2,534,087
Canada	726,895	791,714	595,341
International	79,414	75,252	59,644
Total assets	$5,282,798	5,695,548	3,189,072

	Long-Lived Assets		
	December 31,		
	2008	2007	2006
	(In Thousands)		
United States	$3,998,129	4,487,257	2,278,733
Canada	691,009	730,418	538,844
International	77,672	73,758	58,595
Total long-lived assets	$4,766,810	5,291,433	2,876,172

(16) CONDENSED CONSOLIDATING FINANCIAL INFORMATION:

The Company's 8% senior notes due 2011, 7¾% senior notes due 2014, and 7¼% senior notes due 2019, as well as the 8½% senior notes due 2014, 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, 2008 and 2007, and for the three years in the period ended December 31, 2008 on an issuer (parent company), guarantor subsidiary, non-guarantor subsidiaries, eliminating entries, and consolidated basis. Eliminating entries presented are necessary to combine the entities.

(16) CONDENSED CONSOLIDATING FINANCIAL INFORMATION: (Continued)

CONDENSED CONSOLIDATING BALANCE SHEETS

(In Thousands)

	December 31, 2008					December 31, 2007				
	Parent Company	Guarantor Subsidiary	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated	Parent Company	Guarantor Subsidiary	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
ASSETS										
Current assets:										
Cash and cash equivalents	$ 1,226	74	905	—	**2,205**	1,189	386	8,110	—	**9,685**
Accounts receivable	106,941	22,003	28,584	(302)	**157,226**	121,698	8,979	80,890	(9,950)	**201,617**
Other current assets	304,424	471	8,723	—	**313,618**	140,752	273	9,047	—	**150,072**
Total current assets	412,591	22,548	38,212	(302)	**473,049**	263,639	9,638	98,047	(9,950)	**361,374**
Property and equipment, at cost	7,327,978	1,259,337	1,465,891	—	**10,053,206**	5,363,127	240,748	2,194,490	—	**7,798,365**
Less accumulated depreciation, depletion and amortization	4,145,061	727,858	667,123	—	**5,540,042**	1,852,033	82,743	837,774	—	**2,772,550**
Net property and equipment	3,182,917	531,479	798,768	—	**4,513,164**	3,511,094	158,005	1,356,716	—	**5,025,815**
Investment in subsidiaries	577,405	—	—	(577,405)	**—**	740,964	—	—	(740,964)	**—**
Note receivable from subsidiary	93,052	—	—	(93,052)	**—**	73,307	—	—	(73,307)	**—**
Goodwill	216,460	22,960	14,226	—	**253,646**	225,178	—	40,440	—	**265,618**
Due from (to) parent and subsidiaries	391,074	141,656	(532,730)	—	**—**	308,381	28,409	(336,790)	—	**—**
Other assets	40,607	5	2,327	—	**42,939**	39,424	1	3,316	—	**42,741**
	$4,914,106	718,648	320,803	(670,759)	**5,282,798**	5,161,987	196,053	1,161,729	(824,221)	**5,695,548**
LIABILITIES AND SHAREHOLDERS' EQUITY										
Current liabilities:										
Accounts payable and accrued liabilities	$ 338,754	27,631	58,858	(302)	**424,941**	293,523	9,810	67,706	(9,950)	**361,089**
Current portion of long-term debt	—	—	—	—	**—**	266,002	—	—	—	**266,002**
Other current liabilities	88,064	1,165	7,241	—	**96,470**	103,288	1,012	6,991	—	**111,291**
Total current liabilities	426,818	28,796	66,099	(302)	**521,411**	662,813	10,822	74,697	(9,950)	**738,382**
Long-term debt	2,641,246	—	94,415	—	**2,735,661**	1,373,909	—	129,126	—	**1,503,035**
Note payable to parent	—	—	93,052	(93,052)	**—**	—	—	73,307	(73,307)	**—**
Other liabilities	128,017	3,397	35,813	—	**167,227**	136,362	1,690	50,841	—	**188,893**
Deferred income taxes	45,113	61,383	79,091	—	**185,587**	577,092	62,509	213,826	—	**853,427**
Total liabilities	3,241,194	93,576	368,470	(93,354)	**3,609,886**	2,750,176	75,021	541,797	(83,257)	**3,283,737**
Shareholders' equity	1,672,912	625,072	(47,667)	(577,405)	**1,672,912**	2,411,811	121,032	619,932	(740,964)	**2,411,811**
	$4,914,106	718,648	320,803	(670,759)	**5,282,798**	5,161,987	196,053	1,161,729	(824,221)	**5,695,548**

(16) CONDENSED CONSOLIDATING FINANCIAL INFORMATION: (Continued)

CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS

(In Thousands)

	Year Ended December 31,														
	2008					2007					2006				
	Parent Company	Guarantor Subsidiary	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated	Parent Company	Guarantor Subsidiary	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated	Parent Company	Guarantor Subsidiary	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
Revenues	$ 1,128,098	109,094	409,971	—	**1,647,163**	649,502	73,588	363,506	(2,704)	**1,083,892**	473,325	72,132	277,266	(2,731)	**819,992**
Operating expenses:															
Lease operating expenses	108,680	14,422	44,619	109	**167,830**	79,745	15,853	71,891	(16)	**167,473**	100,060	14,357	40,562	(105)	**154,874**
Other direct operating costs	75,493	8,180	17,946	—	**101,619**	50,651	5,475	19,338	—	**75,464**	38,219	6,315	16,383	—	**60,917**
General and administrative (including stock-based compensation)	64,826	336	9,570	—	**74,732**	51,022	119	12,610	—	**63,751**	40,960	182	7,166	—	**48,308**
Depreciation and depletion	361,443	25,780	145,125	(167)	**532,181**	229,069	19,186	142,094	(11)	**390,338**	140,442	19,253	107,186	—	**266,881**
Impairment of oil and gas properties	1,881,808	34,015	453,232	—	**2,369,055**	—	—	—	—	**—**	—	—	3,668	—	**3,668**
Gain on sale of assets	—	—	(21,063)	—	**(21,063)**	—	—	(7,176)	—	**(7,176)**	—	—	—	—	**—**
Other operating expenses	6,098	180	1,324	—	**7,602**	3,844	192	2,028	—	**6,064**	10,975	127	1,410	—	**12,512**
Total operating expenses	2,498,348	82,913	650,753	(58)	**3,231,956**	414,331	40,825	240,785	(27)	**695,914**	330,656	40,234	176,375	(105)	**547,160**
Earnings (loss) from operations	(1,370,250)	26,181	(240,782)	58	**(1,584,793)**	235,171	32,763	122,721	(2,677)	**387,978**	142,669	31,898	100,891	(2,626)	**272,832**
Equity earnings in subsidiaries	(112,817)	—	—	112,817	**—**	2,119	—	—	(2,119)	**—**	85,360	—	—	(85,360)	**—**
Other income and expense:															
Interest expense	111,316	—	31,452	(17,089)	**125,679**	74,727	9	54,727	(16,301)	**113,162**	61,673	111	19,457	(9,454)	**71,787**
Realized and unrealized (gains) losses on derivative instruments, net	(75,236)	(53,769)	(36,524)	—	**(165,529)**	7,750	7,181	26,603	—	**41,534**	(48,696)	(13,454)	2,385	—	**(59,765)**
Realized and unrealized foreign currency exchange losses (gains), net	—	—	20,440	—	**20,440**	—	—	(15,415)	—	**(15,415)**	—	—	70	3,546	**3,616**
Unrealized losses on other investments, net	34,042	—	—	—	**34,042**	4,948	—	—	—	**4,948**	—	—	—	—	**—**
Other (income) expense, net	(13,334)	(10)	(3,130)	18,050	**1,576**	(78,759)	755	9,148	80,904	**12,048**	(9,820)	696	(119)	9,454	**211**
Total other income and expense	56,788	(53,779)	12,238	961	**16,208**	8,666	7,945	75,063	64,603	**156,277**	3,157	(12,647)	21,793	3,546	**15,849**
Earnings (loss) before income taxes	(1,539,855)	79,960	(253,020)	111,914	**(1,601,001)**	228,624	24,818	47,658	(69,399)	**231,701**	224,872	44,545	79,098	(91,532)	**256,983**
Income tax	(513,532)	28,586	(89,732)	—	**(574,678)**	59,318	9,242	(6,165)	—	**62,395**	56,370	18,344	16,189	—	**90,903**
Earnings (loss) from continuing operations	(1,026,323)	51,374	(163,288)	111,914	**(1,026,323)**	169,306	15,576	53,823	(69,399)	**169,306**	168,502	26,201	62,909	(91,532)	**166,080**
Income from discontinued operations, net of tax	—	—	—	—	**—**	—	—	—	—	**—**	—	—	2,422	—	**2,422**
Net earnings (loss)	$(1,026,323)	51,374	(163,288)	111,914	**(1,026,323)**	$169,306	15,576	53,823	(69,399)	**169,306**	$168,502	26,201	65,331	(91,532)	**168,502**

(16) CONDENSED CONSOLIDATING FINANCIAL INFORMATION:

CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS

(In Thousands)

	Year Ended December 31,											
	2008				2007				2006			
	Parent Company	Guarantor Subsidiary	Combined Non-Guarantor Subsidiaries	Consolidated	Parent Company	Guarantor Subsidiary	Combined Non-Guarantor Subsidiaries	Consolidated	Parent Company	Guarantor Subsidiary	Combined Non-Guarantor Subsidiaries	Consolidated
Operating activities:												
Net earnings (loss)	$ (913,506)	51,374	(164,191)	**(1,026,323)**	99,907	15,576	53,823	**169,306**	76,970	26,201	65,331	**168,502**
Adjustments to reconcile net earnings (loss) to net cash provided by operating activities:												
Depreciation and depletion	361,443	25,780	144,958	**532,181**	229,069	19,186	142,083	**390,338**	140,442	19,253	107,186	**266,881**
Unrealized (gains) losses on derivative instruments, net	(110,904)	(69,091)	(41,495)	**(221,490)**	69,053	11,318	37,128	**117,499**	(67,022)	(20,241)	3,634	**(83,629)**
Deferred income tax	(521,281)	28,586	(93,122)	**(585,817)**	53,192	9,242	(6,038)	**56,396**	54,384	18,344	17,276	**90,004**
Impairment of oil and gas properties	1,881,808	34,015	453,232	**2,369,055**	—	—	—	**—**	—	—	3,668	**3,668**
Other, net	53,485	180	1,019	**54,684**	14,154	192	(5,907)	**8,439**	24,357	127	5,682	**30,166**
Changes in operating assets and liabilities, net of effects of acquisitions and divestitures:												
Accounts receivable	20,872	3,709	18,273	**42,854**	6,825	449	(6,921)	**353**	8,200	1,511	(10,351)	**(640)**
Other current assets	(78,166)	56	(2,104)	**(80,214)**	(3,250)	2,107	2,700	**1,557**	(32,109)	(2,105)	(5,646)	**(39,860)**
Accounts payable and accrued liabilities	(3,532)	4,859	14,469	**15,796**	4,091	1,856	(15,539)	**(9,592)**	(5,791)	(3,098)	18,089	**9,200**
Accrued interest and other current liabilities	(30,258)	(549)	121	**(30,686)**	(3,226)	(207)	(22,618)	**(26,051)**	(18,791)	1,650	(4,673)	**(21,814)**
Net cash provided by operating activities	659,961	78,919	331,160	**1,070,040**	469,815	59,719	178,711	**708,245**	180,640	41,642	200,196	**422,478**
Investing activities:												
Acquisition of Houston Exploration, net of cash acquired	—	—	—	**—**	(775,365)	—	—	**(775,365)**	—	—	—	**—**
Capital expenditures for property and equipment	(1,828,225)	(124,247)	(452,021)	**(2,404,493)**	(423,526)	(30,605)	(365,773)	**(819,904)**	(573,602)	(32,366)	(310,430)	**(916,398)**
Proceeds from sales of assets	284,677	—	25,263	**309,940**	405,857	26,161	70,030	**502,048**	1,074	357	5,076	**6,507**
Other, net	933	(4)	131	**1,060**	—	—	—	**—**	—	—	—	**—**
Net cash used by investing activities	(1,542,615)	(124,251)	(426,627)	**(2,093,493)**	(793,034)	(4,444)	(295,743)	**(1,093,221)**	(572,528)	(32,009)	(305,354)	**(909,891)**
Financing activities:												
Proceeds from bank borrowings	2,847,000	—	356,360	**3,203,360**	1,308,000	—	228,526	**1,536,526**	1,398,102	—	164,676	**1,562,778**
Repayments of bank borrowings	(1,822,000)	—	(373,101)	**(2,195,101)**	(1,166,000)	—	(199,178)	**(1,365,178)**	(1,296,000)	—	(136,574)	**(1,432,574)**
Repayments of debt	—	—	—	**—**	(176,885)	—	(375,000)	**(551,885)**	—	—	—	**—**
Issuance of 7¼% senior notes, net of issuance costs	247,188	—	—	**247,188**	739,176	—	—	**739,176**	—	—	—	**—**
Redemption of 8% senior notes	(265,000)	—	—	**(265,000)**	—	—	—	**—**	—	—	—	**—**
Repurchase of 7% senior subordinated notes	(4,710)	—	—	**(4,710)**	—	—	—	**—**	—	—	—	**—**
Proceeds from Alaska Credit Agreements, net of issuance costs	—	—	—	**—**	—	—	—	**—**	—	—	367,706	**367,706**
Net activity in investments of subsidiaries	(147,079)	42,755	104,324	**—**	(389,846)	(55,578)	445,424	**—**	264,058	(10,109)	(253,949)	**—**
Other, net	27,292	2,265	964	**30,521**	9,192	563	(8,842)	**913**	24,537	602	(9,217)	**15,922**
Net cash provided (used) by financing activities	882,691	45,020	88,547	**1,016,258**	323,637	(55,015)	90,930	**359,552**	390,697	(9,507)	132,642	**513,832**
Effect of exchange rate changes on cash	—	—	(285)	**(285)**	—	—	1,945	**1,945**	—	—	(486)	**(486)**
Net increase (decrease) in cash and cash equivalents	37	(312)	(7,205)	**(7,480)**	418	260	(24,157)	**(23,479)**	(1,191)	126	26,998	**25,933**
Cash and cash equivalents at beginning of period	1,189	386	8,110	**9,685**	771	126	32,267	**33,164**	1,962	—	5,269	**7,231**
Cash and cash equivalents at end of period	$ 1,226	74	905	**2,205**	1,189	386	8,110	**9,685**	771	126	32,267	**33,164**

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

The following information is presented in accordance with SFAS No. 69, *Disclosures about Oil and Gas Producing Activities*.

(A) Costs Incurred in Oil and Gas Acquisition, Exploration, and Development Activities. The following costs were incurred in oil and gas acquisition, exploration, and development activities during the years ended December 31, 2008, 2007, and 2006:

	United States	Canada	International	Total
		(In Thousands)		
2008				
Property acquisition costs:				
Proved properties	$ 804,616	—	—	804,616
Unproved properties	566,952	—	—	566,952
Exploration costs	290,066	51,628	6,507	348,201
Development costs	899,306	146,325	709	1,046,340
Total costs incurred[1]	$2,560,940	197,953	7,216	2,766,109
2007				
Property acquisition costs:				
Proved properties	$1,744,087	6	—	1,744,093
Unproved properties	449,346	—	—	449,346
Exploration costs	96,483	35,861	15,853	148,197
Development costs	518,020	137,351	—	655,371
Total costs incurred[1]	$2,807,936	173,218	15,853	2,997,007
2006				
Property acquisition costs:				
Proved properties	$ 262,534	—	—	262,534
Unproved properties	53,788	—	—	53,788
Exploration costs	155,824	99,657	6,984	262,465
Development costs	312,104	52,348	—	364,452
Total costs incurred[1]	$ 784,250	152,005	6,984	943,239

(1) Includes amounts relating to estimated asset retirement obligations of $15.0 million, $37.8 million, and $2.4 million for assets placed in service in the years ended December 31, 2008, 2007, and 2006, respectively.

(B) Aggregate Capitalized Costs. The aggregate capitalized costs relating to oil and gas activities at the end of each of the years indicated were as follows:

	2008	2007	2006
		(In Thousands)	
Costs related to proved properties	$ 8,952,292	7,157,249	4,751,171
Costs related to unproved properties	964,027	568,510	261,259
	9,916,319	7,725,759	5,012,430
Less accumulated depletion	(5,502,782)	(2,742,539)	(2,265,018)
	$ 4,413,537	$4,983,220	2,747,412

(17) **SUPPLEMENTAL FINANCIAL DATA—OIL AND GAS PRODUCING ACTIVITIES (unaudited): (Continued)**

(C) Results of Operations from Producing Activities. Results of operations from producing activities for the years ended December 31, 2008, 2007, and 2006 are presented below.

	United States	Canada	Total
	(In Thousands)		
2008			
Oil and gas sales	$ 1,396,669	250,502	1,647,171
Expenses:			
Production expense	220,110	49,339	269,449
Depletion expense	437,952	85,859	523,811
Impairment of oil and gas properties	2,369,055	—	2,369,055
Accretion of asset retirement obligations	6,387	1,130	7,517
Income tax	(591,388)	33,721	(557,667)
Total expenses	2,442,116	170,049	2,612,165
Results of operations from producing activities	$(1,045,447)	80,453	(964,994)
Depletion rate per Mcfe	$ 2.74	2.87	2.76
2007			
Oil and gas sales	$ 892,818	190,263	1,083,081
Expenses:			
Production expense	197,534	45,403	242,937
Depletion expense	301,048	84,181	385,229
Accretion of asset retirement obligations	5,111	903	6,014
Income tax expense	139,696	16,486	156,182
Total expenses	643,389	146,973	790,362
Results of operations from producing activities	$ 249,429	43,290	292,719
Depletion rate per Mcfe	$ 2.42	2.68	2.47
2006			
Oil and gas sales	$ 636,897	177,572	814,469
Expenses:			
Production expense	174,648	41,143	215,791
Depletion expense	188,073	75,366	263,439
Accretion of asset retirement obligations	6,046	1,004	7,050
Income tax expense	103,498	17,970	121,468
Total expenses	472,265	135,483	607,748
Results of operations from producing activities	$ 164,632	42,089	206,721
Depletion rate per Mcfe	$ 2.09	2.42	2.17

(D) Estimated Proved Oil and Gas Reserves. The Company's estimates of its net proved and proved developed oil and gas reserves and changes for 2008, 2007, and 2006 follows. These estimates were made in accordance with guidelines established by the SEC. Proved oil and gas reserves are the estimated quantities of crude oil, natural gas, and natural gas liquids that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, that is, prices and costs as of the date the estimate is made. For the years ended December 31, 2008, 2007, and 2006 we engaged DeGolyer and MacNaughton, an independent petroleum engineering firm, to perform reserve audit services.

Prices include consideration of changes in existing prices provided only by contractual arrangement, but not on escalations based on future conditions. Prices do not include the effects of commodity hedges. Purchases of reserves in place represent volumes recorded on the closing dates of the acquisitions for financial accounting purposes.

Proved developed oil and gas reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Additional oil and gas expected to be obtained through the application of fluid injection or other improved recovery techniques for supplementing the natural forces and mechanisms of primary recovery are included as "proved developed reserves" only after testing by a pilot project or after the operation of an installed program has confirmed through production response that increased recovery will be achieved.

Proved undeveloped oil and gas reserves are reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

	Liquids (MBbls)				Gas (MMcf)				
	United States	Canada	Italy	Total	United States	Canada	Italy	Total	Total MMcfe
Balance at January 1, 2006	92,078	4,992	—	97,070	743,174	141,509	—	884,683	1,467,103
Revisions of previous estimates	26,286	735	—	27,021	(83,435)	28,451	—	(54,984)	107,142
Extensions and discoveries	4,850	1,107	—	5,957	102,173	52,333	—	154,506	190,248
Production	(6,887)	(1,139)	—	(8,026)	(48,674)	(24,350)	—	(73,024)	(121,180)
Sales of reserves in place	(13,047)	—	—	(13,047)	(248,028)	—	—	(248,028)	(326,310)
Purchases of reserves in place	3,889	—	—	3,889	114,886	—	—	114,886	138,220
Balance at December 31, 2006	107,169	5,695	—	112,864	580,096	197,943	—	778,039	1,455,223
Revisions of previous estimates	(836)	(357)	—	(1,193)	(21,202)	(12,837)	—	(34,039)	(41,197)
Extensions and discoveries	10,981	3,041	—	14,022	202,349	48,171	56,308	306,828	390,960
Production	(6,885)	(1,060)	—	(7,945)	(82,963)	(25,079)	—	(108,042)	(155,712)
Sales of reserves in place	(29,749)	—	—	(29,749)	(7,983)	—	—	(7,983)	(186,477)
Purchases of reserves in place	6,477	—	—	6,477	617,573	—	—	617,573	656,435
Balance at December 31, 2007	87,157	7,319	—	94,476	1,287,870	208,198	56,308	1,552,376	2,119,232
Revisions of previous estimates	(12,655)	(1,493)	—	(14,148)	(129,633)	1,813	—	(127,820)	(212,708)
Extensions and discoveries	17,571	4,112	—	21,683	351,628	50,817	—	402,445	532,543
Production	(6,929)	(1,102)	—	(8,031)	(118,120)	(23,313)	—	(141,433)	(189,619)
Sales of reserves in place	(3,884)	—	—	(3,884)	(69,554)	—	—	(69,554)	(92,858)
Purchases of reserves in place	19,024	—	—	19,024	397,392	—	—	397,392	511,536
Balance at December 31, 2008	100,284	8,836	—	109,120	1,719,583	237,515	56,308	2,013,406	2,668,126
Proved developed reserves at:									
December 31, 2006	73,239	5,041	—	78,280	407,965	158,174	—	566,139	1,035,819
December 31, 2007	61,650	4,947	—	66,597	900,483	163,438	28,154	1,092,075	1,491,657
December 31, 2008	64,014	5,827	—	69,841	1,039,586	192,338	28,154	1,260,078	1,679,124

(E) Standardized Measure of Discounted Future Net Cash Flows. Future oil and gas sales and production and development costs, which include costs related to plugging of wells, removal of facilities and equipment, and site restoration, have been estimated using prices and costs in effect at the end of

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

the years indicated, except in those instances where the sale of oil and natural gas is covered by contracts. Where the sale is covered by contracts, the applicable contract prices, including fixed and determinable escalations, were used for the duration of the contract. Thereafter, the current spot price was used. All cash flow amounts, including income taxes, are discounted at 10%.

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 natural gas reserves, less the tax bases of the properties involved. The future income tax expenses give effect to tax credits and allowances, but do not reflect the impact of general and administrative and interest expense.

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, 2008			
	United States	Canada	Italy	Total
		(In Thousands)		
Future oil and gas sales	$11,442,387	1,605,699	1,069,845	14,117,931
Future production costs	(3,193,613)	(349,487)	(72,891)	(3,615,991)
Future development costs	(1,895,124)	(145,415)	(37,067)	(2,077,606)
Future income taxes	(1,042,295)	(229,487)	(362,914)	(1,634,696)
Future net cash flows	5,311,355	881,310	596,973	6,789,638
10% annual discount for estimated timing of cash flows	(2,882,676)	(360,635)	(218,547)	(3,461,858)
Standardized measure of discounted future net cash flows	$ 2,428,679	520,675	378,426	3,327,780

	December 31, 2007			
	United States	Canada	Italy	Total
		(In Thousands)		
Future oil and gas sales	$14,248,411	1,850,767	957,010	17,056,188
Future production costs	(3,249,115)	(410,650)	(71,658)	(3,731,423)
Future development costs	(1,086,890)	(141,838)	(37,067)	(1,265,795)
Future income taxes	(2,504,853)	(277,975)	(348,467)	(3,131,295)
Future net cash flows	7,407,553	1,020,304	499,818	8,927,675
10% annual discount for estimated timing of cash flows	(3,790,817)	(388,956)	(208,767)	(4,388,540)
Standardized measure of discounted future net cash flows	$ 3,616,736	631,348	291,051	4,539,135

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

	December 31, 2006			
	United States	Canada	Italy	Total
		(In Thousands)		
Future oil and gas sales	$ 8,600,619	1,276,442	—	9,877,061
Future production costs	(2,349,072)	(287,054)	—	(2,636,126)
Future development costs	(681,060)	(87,555)	—	(768,615)
Future income taxes	(1,317,621)	(214,804)	—	(1,532,425)
Future net cash flows	4,252,866	687,029	—	4,939,895
10% annual discount for estimated timing of cash flows	(2,109,005)	(236,526)	—	(2,345,531)
Standardized measure of discounted future net cash flows	$ 2,143,861	450,503	—	2,594,364

(F) 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, 2008			
	United States	Canada	Italy	Total
		(In Thousands)		
Standardized measure of discounted future net cash flows relating to proved oil and gas reserves, at beginning of year	$ 3,616,736	631,348	291,051	4,539,135
Changes resulting from:				
Sales of oil and gas, net of production costs	(1,176,547)	(201,163)	—	(1,377,710)
Net changes in prices and future production costs	(3,134,532)	(330,774)	77,416	(3,387,890)
Net changes in future development costs	66,318	51,230	(416)	117,132
Extensions, discoveries, and improved recovery	1,337,152	266,578	—	1,603,730
Development costs incurred during the period	234,938	51,413	709	287,060
Revisions of previous quantity estimates	(316,030)	(15,250)	—	(331,280)
Changes in production rates, timing, and other	(109,990)	(43,484)	(44,457)	(197,931)
Sales of reserves in place	(214,872)	—	—	(214,872)
Purchases of reserves in place	904,289	—	—	904,289
Accretion of discount on reserves at beginning of year before income taxes	470,619	78,485	48,125	597,229
Net change in income taxes	750,598	32,292	5,998	788,888
Standardized measure of discounted future net cash flows relating to proved oil and gas reserves, at end of year	$ 2,428,679	520,675	378,426	3,327,780

The computation of the standardized measure of discounted future net cash flows relating to proved oil and gas reserves at December 31, 2008 was based on weighted average year-end spot natural gas prices of approximately $4.94 per Mcf in the United States, approximately $5.64 per Mcf in

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

Canada, and $19.00 per Mcf in Italy, and on weighted average year-end spot oil prices of approximately $29.42 per barrel in the United States and approximately $30.20 per barrel in Canada.

	December 31, 2007			
	United States	Canada	Italy	Total
	(In Thousands)			
Standardized measure of discounted future net cash flows relating to proved oil and gas reserves, at beginning of year	$2,143,861	450,503	—	2,594,364
Changes resulting from:				
Sales of oil and gas, net of production costs	(695,321)	(144,860)	—	(840,181)
Net changes in prices and future production costs	1,258,999	171,640	—	1,430,639
Net changes in future development costs	(78,440)	5,576	—	(72,864)
Extensions, discoveries, and improved recovery	445,794	115,047	481,250	1,042,091
Development costs incurred during the period	399,218	54,296	—	453,514
Revisions of previous quantity estimates	(85,383)	(48,806)	—	(134,189)
Changes in production rates, timing, and other	6,889	(2,197)	—	4,692
Sales of reserves in place	(871,495)	—	—	(871,495)
Purchases of reserves in place	1,369,079	—	—	1,369,079
Accretion of discount on reserves at beginning of year before income taxes	268,804	57,650	—	326,454
Net change in income taxes	(545,269)	(27,501)	(190,199)	(762,969)
Standardized measure of discounted future net cash flows relating to proved oil and gas reserves, at end of year	$3,616,736	631,348	291,051	4,539,135

The computation of the standardized measure of discounted future net cash flows relating to proved oil and gas reserves at December 31, 2007 was based on weighted average year-end spot natural gas prices of approximately $6.20 per Mcf in the United States, approximately $6.12 per Mcf in

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

Canada, and $17.00 per Mcf in Italy, and on weighted average year-end spot oil prices of approximately $71.89 per barrel in the United States and approximately $78.71 per barrel in Canada.

	December 31, 2006			
	United States	Canada	Italy	Total
	(In Thousands)			
Standardized measure of discounted future net cash flows relating to proved oil and gas reserves, at beginning of year	$ 3,339,202	513,423	—	3,852,625
Changes resulting from:				
Sales of oil and gas, net of production costs	(507,337)	(136,429)	—	(643,766)
Net changes in prices and future production costs	(1,245,361)	(241,144)	—	(1,486,505)
Net changes in future development costs	(151,433)	(9,971)	—	(161,404)
Extensions, discoveries, and improved recovery	286,598	136,881	—	423,479
Development costs incurred during the period	311,883	51,729	—	363,612
Revisions of previous quantity estimates	304,238	84,013	—	388,251
Changes in production rates, timing, and other	(454,458)	(45,975)	—	(500,433)
Sales of reserves in place	(1,380,077)	—	—	(1,380,077)
Purchases of reserves in place	371,265	—	—	371,265
Accretion of discount on reserves at beginning of year before income taxes	468,429	67,036	—	535,465
Net change in income taxes	800,912	30,940	—	831,852
Standardized measure of discounted future net cash flows relating to proved oil and gas reserves, at end of year	$ 2,143,861	450,503	—	2,594,364

The computation of the standardized measure of discounted future net cash flows relating to proved oil and gas reserves at December 31, 2006 was based on weighted average year-end spot natural gas prices of approximately $5.28 per Mcf in the United States and approximately $5.05 per Mcf in Canada, and on weighted average year-end spot oil prices of approximately $51.69 per barrel in the United States and approximately $48.76 per barrel in Canada.

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, David H. Keyte, evaluated the effectiveness of our disclosure controls and procedures, as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended (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 Securities Exchange Act of 1934 (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.

Changes in Internal Controls 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, 2008 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

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, 2008. The effectiveness of our internal control over financial reporting as of December 31, 2008 has been audited by Ernst & Young LLP, an independent registered public accounting firm, as stated in their report which is included herein.

Item 9B. Other Information.

None.

Report of Independent Registered Public Accounting Firm

The Board of Directors and Shareholders of Forest Oil Corporation

We have audited Forest Oil Corporation's internal control over financial reporting as of December 31, 2008, 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's management is responsible for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's Annual Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the company's internal control over financial reporting based on our audit.

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

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

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

In our opinion, Forest Oil Corporation maintained, in all material respects, effective internal control over financial reporting as of December 31, 2008, 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 as of December 31, 2008 and 2007, and the related consolidated statements of operations, shareholders' equity, and cash flows for each of the three years in the period ended December 31, 2008 and our report dated February 26, 2009 expressed an unqualified opinion thereon.

Ernst & Young LLP

Denver, Colorado
February 26, 2009

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 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, 2008 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 Forest's procedures for recommending nominees to the Board and 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"
- 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"
- Information about compliance with Section 16(a) of the Securities Exchange Act of 1934, as amended, 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 is set forth under the captions "Executive Compensation" in the Proxy Statement, which information is incorporated herein by reference. Information regarding Forest's compensation of its directors is set forth under the caption "Executive Compensation—Director 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" included 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 captions "Principal Accountant Fees and Services" and "Report of the Audit Committee" in the Proxy Statement, which information is incorporated herein by reference.

PART IV

Item 15. Exhibits and 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, 2008 and 2007
3. Consolidated Statements of Operations—Years Ended December 31, 2008, 2007, and 2006
4. Consolidated Statements of Shareholders' Equity—Years Ended December 31, 2008, 2007, and 2006
5. Consolidated Statements of Cash Flows—Years Ended December 31, 2008, 2007, and 2006
6. Notes to Consolidated Financial Statements—Years Ended December 31, 2008, 2007, and 2006

(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 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, and No. 4, incorporated herein by reference to Exhibit 3.1 to Form 10-Q for Forest Oil Corporation for the quarter ended June 30, 2008 (File No. 001-13515).
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.
4.5	Registration Rights Agreement, dated as of July 10, 2000, by and between Forest Oil Corporation and the other signatories thereto, incorporated herein by reference to Exhibit 4.15 to Forest Oil Corporation Registration Statement on Form S-4, dated November 6, 2000 (File No. 333-49376).
4.6	Registration Rights Agreement by and among Forest Oil Corporation, Forest Oil Permian Corporation and Banc of America Securities LLC, for itself and on behalf of the several Initial Purchasers dated as of May 22, 2008, incorporated herein by reference to Exhibit 4.1 to Form 10-Q for Forest Oil Corporation for the quarter ended June 30, 2008 (File No. 001-13515).

Exhibit Number	Description
4.7†	Registration Rights Agreement by and among Forest Oil Corporation, Forest Oil Permian Corporation and J.P.Morgan Securities Inc., Banc of America Securities LLC, BNP Paribas Securities Corp., Credit Suisse Securities (USA) LLC, Deutsche Bank Securities Inc., TD Securities (USA) Inc., Scotia Capital (USA) Inc. and Wachovia Capital Markets, LLC dated February 17, 2009.
4.8	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).
4.9	Mortgage, Deed of Trust, Assignment, Security Agreement, Financing Statement and Fixture Filing from Forest Oil Corporation to Robert C. Mertensotto, trustee, and Gregory P. Williams, trustee (Utah), and The Chase Manhattan Bank, as Global Administrative Agent, dated as of December 7, 2000, incorporated herein by reference to Exhibit 4.13 to Form 10-K for Forest Oil Corporation for the year ended December 31, 2000 (File No. 001-13515).
4.10	U.S. Credit Agreement—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).
4.11	Canadian Credit Agreement—Second Amended and Restated Credit Agreement dated as of June 6, 2007 among Canadian Forest Oil Ltd., each of the lenders party thereto, Bank of America, N.A. and Citibank, N.A., as Co-Global Syndication Agents, Bank of Montreal and The Toronto Dominion Bank, as Co-Canadian Documentation Agents, JPMorgan Chase Bank, N.A., Toronto Branch, as Canadian Administrative Agent, and JPMorgan Chase Bank, N.A. as Global Administrative Agent, incorporated herein by reference to Exhibit 4.5 to Form 10-Q for Forest Oil Corporation for the quarter ended June 30, 2007 (File No. 001-13515).
4.12	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).
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).

Exhibit Number	Description
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*	Form of Restricted Stock Agreement pursuant to the Forest Oil Corporation 2007 Stock Incentive Plan, incorporated herein by reference to Exhibit 10.3 to Form 10-Q for Forest Oil Corporation for the quarter ended June 30, 2007 (File No. 001-13515).
10.19*	Form of Non-Employee Director Restricted Stock Agreement pursuant to the Forest Oil Corporation 2007 Stock Incentive Plan, incorporated herein by reference to Exhibit 10.1 to Form 10-Q for Forest Oil Corporation for the quarter ended March 31, 2008 (File No. 001-13515).
10.20*	Form of Phantom Stock Unit Agreement pursuant to the Forest Oil Corporation 2007 Stock Incentive Plan, incorporated herein by reference to Exhibit 10.4 to Form 10-Q for Forest Oil Corporation for the quarter ended June 30, 2007 (File No. 001-13515).

Exhibit Number	Description
10.21*	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).
10.22*	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).
10.23*	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).
10.24*	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).
10.25*	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).
10.26*	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).
10.27*	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).
10.28*	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).
10.29†	Form of Amendment to Form of Severance Agreement for Senior Vice President.
10.30†	Form of Amendment to Form of Severance Agreement for Grandfathered Executive Officer.
10.31*	Forest Oil Corporation Pension Trust Agreement dated as of January 1, 2002 by and between Forest Oil Corporation and the trustees named therein or their successors, incorporated herein by reference to Exhibit 10.1 to Form 10-Q for Forest Oil Corporation for the quarter ended September 30, 2002, dated November 14, 2002 (File No. 001-13515).
10.32*	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).
10.33*	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).
10.34*	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).
10.35*	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).

Exhibit Number	Description
10.36*	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).
10.37*	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).
10.38*	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).
10.39*	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).
10.40*	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).
10.41†	Forest Oil Corporation Executive Deferred Compensation Plan as Amended and Restated, effective as of December 1, 2008.
10.42	Agreement and Plan of Merger dated as of September 9, 2005 among Forest Oil Corporation, SML Wellhead Corporation, Mariner Energy, Inc. and MEI Sub, Inc., incorporated herein by reference to Exhibit 10.1 to Form 10-Q for Forest Oil Corporation for the quarter ended September 30, 2005 (No. 001-13515).
10.43	Agreement and Plan of Merger by and among Forest Oil Corporation, MJCO Corporation and The Houston Exploration Company dated as of January 7, 2007, incorporated herein by reference to Exhibit 2.1 to Form 8-K for Forest Oil Corporation dated January 7, 2007 (File No. 001-13515).
10.44	Membership Interest Purchase Agreement dated as of May 24, 2007, among Forest Alaska Operating LLC, Forest Oil Corporation, and Pacific Energy Resources Ltd., incorporated herein by reference to Exhibit 10.1 to Form 8-K for Forest Oil Corporation dated May 28, 2007 (File No. 001-13515).
10.45	Asset Sales Agreement dated as of May 24, 2007, between Forest Oil Corporation and Pacific Energy Resources Ltd., incorporated herein by reference to Exhibit 10.2 to Form 8-K for Forest Oil Corporation dated May 28, 2007 (File No. 001-13515).
10.46	Amendment No. 1 to Membership Interest Purchase Agreement dated July 31, 2007, among Forest Alaska Holding LLC, Forest Alaska Operating LLC, Forest Oil Corporation, and Pacific Energy Resources Ltd., incorporated herein by reference to Exhibit 10.1 to Form 8-K for Forest Oil Corporation dated July 31, 2007 (File No. 001-13515).
10.47	Amendment No. 1 to Asset Sales Agreement dated July 31, 2007, between Forest Oil Corporation and Pacific Energy Resources Ltd., incorporated herein by reference to Exhibit 10.2 to Form 8-K for Forest Oil Corporation dated July 31, 2007 (File No. 001-13515).
10.48	Asset Purchase and Sale Agreement dated August 15, 2008, between Forest Oil Corporation and Cordillera Texas, L.P., incorporated herein by reference to Exhibit 10.1 to Form 8-K for Forest Oil Corporation dated September 30, 2008 (File No. 001-13515).

Exhibit Number	Description
10.49	Amendment No. 1 to Asset Purchase and Sale Agreement dated August 15, 2008, between Forest Oil Corporation and Cordillera Texas, L.P., incorporated herein by reference to Exhibit 10.2 to Form 8-K for Forest Oil Corporation dated September 30, 2008 (File No. 001-13515).
10.50	Forest Oil Corporation 2008 Annual Incentive Plan, incorporated herein by reference to Exhibit 10.35 to Form 10-K for Forest Oil Corporation for the year ended December 31, 2007 (File No. 001-13515).
14.1	Forest Oil Corporation Proper Business Practices Policy Revised as of January 21, 2005, incorporated by reference to Form 10-K for Forest Oil Corporation for the year ended December 31, 2007 (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 Act of 1934.
31.2†	Certification of Principal Financial Officer of Forest Oil Corporation as required by Rule 13a-14(a) of the Securities 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.

* 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 Form 10-K.

SIGNATURES

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

Date: March 2, 2009

FOREST OIL CORPORATION
(Registrant)

By: /s/ H. CRAIG CLARK

H. Craig Clark
President and Chief Executive Officer

Power of Attorney

The officers and directors of Forest Oil Corporation, whose signatures appear below, hereby constitute and appoint H. Craig Clark, David H. Keyte, Cyrus D. Marter IV, and Victor A. Wind and each of them (with full power to each of them to act alone), the true and lawful attorney-in-fact to sign and execute, on behalf of the undersigned, any amendment(s) to this Form 10-K Annual Report for the year ended December 31, 2008, and any instrument or document filed as part of, as an exhibit to or in connection with any amendment, and each of the undersigned does hereby ratify and confirm as his own act and deed all that said attorneys shall do or cause to be done by virtue thereof.

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

Signatures	Title	Date
/s/ H. CRAIG CLARK H. Craig Clark	President and Chief Executive Officer and Director (Principal Executive Officer)	March 2, 2009
/s/ DAVID H. KEYTE David H. Keyte	Executive Vice President and Chief Financial Officer (Principal Financial Officer)	March 2, 2009
/s/ VICTOR A. WIND Victor A. Wind	Corporate Controller (Principal Accounting Officer)	March 2, 2009
/s/ JAMES D. LIGHTNER James D. Lightner	Chairman of the Board	March 2, 2009
/s/ WILLIAM L. BRITTON William L. Britton	Director	March 2, 2009
/s/ LOREN K. CARROLL Loren K. Carroll	Director	March 2, 2009
/s/ DOD. A. FRASER Dod. A. Fraser	Director	March 2, 2009
/s/ JAMES H. LEE James H. Lee	Director	March 2, 2009
/s/ PATRICK R. MCDONALD Patrick R. McDonald	Director	March 2, 2009

Index to Exhibits

Exhibit Number	Description
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.
4.7	Registration Rights Agreement by and among Forest Oil Corporation, Forest Oil Permian Corporation and J.P.Morgan Securities Inc., Banc of America Securities LLC, BNP Paribas Securities Corp., Credit Suisse Securities (USA) LLC, Deutsche Bank Securities Inc., TD Securities (USA) Inc., Scotia Capital (USA) Inc. and Wachovia Capital Markets, LLC dated February 17, 2009.
10.29	Form of Amendment to Form of Severance Agreement for Senior Vice President.
10.30	Form of Amendment to Form of Severance Agreement for Grandfathered Executive Officer.
10.41	Forest Oil Corporation Executive Deferred Compensation Plan as Amended and Restated, effective as of December 1, 2008.
21.1	List of Subsidiaries of Registrant.
23.1	Consent of Ernst & Young LLP.
23.2	Consent of DeGolyer and MacNaughton.
31.1	Certification of Principal Executive Officer of Forest Oil Corporation as required by Rule 13a-14(a) of the Securities Act of 1934.
31.2	Certification of Principal Financial Officer of Forest Oil Corporation as required by Rule 13a-14(a) of the Securities 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.

* Furnished herewith.

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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

BNY Mellon Shareowner Services
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/isd

INVESTOR RELATIONS

Additional information, including an Investor Package, may be obtained from:
Forest Oil Corporation
Patrick J. Redmond, Director – 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 12, 2009 at 9:00 a.m. (MDT)

CERTIFICATIONS

The most recent certifications by our Chief Executive Officer and Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 are filed as exhibits to our Form 10-K. Forest has also submitted to the New York Stock Exchange a certificate of the Chief Executive Officer certifying that he is not aware of any violations by Forest of the NYSE corporate governance listing standards.

NON-GAAP FINANCIAL MEASURES

In this annual report, Forest has reported net earnings adjusted for certain items, a non-GAAP financial measure, which facilitates comparisons to earnings forecasts prepared by stock analysts and other third parties. Such forecasts generally exclude the effects of items that are difficult to predict or to measure in advance and are not directly related to Forest's ongoing operations. Net earnings excluding the effects of certain items should not be considered a substitute for net earnings as reported in accordance with GAAP.

Forest reported adjusted EBITDA, which consists of net earnings plus income tax expense—discontinued operations, income tax expense—continuing operations, unrealized losses (gains) on derivative instruments, net, unrealized foreign currency exchange (gains) losses, unrealized losses on other investments, realized foreign currency exchange gains, interest expense, write-off of unamortized debt costs and prepayment premiums, accretion of asset retirement obligations, depreciation and depletion, impairments and stock-based compensation. Forest further reported adjusted discretionary cash flow, which consists of adjusted EBITDA minus interest expense, write-off of unamortized debt costs and prepayment premiums, current income tax benefit (expense) and other non-cash items. Management uses adjusted EBITDA and adjusted discretionary cash flow as measures of operational performance. Adjusted EBITDA and adjusted discretionary cash flow should not be considered as alternatives to net earnings as reported under GAAP.

Forest reported total cash costs as a non-GAAP measure calculated in accordance with oil and gas industry standards that is used by management to assess the cash operating performance. Total cash costs is defined as all cash operating costs, including production expense, general and administrative expense (excluding stock-based compensation), interest expense and current income tax (benefit) expense.

All-Sources Reserve Replacement Ratio

Forest's all-sources reserve replacement ratio of 549% was calculated by dividing the sum of total reserve additions, 1,044 Bcfe, by 2008 net sales volumes of 190 Bcfe. The replacement ratio does not include the effects of reserve revisions during the year.

FD&A Costs

Forest's FD&A costs of $2.61 per Mcfe exclude reserve revisions and were calculated by dividing the sum of total exploration, development, and acquisition costs, $2.73 billion, by the sum of total additions to estimated proved oil and gas reserves during 2008 of 1,044 Bcfe.

Organic Reserve Replacement Ratio

Forest's organic reserve replacement ratio of 281% was calculated by dividing discoveries and extensions during 2008 of 533 Bcfe, by 2008 net sales volumes of 190 Bcfe. The replacement ratio does not include the effects of reserve revisions during the year.

Organic F&D Costs

Forest's organic F&D costs of $2.54 per Mcfe exclude reserve revisions and were calculated by dividing the sum of total exploration and development costs, $1.36 billion, by discoveries and extensions during 2008 of 533 Bcfe.

The reconciliation of net earnings adjusted for certain items, adjusted EBITDA, adjusted discretionary cash flow, and total cash costs to their most comparable GAAP measures and the estimated proved reserve information are presented in Forest's February 23, 2009 year end press release, which can be viewed at www.forestoil.com.

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 "Estimates of oil and gas reserves are uncertain and inherently imprecise", in Forest's 2008 10-K for additional disclosures.

FOREST OIL CORPORATION • 707 SEVENTEENTH STREET, SUITE 3600 • DENVER, COLORADO 80202
303.812.1400 • www.forestoil.com