DENBURY RESOURCES INC.
2007 ANNUAL REPORT

A Peak Oil Company

When the Jackson Dome Volcano erupted, the land was dominated by dinosaurs such as Velociraptors. They were bipedal feathered carnivores that attacked larger dinosaurs. These small-to medium-sized animals are distinguished by having a large retractable curved claw on their second toes.

TWIN PEAKS

Millions of years ago, a volcano rose out of the shallow sea in what is now Jackson Dome, Mississippi. It created a peak that towered perhaps 10,000 feet over the late Cretaceous landscape. Carbon dioxide from the volcano's eruption became trapped in surrounding rocks and today forms the CO_2 reserves that allow Denbury to recover more oil from depleted oil fields.

Today, a very different peak, that of world oil productive capacity, may be approaching. In a controversial viewpoint, peak oil advocates warn that the world supply of oil may begin to decrease shortly. What is certain is that global demand growth has overtaken global supply growth resulting in a higher value for Denbury's strategy of producing more oil from old fields.

Amounts in thousands, unless otherwise noted	Year Ended December 31, 2007	2006	2005	2004[2]	2003	Average Annual Growth[1]
Consolidated Statements of Operations Data:						
Revenues	**$ 971,950**	$ 732,312	$ 560,706	$ 382,836	$ 333,270	31%
Net income	**253,147**	202,457[3]	166,471	82,448	56,553[4]	45%
Net income per common share[5]:						
Basic	**$ 1.05**	$ 0.87[3]	$ 0.74	$ 0.38	$ 0.26[4]	42%
Diluted	**1.00**	0.82[3]	0.70	0.36	0.25[4]	41%
Weighted average number of common shares outstanding[5]:						
Basic	**240,065**	233,101	223,485	219,482	215,525	3%
Diluted	**252,101**	247,547	239,267	229,206	221,856	3%
Consolidated Statements of Cash Flow Data:						
Cash provided by (used by):						
Operating activities	**$ 570,214**	$ 461,810	$ 360,960	$ 168,652	$ 197,615	30%
Investing activities	**(762,513)**	(856,627)	(383,687)	(93,550)	(135,878)	54%
Financing activities	**198,533**	283,601	154,777	(66,251)	(61,489)	–%
Production (daily):						
Oil (Bbls)	**27,925**	22,936	20,013	19,247	18,894	10%
Natural gas (Mcf)	**97,141**	83,075	58,696	82,224	94,858	1%
BOE (6:1)	**44,115**	36,782	29,795	32,951	34,704	6%
Unit Sales Price (excluding hedges):						
Oil (per Bbl)	**$ 69.80**	$ 59.87	$ 50.30	$ 36.46	$ 27.47	26%
Natural gas (per Mcf)	**6.81**	7.10	8.48	6.24	5.66	5%
Unit Sales Price (including hedges):						
Oil (per Bbl)	**$ 68.84**	$ 59.23	$ 50.30	$ 27.36	$ 24.52	29%
Natural gas (per Mcf)	**7.66**	7.10	7.70	5.57	4.45	15%
Costs per BOE:						
Lease operating expenses	**$ 14.34**	$ 12.46	$ 9.98	$ 7.22	$ 7.06	19%
Production taxes and marketing expenses	**3.05**	2.71	2.54	1.55	1.17	27%
General and administrative	**3.04**	3.20	2.62	1.78	1.20	26%
Depletion, depreciation and amortization	**12.17**	11.11	9.09	8.09	7.48	13%
Proved Reserves:						
Oil (MBbls)	**134,978**	126,185	106,173	101,287	91,266	10%
Natural gas (MMcf)	**358,608**	288,826	278,367	168,484	221,887	13%
MBOE (6:1)	**194,746**	174,322	152,568	129,369	128,247	11%
Carbon dioxide (MMcf)[6]	**5,641,054**	5,525,948	4,645,702	2,664,633	1,613,840	37%
Consolidated Balance Sheet Data:						
Total assets	**$ 2,771,077**	$ 2,139,837	$ 1,505,069	$ 992,706	$ 982,621	30%
Total long-term liabilities	**1,102,066**	833,380	617,343	368,128	434,845	26%
Stockholders' equity[7]	**1,404,378**	1,106,059	733,662	541,672	421,202	35%

(1) Four-year compounded average annual growth rate computed using 2003 as a base year.
(2) We sold Denbury Offshore, Inc. in July 2004.
(3) Effective January 1, 2006, we adopted Statement of Financial Accounting Standards No. 123(R), "Share Based Payment."
(4) In 2003, we recognized a gain of $2.6 million for the cumulative effect adoption of SFAS No. 143, "Accounting for Asset Retirement Obligations." The adoption of SFAS 143 increased basic and diluted net income per common share by $0.01. In April 2003, we recorded a pre-tax charge of $17.6 million associated with an early debt retirement.
(5) On December 5, 2007, and October 31, 2005, we split our common stock on a 2-for-1 basis. Information relating to all prior years and earnings per share has been retroactively restated to reflect the stock splits.
(6) Based on a gross working interest basis and includes reserves dedicated to volumetric production payments of 182.3 Bcf at December 31, 2007, 210.5 Bcf at December 31, 2006, 237.1 Bcf at December 31, 2005, 178.7 Bcf at December 31, 2004 and 162.6 Bcf at December 31, 2003. (See Note 15 to the Consolidated Financial Statements).
(7) We have never paid any dividends on our common stock.

Reporting Format: Unless otherwise noted, the disclosures in this report have (i) production volumes expressed on a net revenue interest basis, and (ii) gas volumes converted to equivalent barrels at 6:1.
See page 26 regarding cautionary notes about forward-looking statements and unproved reserves referenced herein.

TO OUR SHAREHOLDERS:

2007 was certainly one of the best years in our corporate history and one in which we set new records for profitability, cash flow, production and reserves, just to name a few. More importantly, despite ongoing operational challenges and volatile oil prices, we saw our increasing focus on tertiary operations bear fruit in 2007 with a 47% increase in our tertiary oil production year over year, averaging 14,767 Bbls/d for 2007, representing 53% of our total corporate oil production. And to make our year even better, our tertiary oil 2007 production results were right on forecast.

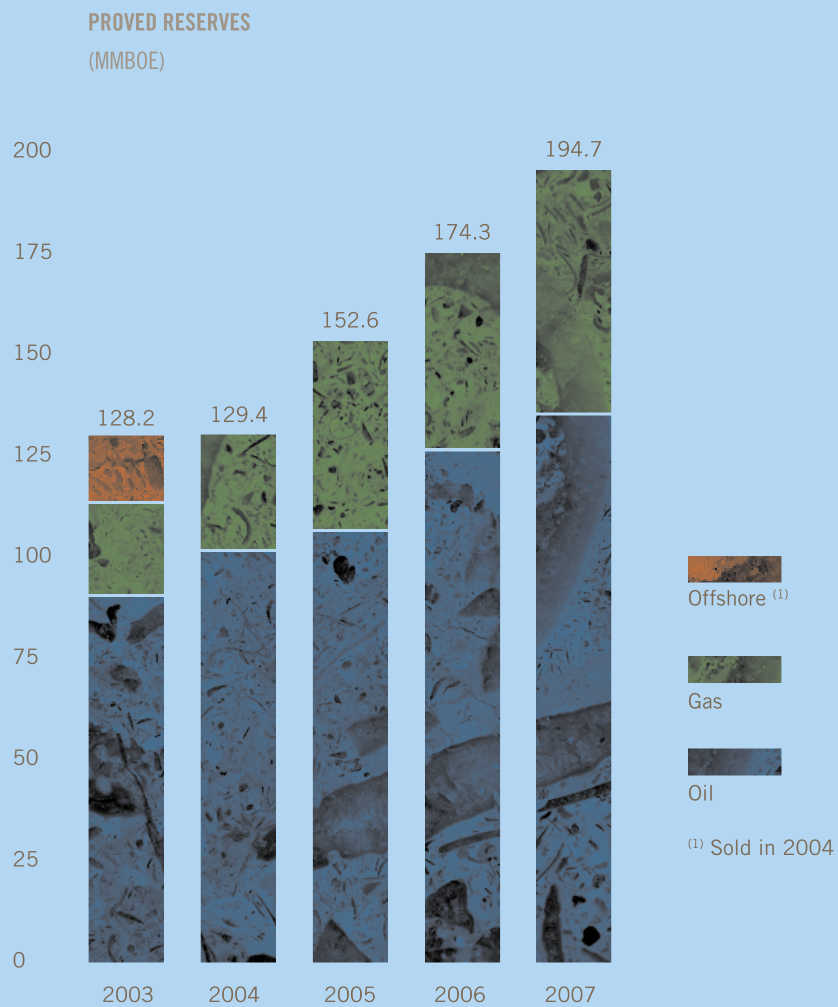
We own (or have an option to acquire) oil fields that have an estimated 314 MMBbls (using range mid-points) of additional oil reserves that can be obtained from tertiary flooding. These potential reserves have a projected PV-10 Value using year-end prices of $7.3 billion.

Let me review with you where Denbury is today and then reflect upon the goals we have set for the future. As of the end of 2007:

- Our average production during the fourth quarter of 2007 was 45,274 BOE/d, adjusted for the Louisiana properties sold in December 2007 and February 2008. On an annual basis, our average production was 39,170 BOE/d, adjusted in the same manner. The production from our tertiary floods contributed 17,428 Bbls/d to the fourth quarter and 14,767 Bbls/d to the annual average.
- We own (or have an option to acquire) oil fields that have an estimated 314 MMBbls (using range mid-points) of additional oil reserves that can be obtained from tertiary flooding. These potential reserves have a projected PV-10 Value using year-end prices of $7.3 billion.
- Our year-end proven CO_2 reserves at Jackson Dome totaled 5.6 Tcf, just marginally less than the 6.3 Tcf needed to extract the proven and potential CO_2 tertiary oil reserves from our eight-phase development plan and service our industrial customers, a total of over 380 MMBbls. We estimate that we have an additional 2–3 Tcf of potential CO_2 reserves at Jackson Dome, which should more than cover the shortfall needed to extract our estimated proven and potential reserves and service our industrial customers.

- In addition to our natural source of CO_2 described above, we have contracts with three proposed gasification plants that could supply us with approximately 800 MMcf/d of additional CO_2. While we are uncertain when and if these three plants will be built, we are in discussions with several others in the same general region, so we expect to have significant incremental man-made sources of CO_2 commencing around 2011 with further incremental supplies likely thereafter.
- We currently have three pipelines in operation distributing CO_2 from Jackson Dome to our oil fields with a combined length of around 300 miles. We are currently transporting over 550 MMcf/d through these lines, primarily for use in our CO_2 tertiary floods.
- We have a significant position in the Barnett Shale, near Fort Worth, Texas, from which we produced an average of 76.4 MMcfe/d during the fourth quarter of 2007. Our proven reserves in the Barnett totaled approximately 369 Bcfe with an estimated PV-10 Value using year-end pricing of $717 million. In addition to our proven reserves, we have almost 90 more probable locations with estimated probable reserves of 170 Bcfe and a PV-10 Value using the same pricing of $200 million. To date, this acreage has been developed based on 500' spacing. We have recently begun to test well spacings of 250', but the results are still too inconclusive at this time.
- We are the general partner of the public master limited partnership, Genesis Energy, LP (trading symbol "GEL"). We also own 7.4% of the outstanding common partnership units. During 2007, Genesis was very active, acquiring over $630 million of assets, funding the acquisitions with a new bank credit line and the public issuance of $185 million of equity. In late March 2008, we expect to complete the "drop-down" to Genesis of our Northeast Jackson Dome (NEJD) and Free State CO_2 pipelines for $250 million, receiving $225 million of cash and $25 million in Genesis common units, and expect to receive in exchange a long-term transportation service arrangement on the Free State line and a 20-year direct financing lease for the NEJD line. This last transaction will benefit both entities by giving us long-term financing for our pipeline infrastructure and providing Genesis with predictable incremental cash flow. As of year-end 2007, Genesis' market capitalization

In addition to our natural source of CO_2 described above, we have contracts with three proposed gasification plants that could supply us with approximately 800 MMcf/d of additional CO_2.



was approximately $917 million and their most recent cash distributions were $0.285 per unit paid for the fourth quarter of 2007, which triggered an incentive cash distribution to us of $75 thousand as a result of our general partner interest.

- Assuming the closing of the drop-downs in March 2008 to Genesis described above, we anticipate $525 million of subordinated debt, no bank debt and over $100 million of cash. Our current untapped bank borrowing base is $500 million; although we anticipate that we can approximately double this borrowing base with our banks at our next redetermination on April 1, 2008.
- Our market capitalization as of year-end 2007 was $7.3 billion, with approximately 245.4 million shares outstanding. In both 2005 and 2007, we completed two-for-one stock splits of our stock as our market capitalization increased approximately five fold since year-end 2004. This increase in liquidity has been beneficial for our stockholders.
- We have approximately 700 experienced, incentivized, and enthusiastic employees. We have a broad-based equity and long-term award program which allows all of our employees to share in the success of our Company. This has allowed us to attract qualified personnel in a competitive and difficult industry environment and maintain an industry-leading retention rate.

- We continue to develop and improve on our already strong corporate governance which starts at the top with our Board of Directors and extends down throughout the Company. During 2007, we placed a renewed emphasis on our health, safety and environmental policies and procedures in order to benefit our employees and the communities where we operate.

2008 AND BEYOND

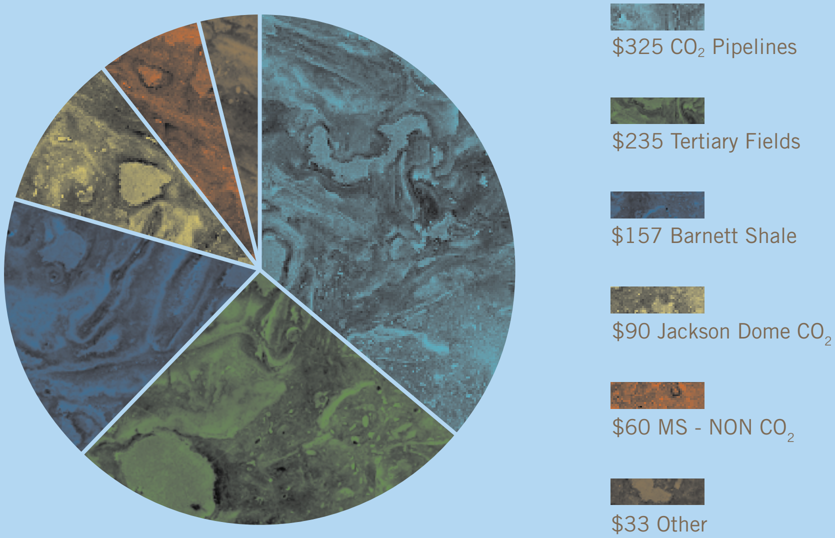
During 2008 and 2009, we plan to invest almost $2 billion, expanding our CO_2 pipeline network from Louisiana to Texas and implementing and expanding additional tertiary floods, all as part of our strategic plan. If oil prices remain at their current levels, most of this can be funded with internally generated cash flow, but if we need to, we can tap into our unused bank credit facility, the public debt markets, additional potential long-term funding of our infrastructure through Genesis, or even possibly from asset sales of our remaining non-core assets.

Our biggest single project during this period will be the construction of the $700 million Green Pipeline, a CO_2 pipeline which we hope to have completed around year-end 2009. We believe this project will be strategic for us as it will create the backbone for a CO_2 gathering and distribution system in the southern Gulf Coast region.

PROJECTED 2008 CAPITAL BUDGET

In Millions

$900 [1]



[1] Excludes acquisitions and capitalized interest

As discussed above, there are numerous potential gasification plants being considered for construction in this area and there are also numerous additional depleted oil fields that could be acquired, making this region of the United States attractive for our continued expansion and growth. Our strategy will be to acquire additional man-made volumes of CO_2 in this area, purchase additional oil fields and expand our development program beyond its current eight phases. Assuming we are successful, this should allow us to continue to increase our tertiary oil production and reserves beyond those amounts currently projected from our existing eight phases.

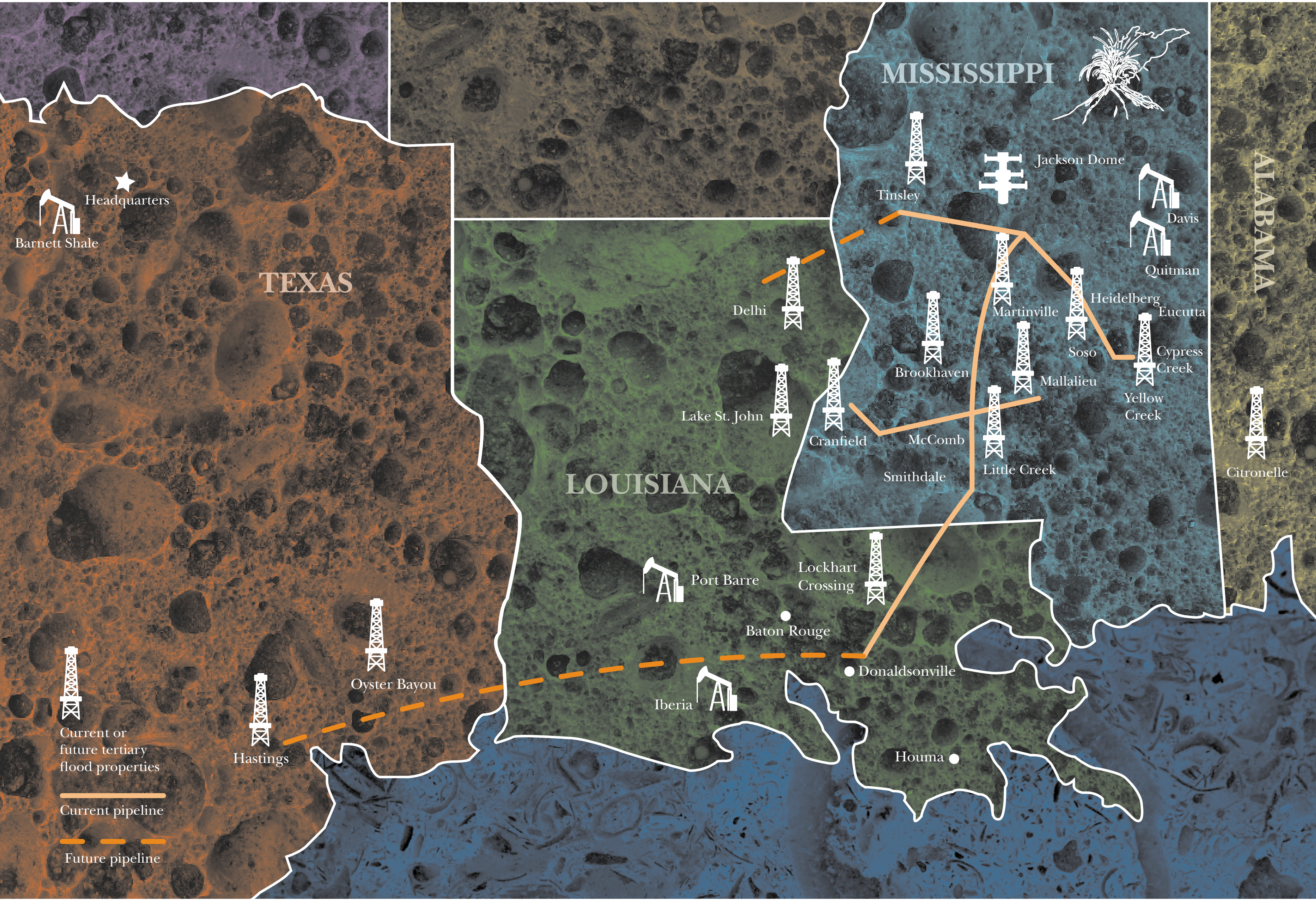
We look forward to 2008 as we expect to significantly increase our tertiary proven oil reserves and expect another strong year of production growth. We currently expect our 2008 production to average approximately 49,000 BOE/d, a growth rate of approximately 25% over average 2007 production levels, after adjusting for the Louisiana property sale.

The current economic environment continues to favor our strategy, with oil prices to date in 2008 above $100/Bbl on occasion. We believe this is primarily due to the inability of worldwide oil production to keep up with the world's growth in demand. We believe that conventional oil production worldwide has peaked and has begun to decline, a view commonly referred to as "peak oil." It also appears that other petroleum volumes that make up total worldwide liquid production (such as NGL's, etc.) could also peak soon. If these assumptions are true, then we are looking at a defining point in the 21st century.

Our reference to this potential peak is contrasted in this year's annual report with another peak, the Jackson Dome volcano, whose presence is indisputable. This volcano and the CO_2 it created millions of years ago is the foundation of our success. We have taken this natural bounty and created a strategic plan to amplify its influence through the expected use of man-made sources of CO_2. This ability to modify our strategy has allowed us to exploit new opportunities, and we must be ready to adjust again should conditions change. Our ability to adapt will be what defines Denbury in the future. We have included pictures in this annual report of some of the creatures, mostly dinosaurs, which existed at the time of the volcanic eruption at Jackson Dome. Conventional wisdom suggests that dinosaurs died out eons ago, but like Denbury they continue to adapt and survive — today we call them birds.

G. Roberts

Gareth Roberts
President and Chief Executive Officer
March 7, 2008


MISSISSIPPI
ALABAMA
TEXAS
LOUISIANA
Headquarters
Barnett Shale
Jackson Dome
Tinsley
Davis
Quitman
Delhi
Martinville
Heidelberg
Eucutta
Brookhaven
Soso
Cypress Creek
Mallalieu
Yellow Creek
Lake St. John
Cranfield
McComb
Smithdale
Little Creek
Citronelle
Port Barre
Lockhart Crossing
Baton Rouge
Donaldsonville
Oyster Bayou
Iberia
Hastings
Houma
Current or future tertiary flood properties
Current pipeline
Future pipeline

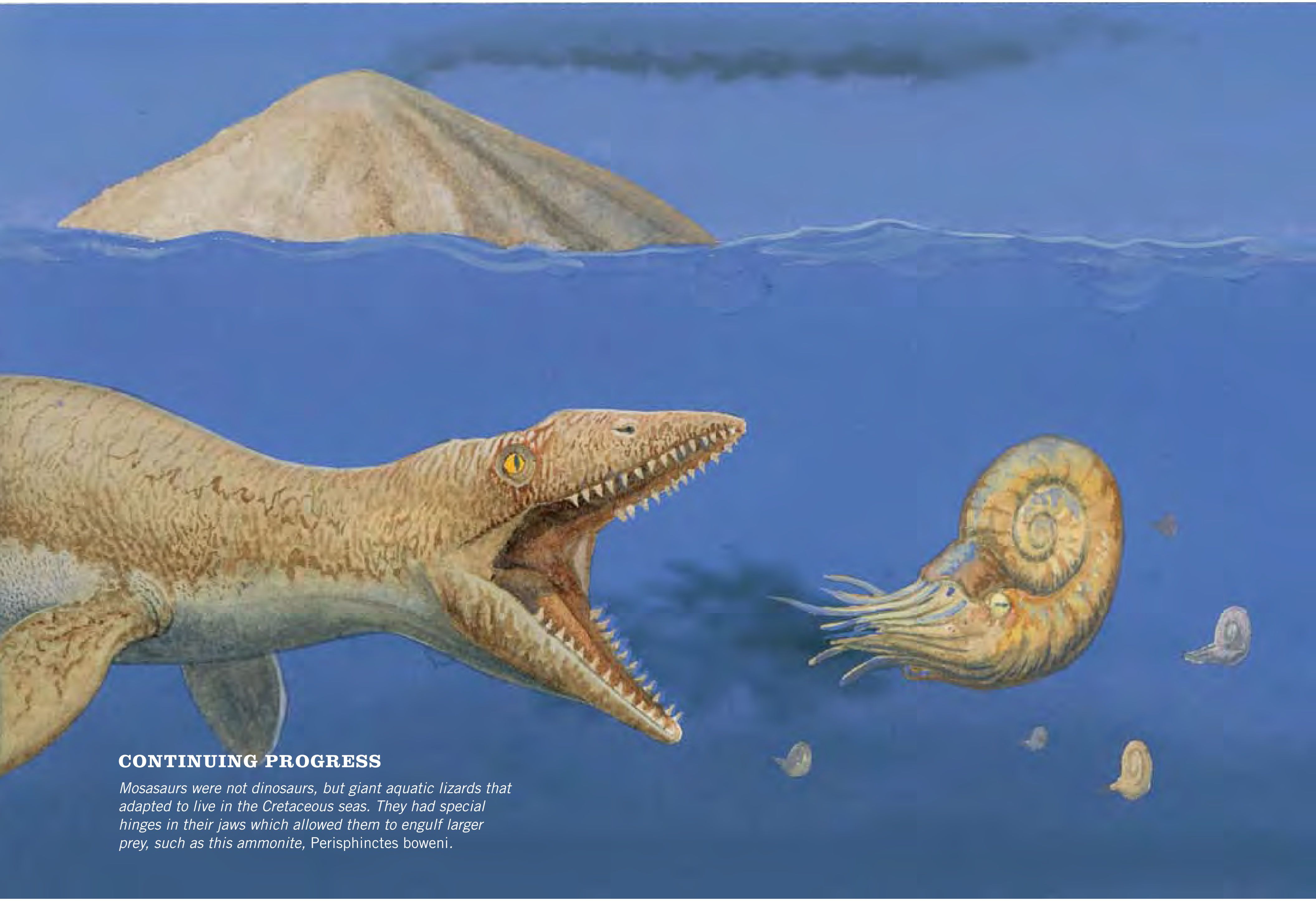
CO_2 TERTIARY OPERATIONS

Our tertiary operations are our core assets and our principal focus. During 2007, we continued the expansion of our Phase I and Phase II tertiary floods and initiated tertiary projects at Lockhart Crossing, our first Louisiana field (Phase I — see description of the various phases below), Tinsley Field in Phase III, and Cranfield Field in Phase IV. We increased our potential tertiary flood candidates during 2007 with the acquisition of significant positions in Oyster Bayou, Fig Ridge and Gillock Fields, Phases VII and VIII, adding to our inventory of future tertiary floods. In addition to our development, expansion and acquisition of new floods, we also made the strategic decision to divest our natural gas assets in South Louisiana that did not contain future CO_2 potential in order to further narrow our focus on CO_2 enhanced oil recovery and our core assets. During the last eight years, we have learned an extensive amount about tertiary operations and working with carbon dioxide ("CO_2"), and our knowledge continues to grow. We like these tertiary operations because (i) tertiary investments provide a reasonable rate of return, even at relatively low oil prices of around $30 per barrel, (ii) tertiary flooding exhibits a lower risk profile than conventional exploration and development, and (iii) to date, in our region of the United States, we have not encountered any industry competition. Generally, from the Texas Gulf Coast to Florida, there are no known significant natural sources of carbon dioxide except our own, and these large volumes of CO_2 are the foundation for our entire tertiary program.

We like tertiary operations because (i) they provide a reasonable rate of return, (ii) they have a lower risk profile, and (iii) in our region, we have not encountered industry competition.

As of year-end 2007, we had a total of 69.5 MMBbls of proved reserves attributable to our tertiary operations, 48.3 MBbls are attributable to fields in Phase I with the balance in Phase II. To date, we have already produced over 20 MMBbls from tertiary operations and we have identified up to 314 MMBbls of additional potential or probable reserves (using the mid-point of several ranges) over and above our existing proven reserves that can be recovered through tertiary operations in our eight currently planned phases.

Through December 31, 2007, we invested a total of $1.0 billion on tertiary oil fields (including allocated acquisition costs) and have received $758.9 million in net operating income (revenue less operating expenses). Of this total, approximately $351.3 million was invested on fields which had little or no proved reserves at December 31, 2007 (i.e., significant incremental proved reserves are anticipated during 2008 and beyond). The proved oil reserves in our tertiary fields have a PV-10 Value of $3.2 billion at December 31, 2007, using constant NYMEX pricing of $95.98 per Bbl and we had an estimated PV-10 Value of our probable oil reserves in our tertiary fields of $7.3 billion using the same prices (on a unrisked basis, using mid-points of the reserve ranges). These amounts



CONTINUING PROGRESS

Mosasaurs were not dinosaurs, but giant aquatic lizards that adapted to live in the Cretaceous seas. They had special hinges in their jaws which allowed them to engulf larger prey, such as this ammonite, Perisphinctes boweni.

do not include the capital costs or related depreciation and amortization of our CO_2 producing properties, but do include CO_2 source field lease operating costs, royalty and transportation costs. Through December 31, 2007, we had a balance of approximately $371.0 million of unrecovered net cash flow for our CO_2 source assets, including $180.3 million associated with CO_2 pipelines.

We plan to use the by product of CO_2 from these plants in our tertiary operations to recover oil that may otherwise not be produced. In addition, our use of this CO_2 will also eliminate the release of this greenhouse gas into the earth's atmosphere.

JACKSON DOME

We believe that having sufficient CO_2 volumes is the key ingredient, if not the most important factor to our tertiary operations. We acquired our Jackson Dome CO_2 source field in February 2001, giving us control of most of the CO_2 supply in Mississippi, as well as ownership and control of the critical 183-mile NEJD CO_2 pipeline. Since February 2001, we have acquired two additional wells and drilled 15 additional CO_2 producing wells, significantly increasing our estimated proved CO_2 reserves from 800 Bcf at the time of acquisition to approximately 5.6 Tcf as of December 31, 2007, replacing 164% of our production during 2007. Today, we own every producing CO_2 well in the region. We plan to drill several additional CO_2 wells during 2008, including four development wells and one exploratory well, to further increase our proven CO_2 reserves and to obtain additional CO_2 deliverability.

During the fourth quarter of 2007, we produced an average of 533 MMcf/d of CO_2, a 35% increase over one year ago. We sold an average of 99 MMcf/d of CO_2 to commercial users and we used an average of 434 MMcf/d for our tertiary activities. We estimate that our February 2008 daily CO_2 deliverability was approximately 700 MMcf/d. By year-end 2008, we estimate that our planned tertiary operations and industrial customers will collectively require approximately 800 MMcf/d, which we believe we can attain with our planned 2008 Jackson Dome projects.

MAN-MADE CO_2 SOURCES

We have entered into three agreements, and are having various levels of discussions with many others, to purchase (if the plants are built) all of the CO_2 production from man-made (anthropogenic) sources of CO_2 from planned solid carbon gasification projects. We project that the first one will not be completed until 2011. These plants may convert petroleum coke, coal, biomass or combinations of all three into a variety of products including ammonia, methanol, synthetic diesel fuel or electric power generation. We plan to use the by product of CO_2 from these plants in our tertiary operations to recover oil that may otherwise not be produced. In addition, our use of this CO_2 will also eliminate the release of this greenhouse gas into the earth's atmosphere.

(continued on page 15)

	Year Ended December 31,		
	2007	2006	2005
Estimated proved reserves:			
Oil (MBbls)	**134.978**	126,185	106,173
Natural gas (MMcf)	**358,608**	288,826	278,367
Oil equivalent (MBOE)	**194,746**	174,322	152,568
Percentage of total MBOE:			
Proved producing	**56%**	48%	40%
Proved non-producing	**13%**	17%	16%
Proved undeveloped	**31%**	35%	44%
Representative oil and gas prices:[1]			
Oil – NYMEX	**$ 95.98**	$ 61.05	$ 61.04
Natural gas – Henry Hub	**6.80**	5.63	10.08
Present Values (thousands):[2]			
Discounted estimated future net cash flow before income taxes ("PV-10 Value")[3]	**$ 5,385,123**	$ 2,695,199	$ 3,215,478
Standardized measure of discounted estimated future net cash flow after income taxes	**3,539,617**	1,837,341	2,084,449

(1) The prices of each year-end were based on market prices in effect as of December 31 of each year, NYMEX prices per Bbl and Henry Hub cash prices per MMBtu, with the appropriate adjustments (transportation, gravity, BS&W, purchasers' bonuses, Btu, etc.) applied to each field to arrive at the appropriate corporate net price.

(2) Determined based on year-end unescalated prices and costs in accordance with the guidelines of SFAS No. 69, discounted at 10% per annum.

(3) PV-10 Value is a non-GAAP measure and is different from the Standardized Measure in that PV-10 Value is a pre-tax number and the Standardized Measure is an after-tax number. The information used to calculate PV-10 Value is derived directly from data determined in accordance with SFAS No. 69. The difference between these two amounts, the discounted estimated future income tax, was $1,845,506 at December 31, 2007, $857,858 at December 31, 2006, and $1,131,029 at December 31, 2005. We believe that PV-10 Value is a useful supplemental disclosure to the Standardized Measure because the Standardized Measure can be impacted by a company's unique tax situation, and it is not practical to calculate the Standardized Measure on a property by property basis. Because of this, PV-10 Value is a widely used measure within the industry and is commonly used by securities analysts, banks and credit rating agencies to evaluate the estimated future net cash flows from proved reserves on a comparative basis across companies or specific properties. PV-10 Value is commonly used by us and others in our industry to evaluate properties that are bought and sold and to assess the potential return on investment in our oil and gas properties. PV-10 Value is not a measure of financial or operating performance under GAAP, nor should it be considered in isolation or as a substitute for the Standardized Measure. Our PV-10 Value and the Standardized Measure do not purport to represent the fair value of our oil and natural gas reserves. See Note 15 to our Consolidated Financial Statements for additional disclosures about the Standardized Measure.

FIELD SUMMARIES

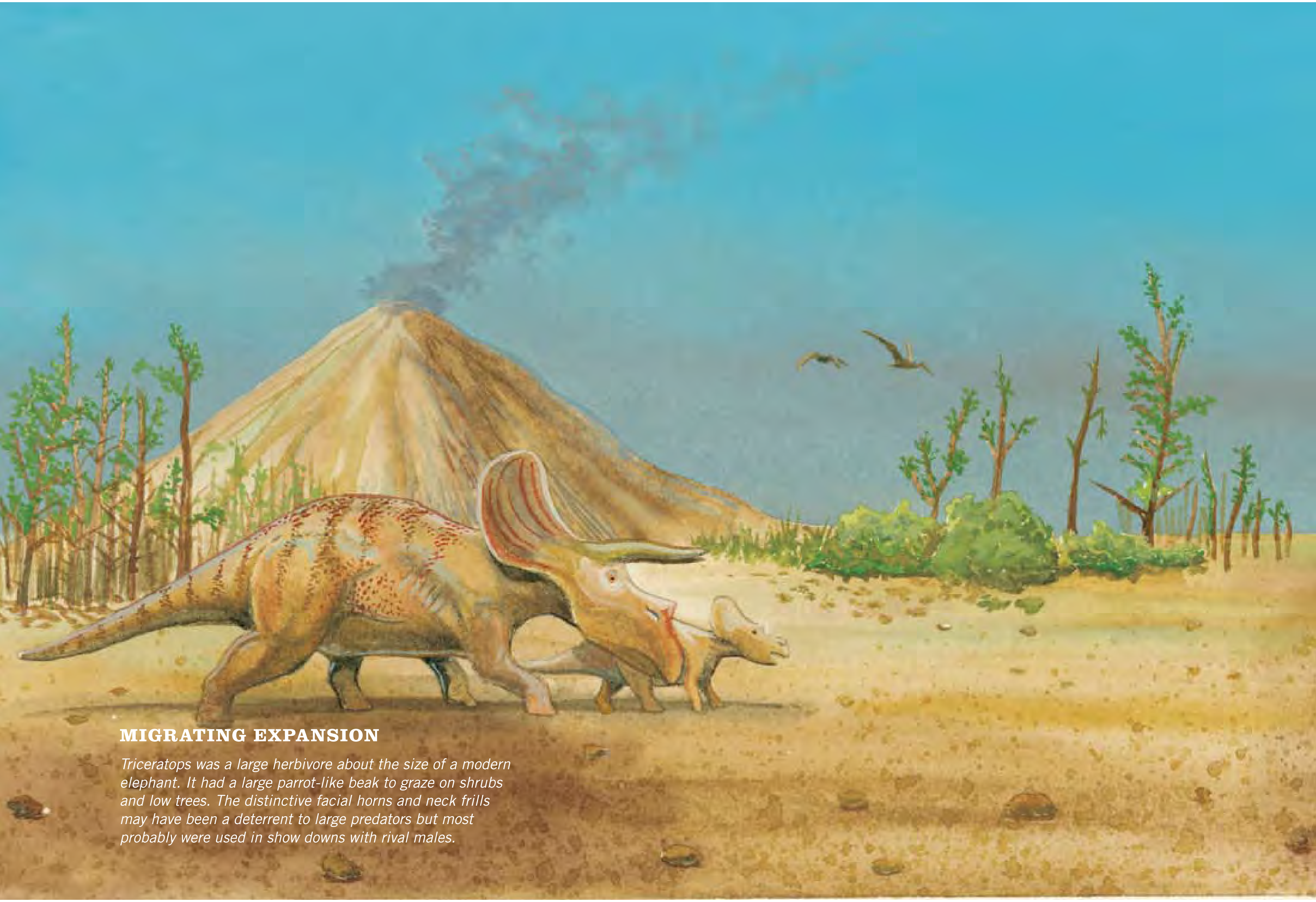
Denbury operates in five primary areas: Eastern Mississippi, Western Mississippi, Texas, Alabama and Louisiana. Our 14 largest fields (listed on the following page) constitute approximately 94% of our total proved reserves on a BOE basis and on a PV-10 Value basis. Within these 14 fields, we own a weighted average 95% working interest and operate all of these fields. The concentration of value in a relatively small number of fields allows us to benefit substantially from any operating cost reductions or production enhancements we achieve, and allows us to effectively manage the properties from our four primary field offices located in Laurel, Mississippi; McComb, Mississippi; Brandon, Mississippi; and Cleburne, Texas.

	Proved Reserves as of December 31, 2007[1]					2007 Average Daily Production		
	Oil (MBbls)	Natural Gas (MMcf)	MBOEs	BOE % of total	PV-10 Value [2] (000's)	Oil (Bbls/d)	Natural Gas (Mcf/d)	Average Net Revenue Interest
Mississippi–CO_2 Floods								
Brookhaven	18,700	—	18,700	9.6%	$ 793,813	2,048	—	81.2%
McComb Area	15,275	—	15,275	7.9%	713,080	1,912	—	78.8%
Mallalieu Area	11,547	—	11,547	5.9%	719,778	5,852	—	76.7%
Eucutta	10,172	—	10,172	5.2%	456,003	1,646	—	83.5%
Soso	9,798	—	9,798	5.0%	363,542	586	—	77.2%
Little Creek Area	2,749	—	2,749	1.4%	132,311	2,014	—	83.2%
Martinville	1,282	—	1,282	0.7%	65,827	709	—	78.1%
Total Mississippi–CO_2 Floods	69,523	—	69,523	35.7%	3,244,354	14,767	—	79.6%
Other Mississippi								
Heidelberg (East & West)	24,666	59,087	34,514	17.7%	728,126	4,942	16,286	80.6%
Tinsley	2,632	–	2,632	1.4%	81,029	1,042	15	67.6%
Sharon	–	11,842	1,974	1.0%	32,057	4	4,491	94.3%
S. Cypress Creek	1,850	654	1,959	1.0%	45,050	247	39	86.6%
Eucutta	1,854	–	1,854	1.0%	47,367	444	22	64.4%
Other Mississippi	7,047	3,641	7,654	3.9%	199,488	2,117	1,246	37.4%
Total Other Mississippi	38,049	75,224	50,587	26.0%	1,133,117	8,796	22,099	63.7%
Texas								
Newark (Barnett Shale)	17,160	265,575	61,423	31.5%	717,213	1,758	46,751	80.5%
Other Texas	340	1,407	574	0.3%	23,943	270	1,527	72.9%
Total Texas	17,500	266,982	61,997	31.8%	741,156	2,028	48,278	80.4%
Louisiana								
Louisiana	634	2,238	1,007	0.5%	42,378	380	1,303	70.8%
Louisiana Sold[3]	422	12,434	2,494	1.3%	59,556	801	24,861	45.6%
Total Louisiana	1,056	14,672	3,501	1.8%	101,934	1,181	26,164	48.6%
Alabama								
Citronelle	8,784	–	8,784	4.5%	159,796	1,150	–	62.7%
Other Alabama	66	1,730	354	0.2%	4,766	3	600	2.5%
Total Alabama and Other	8,850	1,730	9,138	4.7%	164,562	1,153	600	11.2%
Company Total	134,978	358,608	194,746	100.0%	$ 5,385,123	27,925	97,141	67.1%

(1) The reserves were prepared using constant prices and costs in accordance with the guidelines of SFAS No. 69 based on the prices received on a field-by-field basis as of December 31, 2007. The prices at that date were a NYMEX oil price of $95.98 per Bbl adjusted to prices received by field and a Henry Hub natural gas average price of $6.80 per MMBtu also adjusted to prices received by field.

(2) PV-10 Value is a non-GAAP measure and is different from the Standardized Measure of Discounted Future Net Cash Flows ("Standardized Measure") in that PV-10 Value is a pre-tax number and the Standardized Measure is an after-tax number. The information used to calculate PV-10 Value is derived directly from data determined in accordance with SFAS No. 69. The Standardized Measure was $3,539,617 at December 31, 2007. A comparison of PV-10 to the Standardized Measure is included in the table on page 12 as well as further information regarding our use of this non-GAAP measure.

(3 Reserves in the Louisiana sold category are associated with the portion of the Louisiana divestiture that closed in February 2008.



MIGRATING EXPANSION

Triceratops was a large herbivore about the size of a modern elephant. It had a large parrot-like beak to graze on shrubs and low trees. The distinctive facial horns and neck frills may have been a deterrent to large predators but most probably were used in show downs with rival males.

(continued from page 11)

The cost of this man-made CO_2 will likely be higher than CO_2 from our natural source, but the location of these plants could mitigate some of the incremental cost of transportation and we believe that there could potentially be a type of carbon credit in the United States in the future which would, if enacted by our government, significantly lower our cost for this CO_2.

We see these sources as a possible expansion of our natural Jackson Dome source, assuming they are economical, and we believe that our potential ability to tie these sources together with pipelines will give us a significant advantage over our competitors, in our geographic area, in acquiring additional oil fields and these future potential man-made sources of CO_2. The potential volumes of CO_2 from these plants could be very significant to us as the smallest plant would produce approximately 200 MMcf/d of CO_2.

CO_2 PIPELINES

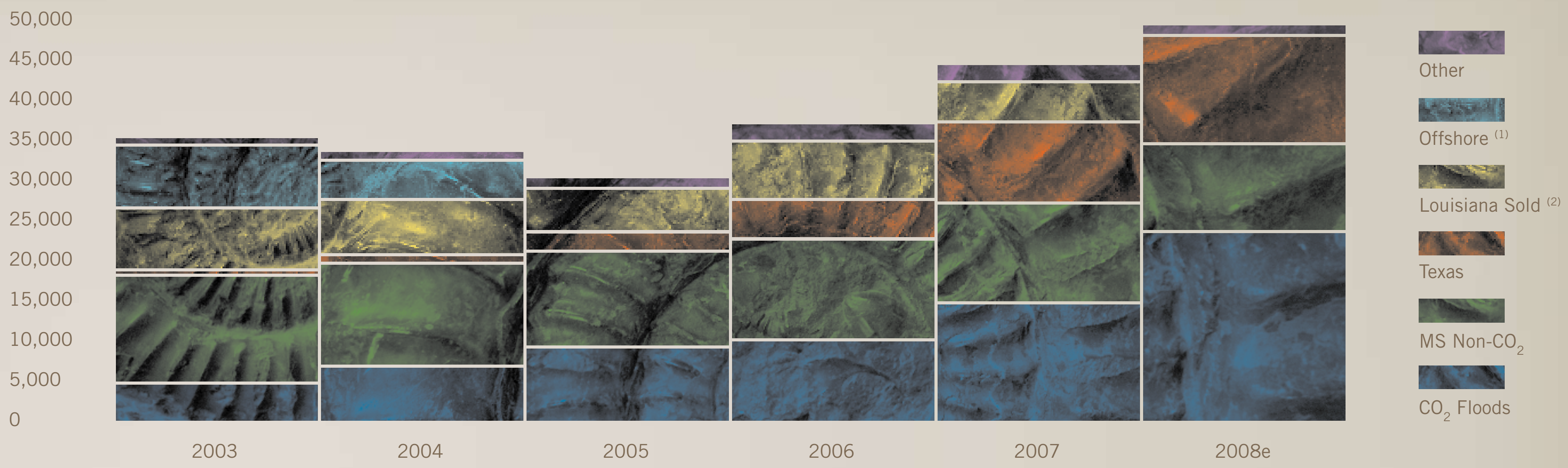
As of January 2008, we have three CO_2 pipelines in service, the NEJD 183-mile CO_2 pipeline that runs from Jackson Dome to near Donaldsonville, Louisiana acquired in 2001, our 84-mile Free State Pipeline that was completed in 2006 and runs from Jackson Dome to our Phase II tertiary fields in East Mississippi, and the first 31-mile segment of our most recently completed pipeline, our Delta Pipeline which runs from Jackson Dome to Tinsley Field, northwest of Jackson, Mississippi. We have completed the reconditioning and conversion of the natural gas pipeline, we acquired from Southern Natural Gas Company in 2006, to CO_2 service and plan to begin transporting CO_2 down this line in the second quarter of 2008 to our first Phase IV field, Cranfield Field. During 2008 we plan to further extend our Delta Pipeline by building a 24" 68-mile extension from Tinsley Field to Delhi Field with completion of this segment anticipated around year-end 2008.

We are also working on a 24" pipeline, named the Green Pipeline, to transport CO_2 to Hastings Field and our 2007 Southeast Texas acquisitions, Oyster Bayou, Fig Ridge and Gillock Fields. The Green Pipeline will connect the southern end of our existing NEJD CO_2 Pipeline, near Donaldsonville, Louisiana, to Hastings Field, near Houston, Texas, this distance estimated to be between 300 and 320 miles. Based on our latest estimates, this pipeline is expected to cost between $700 million and $750 million. Our efforts in 2007 were focused on engineering design, right-of-way acquisition and securing the manufacturing of the 24" pipe. Although our definitive schedules are still in flux, our goal is to begin construction of the Green Pipeline around year-end 2008 and hope to have it completed around year-end 2009. Initially, we anticipate transporting CO_2 from our natural source at Jackson Dome in this line, but ultimately we expect that it will be used to ship predominately man-made (anthropogenic) sources of CO_2.

DOMINATING PRESENCE

Tyrannosaurus was a giant bipedal carnivore that was widespread about the time of the Jackson Dome eruption. It was probably an active hunter, with stereoscopic vision and a reinforced skull to allow bone-crushing bites. It is likely that Tyrannosaurus could "island hop" by swimming to new hunting grounds.

Average Daily Production (BOE/d)



(1) Offshore properties sold in 2004.
(2) Louisiana natural gas properties sold in late 2007 and early 2008.

TERTIARY OIL FIELDS

We talk about our tertiary oil operations by labeling operating areas or groups of fields as phases.

PHASE I

Phase I, in Southwest Mississippi, includes several fields along our 183-mile NEJD CO_2 Pipeline. The most significant fields in this area are Little Creek, Mallalieu, McComb and Brookhaven. Phase I was our first area of tertiary operations which began with the purchase of Little Creek in 1999, contains the largest quantity of proven tertiary reserves (48.3 MMBbls) and has produced almost all of our tertiary production to date (18.9 MMBbls). We estimate that there are up to 16 MMBbls of additional potential reserves in this area, primarily from anticipated higher recovery rates, in addition to further expansion of existing floods and implementation of enhanced recovery projects in smaller fields.

During 2007, most of our Phase I work was related to further expansion of the floods and facilities in existing fields and initiation of a flood at Lockhart Crossing, our first Louisiana field. Production from this area averaged 12,864 Bbls/d in the fourth quarter of 2007, an increase of 31% over the fourth quarter of 2006 average production level. We expect our tertiary oil production in this area to further increase in 2008 in all of our fields except for Little Creek Field, our oldest flood which began to decline in 2006, including initial oil production from Lockhart Crossing Field late in 2008.

PHASE II

Phase II, in East Mississippi, currently contains three active CO_2 projects. This area has 21.3 MMBbls of tertiary proven reserves as of December 31, 2007 plus an estimated 55 MMBbls of additional potential reserves from future tertiary operations. After completion of our Free State CO_2 Pipeline from Jackson Dome to Eucutta Field in 2006, we initiated injections at three of our Phase II fields, Eucutta, Soso, and Martinville Fields. We saw our first oil production response in 2007 and during the fourth quarter of 2007, these three fields averaged over 4,500 Bbls/d. As a result of the production response, we were able to book over 11 MMBbls of proved reserves at Soso and Martinville during 2007. We expect production to continue to increase in this area throughout 2008. Our 2008 capital budget includes the construction of the pipeline lateral from our Free State Pipeline to Heidelberg Field, our largest conventional field, in order to initiate tertiary operations, with initial injections expected to commence there during 2009.

During 2007, our tertiary oil production increased 47% year over year, averaging 17,428 Bbls/d in the fourth quarter of 2007.

WHERE DOES OUR MONEY GO?
(per 2007 BOE Data)

PHASE III

Tinsley Field, northwest of Jackson Dome, was the most significant field acquired in our $250 million January 2006 acquisition. Tinsley, the only field in Phase III, is one of the largest oil fields in the state of Mississippi, and while it has no current proven tertiary oil reserves, we believe that it has in excess of 40 MMBbls of incremental potential recoverable oil reserves from tertiary operations.

NATURAL GROWTH

After the eruption of Jackson Dome the volcano was eroded and formed a large area of sandbars and beaches along the shallow sea. Ironically, some of this sand became the Woodruff sandstone, the main producing reservoir at Tinsley Field, our Phase III tertiary flood.

Mosasaurs had large conical teeth that could grip the smooth slippery skins of other aquatic reptiles and fish.

FLYING HIGH

First to colonize the new Jackson Dome islands would have been Pterosaurs such as this large Pteranodon. These creatures could grow up to 50 feet in wingspan, the largest flying animals known.

The acquisition of the field included an 8" pipeline which we converted to CO_2 service in 2007 and initiated injections. We also built a 24", 31-mile replacement line from Jackson Dome to Tinsley, during 2007, that was placed in service in January 2008 with a resultant increase in injection rates thereafter. We expect to have our first enhanced oil production from Tinsley Field in the second half of 2008, and if the production response is significant before year-end, we anticipate booking a portion of the forecasted proved reserves at Tinsley during 2008.

PHASE IV

Phase IV includes Cranfield and Lake St. John Fields, two fields, located on opposite sides of the Mississippi River, with Cranfield located in Mississippi and Lake St. John located in Louisiana, both in the Southwest Mississippi area just west of our Phase I fields and both acquired during 2005. We believe that these two fields have approximately 28 MMBbls of potentially recoverable oil from tertiary operations. During 2006, we acquired an 18" natural gas pipeline that runs from Gwinville Field in central Mississippi, through Cranfield Field and then terminates at the Mississippi River. During 2007 we reconditioned and converted the pipeline from natural gas service to CO_2 service and expect to place the pipeline in service during the second quarter of 2008, at which time we will begin CO_2 injections at Cranfield. We do not expect any significant oil production from Cranfield until 2009, and Lake St. John Field will not be flooded for a couple more years as it will require that we extend the pipeline under the Mississippi River to the field.

PHASE V

Phase V consists of Delhi Field, a Louisiana field we acquired in May 2006 for $50 million, plus a 25% reversionary interest to the seller after we have achieved $200 million in net operating revenue, as defined in the agreement. We believe that Delhi Field has approximately 33 MMBbls of potentially recoverable oil from tertiary operations. We expect the CO_2 pipeline to be completed to Delhi around year-end 2008, with CO_2 injection to commence shortly thereafter, and expect our first oil production late in 2009.

PHASE VI

We also plan to ultimately flood Citronelle Field, a field in Southwest Alabama, acquired in our $250 million January 2006 acquisition, which we believe has over 25 MMBbls of potentially recoverable oil from tertiary operations. However, in order to flood this field, we will need to extend our Free State Pipeline from Eucutta Field another 60 to 70 miles to Citronelle Field. We have not yet firmly scheduled this expansion.

Our net Barnett Shale production increased from 35.4 MMcfe/d during the fourth quarter of 2006 to 76.4 MMcfe/d during the fourth quarter of 2007.

PHASES VII AND VIII

During November 2006, we acquired an option to purchase, on September 1, 2008, or September 1, 2009, with an effective date of January 1 of the following year, Hastings Field, a strategically significant potential tertiary flood candidate located near Houston, Texas. The purchase price for the conventional proved reserves will be determined at the time the option is exercised, either by agreement or by a pre-designated independent petroleum engineering firm. As consideration for the purchase option, we made an upfront payment of $37.5 million, with additional payments totaling $12.5 million due or paid during 2007 and 2008. None of the option payment amounts will be credited against the purchase price if we exercise the option.

We believe that Hastings Field possesses from 50 to 80 MMBbls of reserve potential from CO_2 tertiary floods, more reserve potential than any other single field in our inventory. Currently, we are working on the right-of-ways required to build a pipeline we have named our Green Pipeline to transport CO_2 to this field (see CO_2 pipelines above). The Hastings Field was the first significant strategic addition in this area, giving us an anchor field in this region. We have already expanded our field inventory in this area as we purchased Oyster Bayou and Fig Ridge Fields with tertiary potential for $42 million in March 2007 and other small fields, Gillock Fields near Hastings Field, in late 2007. We believe Oyster Bayou and Fig Ridge have significant tertiary reserve potential estimated to be between 25 and 35 MMBbls and project that Gillock Field has approximately 10 MMBbls of additional potential incremental oil. Since our CO_2 pipeline to this area is not expected to be completed until year-end 2009, our goal is to continue to pursue the acquisition of other fields in this area, which will help reduce the cost of CO_2 for each field by fully utilizing the proposed pipeline and thereby reducing our transportation cost per Mcf.

TEXAS AND THE BARNETT SHALE

We currently own about 19,398 net acres of leases in the more tested northern Barnett Shale area in North Central Texas, with additional southern acreage on which we have currently ceased development and may attempt to divest. We acquired our initial acreage in this area in 2001, but only limited development occurred until 2005. Through December 31, 2007, we have invested a total of $423.9 million on the Barnett Shale area and have received $204.8 million in net operating income (revenue less operating expenses), or net negative cash flow of $219.1 million. As of December 31, 2007, we had approximately 368.5 Bcfe of proved reserves in the

Barnett Shale area with a PV-10 Value of approximately $717.2 million, using December 31, 2007, Henry Hub indicative cash pricing of $6.80 per MMBtu.

We continue to refine our completion and fracturing techniques, including an analysis of the best number of fracture treatments to adequately stimulate the entire length of the lateral sections of our horizontal wells, which can exceed 4,000', and the most efficient spacing between the wells. During 2007, we drilled and completed 45 horizontal wells, increasing our net Barnett Shale production from approximately 35.4 MMcfe/d during the fourth quarter of 2006 to approximately 76.4 MMcfe/d during the fourth quarter of 2007. Horizontal wells in the Barnett Shale were initially drilled by spacing horizontal wells approximately 1,500' apart and drilling 3,000' to 4,500' laterals. As our development progressed we began testing wells at various spacings of 750' and subsequently 500' along with other operators in the Barnett. Initial production rates and early production data indicated that we are not efficiently draining the reservoir on the larger initial well spacing, and thus we began developing our acreage position on 500' well spacing which significantly increased the number of future well locations that we can drill. Our year-end reserves included 85 proved undeveloped locations and an additional 88 probable undeveloped locations based on 500' well spacing. We have recently begun testing well spacings less than 500' but the results of this additional downspacing is inconclusive at this time. We plan to drill 45 to 50 wells per year during 2008 and likely during 2009. We believe that our fourth quarter of 2007 production has peaked, or is near its peak, based on the anticipated level of future drilling activity. These wells are characterized by steep decline rates in their first year of production (typically 50% to 60%), followed by a gradual leveling-off of production and a resultant slow decline rate, resulting in a long production life.

EAST MISSISSIPPI (NON-CO_2 PROPERTIES)

We have been active in East Mississippi since Denbury was founded in 1990 and are by far the largest producer in the basin. Historically, this has been our area with the highest production and most proved reserves, and while still significant, it is no longer the largest. Production during the fourth quarter of 2007 averaged approximately 12,530 BOE/d (25% of our Company total) and we had proved reserves of 50.6 MMBOE as of December 31, 2007 (26% of our Company total). Since we have generally owned these East Mississippi properties longer than properties in our other regions, they tend to be more fully developed, and although most are targeted for tertiary operations in the future, only three fields currently have tertiary operations (Soso, Martinville and Eucutta Fields). Production from our East Mississippi fields has been relatively consistent over the last three years, averaging 12,072 BOE/d in 2005, 12,743 BOE/d in 2006, and 12,479 BOE/d in 2007. For 2008, we expect our budget in this region for conventional operations to be around $60 million, about the same as in 2007, representing approximately 7% of our current 2008 exploration and development budget of $900 million.

HEIDELBERG FIELD

The largest field in the region and one of our largest fields corporately is Heidelberg Field, which for the fourth quarter of 2007, produced an average of 7,770 BOE/d, 4% more than the 2006 fourth quarter average of 7,444 BOE/d. Heidelberg Field was acquired from Chevron in December 1997 and was producing approximately 2,800 BOE/d at that time.

The majority of the oil production at Heidelberg is from six waterflood units that produce from the Eutaw formation (at approximately 4,400 feet). Most of our recent activity at Heidelberg has been the development of the Selma Chalk, a natural gas reservoir at a depth of around 3,700 feet. We have steadily developed the Selma Chalk since 2001, drilling from 13 to 20 wells per year, increasing the natural gas production at Heidelberg to a peak quarterly average of 17.3 MMcf/d in the fourth quarter of 2007, with average natural gas production of 16.3 MMcf/d during 2007.

SALE OF LOUISIANA NATURAL GAS ASSETS

In October 2007 we entered into an agreement to sell our Louisiana natural gas assets to a privately held company for approximately $180 million (before closing adjustments) plus any amounts received in the future from a net profits interest. In late December 2007, we closed on approximately 70% of that sale with net proceeds of approximately $108.6 million (including estimated final purchase price adjustments) and closed on the remaining 30% on February 20, 2008, with net proceeds at the second closing of approximately $48.9 million. The operating net revenue, net of capital expenditures, between the August 1, 2007 effective date and the respective closing dates were adjustments to the purchase price, along with other minor closing adjustments. The potential net profits interest relates to a well in the South Chauvin Field and is only earned if operating income from that well exceeds certain levels, which we believe could potentially increase the ultimate sales price by up to 10%.

Production attributable to the sold properties averaged approximately 30.6 MMcfe/d (82% natural gas) during the fourth quarter of 2007, representing approximately 10% of our total fourth quarter production and approximately 4% of our total proved reserve quantities as of December 31, 2006.

WINNING STRATEGIES

"Dino-birds" lived at the time of the Jackson Dome volcano. They looked like their modern day relatives with feathers, beaks and feet-but retained large claws on their wings. Theirs became a winning strategy.

CORPORATE HEADQUARTERS

Denbury Resources Inc.
5100 Tennyson Pkwy, Ste. 1200
Plano, Texas 75024
T: 972.673.2000
F: 972.673.2150

FIELD OFFICES

Brandon, MS:	T: 601.824.1198
Cleburne, TX:	T: 817.645.8100
Laurel, MS:	T: 601.428.1998
Little Creek, MS:	T: 601.276.2147

DATA REQUESTS

Cynthia Rodriguez

INVESTOR RELATIONS

Laurie Burkes
www.denbury.com

QUESTIONS RE: PRESS RELEASES AND STOCKHOLDER REPORTS

Gareth Roberts
President & Chief Executive Officer

Phil Rykhoek
Senior Vice President
& Chief Financial Officer

Laurie Burkes
Investor Relations Manager

ACCOUNTING

Mark Allen, Vice President & Chief Accounting Officer

ACQUISITIONS

Brad Cox, Vice President, Business Development

ENGINEERING AND ANTHROPOGENIC CO_2

Tracy Evans, Senior Vice President, Reservoir Engineering

ENGINEERING AND GEOSCIENCES

Charlie Gibson, Vice President, Reservoir Engineering

FINANCE

Phil Rykhoek, Senior Vice President & Chief Financial Officer

LAND

Ray Dubuisson, Vice President, Land

MARKETING

Dan Cole, Vice President, Marketing

OPERATIONS

Robert Cornelius, Senior Vice President, Operations
Barry Schneider, Vice President, Production & Operations

CAUTIONARY NOTE TO U.S. INVESTORS

The United States Securities and Exchange Commission permits oil and natural gas companies, in their filings with the SEC, to disclose only proved reserves that a company has demonstrated by actual production or conclusive formation tests to be economically and legally producible under existing economic and operating conditions. We use certain terms in the preceding section of this annual report, such as probable and potential reserves or production forecasts or PV-10 Values derived from such probable and potential reserves, that the SEC's guidelines strictly prohibit us from including in filings with the SEC.

FORWARD-LOOKING STATEMENTS

The data contained in this annual report that are not historical facts are forward-looking statements that involve a number of risks and uncertainties. Such statements may relate to, among other things, capital expenditures, drilling activity, development activities, production efforts and volumes, asset values, proved reserves, potential reserves and anticipated production growth rates in our CO_2 models, production and expenditure estimates, availability and cost of equipment and services, and other enumerated reserve potential. These forward-looking statements are generally accompanied by words such as "estimated", "projected", "potential", "possible", "anticipated", "forecasted" or other words that convey the uncertainty of future events or outcomes. These statements are based on management's current plans and assumptions and are subject to a number of risks and uncertainties as further outlined in our most recent 10-K and 10-Q. Therefore, the actual results may differ materially from the expectations, estimates or assumptions expressed in or implied by any forward-looking statement made by or on behalf of the Company.

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

2007 FORM 10-K

(Mark One)

_X_ Annual report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
For the fiscal year ended December 31, 2007
OR
___ Transition report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
For the transition period from ____________ to ____________

Commission file number 1-12935

DENBURY RESOURCES INC.

(Exact name of Registrant as specified in its charter)

Delaware	**20-0467835**
(State or other jurisdiction of incorporation or organization)	*(I.R.S. Employer Identification No.)*
5100 Tennyson Parkway, Suite 1200, Plano, TX	**75024**
(Address of principal executive offices)	*(Zip Code)*

Registrant's telephone number, including area code: (972) 673-2000

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

Title of Each Class:	Name of Each Exchange on Which Registered:
Common Stock $.001 Par Value	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 _X_ 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 _X_

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

Indicate by check mark 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 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 definition of "large accelerated filer," "accelerated filer," and "small reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

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

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

The aggregate market value of the registrant's common stock held by non-affiliates, based on the closing price of the registrant's common stock as of the last business day of the registrant's most recently completed second fiscal quarter was $3,233,003,475.

The number of shares outstanding of the registrant's Common Stock as of January 31, 2008, was 245,193,057.

DOCUMENTS INCORPORATED BY REFERENCE

Document:	Incorporated as to:
1. Notice and Proxy Statement for the Annual Meeting of Shareholders to be held May 15, 2008.	*1. Part III, Items 10, 11, 12, 13, 14*

Table of Contents

Glossary and Selected Abbreviations

Bbl	One stock tank barrel, of 42 U.S. gallons liquid volume, used herein in reference to crude oil or other liquid hydrocarbons.
Bbls/d	Barrels of oil produced per day.
Bcf	One billion cubic feet of natural gas or CO_2.
Bcfe	One billion cubic feet of natural gas equivalent using the ratio of one barrel of crude oil, condensate or natural gas liquids to 6 Mcf of natural gas.
BOE	One barrel of oil equivalent using the ratio of one barrel of crude oil, condensate or natural gas liquids to 6 Mcf of natural gas.
BOE/d	BOEs produced per day.
Btu	British thermal unit, which is the heat required to raise the temperature of a one-pound mass of water from 58.5 to 59.5 degrees Fahrenheit.
CO_2	Carbon dioxide.
Finding and Development Cost	The average cost per BOE to find and develop proved reserves during a given period. It is calculated by dividing costs, which includes the total acquisition, exploration and development costs incurred during the period plus future development and abandonment costs related to the specified property or group of properties, by the sum of (i) the change in total proved reserves during the period plus (ii) total production during that period.
MBbls	One thousand barrels of crude oil or other liquid hydrocarbons.
MBOE	One thousand BOEs.
Mbtu	One thousand Btus.
Mcf	One thousand cubic feet of natural gas or CO_2.
Mcf/d	One thousand cubic feet of natural gas or CO_2 produced per day.
Mcfe	One thousand cubic feet of natural gas equivalent using the ratio of one barrel of crude oil, condensate or natural gas liquids to 6 Mcf of natural gas.
Mcfe/d	Mcfes produced per day.
MMBbls	One million barrels of crude oil or other liquid hydrocarbons.
MMBOE	One million BOEs.
MMBtu	One million Btus.
MMcf	One million cubic feet of natural gas or CO_2.
MMcf/d	One million cubic feet of natural gas or CO_2 per day.
MMcfe	One thousand Mcfe.
MMcfe/d	MMcfes produced per day.
PV-10 Value	When used with respect to oil and natural gas reserves, PV-10 Value means the estimated future gross revenue to be generated from the production of proved reserves, net of estimated production and future development costs and abandonment, using prices and costs in effect at the determination date, and before income taxes, discounted to a present value using an annual discount rate of 10%. PV-10 Value is a non-GAAP measure and its use is further discussed in footnote 3 to the table on page 19.
Proved Developed Reserves*	Reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.
Proved Reserves*	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.
Proved Undeveloped Reserves*	Reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required.
Tcf	One trillion cubic feet of natural gas or CO_2.

** This definition is an abbreviated version of the complete definition as defined by the SEC in Rule 4-10(a) of Regulation S-X.*
See **www.sec.gov/divisions/corpfin/forms/regsx.htm#gas** *for the complete definition.*

Item 1. Business

Website Access to Reports

We make our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and amendments to those reports, filed or furnished pursuant to section 13(a) or 15(d) of the Securities Exchange Act of 1934, available free of charge on or through our Internet website, www.denbury.com, as soon as reasonably practicable after we electronically file such material with, or furnish it to, the SEC.

The Company

Denbury Resources Inc. is a Delaware corporation organized under *Delaware General Corporation Law* ("DGCL") and is engaged in the acquisition, development, operation and exploration of oil and natural gas properties in the Gulf Coast region of the United States, primarily in Mississippi, Louisiana, Texas and Alabama. Our corporate headquarters is located at 5100 Tennyson Parkway, Suite 1200, Plano, Texas 75024, and our phone number is 972-673-2000. At December 31, 2007, we had 686 employees, 420 of whom were employed in field operations or at the field offices. Our employee count does not include the approximately 660 employees of Genesis Energy, Inc. as of December 31, 2007, as its employees exclusively carry out the business activities of Genesis Energy, L.P., which we do not consolidate in our financial statements (see Note 1 to the Consolidated Financial Statements).

Incorporation and Organization

Denbury was originally incorporated in Canada in 1951. In 1992, we acquired all of the shares of a United States operating company, Denbury Management, Inc. ("DMI"), and subsequent to the merger we sold all of its Canadian assets. Since that time, all of our operations have been in the United States.

In April 1999, our stockholders approved a move of our corporate domicile from Canada to the United States as a Delaware corporation. Along with the move, our wholly owned subsidiary, DMI, was merged into the new Delaware parent company, Denbury Resources Inc. This move of domicile did not have any effect on our operations or assets.

Effective December 29, 2003, Denbury Resources Inc. changed its corporate structure to a holding company format. As part of this restructure, Denbury Resources Inc. (predecessor entity) merged into a newly formed limited liability company, and survived as Denbury Onshore, LLC, a Delaware limited liability company and an indirect subsidiary of the newly formed holding company, Denbury Holdings, Inc. Denbury Holdings, Inc. subsequently assumed the name Denbury Resources Inc. (new entity). Stockholders' ownership interests in the business did not change as a result of the new structure and shares of the Company remain publicly traded under the same symbol (DNR) on the New York Stock Exchange.

Business Strategy

As part of our corporate strategy, we believe in the following fundamental principles:

- remain focused in specific regions;
- acquire properties where we believe additional value can be created through a combination of exploitation, development, exploration and marketing, including secondary and tertiary operations;
- acquire properties that give us a majority working interest and operational control or where we believe we can ultimately obtain it;
- maximize the value of our properties by increasing production and reserves while reducing cost; and
- maintain a highly competitive team of experienced and incentivized personnel.

Acquisitions

Information as to recent acquisitions and divestitures by Denbury is set forth under Note 2, "Acquisitions and Divestitures," to the Consolidated Financial Statements.

Oil and Gas Operations

Our CO_2 Assets

During 2007, we continued to focus on carbon dioxide ("CO_2") enhanced oil recovery. We continued the expansion of our Phase I and Phase II tertiary floods and initiated tertiary projects at Lockhart Crossing, our first Louisiana field in Phase I (see description of the various phases below), Tinsley Field in Phase III, and Cranfield Field in Phase IV. We increased our potential tertiary flood candidates during 2007 with the acquisition of significant positions in Oyster Bayou, Fig Ridge and Gillock Fields, Phases VII and VIII, adding to our inventory of future tertiary floods. In addition to our development, expansion and acquisition of new floods, we also made the strategic decision to divest our natural gas assets in South Louisiana that did not contain future CO_2 potential in order to further narrow our focus on CO_2 enhanced oil recovery and our core assets. During the last eight years, we have learned a considerable amount about tertiary operations and working with CO_2, and our knowledge continues to grow. We like these tertiary operations because (i) CO_2 investments provide a reasonable rate of return, even at relatively low oil prices, (ii) tertiary flooding exhibits a lower risk profile, and (iii) to date, in our region of the United States, we have not encountered any industry competition. Generally, from the Texas Gulf Coast to Florida, there are no known significant natural sources of carbon dioxide except our own, and these large volumes of CO_2 are the foundation for our entire tertiary program.

CO_2 is one of the most efficient tertiary recovery mechanisms for crude oil. The CO_2 acts somewhat like a solvent for the oil, removing it from the oil-bearing formation as the CO_2 passes through the rock. CO_2 tertiary floods are unique because they require large volumes of CO_2, the location of which, to our knowledge, is limited to a few geological basins, one of which is our source near Jackson, Mississippi. Further, the most efficient way to transport CO_2 is via dedicated pipelines, which are also in limited supply. Because the sources and methods of transportation of CO_2 are limited, only 3% or approximately 250,000 Bbls/d of the United States domestic oil production is derived from tertiary recovery projects.

Our CO_2 source field, Jackson Dome, located near Jackson, Mississippi, was discovered during the 1970s while being explored for hydrocarbons. This significant source of CO_2 is the only known one of its kind in the United States east of the Mississippi River. Mississippi's first enhanced oil recovery project began in the mid 1980s in Little Creek Field following the installation of Shell Oil Company's Choctaw CO_2 Pipeline. The 183-mile Choctaw Pipeline (now referred to as NEJD Pipeline) transported CO_2 produced from Jackson Dome to Little Creek Field. While the CO_2 flood initially proved to be successful in recovering significant amounts of oil, commodity prices at that time made the project unattractive for Shell and they later sold their oil fields in this area, as well as the CO_2 source wells and pipeline.

While enhanced oil recovery ("EOR") projects utilizing CO_2 may not be considered a new technology, Denbury applies several additional technologies to the fields: well evaluations, new completion or stimulation techniques, operating equipment and seismic interpretations. We began our CO_2 operations in August 1999, when we acquired Little Creek Field in Mississippi, followed by our acquisition of Jackson Dome CO_2 reserves and pipeline in 2001. Based upon our success at Little Creek, we embarked upon a strategic program to improve our understanding and knowledge of CO_2 production and tertiary recovery to build a dominant position in this niche play.

Tertiary Recovery Phases

We talk about our tertiary operations by labeling operating areas or groups of fields as phases. Phase I is in Southwest Mississippi and includes several fields along our 183-mile NEJD CO_2 Pipeline that we acquired in 2001. The most significant fields in this area are Little Creek, Mallalieu, McComb and Brookhaven. We further expanded our Phase I area by developing Lockhart Crossing Field in South Louisiana during 2007. Lockhart Crossing, although a relatively small field, is the first of three fields to be CO_2 flooded in Louisiana and our first flood outside the state of Mississippi. Phase II, which began with the early 2006 completion of the Free State CO_2 Pipeline to East Mississippi, includes Eucutta, Soso, Martinville and Heidelberg Fields. Tinsley Field, located northwest of Jackson, Mississippi, acquired in January 2006, is our Phase III and is serviced by that portion of the Delta CO_2 Pipeline completed in January 2008. Phase IV includes Cranfield and Lake St. John Fields, two fields near the Mississippi/Louisiana border located west of the Phase I fields, and Phase V is Delhi Field, a Louisiana field we acquired in 2006, located southwest of Tinsley Field. Flooding in Phase V will begin in 2009 upon completion of the Delta CO_2 Pipeline from Tinsley to Delhi. Citronelle Field in Southwest Alabama, another field acquired in 2006, is our Phase VI which will require an extension to the Free State CO_2 Pipeline, the timing of which is uncertain at this time. Our last two currently existing phases will require completion of our proposed 300-mile Green Pipeline, which will run from Southern Louisiana to near Houston, Texas, and is scheduled for completion in late 2009 or 2010. Hastings Field, a field on which we acquired a purchase option in late 2006, is our Phase VII and the Seabreeze Complex, acquired in 2007, will be our Phase VIII.

Jackson Dome. In February 2001, we acquired approximately 800 Bcf of proved producing CO_2 reserves for $42 million, a purchase that gave us control of most of the CO_2 supply in Mississippi, as well as ownership and control of a critical 183-mile CO_2 pipeline. This acquisition provided the platform to significantly expand our CO_2 tertiary recovery operations by assuring that CO_2 would be available to us on a reliable basis and at a reasonable and predictable cost. Since February 2001, we have acquired two additional wells and drilled 15 additional CO_2 producing wells, significantly increasing our estimated proved CO_2 reserves to approximately 5.6 Tcf as of December 31, 2007, which is almost enough for our existing and currently planned phases of operations. The estimate of 5.6 Tcf of proved CO_2 reserves is based on 100% ownership of the CO_2 reserves, of which Denbury's net ownership (net revenue interest) is approximately 4.5 Tcf and is included in the evaluation of proved CO_2 reserves prepared by DeGolyer and MacNaughton. In discussing our available CO_2 reserves, we make reference to the gross amount of proved reserves, as this is the amount that is available both for Denbury's tertiary recovery programs and for industrial users who are customers of Denbury and others, as Denbury is responsible for distributing the entire CO_2 production stream for both of these uses. Today, we own every producing CO_2 well in the region. Although our current proven and potential CO_2 reserves are quite large, in order to continue our tertiary development of oil fields in the area, incremental deliverability of CO_2 is needed. In order to obtain additional CO_2 deliverability, we plan to drill several additional CO_2 wells in the future, including four development wells and one exploratory well during 2008.

During the fourth quarter of 2007, we produced an average of 533 MMcf/d of CO_2, a 35% increase over one year ago. We sold an average of 99 MMcf/d of CO_2 to commercial users, and we used an average of 434 MMcf/d for our tertiary activities. We estimate that our current daily CO_2 deliverability is around 700 MMcf/d. By year-end 2008, we estimate that our planned tertiary operations will require approximately 800 MMcf/d, which we believe we can attain with our planned 2008 Jackson Dome projects. Our geoscientists are using a 100-square-mile 3-D seismic survey to locate additional structures that are expected to contain CO_2. During 2007, we drilled our first previously undrilled structure based on our 100-square-mile seismic survey and re-entered a previously drilled well on another structure. The successful testing of this undrilled structure and our successful re-entry and testing of this previously drilled well, along with our development work at DRI Ice Field, increased our confidence that significant volumes of additional CO_2 can be developed in the Jackson Dome area beyond our proved reserve base. We plan to continue our CO_2 drilling activity in 2008 and beyond, with additional development of DRI Ice Field to increase our deliverability of CO_2 and additional testing of undrilled structures to potentially increase our proved reserves, as our CO_2 deliverability and reserves requirements will continue to grow as we expand our planned tertiary projects and acquire additional tertiary projects.

Man-made CO_2 Sources. We entered into two additional agreements and committed to purchase (if the plants are built) 100% of the man-made (anthropogenic) CO_2 production, from two proposed solid carbon gasification projects scheduled to be completed in 2011 and 2012. These projects are in addition to our 2006 agreement for the Faustina plant, proposed to be located near Donaldsonville, Louisiana, that will convert petroleum coke into ammonia. As a by-product of the gasification of solid carbon, large quantities of CO_2 are produced. Assuming these three projects are built, the total volume of CO_2 expected to be produced is estimated to be between 750 and 850 MMcf/d. We plan to use this CO_2 in our tertiary operations to recover oil that may otherwise not be produced. In addition, our use of this CO_2 will also eliminate the release of this greenhouse gas into the earth's atmosphere. These agreements potentially allow us to add the equivalent volume of an additional three to four Tcf of CO_2 over the terms of our contracts. Construction of these plants has not yet begun, so we are not certain whether these plants will be built, although it appears likely that some gasification plants will be built in this area, if not these particular three. We are in discussions with several other entities that are considering other types of solid carbon gasification plants. These plants may convert petroleum coke, coal, biomass or combinations of all three into a variety of products including ammonia, methanol, synthetic diesel fuel or for electrical power generation. The cost of man-made CO_2 will likely be higher than CO_2 from our natural source, but the location of these plants could mitigate some of the incremental cost of transportation, and we believe that there could potentially be a type of carbon credit in the United States that could significantly lower our cost for this CO_2. Further, we see these sources as a possible expansion of our natural Jackson Dome source, assuming they are economical, and we believe that our potential ability to tie these sources together with pipelines will give us a significant advantage over our competitors in our geographic area in acquiring additional oil fields and future potential man-made sources of CO_2.

CO_2 Pipelines. We acquired the NEJD 183-mile CO_2 Pipeline that runs from Jackson Dome to near Donaldsonville, Louisiana, as part of the 2001 acquisition of our Jackson Dome source field (see above). Construction of our Free State Pipeline was completed in 2006 and it is currently transporting CO_2 to our three existing Phase II tertiary fields in East Mississippi (Eucutta, Soso and Martinville) and will also be used for our proposed projects at Heidelberg, South Cypress Creek and other fields in Phase II. We continued our expansion of our CO_2 pipeline infrastructure with the completion of the first segment of our Delta Pipeline between Jackson Dome and Tinsley Field in January 2008, and the reconditioning and conversion of the natural gas pipeline we acquired from Southern Natural Gas Company in 2006 to CO_2 service which we will use to transport CO_2 to our Phase IV fields, Cranfield and Lake St. John Fields. Although neither of these pipeline projects were completed during 2007, during January 2008 we placed the Delta Pipeline in service between Jackson Dome and Tinsley Field and expect to make

our first deliveries of CO_2 to Cranfield during the second quarter of 2008. During 2008, we plan to further extend our Delta Pipeline by building a 24″ 68-mile extension from Tinsley Field to Delhi Field with completion of this segment anticipated around year-end 2008.

In late 2006, we purchased an option to acquire Hastings Field, a potential tertiary flood located near Houston, Texas. We plan to build a 24″ pipeline, named the Green Pipeline, to transport CO_2 to Hastings Field and our 2007 Southeast Texas acquisitions, Oyster Bayou, Fig Ridge and Gillock Fields. The Green Pipeline will go from the southern end of our existing NEJD CO_2 pipeline that terminates near Donaldsonville, Louisiana, to Hastings Field, near Houston, Texas, estimated to be between 300 and 320 miles. Based on our latest estimates, this pipeline is expected to cost between $700 million and $750 million. Our efforts in 2007 were focused on engineering design and right-of-way acquisitions. We acquired approximately 100-plus miles of the necessary 300-plus miles of right-of-way in 2007 and completed a substantial portion of our engineering design. In addition, we signed a letter of intent with a steel mill to manufacture the 24″ pipe and thereby locked-in the pipe purchase price. Although our definitive schedules are still in flux, our goal is to begin construction of the Green Pipeline around year-end 2008 and hope to have it completed around year-end 2009. Initially, we anticipate transporting CO_2 from our natural source at Jackson Dome on this line, but ultimately we expect that it will be used to ship predominately man-made (anthropogenic) sources of CO_2.

Overall Economics. Initially, our tertiary operations were generally economic at oil prices below $20 per Bbl, although the economics have always varied by field. Our costs have escalated during the last few years due to general cost inflation in the industry, raising our current economic oil price to around $30 per Bbl, again dependent on the specific field. Our inception to date finding and development costs (including future development and abandonment costs but excluding expenditures on fields without proven reserves) for our tertiary oil fields through December 31, 2007, was approximately $9.75 per BOE. Currently, we forecast that these costs will range from $5 to $10 per BOE over the life of each field, depending on the state of a particular field at the time we begin operations, the amount of potential oil, the proximity to a pipeline or other facilities, etc. Our operating costs for tertiary operations are expected to range from $15.00 to $20.00 per BOE over the life of each field (at today's prices), again depending on the field itself.

While these economic factors have wide ranges, our rate of return from these operations has generally been better than the rate of return on our traditional oil and gas operations and entail less risk, and thus our tertiary operations have become our single most important focus area. While it is extremely difficult to accurately forecast future production, we do believe that our tertiary recovery operations provide significant long-term production and reserve growth potential at reasonable rates of return, with relatively low risk, and thus will be the backbone of our Company's growth for the foreseeable future. Although we believe that our plans and projections are reasonable and achievable, there could be delays or unforeseen problems in the future that could delay or affect the economics of our overall tertiary development program. We believe that such delays or price effects, if any, should only be temporary.

Tentatively, we plan to spend approximately $90 million in 2008 in the Jackson Dome area with the intent to add additional CO_2 reserves and deliverability for future operations. Approximately $27 million in capital expenditures is budgeted in 2008 for our Phase II properties (East Mississippi) and approximately $27 million for Phase III properties (Tinsley), plus an additional $180 million for properties in other phases, plus an additional $235 million for our Delta and Green CO_2 Pipelines, making our combined CO_2 related expenditures just over 72% of our $900 million 2008 capital budget.

Our Tertiary Oil Fields With Proved Tertiary Reserves

At December 31, 2007, we had total tertiary-related proved oil reserves of approximately 69.5 MMBbls, consisting of 2.7 MMBbls at Little Creek Field (and surrounding smaller fields), 11.5 MMBbls at Mallalieu Field, 15.3 MMBbls at McComb and Smithdale Fields, 18.7 MMBbls at Brookhaven Field, 10.2 MMBbls at Eucutta Field, 9.8 MMBbls at Soso Field, and 1.3 MMBbls at Martinville Field. Overall, our production from tertiary operations has increased from approximately 1,350 Bbls/d in 1999, the then existing production at Little Creek Field at the time of acquisition, to an average of 17,428 Bbls/d during the fourth quarter of 2007. We expect this production to continue to increase for several years as we expand our tertiary operations to additional fields.

With regard to our proved tertiary reserves, we added 12.7 MMBbls of tertiary-related proved oil reserves during the year, primarily oil reserves at Soso, Martinville and minor incremental barrels at various fields in the Phase I area. Previously, we booked most proved tertiary oil reserves near the start of a project as almost all the oil fields in Phase I were analogous to Little Creek Field (our first flood) and thus it was not necessary to have an oil production response to the CO_2 injections before they were considered proved. Conversely, our new floods (after Phase I) are not analogous (for the most part), as the tertiary floods will be in different geological formations. Therefore, for these new phases, there must be an oil production response to the CO_2 injections before we can recognize proved oil reserves, even though we believe that these formations have a similar risk profile. We anticipate booking significant amounts of proven tertiary oil reserves during 2008 with initial response expected at Tinsley and Lockhart Crossing Fields and possibly at Cranfield Field.

Mallalieu Field. The Mallalieu Field consists of two fields, West Mallalieu and the smaller East Mallalieu Fields. Combined they are our most prolific tertiary flood, producing 6,304 Bbls/d for the fourth quarter 2007. In contrast to many of our existing fields, Mallalieu Field was not waterflooded prior to CO_2 injection. Therefore, we believe that the tertiary recovery of oil from Mallalieu Field as a result of CO_2 injection could approach 25% of the original oil in place. During 2006, we increased our proved reserves in this area, raising our estimated recovery factor from 17% to 20% for these fields, based on production performance to date. A total of $16.6 million was invested in this field during 2007 to drill, re-enter or recomplete wells in efforts to improve production.

From inception through December 31, 2007, we had net positive cash flow (revenue less operating expenses and capital expenditures) from Mallalieu Field of $253.2 million, plus the fields have a PV-10 Value of $719.8 million, using December 31, 2007, NYMEX pricing of $95.98 per barrel.

McComb and Smithdale Fields. We commenced tertiary recovery operations in 2003 at McComb Field and started injecting CO_2 late that year. Significant development occurred during 2004 and 2005 as we expanded the nearby Olive Field CO_2 facility to handle the processing of McComb's produced oil, water and CO_2, and developed an additional four injection patterns. The first production response occurred in the second quarter of 2004 and has increased since that time, averaging 1,388 Bbls/d in the fourth quarter of 2007. During 2007, we continued the expansion of our operations within McComb Field, expanding the production facilities, and completing our installation of the facilities necessary to raise the injection pressure throughout the field. Although we encountered injection issues, which initially limited our CO_2 injections at McComb, the increased injection pressure has resulted in significant increases in CO_2 injections at McComb Field. Since we increased the CO_2 injections, we have seen increased amounts of water production which is generally the precursor for increasing oil production. During 2007, nearby Smithdale Field saw significant production increases. Oil production increased from less than 100 Bbls/d in 2006 to an average of 708 Bbls/d in the fourth quarter of 2007. Smithdale development was slower than expected due to a larger percentage of re-entry failures than we have experienced in our other fields. The reservoir at Smithdale is very channelized and thus the drilling of replacement wells for the re-entry failures was postponed until we were able to complete our evaluation of a 2007 3-D seismic survey covering McComb and Smithdale Fields. By utilizing the 3-D seismic data, our geoscientists are able to locate wells in optimal positions within the channels at Smithdale to maximize the aerial coverage and sweep of the CO_2 project.

From inception through December 31, 2007, we had not yet recovered our costs in these fields, with net negative cash flow (revenue less operating expenses and capital expenditures, including the acquisition costs) from these fields of $113.3 million, although the fields have a PV-10 Value of $713.1 million, using December 31, 2007, NYMEX pricing.

Brookhaven Field. Our first tertiary CO_2 production response at Brookhaven Field occurred during the fourth quarter of 2005, with oil production rates averaging 125 Bbls/d during the fourth quarter of 2005. Production rates continued to increase throughout 2006 and 2007 as additional patterns have been developed. Brookhaven Field has three discrete reservoirs that are being simultaneously CO_2 flooded. Significant incremental work on CO_2 injection wells is required to improve injection rates and to ensure the CO_2 is entering the proper intervals. Injection of CO_2 in certain wells has been less than originally anticipated and thus additional injection pumps were installed on certain wells to increase injection rates. Our oil production here during the fourth quarter of 2007 averaged 2,507 Bbls/d.

From inception through December 31, 2007, we had not yet recovered our costs in this field with net negative cash flow (revenue less operating expenses and capital expenditures, including the acquisition cost) from Brookhaven of $44.8 million, although the field has a PV-10 Value of $793.8 million attributed to the tertiary recovery reserves, using December 31, 2007, NYMEX pricing.

Little Creek Area. During the fourth quarter of 2007, production averaged 1,957 Bbls/d from the Little Creek area, which includes Lazy Creek. Production at Little Creek Field began declining in 2006 and is expected to continue to decline over the next several years. We are working to mitigate production declines by monitoring injection patterns, reworking producing wells and using injection surveys to control at which intervals the CO_2 is injected. From inception through December 31, 2007, we had net positive cash flow (revenue less operating expenses and capital expenditures, including the acquisition cost) from Little Creek (including adjoining smaller fields) of $153.9 million, plus the fields have a PV-10 Value of $132.3 million, using December 31, 2007, NYMEX pricing.

Eucutta Field. The oil response we have experienced in Eucutta has confirmed the results of the pilot project that was performed in the early 1980s. The Eutaw formation at Eucutta was unitized for water flooding in 1966 and has gone through several stages of development. During the 1980s, Amerada Hess installed an inverted 5-spot injection pilot in the First City Bank sand (one of the Eutaw sands) to test the application of CO_2 flooding. Although the pilot test only covered approximately 20 acres, the pilot was successful in recovering an additional 17% of the original oil in place within the pattern. Based on this success, we designed and constructed a CO_2 flood and facility for the Eucutta Field. Initial well work was completed and CO_2 injection started during the first quarter of 2006, with the first minor tertiary oil production during the fourth quarter of 2006. Our plans for 2008 include the development of the remaining patterns and expansion of our CO_2 facilities. At December 31, 2007, we had 10.2 MMBbls of proved reserves in the Eucutta Field attributable to the CO_2 flood with a corresponding PV-10 Value of $456.0 million using year-end prices. The proved reserve estimate is based on a 13% recovery factor, which is lower than was achieved in the pilot program in the 1980s, and therefore we expect upward reserve revisions here in the future. Eucutta is analogous to Heidelberg Field in that the majority of its historical production was produced from the Eutaw formation.

From inception through December 31, 2007, we had not yet recovered our costs in this field, with net negative cash flow (revenue less operating expenses and capital expenditures, including the acquisition cost) from Eucutta of $40.3 million, although the field has a PV-10 Value of $456.0 million attributed to the tertiary recovery reserves, using December 31, 2007, NYMEX pricing.

Soso Field. Soso Field, near Laurel, Mississippi, produced from numerous reservoirs during primary production including the Rodessa, Bailey and Cotton Valley sands, all of which we plan to CO_2 flood. The Bailey sand exhibits comparable reservoir characteristics to our West Mississippi floods, and we expect the Bailey tertiary flood to perform in a similar manner. We elected to co-develop the Bailey sand and Rodessa sand to accelerate the development of the potential tertiary oil reserves at Soso. Although we began initial development of the Bailey sand very late in 2005, the majority of our capital investment to date occurred in 2006, which involved the construction of CO_2 facilities and the establishment of the two tertiary injection projects. During the first quarter 2006, we initiated our first injections of CO_2 into five Bailey injection wells and initiated injection in the Rodessa during the second quarter of 2006, although injections in the Bailey formation were initially limited because of delays in getting the well work done and limited CO_2 supplies. As expected, we saw our first tertiary production in Soso Field during early 2007 from the Bailey.

In 2007 we continued the development of additional patterns in both the Rodessa and Bailey intervals, and by the fourth quarter of 2007 response in the Bailey continued to increase, and initial response from the Rodessa was also achieved. During the fourth quarter of 2007, production at Soso had increased to 1,109 Bbls/d. From inception through December 31, 2007, we had not yet recovered our costs in this field with net negative cash flow (revenue less operating expenses and capital expenditures, including the acquisition cost) from Soso of $93.2 million, although the field has a PV-10 Value of $363.5 million attributed to the tertiary recovery reserves, using December 31, 2007, NYMEX pricing.

Martinville Field. We initiated our first injections of CO_2 in Martinville Field during the first quarter of 2006 in both the Rodessa and Mooringsport formations. As is the case with most of the East Mississippi fields, Martinville produces from multiple reservoirs. Unlike the majority of our other planned CO_2 projects, Martinville does not contain a single large reservoir to CO_2 flood, but rather several smaller reservoirs. We completed construction of the CO_2 facilities and essentially completed the development of the Mooringsport sand during 2006. During the fourth quarter of 2006, the first Mooringsport well responded, although the average rate for the quarter was only 24 Bbls/d. The tertiary oil rate has increased to approximately 883 Bbls/d during the fourth quarter of 2007 including initial response in the Rodessa. Although we booked minimal proved reserves in 2006 from the one responding well in the Mooringsport, we booked additional reserves, approximately 1.5 MMBbls at December 31, 2007, in the Mooringsport and the Rodessa IX reservoir. There are several additional Rodessa reservoirs that will be developed following completion of the CO_2 flood in the Rodessa IX.

From inception through December 31, 2007, we had not yet recovered our costs in this field with net negative cash flow (revenue less operating expenses and capital expenditures, including the acquisition cost) from Martinville of $10.8 million, although the field has a PV-10 Value of $65.8 million attributed to the tertiary recovery reserves, using December 31, 2007, NYMEX pricing.

The Wash Fred 8500' reservoir in the Martinville Field contains a low oil gravity (thick oil), 15° API, which will not develop miscibility with CO_2 at reservoir conditions. Denbury has several fields with similar gravity oils, which like the Wash Fred 8500' have had lower recoveries due to the low oil gravities and strong water drives, which do not sweep the oil efficiently. We initiated CO_2 injection during the first quarter of 2006 at the crest of the structure. Although we will not achieve miscibility, the injection of CO_2 is expected to swell the oil, decrease the oil viscosity, and displace the water and oil downward in the reservoir to the adjacent producing wells and result in incremental oil production. Well bore issues delayed the implementation of this flood during 2006, and fluid handling and processing of the CO_2 and this heavy crude have continued to hamper the development of this flood. Although we have seen indications of CO_2 response, the ability to produce and process this heavy crude with the associated CO_2 production is proving very difficult. We are evaluating various ideas and scenarios to address the processing issues we are experiencing. If we can resolve these issues, this field could provide the impetus to look at a whole new array of fields that have historically not been considered for CO_2 injection, although there can be no assurance that this technique will be successful or economic.

Our Tertiary Oil Fields Without Proved Tertiary Reserves

During 2007, we commenced tertiary operations at a small field, Lockhart Crossing (Phase I), our first Louisiana flood, reconditioned the pipeline necessary to transport CO_2 to Cranfield Field in West Mississippi (Phase IV), and initiated CO_2 injections at Tinsley Field (Phase III).

Tinsley Field. Tinsley Field was acquired in January 2006 and is one of the largest oil fields in the state of Mississippi. As is the case with the majority of fields in Mississippi, Tinsley produces from multiple reservoirs. While we are working the other reservoirs in an attempt to increase current conventional production and reserves, our primary target in Tinsley for CO_2 enhanced oil recovery operations is the Woodruff formation. One of the prior operators performed a pilot CO_2 project at Tinsley in the Perry sandstone. The CO_2 was successful at mobilizing oil but the operator decided not to expand the flood due to low oil prices. The acquisition of the field included an 8" pipeline that was installed to deliver CO_2 to the pilot project but was converted to natural gas service some time ago. We have reconditioned the pipeline for CO_2 service and initiated limited CO_2 injection in Tinsley Field in January 2007. Although injections were limited throughout 2007, we completed unitization of the entire field, constructed a substantial portion of our CO_2 recycling facilities, and expanded the CO_2 flood throughout the west fault block of the field. Construction of the first segment of our larger Delta Pipeline was completed in January 2008 with a resultant increase in injection rates thereafter. Although we only had limited injections during 2007, we did observe increasing reservoir pressures, and we plan to continue that re-pressuring process during 2008 with the higher injection rates. Once the reservoir pressure increases to our target amount, we expect to see our initial tertiary oil production, most likely in the third or fourth quarter of 2008. If the production response is significant and occurs before year-end, we anticipate booking a portion of the forecasted proved reserves at Tinsley in 2008.

Delhi Field. During May 2006, we purchased the Delhi Holt-Bryant Unit ("Delhi") in Northern Louisiana for $50 million, plus a 25% reversionary interest to the seller after we achieve $200 million in net operating revenue, as defined. Delhi is also a planned future CO_2 tertiary oil flood that will require construction of a CO_2 pipeline before flooding can commence, an extension of the larger, Delta Pipeline constructed from Jackson Dome to Tinsley Field. Our goal is to have this segment of the Delta Pipeline installed by around year-end 2008, with initial oil production from tertiary operations currently anticipated during 2009. As of December 31, 2007, there was no significant oil production nor proved oil reserves at Delhi Field.

Hastings Field. During November 2006, we entered into an agreement with a subsidiary of Venoco, Inc. that gives us an option on September 1, 2008, or September 1, 2009, with an effective date of January 1 of the following year, to purchase their interest in Hastings Field, a strategically significant potential tertiary flood candidate located near Houston, Texas. The agreement provides for the parties to agree upon a purchase price for the conventional proved reserves at the time of the exercise of the option, which may be paid in cash or through a volumetric production payment; failing agreement as to price, the price will be determined by a pre-designated independent petroleum engineering firm using specified criteria for calculation of the discounted present value of proved reserves at that time. As consideration for the option agreement, we made an upfront payment of $37.5 million upon execution of the agreement and made an additional $7.5 million payment in 2007, and are required to make an additional payment of $5 million by November 2008. We can extend the option period beyond November 2009 for up to seven additional years at an incremental cost of $30 million per year. None of the option payment amounts will be credited against the purchase price if we exercise the option. If we exercise the option, we will be committed to make aggregate net capital expenditures in the field of approximately $175 million over the subsequent five years to develop the field for tertiary operations, with an obligation to commence CO_2 injections in the field within three years following the option exercise. Hastings Field is currently producing approximately 2,800 Bbls/d gross, although we currently have no economic interest in this production.

Based on preliminary engineering data, the West Hastings Unit (the most likely area to be initially developed as a tertiary flood) has significant net reserve potential from CO_2 tertiary floods, more reserve potential than any other single field in our inventory. We plan to build the Green Pipeline to transport CO_2 to this field (see "CO_2 pipelines" above). Based on our latest estimates, it will cost between $400 million and $600 million to develop the West Hastings Unit as a tertiary flood, excluding the cost of the Green Pipeline.

Oyster Bayou, Fig Ridge and Gillock Fields. During 2007, we acquired an interest in three additional fields in Southeast Texas with significant tertiary potential. The Oyster Bayou and Fig Ridge Fields are located in close proximity to each other and are located very close to the planned route of the Green Pipeline. We acquired the majority interest in Oyster Bayou Field and a significant interest in Fig Ridge Field. We plan to start the unitization hearings required at Oyster Bayou Field during 2008. Because of current lack of majority interest at Fig Ridge Field, we will need the cooperation of other operators and lease owners to form the necessary unit, and we have initiated those discussions. Our acquisitions in Gillock Field include an acquisition of 99+% (subject to a 20% preferential right election) of the South Gillock Unit, 99+% of the Southeast Gillock unit and the acquisition of a key lease in the Gillock Field. The Gillock acquisitions are located near the proposed Green Pipeline and Hastings Field. Denbury continues to evaluate other potential acquisition candidates in Southeast Texas and in Louisiana in proximity to our proposed Green Pipeline.

Overall Tertiary Economics to Date. Through December 31, 2007, we have invested a total of $1.0 billion on tertiary oil fields (including the allocated acquisition costs), and received $758.9 million in net operating income (revenue less operating expenses), or net unrecovered cash flow of $250.8 million, the deficit primarily due to the significant funds expended on acquisitions during 2006. Of our total spending, approximately $351.3 million was spent to date on fields that had little or no proved reserves at December 31, 2007 (i.e., significant incremental proved reserves are anticipated during 2008 and beyond). These amounts do not include the capital costs or related depreciation and amortization of our CO_2 producing properties at Jackson Dome, which had an unrecovered net cash flow of $371.0 million as of December 31, 2007, including $180.3 million associated with CO_2 pipelines. At year-end 2007, the proved oil reserves in our tertiary recovery oil fields had a PV-10 Value of $3.2 billion, using December 31, 2007, NYMEX pricing of $95.98 per barrel. In addition, there are significant probable and potential reserves at several other fields for which tertiary operations are under way or planned.

Texas Barnett Shale

We currently own approximately 55,649 gross acres and 40,240 net acres of leases in the Barnett Shale area in North Central Texas, of which approximately 19,984 gross acres and 19,398 net acres are in the more tested northern areas of Parker and Wise counties, with the remainder in Erath County and adjoining more southern and untested counties. We acquired our initial acreage in this area in 2001 and did only limited development until 2005. Through December 31, 2007, we have invested a total of $423.9 million on the Barnett Shale area (including acquisition costs) and have received $204.8 million in net operating income (revenue less operating expenses), or net negative cash flow of $219.1 million. At December 31, 2007, we had approximately 368.5 Bcfe of proved reserves in the Barnett Shale area with a PV-10 Value of approximately $717.2 million, using December 31, 2007, Henry Hub indicative cash pricing of $6.80 per MMBtu.

We continue to refine our completion and fracturing techniques, including an analysis of the best number of fracture treatments to adequately stimulate the entire length of the lateral sections of our horizontal wells, which can exceed 4,000′. During 2007, we drilled and completed 45 horizontal wells, increasing our net Barnett Shale production from approximately 35.4 MMcfe/d in the fourth quarter of 2006 to approximately 76.4 MMcfe/d during the fourth quarter of 2007. Horizontal wells in the Barnett Shale were initially drilled by spacing horizontal wells approximately 1,500′ apart and drilling 3,000′ to 4,500′ laterals. As our development progressed we began testing wells at various spacings of 750′ and subsequently 500′ along with other operators in the Barnett. Initial production rates and early production data indicated that we are not efficiently draining the reservoir on the larger initial well spacing, and thus we began developing our acreage position on 500′ well spacing which significantly increased the number of future well locations that we can drill. Our year-end reserves included 85 proved undeveloped locations and an additional 88 probable undeveloped locations based on 500′ well spacing. We have recently begun testing well spacings less than 500′ but the results of this additional downspacing is inconclusive at this time. If our testing of the Barnett Shale on tighter well spacing is successful, it would significantly increase our number of future locations. We expect production in this area to grow modestly during 2008 as we plan to drill approximately 45 to 50 horizontal wells, all of which are scheduled for Parker and Wise Counties. Including seismic costs and pipeline infrastructure costs, our planned 2008 capital expenditures in the Barnett Shale area are estimated to make up $157 million of our current $900 million capital budget for 2008.

We have completed a review of our 2006 drilling and completion work in our southern acreage, primarily Erath County. As a result of this review, we have determined to no longer pursue the development of this southern acreage position and will seek to divest these assets.

East Mississippi Fields Without Proved Tertiary Oil Reserves

We have been active in East Mississippi since Denbury was founded in 1990 and are by far the largest oil producer in the basin. Historically, this was our area with the highest production and most proved reserves, and while still significant, it is no longer our largest. Production during the fourth quarter of 2007 averaged approximately 12,530 BOE/d from this area (25% of our Company total), and we had proved reserves of 50.6 MMBOE as of December 31, 2007 (26% of our Company total). Since we have generally owned these Eastern Mississippi properties longer than properties in our other regions, they tend to be more fully developed, and although most are targeted for tertiary operations in the future, only three currently have tertiary operations (Soso, Martinville and Eucutta Fields). Production from our East Mississippi fields has been relatively consistent over the last three years, averaging 12,072 BOE/d in 2005, 12,743 BOE/d in 2006 and 12,479 BOE/d during 2007. For 2008, we expect our budget in this region for conventional operations to be around $60 million, about the same as in 2007, representing approximately 7% of our current 2008 exploration and development budget of $900 million.

Heidelberg Field. The largest field in the region and one of our largest fields corporately is Heidelberg Field, which for the fourth quarter of 2007 produced an average of 7,770 BOE/d, 4% more than the 2006 fourth quarter average of 7,444 BOE/d. Heidelberg Field was acquired from Chevron in December 1997. The field is a large salt-cored anticline that is divided into western and eastern segments due to subsequent faulting, and most of the past and current production comes from the Eutaw, Selma Chalk and Christmas sands at depths of 3,500' to 5,000'.

The majority of the oil production at Heidelberg is from six waterflood units that produce from the Eutaw formation (at approximately 4,400'). Most of our recent development at Heidelberg has been in the Selma Chalk, a natural gas reservoir at around 3,700', making Heidelberg our second largest gas field. We have steadily developed the Selma Chalk since 2001, drilling from 13 to 20 wells per year, increasing the natural gas production at Heidelberg to a peak quarterly average of 17.3 MMcf/d in the fourth quarter of 2007, averaging 16.3 MMcf/d during 2007. During late 2006 and early 2007, we drilled our first horizontal wells in West Heidelberg Field where vertical wells were generally uneconomic. The horizontal wells have performed very well and thus we expect to be able to expand our Selma Chalk development throughout West Heidelberg Field. During 2007, we drilled 13 horizontal Selma Chalk wells, two of which were located in West Heidelberg, and we plan to drill 12 horizontal wells during 2008.

Our capital program for 2008 includes $39 million for construction of the pipeline necessary to transport CO_2 from the Free State Pipeline to Heidelberg Field, construction of the initial phase of the CO_2 recycle facilities and initial development of a CO_2 flood in West Heidelberg Field. The initial phase of our CO_2 project in Heidelberg will be conducted in the WHEOUP Unit in West Heidelberg. The reservoir associated with the WHEOUP unit is the Eutaw formation, the same formation we are CO_2 flooding at Eucutta Field. Thus we expect the results at Heidelberg to be very similar to the results at Eucutta Field. Although similar in many respects, the Eutaw reservoir at Heidelberg contains two to three times the potential oil reserves as the Eutaw at Eucutta. Our forecasts do not include any production response from the CO_2 project at Heidelberg in 2008, but we do expect to see a production response in 2009.

Sale of Louisiana Natural Gas Assets

In October 2007 we entered into an agreement to sell our Louisiana natural gas assets to a privately held company for approximately $180 million (before closing adjustments) plus any amounts received in the future from a net profits interest. In late December 2007, we closed on approximately 70% of that sale with net proceeds of approximately $108.6 million (including estimated final purchase price adjustments), and closed on the remaining 30% on February 20, 2008, with net proceeds at the second closing of approximately $48.9 million. The operating net revenue, net of capital expenditures, between the August 1, 2007, effective date and the respective closing dates were adjustments to the purchase price, along with other minor closing adjustments. The potential net profits interest relates to a well in the South Chauvin Field and is only earned if operating income from that well exceeds certain levels, which we believe could potentially increase the ultimate sales price by up to 10%.

Production attributable to the sold properties averaged approximately 30.6 MMcfe/d (82% natural gas) during the fourth quarter of 2007, representing approximately 10% of our total fourth quarter production and approximately 4% of our total proved reserve quantities as of December 31, 2006.

Field Summaries

Denbury operates in five primary areas: Eastern Mississippi, Western Mississippi, Texas, Alabama and Louisiana. Our 14 largest fields (listed below) constitute approximately 94% of our total proved reserves on a BOE basis and on a PV-10 Value basis. Within these 14 fields, we own a weighted average 95% working interest and operate all of these fields. The concentration of value in a relatively small number of fields allows us to benefit substantially from any operating cost reductions or production enhancements we achieve, and allows us to effectively manage the properties from our four primary field offices located in Laurel, Mississippi; McComb, Mississippi; Brandon, Mississippi; and Cleburne, Texas.

	Proved Reserves as of December 31, 2007 (1)					2007 Average Daily Production		
	Oil (MBbls)	Natural Gas (MMcf)	MBOEs	BOE % of total	PV-10 Value (2) (000's)	Oil (Bbls/d)	Natural Gas (Mcf/d)	Average Net Revenue Interest
Mississippi – CO_2 Floods								
Brookhaven	18,700	—	18,700	9.6%	$ 793,813	2,048	—	81.2%
McComb Area	15,275	—	15,275	7.9%	713,080	1,912	—	78.8%
Mallalieu Area	11,547	—	11,547	5.9%	719,778	5,852	—	76.7%
Eucutta	10,172	—	10,172	5.2%	456,003	1,646	—	83.5%
Soso	9,798	—	9,798	5.0%	363,542	586	—	77.2%
Little Creek Area	2,749	—	2,749	1.4%	132,311	2,014	—	83.2%
Martinville	1,282	—	1,282	0.7%	65,827	709	—	78.1%
Total Mississippi – CO_2 Floods	69,523	—	69,523	35.7%	3,244,354	14,767	—	79.6%
Other Mississippi								
Heidelberg (East & West)	24,666	59,087	34,514	17.7%	728,126	4,942	16,286	80.6%
Tinsley	2,632	—	2,632	1.4%	81,029	1,042	15	67.6%
Sharon	—	11,842	1,974	1.0%	32,057	4	4,491	94.3%
S. Cypress Creek	1,850	654	1,959	1.0%	45,050	247	39	86.6%
Eucutta	1,854	—	1,854	1.0%	47,367	444	22	64.4%
Other Mississippi	7,047	3,641	7,654	3.9%	199,488	2,117	1,246	37.4%
Total Other Mississippi	38,049	75,224	50,587	26.0%	1,133,117	8,796	22,099	63.7%
Texas								
Newark (Barnett Shale)	17,160	265,575	61,423	31.5%	717,213	1,758	46,751	80.5%
Other Texas	340	1,407	574	0.3%	23,943	270	1,527	72.9%
Total Texas	17,500	266,982	61,997	31.8%	741,156	2,028	48,278	80.4%
Louisiana								
Louisiana	634	2,238	1,007	0.5%	42,378	380	1,303	70.8%
Louisiana sold (3)	422	12,434	2,494	1.3%	59,556	801	24,861	45.6%
Total Louisiana	1,056	14,672	3,501	1.8%	101,934	1,181	26,164	48.6%
Alabama & Other								
Citronelle	8,784	—	8,784	4.5%	159,796	1,150	—	62.7%
Other Alabama	66	1,730	354	0.2%	4,766	3	600	2.5%
Total Alabama and Other	8,850	1,730	9,138	4.7%	164,562	1,153	600	11.2%
Company Total	134,978	358,608	194,746	100.0%	$5,385,123	27,925	97,141	67.1%

(1) The reserves were prepared using constant prices and costs in accordance with the guidelines of SFAS No. 69 based on the prices received on a field-by-field basis as of December 31, 2007. The prices at that date were a NYMEX oil price of $95.98 per Bbl adjusted to prices received by field and a Henry Hub natural gas average price of $6.80 per MMBtu also adjusted to prices received by field.

(2) PV-10 Value is a non-GAAP measure and is different from the Standardized Measure of Discounted Future Net Cash Flows ("Standardized Measure") in that PV-10 Value is a pre-tax number and the Standardized Measure is an after-tax number. The information used to calculate PV-10 Value is derived directly from data determined in accordance with SFAS No. 69. The Standardized Measure was $3,539,617 at December 31, 2007. A comparison of PV-10 to the Standardized Measure is included in the table on page 19 as well as further information regarding our use of this non-GAAP measure.

(3) Reserves in the Louisiana sold category are associated with the portion of the Louisiana divestiture that closed in February 2008.

Oil and Gas Acreage, Productive Wells, and Drilling Activity

In the data below, “gross” represents the total acres or wells in which we own a working interest and “net” represents the gross acres or wells multiplied by Denbury’s working interest percentage. For the wells that produce both oil and gas, the well is typically classified as an oil or natural gas well based on the ratio of oil to gas production.

Oil and Gas Acreage

The following table sets forth Denbury’s acreage position at December 31, 2007:

	Developed		Undeveloped		Total	
	Gross	Net	Gross	Net	Gross	Net
Mississippi	109,630	88,911	266,204	46,046	375,834	134,957
Louisiana	36,805	35,212	4,560	3,881	41,365	39,093
Texas	39,190	34,186	41,200	24,790	80,390	58,976
Alabama	35,209	21,860	72,113	14,638	107,322	36,498
Other	2,680	816	38,710	9,687	41,390	10,503
Total	223,514	180,985	422,787	99,042	646,301	280,027

Denbury’s net undeveloped acreage that is subject to expiration over the next three years, if not renewed, is approximately 22% in 2008, 26% in 2009 and 14% in 2010.

Productive Wells

The following table sets forth our gross and net productive oil and natural gas wells at December 31, 2007:

	Producing Oil Wells		Producing Natural Gas Wells		Total	
	Gross	Net	Gross	Net	Gross	Net
Operated Wells:						
Mississippi	553	530.6	187	171.0	740	701.6
Louisiana	19	15.1	7	6.0	26	21.1
Texas	14	12.3	159	152.1	173	164.4
Alabama	155	122.0	32	19.2	187	141.2
Total	741	680.0	385	348.3	1,126	1,028.3
Non-Operated Wells:						
Mississippi	37	3.4	18	4.2	55	7.6
Louisiana	—	—	—	—	—	—
Texas	—	—	4	0.3	4	0.3
Alabama	—	—	11	1.7	11	1.7
Other	3	—	—	—	3	—
Total	40	3.4	33	6.2	73	9.6
Total Wells:						
Mississippi	590	534.0	205	175.2	795	709.2
Louisiana	19	15.1	7	6.0	26	21.1
Texas	14	12.3	163	152.4	177	164.7
Alabama	155	122.0	43	20.9	198	142.9
Other	3	—	—	—	3	—
Total	781	683.4	418	354.5	1,199	1,037.9

Drilling Activity

The following table sets forth the results of our drilling activities over the last three years:

	Year Ended December 31,					
	2007		2006		2005	
	Gross	Net	Gross	Net	Gross	Net
Exploratory Wells:(1)						
Productive(2)	**9**	**6.2**	10	8.5	12	7.1
Non-productive(3)	**4**	**3.4**	8	6.8	1	0.6
Development Wells:(1)						
Productive(2)	**101**	**96.8**	90	82.7	81	74.3
Non-productive(3)(4)	**—**	**—**	—	—	—	—
Total	**114**	**106.4**	108	98.0	94	82.0

(1) An exploratory well is a well drilled either in search of a new, as yet undiscovered, oil or gas reservoir or to greatly extend the known limits of a previously discovered reservoir. A development well is a well drilled within the presently proved productive area of an oil or natural gas reservoir, as indicated by reasonable interpretation of available data, with the objective of completing in that reservoir.

(2) A productive well is an exploratory or development well found to be capable of producing either oil or natural gas in sufficient quantities to justify completion as an oil or natural gas well.

(3) A nonproductive well is an exploratory or development well that is not a producing well.

(4) During 2007, 2006 and 2005, an additional 23, 14, and 5 wells, respectively, were drilled for water or CO_2 injection purposes.

Production and Unit Prices

Information regarding average production rates, unit sale prices and unit costs per BOE are set forth under "Management's Discussion and Analysis of Financial Condition and Results of Operations – Operating Income" included herein.

Title to Properties

Customarily in the oil and gas industry, only a perfunctory title examination is conducted at the time properties believed to be suitable for drilling operations are first acquired. Prior to commencement of drilling operations, a thorough drill site title examination is normally conducted, and curative work is performed with respect to significant defects. During acquisitions, title reviews are performed on all properties; however, formal title opinions are obtained on only the higher value properties. We believe that we have good title to our oil and natural gas properties, some of which are subject to minor encumbrances, easements and restrictions.

Geographic Segments

All of our operations are in the United States.

Significant Oil and Gas Purchasers and Product Marketing

Oil and gas sales are made on a day-to-day basis under short-term contracts at the current area market price. The loss of any single purchaser would not be expected to have a material adverse effect upon our operations; however, the loss of a large single purchaser could potentially reduce the competition for our oil and natural gas production, which in turn could negatively impact the prices we receive. For the year ended December 31, 2007, we had three purchasers that each accounted for 10% or more of our oil and natural gas revenues: Marathon Ashland Petroleum LLC (43%), Hunt Crude Oil Supply Co. (19%) and Crosstex Energy Field Services Inc. (16%). For the year ended December 31, 2006, we had two purchasers that each accounted for 10% or more of our oil and natural gas revenues: Marathon Ashland Petroleum LLC (28%) and Hunt Crude Oil Supply Co. (18%). For the year ended December 31, 2005, three purchasers each accounted for more than 10% of our total oil and natural gas revenues: Marathon Ashland Petroleum LLC (28%), Hunt Crude Oil Supply Co. (20%) and Sunoco, Inc. (13%).

Our ability to market oil and natural gas depends on many factors beyond our control, including the extent of domestic production and imports of oil and gas, the proximity of our gas production to pipelines, the available capacity in such pipelines, the demand for oil and natural gas, the effects of weather, and the effects of state and federal regulation. Our production is primarily from developed fields close to major pipelines or refineries and established infrastructure. As a result, we have not experienced any difficulty to date in finding a market for all of our production as it becomes available or in transporting our production to those markets; however, there is no assurance that we will always be able to market all of our production or obtain favorable prices.

Oil Marketing

The quality of our crude oil varies by area, thereby impacting the corresponding price received. In Heidelberg Field, one of our larger fields, and our other Eastern Mississippi properties, our oil production is primarily light to medium sour crude and sells at a significant discount to the NYMEX prices. In Western Mississippi, the location of our Phase I CO_2 operations, our oil production is primarily light sweet crude, which typically sells at near NYMEX prices, or often at a premium. For the year ended December 31, 2007, the discount for our oil production from Heidelberg Field averaged $11.10 per Bbl and for our Eastern Mississippi properties as a whole the discount averaged $9.46 per Bbl relative to NYMEX oil prices. For our Phase I fields in Southwest Mississippi, we averaged a premium of $4.36 per Bbl over NYMEX oil prices during 2007. Our Texas Barnett Shale properties averaged $20.79 per Bbl below NYMEX prices during 2007, largely because the reported oil sales include a significant amount of natural gas liquids, which typically sell at a lower price than crude oil.

Natural Gas Marketing

Virtually all of our natural gas production is close to existing pipelines and consequently we generally have a variety of options to market our natural gas. We sell the majority of our natural gas on one-year contracts with prices fluctuating month-to-month based on published pipeline indices with slight premiums or discounts to the index. We receive near NYMEX or Henry Hub prices for most of our natural gas sales due to our proximity to Henry Hub and the high Btu content of our natural gas. For the year ended December 31, 2007, we averaged $0.36 above NYMEX prices for our Louisiana natural gas production. However, in the Barnett Shale area in Texas, due primarily to its location, the price we received averaged $0.78 below NYMEX prices. We expect our overall differential to NYMEX prices to gradually increase in the future due to our increasing emphasis in the Barnett Shale area.

Competition and Markets

We face competition from other oil and natural gas companies in all aspects of our business, including acquisition of producing properties and oil and gas leases, marketing of oil and gas, and obtaining goods, services and labor. Many of our competitors have substantially larger financial and other resources. Factors that affect our ability to acquire producing properties include available funds, available information about prospective properties and our standards established for minimum projected return on investment. Gathering systems are the only practical method for the intermediate transportation of natural gas. Therefore, competition for natural gas delivery is presented by other pipelines and gas gathering systems. Competition is also presented by alternative fuel sources, including heating oil and other fossil fuels. Because of the nature of our core assets (our tertiary operations) and our ownership of a relatively uncommon significant natural source of carbon dioxide, we believe that we are effective in competing in the market.

The demand for qualified and experienced field personnel to drill wells and conduct field operations, geologists, geophysicists, engineers and other professionals in the oil and natural gas industry can fluctuate significantly, often in correlation with oil and natural gas prices, causing periodic shortages. There have also been shortages of drilling rigs and other equipment, as demand for rigs and equipment has increased along with the number of wells being drilled. These factors also cause significant increases in costs for equipment, services and personnel. Higher oil and natural gas prices generally stimulate increased demand and result in increased prices for drilling rigs, crews and associated supplies, equipment and services. We cannot be certain when we will experience these issues, and these types of shortages or price increases could significantly decrease our profit margin, cash flow and operating results or restrict our ability to drill those wells and conduct those operations that we currently have planned and budgeted.

Federal and State Regulations

Numerous federal and state laws and regulations govern the oil and gas industry. These laws and regulations are often changed in response to changes in the political or economic environment. Compliance with this evolving regulatory burden is often difficult and costly, and substantial penalties may be incurred for noncompliance. The following section describes some specific laws and regulations that may affect us. We cannot predict the impact of these or future legislative or regulatory initiatives.

Management believes that we are in substantial compliance with all laws and regulations applicable to our operations and that continued compliance with existing requirements will not have a material adverse impact on us. The future annual capital costs of complying with the regulations applicable to our operations is uncertain and will be governed by several factors, including future changes to regulatory requirements. However, management does not currently anticipate that future compliance will have a materially adverse effect on our consolidated financial position or results of operations.

Regulation of Natural Gas and Oil Exploration and Production

Our operations are subject to various types of regulation at the federal, state and local levels. Such regulation includes requiring permits for drilling wells; maintaining bonding requirements in order to drill or operate wells and regulating the location of wells; the method of drilling and casing wells; the surface use and restoration of properties upon which wells are drilled; the plugging and abandoning of wells; and the disposal of fluids used in connection with operations. Our operations are also subject to various conservation laws and regulations. These include regulation of the size of drilling, spacing or proration units and the density of wells that may be drilled in those units, and the unitization or pooling of oil and gas properties. In addition, state conservation laws which establish maximum rates of production from oil and gas wells, generally prohibit the venting or flaring of gas and impose certain requirements regarding the ratability of production. The effect of these regulations may limit the amount of oil and gas we can produce from our wells and may limit the number of wells or the locations at which we can drill. The regulatory burden on the oil and gas industry increases our costs of doing business and, consequently, affects our profitability.

Federal Regulation of Sales Prices and Transportation

The transportation and certain sales of natural gas in interstate commerce are heavily regulated by agencies of the U.S. federal government and are affected by the availability, terms and cost of transportation. In particular, the price and terms of access to pipeline transportation are subject to extensive U.S. federal and state regulation. The Federal Energy Regulatory Commission (FERC) is continually proposing and implementing new rules and regulations affecting the natural gas industry. The stated purpose of many of these regulatory changes is to promote competition among the various sectors of the natural gas industry. The ultimate impact of the complex rules and regulations issued by FERC cannot be predicted. Some of FERC's proposals may, however, adversely affect the availability and reliability of interruptible transportation service on interstate pipelines. While our sales of crude oil, condensate and natural gas liquids are not currently subject to FERC regulation, our ability to transport and sell such products is dependent on certain pipelines whose rates, terms and conditions of service are subject to FERC regulation. Additional proposals and proceedings that might affect the natural gas industry are considered from time to time by Congress, FERC, state regulatory bodies and the courts. We cannot predict when or if any such proposals might become effective and their effect, if any, on our operations. Historically, the natural gas industry has been heavily regulated; therefore, there is no assurance that the less stringent regulatory approach recently pursued by FERC, Congress and the states will continue indefinitely into the future.

Federal Energy Legislation

The Energy Independence and Security Act of 2007 (Public Law No. 110-140) became law on December 19, 2007. Among other provisions, the Act supports research and development in alternative and renewable fuels sources, energy storage for transportation and electric power, and carbon capture and sequestration. The Act does not repeal certain tax incentives for expenditures by companies engaged in the exploration and production of oil, gas and other minerals, nor does it impose new excise taxes specifically on certain companies engaged in the exploration and production of oil, gas and other minerals, both of which had been proposed in earlier versions of the legislation. As a result of this new legislation, in 2008 Congress may decide to revisit legislation to repeal existing incentives or impose new taxes on the exploration and production of oil, gas and other minerals, and/or create new incentives for alternative energy sources. Congress may also consider legislation to reduce emissions of carbon dioxide or other gases. If enacted, such legislation could reduce the demand for and uses of oil, gas and other minerals and/or increase the costs incurred by the Company in its exploration and production activities.

Natural Gas Gathering Regulations

State regulation of natural gas gathering facilities generally include various safety, environmental and, in some circumstances, nondiscriminatory-take requirements. Although such regulation has not generally been affirmatively applied by state agencies, natural gas gathering may receive greater regulatory scrutiny in the future.

Federal, State or Indian Leases

Our operations on federal, state or Indian oil and gas leases are subject to numerous restrictions, including nondiscrimination statutes. Such operations must be conducted pursuant to certain on-site security regulations and other permits and authorizations issued by the Bureau of Land Management, Minerals Management Service ("MMS") and other agencies.

Environmental Regulations

Public interest in the protection of the environment has increased dramatically in recent years. Our oil and natural gas production and saltwater disposal operations, and our processing, handling and disposal of hazardous materials such as hydrocarbons and naturally occurring radioactive materials are subject to stringent regulation. We could incur significant costs, including cleanup costs resulting from a release of hazardous material, third-party claims for property damage and personal injuries, fines and sanctions, as a result of any violations or liabilities under environmental or other laws. Changes in or more stringent enforcement of environmental laws could also result in additional operating costs and capital expenditures.

Various federal, state and local laws regulating the discharge of materials into the environment, or otherwise relating to the protection of the environment, directly impact oil and gas exploration, development and production operations, and consequently may impact the Company's operations and costs. These regulations include, among others, (i) regulations by the EPA and various state agencies regarding approved methods of disposal for certain hazardous and nonhazardous wastes; (ii) the Comprehensive Environmental Response, Compensation, and Liability Act, Federal Resource Conservation and Recovery Act and analogous state laws that regulate the removal or remediation of previously disposed wastes (including wastes disposed of or released by prior owners or operators), property contamination (including groundwater contamination), and remedial plugging operations to prevent future contamination; (iii) the Clean Air Act and comparable state and local requirements, which may result in the gradual imposition of certain pollution control requirements with respect to air emissions from the operations of the Company; (iv) the Oil Pollution Act of 1990, which contains numerous requirements relating to the prevention of and response to oil spills into waters of the United States; (v) the Resource Conservation and Recovery Act, which is the principal federal statute governing the treatment, storage and disposal of hazardous wastes; and (vi) state regulations and statutes governing the handling, treatment, storage and disposal of naturally occurring radioactive material ("NORM").

Management believes that we are in substantial compliance with applicable environmental laws and regulations. To date, we have not expended any material amounts to comply with such regulations, and management does not currently anticipate that future compliance will have a materially adverse effect on our consolidated financial position, results of operations or cash flows.

Estimated Net Quantities of Proved Oil and Gas Reserves and Present Value of Estimated Future Net Revenues

DeGolyer and MacNaughton, independent petroleum engineers located in Dallas, Texas, prepared estimates of our net proved oil and natural gas reserves as of December 31, 2007, 2006 and 2005. The reserve estimates were prepared using constant prices and costs in accordance with the guidelines of the Securities and Exchange Commission ("SEC"). The prices used in preparation of the reserve estimates were based on the market prices in effect as of December 31 of each year, with the appropriate adjustments (transportation, gravity, basic sediment and water ("BS&W"), purchasers' bonuses, Btu, etc.) applied to each field. The reserve estimates do not include any value for probable or possible reserves that may exist, nor do they include any value for undeveloped acreage. The reserve estimates represent our net revenue interests in our properties. During 2007, we provided oil and gas reserve estimates for 2006 to the United States Energy Information Agency. The information provided was substantially the same as the reserve estimates included in our Form 10-K for the year ended December 31, 2006.

Our proved nonproducing reserves primarily relate to reserves that are to be recovered from productive zones that are currently behind pipe. Since a majority of our properties are in areas with multiple pay zones, these properties typically have both proved producing and proved nonproducing reserves.

Proved undeveloped reserves associated with our CO_2 tertiary operations and our Heidelberg waterfloods in East Mississippi account for approximately 78% of our proved undeveloped oil reserves. We consider these reserves to be lower risk than other proved undeveloped reserves that require drilling at locations offsetting existing production because all of these proved undeveloped reserves are associated with secondary recovery or tertiary recovery operations in fields and reservoirs that historically produced substantial volumes of oil under primary production. The main reason these reserves are classified as undeveloped is because they require significant additional capital associated with drilling/re-entering wells or additional facilities in order to produce the reserves and/or are waiting for a production response to the water or CO_2 injections. Our proved undeveloped natural gas reserves associated with our Selma Chalk play at Heidelberg and the Barnett Shale play account for approximately 97% of our proved undeveloped natural gas reserves. Our current plans for 2008 include drilling 55 to 65 new wells in these two primary natural gas plays.

	December 31, 2007	2006	2005
Estimated Proved Reserves:			
Oil (MBbls)	**134,978**	126,185	106,173
Natural gas (MMcf)	**358,608**	288,826	278,367
Oil equivalent (MBOE)	**194,746**	174,322	152,568
Percentage of Total MBOE:			
Proved producing	**56%**	48%	40%
Proved non-producing	**13%**	17%	16%
Proved undeveloped	**31%**	35%	44%
Representative Oil and Gas Prices:(1)			
Oil – NYMEX	**$ 95.98**	$ 61.05	$ 61.04
Natural gas – Henry Hub	**6.80**	5.63	10.08
Present Values (thousands):(2)			
Discounted estimated future net cash flow before income taxes (“PV-10 Value”) (3)	**$ 5,385,123**	$2,695,199	$ 3,215,478
Standardized measure of discounted estimated future net cash flow after income taxes	**3,539,617**	1,837,341	2,084,449

(1) The prices of each year-end were based on market prices in effect as of December 31 of each year, NYMEX prices per Bbl and Henry Hub cash prices per MMBtu, with the appropriate adjustments (transportation, gravity, BS&W, purchasers' bonuses, Btu, etc.) applied to each field to arrive at the appropriate corporate net price.

(2) Determined based on year-end unescalated prices and costs in accordance with the guidelines of SFAS No. 69, discounted at 10% per annum.

(3) PV-10 Value is a non-GAAP measure and is different from the Standardized Measure in that PV-10 Value is a pre-tax number and the Standardized Measure is an after-tax number. The information used to calculate PV-10 Value is derived directly from data determined in accordance with SFAS No. 69. The difference between these two amounts, the discounted estimated future income tax, was $1,845,506 at December 31, 2007, $857,858 at December 31, 2006, and $1,131,029 at December 31, 2005. We believe that PV-10 Value is a useful supplemental disclosure to the Standardized Measure because the Standardized Measure can be impacted by a company's unique tax situation, and it is not practical to calculate the Standardized Measure on a property by property basis. Because of this, PV-10 Value is a widely used measure within the industry and is commonly used by securities analysts, banks and credit rating agencies to evaluate the estimated future net cash flows from proved reserves on a comparative basis across companies or specific properties. PV-10 Value is commonly used by us and others in our industry to evaluate properties that are bought and sold and to assess the potential return on investment in our oil and gas properties. PV-10 Value is not a measure of financial or operating performance under GAAP, nor should it be considered in isolation or as a substitute for the Standardized Measure. Our PV-10 Value and the Standardized Measure do not purport to represent the fair value of our oil and natural gas reserves. See Note 15 to our Consolidated Financial Statements for additional disclosures about the Standardized Measure.

There are numerous uncertainties inherent in estimating quantities of proved oil and natural gas reserves and their values, including many factors beyond our control. See “Risk Factors – Estimating our reserves, production and future net cash flow is difficult to do with any certainty.” See also Note 15, “Supplemental Oil and Natural Gas Disclosures,” to the Consolidated Financial Statements.

Item 1A. Risk Factors

Risks Related To Our Business

Our production will decline if our access to sufficient amounts of carbon dioxide is limited.

Our current long-term growth strategy is focused on our CO_2 tertiary recovery operations, and we expect approximately 72% of our 2008 capital expenditures to be in this area. The crude oil production from our tertiary recovery projects depends on having access to sufficient amounts of carbon dioxide. Our ability to produce this oil would be hindered if our supply of carbon dioxide were limited due to problems with our current CO_2 producing wells and facilities, including compression equipment, or catastrophic pipeline failure. Our anticipated future crude oil production is also dependent on our ability to increase the production volumes of CO_2 and inject adequate amounts of CO_2 into the proper formation and area within each oil field. The production of crude oil from tertiary operations is highly dependent on the timing, volumes and location of the CO_2 injections. If our crude oil production were to decline, it could have a material adverse effect on our financial condition, results of operations and cash flows.

Oil and natural gas prices are volatile. A substantial decrease in oil and natural gas prices could adversely affect our financial results.

Our future financial condition, results of operations and the carrying value of our oil and natural gas properties depend primarily upon the prices we receive for our oil and natural gas production. Oil and natural gas prices historically have been volatile and likely will continue to be volatile in the future, especially given current world geopolitical conditions. Our cash flow from operations is highly dependent on the prices that we receive for oil and natural gas. This price volatility also affects the amount of our cash flow available for capital expenditures and our ability to borrow money or raise additional capital. The amount we can borrow or have outstanding under our bank credit facility is subject to semi-annual redeterminations. Oil prices are likely to affect us more than natural gas prices because approximately 69% of our December 31, 2007 proved reserves are oil, with oil being an even larger percentage of our future potential reserves and projects due to our focus on tertiary operations. The prices for oil and natural gas are subject to a variety of additional factors that are beyond our control. These factors include:

- the level of consumer demand for oil and natural gas;
- the domestic and foreign supply of oil and natural gas;
- the ability of the members of the Organization of Petroleum Exporting Countries ("OPEC") to agree to and maintain oil price and production controls;
- the price of foreign oil and natural gas;
- domestic governmental regulations and taxes;
- the price and availability of alternative fuel sources;
- weather conditions, including hurricanes and tropical storms in and around the Gulf of Mexico;
- market uncertainty;
- political conditions in oil and natural gas producing regions, including the Middle East; and
- worldwide economic conditions.

These factors and the volatility of the energy markets generally make it extremely difficult to predict future oil and natural gas price movements with any certainty. Also, oil and natural gas prices do not necessarily move in tandem. Declines in oil and natural gas prices would not only reduce revenue, but could reduce the amount of oil and natural gas that we can produce economically and, as a result, could have a material adverse effect upon our financial condition, results of operations, oil and natural gas reserves and the carrying values of our oil and natural gas properties. If the oil and natural gas industry experiences significant price declines, we may, among other things, be unable to meet our financial obligations or make planned expenditures.

Since the end of 1998, oil prices have gone from near historic low prices to historic highs. At the end of 1998, NYMEX oil prices were at historic lows of approximately $12.00 per Bbl, but have generally increased since that time, albeit with fluctuations. For 2007, NYMEX oil prices were high throughout the year, averaging approximately $72.45 per Bbl. During 2004, 2005 and 2006, the price we received for our heavier, sour crude oil did not correlate as well with NYMEX prices as it had historically. During 2002 and 2003, our average discount to NYMEX was $3.73 per Bbl and $3.60 per Bbl, respectively. During 2004, this differential increased to $4.91 per Bbl for the year as a result of the price deterioration for heavier, sour crudes, and was even higher during 2005 and 2006, averaging $6.33 per Bbl and $6.41 per Bbl, respectively. In 2007, our differential improved to $2.65 per Bbl, as a large portion of our oil production was sold at markets that were priced favorably to the West Texas Intermediate NYMEX price, due to lack of available storage capacity in the mid-continent area, an oversupply of crude from Canada, capacity/transportation issues moving the crude out of the Cushing, Oklahoma area and unanticipated refinery outages. This positive trend in 2007 began to reverse in the fourth quarter of 2007, when our NYMEX differential averaged $7.27 per Bbl due to the significant increase in liquids extracted from our Barnett Shale production, which is recorded as oil production but is sold at a significant discount to the NYMEX oil price. While we attempt to obtain the best price for our crude in our marketing efforts, we cannot control these market price swings and are subject to the market volatility for this type of oil. These price differentials relative to NYMEX prices can significantly impact our profitability.

Natural gas prices have also experienced volatility during the last few years. During 1999, natural gas prices averaged approximately $2.35 per Mcf and, like crude oil, have generally trended upward since that time, although with significant fluctuations along the way. NYMEX natural gas prices averaged $8.97 per MMBtu during 2005, $6.97 per MMBtu during 2006, and $7.09 per MMBtu during 2007.

Product Price Derivative Contracts may expose us to potential financial loss.

To reduce our exposure to fluctuations in the prices of oil and natural gas, we currently and may in the future enter into derivative contracts in order to economically hedge a portion of our oil and natural gas production. Derivative contracts expose us to risk of financial loss in some circumstances, including when:

- production is less than expected;
- the counter-party to the derivative contract defaults on its contract obligations; or
- there is a change in the expected differential between the underlying price in the hedging agreement and actual prices received.

In addition, these derivative contracts may limit the benefit we would receive from increases in the prices for oil and natural gas. Information as to these activities is set forth under "Management's Discussion and Analysis of Financial Condition and Results of Operations – Market Risk Management," and in Note 10, "Derivative Instruments and Hedging Activities," to the Consolidated Financial Statements.

Shortages of oil field equipment, services and qualified personnel could reduce our cash flow and adversely affect results of operations.

The demand for qualified and experienced field personnel to drill wells and conduct field operations, geologists, geophysicists, engineers and other professionals in the oil and natural gas industry can fluctuate significantly, often in correlation with oil and natural gas prices, causing periodic shortages. Due to the recent record high oil and gas prices, we have experienced shortages of equipment used in our tertiary facilities, drilling rigs and other equipment, as demand for rigs and equipment has increased along with higher commodity prices. Higher oil and natural gas prices generally stimulate increased demand and result in increased prices for drilling rigs, crews and associated supplies, oilfield equipment and services and personnel in our exploration and production operations. These types of shortages or price increases could significantly decrease our profit margin, cash flow and operating results and/or restrict or delay our ability to drill those wells and conduct those operations that we currently have planned and budgeted, causing us to miss our forecasts and projections.

Our future performance depends upon our ability to find or acquire additional oil and natural gas reserves that are economically recoverable.

Unless we can successfully replace the reserves that we produce, our reserves will decline, resulting eventually in a decrease in oil and natural gas production and lower revenues and cash flows from operations. We have historically replaced reserves through both drilling and acquisitions. In the future, we may not be able to continue to replace reserves at acceptable costs. The business of exploring for, developing or acquiring reserves is capital intensive. We may not be able to make the necessary capital investment to maintain or expand our oil and natural gas reserves if our cash flows from operations are reduced, due to lower oil or natural gas prices or otherwise, or if external sources of capital become limited or unavailable. Further, the process of using CO_2 for tertiary recovery and the related infrastructure requires significant capital investment, often one to two years prior to any resulting production and cash flows from these projects, heightening potential capital constraints. If we do not continue to make significant capital expenditures, or if outside capital resources become limited, we may not be able to maintain our growth rate or meet expectations. In addition, certain of our drilling activities are subject to numerous risks, including the risk that no commercially productive oil or natural gas reserves will be encountered. Exploratory drilling involves more risk than development drilling because exploratory drilling is designed to test formations for which proved reserves have not been discovered.

In January 2006, we purchased three oil fields for $250 million that we believe have significant potential oil reserves that can be recovered through the use of tertiary flooding: Tinsley Field approximately 40 miles northwest of Jackson, Mississippi; Citronelle Field in Southwest Alabama, and the smaller South Cypress Creek Field near our Eucutta Field in Eastern Mississippi. These three fields produced approximately 2,392 BOE/d net to the acquired interests during the fourth quarter of 2007, and have proved reserves of approximately 13.4 MMBOEs. We purchased these fields because we believe that they have significant additional potential through tertiary flooding and we paid a premium price for these properties based on that assumption. In addition to this specific acquisition, we have, and plan to continue, acquiring other old oil fields that we believe are tertiary flood candidates, likely at a premium price. We are investing significant amounts of capital as part of this strategy. If we are unable to successfully develop the potential oil in these acquired fields, it would negatively affect the return on our investment on these acquisitions and could severely reduce our ability to obtain additional capital for the future, fund future acquisitions, and negatively affect our financial results to a significant degree.

We face competition from other oil and natural gas companies in all aspects of our business, including acquisition of producing properties and oil and gas leases. Many of our competitors have substantially larger financial and other resources. Other factors that affect our ability to acquire producing properties include available funds, available information about prospective properties and our standards established for minimum projected return on investment.

Oil and natural gas drilling and producing operations involve various risks.

Drilling activities are subject to many risks, including the risk that no commercially productive reservoirs will be discovered. There can be no assurance that new wells drilled by us will be productive or that we will recover all or any portion of our investment in such wells. Drilling for oil and natural gas may involve unprofitable efforts, not only from dry wells but also from wells that are productive but do not produce sufficient net reserves to return a profit after deducting drilling, operating and other costs. The seismic data and other technologies used by us do not provide conclusive knowledge, prior to drilling a well, that oil or natural gas is present or may be produced economically. The cost of drilling, completing and operating a well is often uncertain, and cost factors can adversely affect the economics of a project. Further, our drilling operations may be curtailed, delayed or canceled as a result of numerous factors, including:

- unexpected drilling conditions;
- title problems;
- pressure or irregularities in formations;
- equipment failures or accidents;
- adverse weather conditions, including hurricanes and tropical storms in and around the Gulf of Mexico that can damage oil and natural gas facilities and delivering systems and disrupt operations;
- compliance with environmental and other governmental requirements; and
- cost of, or shortages or delays in the availability of, drilling rigs, equipment and services.

Our operations are subject to all the risks normally incident to the operation and development of oil and natural gas properties and the drilling of oil and natural gas wells, including encountering well blowouts, cratering and explosions, pipe failure, fires, formations with abnormal pressures, uncontrollable flows of oil, natural gas, brine or well fluids, release of contaminants into the environment and other environmental hazards and risks.

The nature of these risks is such that some liabilities could exceed our insurance policy limits, or, as in the case of environmental fines and penalties, cannot be insured. We could incur significant costs, related to these risks that could have a material adverse effect on our results of operations, financial condition and cash flows.

Our CO_2 tertiary recovery projects require a significant amount of electricity to operate the facilities. If these costs were to increase significantly, it could have an adverse effect upon the profitability of these operations.

We depend on our key personnel.

We believe our continued success depends on the collective abilities and efforts of our senior management. The loss of one or more key personnel could have a material adverse effect on our results of operations. We do not have any employment agreements and do not maintain any key man life insurance policies. Additionally, if we are unable to find, hire and retain needed key personnel in the future, our results of operations could be materially and adversely affected.

The loss of more than one of our large oil and natural gas purchasers could have a material adverse effect on our operations.

For the year ended December 31, 2007, three purchasers each accounted for more than 10% of our oil and natural gas revenues and in the aggregate, for 78% of these revenues. We would not expect the loss of any single purchaser to have a material adverse effect upon our operations. However, the loss of a large single purchaser could potentially reduce the competition for our oil and natural gas production, which in turn could negatively impact the prices we receive.

Estimating our reserves, production and future net cash flow is difficult to do with any certainty.

Estimating quantities of proved oil and natural gas reserves is a complex process. It requires interpretations of available technical data and various assumptions, including assumptions relating to economic factors, such as future commodity prices, production costs, severance and excise taxes, capital expenditures and workover and remedial costs, and the assumed effect of governmental regulation. There are numerous uncertainties about when a property may have proved reserves as compared to potential or probable reserves, particularly relating to our tertiary recovery operations. Forecasting the amount of oil reserves recoverable from tertiary operations and the production rates anticipated therefrom requires estimates, one of the most significant being the oil recovery factor. Actual results most likely will vary from our estimates. Also, the use of a 10% discount factor for reporting purposes, as prescribed by the SEC, may not necessarily represent the most appropriate discount factor, given actual interest rates and risks to which our business or the oil and natural gas industry in general are subject. Any significant inaccuracies in these interpretations or assumptions or changes of conditions could result in a reduction of the quantities and net present value of our reserves.

Quantities of proved reserves are estimated based on economic conditions, including oil and natural gas prices in existence at the date of assessment. Our reserves and future cash flows may be subject to revisions based upon changes in economic conditions, including oil and natural gas prices, as well as due to production results, results of future development, operating and development costs and other factors. Downward revisions of our reserves could have an adverse effect on our financial condition, operating results and cash flows.

The reserve data included in documents incorporated by reference represent only estimates. In accordance with requirements of the SEC, the estimates of present values are based on prices and costs as of the date of the estimates. Actual future prices and costs may be materially higher or lower than the prices and cost as of the date of the estimate.

As of December 31, 2007, approximately 31% of our estimated proved reserves were undeveloped. Recovery of undeveloped reserves requires significant capital expenditures and may require successful drilling operations. The reserve data assumes that we can and will make these expenditures and conduct these operations successfully, but these assumptions may not be accurate, and this may not occur.

We are subject to complex federal, state and local laws and regulations, including environmental laws, which could adversely affect our business.

Exploration for and development, exploitation, production and sale of oil and natural gas in the United States are subject to extensive federal, state and local laws and regulations, including complex tax laws and environmental laws and regulations. Existing laws or regulations, as currently interpreted or reinterpreted in the future, or future laws, regulations or incremental taxes and fees, could harm our business, results of operations and financial condition. We may be required to make large expenditures to comply with environmental and other governmental regulations.

It is possible that new taxes on our industry could be implemented and/or tax benefits could be eliminated or reduced, reducing our profitability and available cash flow. In addition to the short-term negative impact on our financial results, such additional burdens, if enacted, would reduce our funds available for reinvestment and thus ultimately reduce our growth and future oil and natural gas production.

Matters subject to regulation include oil and gas production and saltwater disposal operations and our processing, handling and disposal of hazardous materials, such as hydrocarbons and naturally occurring radioactive materials, discharge permits for drilling operations, spacing of wells, environmental protection and taxation. We could incur significant costs as a result of violations of or liabilities under environmental or other laws, including third-party claims for personal injuries and property damage, reclamation costs, remediation and clean-up costs resulting from oil spills and discharges of hazardous materials, fines and sanctions, and other environmental damages.

Our level of indebtedness may adversely affect operations and limit our growth.

As of February 28, 2008, we had outstanding $525 million (principal amount) of 7.5% subordinated notes and $111 million of bank debt. Our bank credit line has approximately $379 million available on our borrowing base. The next semi-annual redetermination of the borrowing base for our bank credit facility will be on April 1, 2008. Our bank borrowing base is adjusted at the banks' discretion and is based in part upon external factors, such as commodity prices, over which we have no control. If our then redetermined borrowing base is less than our outstanding borrowings under the facility, we will be required to repay the deficit over a period of six months.

We may incur additional indebtedness in the future under our bank credit facility in connection with our acquisition, development, exploitation and exploration of oil and natural gas producing properties. Further, our cash flow from operations is highly dependent on the prices that we receive for oil and natural gas. If oil and natural gas prices were to decline significantly, particularly for an extended period of time, our degree of leverage could increase substantially. The level of our indebtedness could have important consequences, including but not limited to the following:

- a substantial portion of our cash flows from operations may be dedicated to servicing our indebtedness and would not be available for other purposes;
- our business may not generate sufficient cash flow from operations to enable us to continue to meet our obligations under our indebtedness;
- our level of indebtedness may impair our ability to obtain additional financing in the future for working capital, capital expenditures, acquisitions or general corporate and other purposes;
- our interest expense may increase in the event of increases in interest rates, because certain of our borrowings are at variable rates of interest;
- our vulnerability to general adverse economic and industry conditions may increase, potentially restricting us from making acquisitions, introducing new technologies or exploiting business opportunities;
- our ability to borrow additional funds, dispose of assets, pay dividends and make certain investments may be limited by the covenants contained in the agreements governing our outstanding indebtedness limit; and
- our debt covenants may also affect our flexibility in planning for, and reacting to, changes in the economy and in our industry. Our failure to comply with such covenants could result in an event of default under such debt instruments which, if not cured or waived, could have a material adverse effect on us.

If we are unable to generate sufficient cash flow or otherwise obtain funds necessary to make required payments on our indebtedness or if we otherwise fail to comply with the various covenants in such indebtedness, including covenants in our bank credit facility, we would be in default. This default would permit the holders of such indebtedness to accelerate the maturity of such indebtedness and could cause defaults under other indebtedness, including the subordinated notes, or result in our bankruptcy. Our ability to meet our obligations will depend upon our future performance, which will be subject to prevailing economic conditions and to financial, business and other factors, including factors beyond our control.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

See Item 1. Business – Oil and Gas Operations. We also have various operating leases for rental of office space, office and field equipment, and vehicles. See "Off-Balance Sheet Agreements – Commitments and Obligations" in Management's Discussion and Analysis of Financial Condition and Results of Operations, and Note 11, "Commitments and Contingencies," to the Consolidated Financial Statements for the future minimum rental payments. Such information is incorporated herein by reference.

Item 3. Legal Proceedings

We are involved in various lawsuits, claims and regulatory proceedings incidental to our businesses. While we currently believe that the ultimate outcome of these proceedings, individually and in the aggregate, will not have a material adverse effect on our financial position or overall trends in results of operations or cash flows, litigation is subject to inherent uncertainties. If an unfavorable ruling were to occur, there exists the possibility of a material adverse impact on our net income in the period in which the ruling occurs. We provide accruals for litigation and claims if we determine that we may have a range of legal exposure that would require accrual.

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

A special meeting of the stockholders was held on November 19, 2007, for the purposes of: (i) approving an amendment to our Restated Certificate of Incorporation to increase the number of shares of our authorized common stock from 250,000,000 shares to 600,000,000 shares; (ii) approving an amendment to our Restated Certificate of Incorporation to split our common shares 2-for-1; and (iii) granting authority to the Company to extend the solicitation period in the event that the special meeting is postponed or adjourned for any reason. At the record date, October 8, 2007, 122,094,117 shares of common stock were outstanding and entitled to one vote per share upon all matters submitted at the meeting. Holders of 111,215,370 shares of common stock, representing approximately 91% of the total issued and outstanding shares of common stock, were present in person or by proxy at the meeting to cast their vote. All matters were approved as listed below.

With respect to the amendment to our Restated Certificate of Incorporation to increase the number of shares of our authorized common stock from 250,000,000 shares to 600,000,000 shares, the votes were cast as follows:

For	Against	Abstentions
81,736,700	29,443,451	35,219

With respect to approving an amendment to our Restated Certificate of Incorporation to split our common shares 2-for-1, the votes were cast as follows:

For	Against	Abstentions
111,049,257	138,146	27,967

With respect to approving an amendment to grant authority to extend the solicitation period in the event that the special meeting is postponed or adjourned for any reason, the votes were cast as follows:

For	Against	Abstentions
61,637,858	48,565,777	1,011,735

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

Common Stock Trading Summary

The following table summarizes the high and low reported sales prices on days in which there were trades of Denbury's common stock on the New York Stock Exchange ("NYSE"), for each quarterly period for the last two fiscal years. The sale prices are adjusted to reflect the 2-for-1 stock split on December 5, 2007. On April 25, 2006, we closed the $125 million sale (net to Denbury) of 6,985,190 shares (3,492,595 pre-split basis) of common stock in a public offering. As of January 31, 2008, the number of record holders of Denbury's common stock was 943. Management believes, after inquiry, that the number of beneficial owners of Denbury's common stock is in excess of 10,500. On January 31, 2008, the last reported sale price of Denbury's common stock, as reported on the NYSE, was $25.30 per share.

	2007		2006	
	High	Low	High	Low
First Quarter	**$ 15.310**	**$ 12.980**	$16.325	$11.785
Second Quarter	**19.380**	**14.835**	18.300	12.955
Third Quarter	**23.380**	**18.275**	17.900	13.265
Fourth Quarter	**30.560**	**22.405**	15.465	12.975

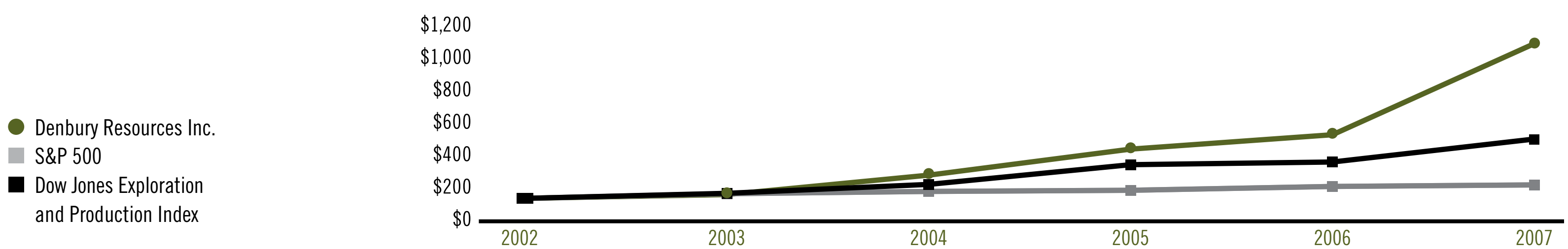
We have never paid any dividends on our common stock, and we currently do not anticipate paying any dividends in the foreseeable future. Also, we are restricted from declaring or paying any cash dividends on our common stock under our bank loan agreement. No unregistered securities were sold by the Company during 2007.

Share Performance Graph

The following Performance Graph and related information shall not be deemed "soliciting material" or to be "filed" with the Securities and Exchange Commission, nor shall such information be incorporated by reference into any future filings under the Securities Act of 1933 or Securities Exchange Act of 1934, each as amended, except to the extent that the Company specifically incorporates it by reference into such filing.

The following graph illustrates changes over the five-year period ended December 31, 2007, in cumulative total stockholder return on our common stock as measured against the cumulative total return of the S&P 500 Index and the Dow Jones U.S. Exploration and Production Index. The results assume $100 was invested on December 31, 2002, and that dividends were reinvested.

CUMULATIVE TOTAL RETURN ON $100 INVESTMENT
(DECEMBER 31, 2002 – DECEMBER 31, 2007)



	December 31,					
	2002	2003	2004	2005	2006	2007
Denbury	$100.00	$ 123.10	$ 242.92	$ 403.19	$ 491.86	**$1,053.10**
S&P 500	100.00	128.68	142.69	149.70	173.34	**182.87**
Dow Jones Exploration and Production	100.00	131.06	185.94	307.40	323.91	**465.35**

Item 6. Selected Financial Data

(In thousands, unless otherwise noted)	Year Ended December 31, 2007	2006	2005	2004 [1]	2003
Consolidated Statements of Operations Data:					
Revenues	**$ 971,950**	$ 732,312	$ 560,706	$ 382,836	$ 333,270
Net income	**253,147**	202,457 [2]	166,471	82,448	56,553 [3]
Net income per common share [4]:					
Basic	**1.05**	0.87 [2]	0.74	0.38	0.26 [3]
Diluted	**1.00**	0.82 [2]	0.70	0.36	0.25 [3]
Weighted average number of common shares outstanding [4]:					
Basic	**240,065**	233,101	223,485	219,482	215,525
Diluted	**252,101**	247,547	239,267	229,206	221,856
Consolidated Statements of Cash Flow Data:					
Cash provided by (used by):					
Operating activities	**$ 570,214**	$ 461,810	$ 360,960	$ 168,652	$ 197,615
Investing activities	**(762,513)**	(856,627)	(383,687)	(93,550)	(135,878)
Financing activities	**198,533**	283,601	154,777	(66,251)	(61,489)
Production (daily):					
Oil (Bbls)	**27,925**	22,936	20,013	19,247	18,894
Natural gas (Mcf)	**97,141**	83,075	58,696	82,224	94,858
BOE (6:1)	**44,115**	36,782	29,795	32,951	34,704
Unit Sales Price (excluding impact of derivative settlements):					
Oil (per Bbl)	**$ 69.80**	$ 59.87	$ 50.30	$ 36.46	$ 27.47
Natural gas (per Mcf)	**6.81**	7.10	8.48	6.24	5.66
Unit Sales Price (including impact of derivative settlements):					
Oil (per Bbl)	**$ 68.84**	$ 59.23	$ 50.30	$ 27.36	$ 24.52
Natural gas (per Mcf)	**7.66**	7.10	7.70	5.57	4.45
Costs per BOE:					
Lease operating expenses	**$ 14.34**	$ 12.46	$ 9.98	$ 7.22	$ 7.06
Production taxes and marketing expenses	**3.05**	2.71	2.54	1.55	1.17
General and administrative	**3.04**	3.20	2.62	1.78	1.20
Depletion, depreciation and amortization	**12.17**	11.11	9.09	8.09	7.48
Proved Reserves:					
Oil (MBbls)	**134,978**	126,185	106,173	101,287	91,266
Natural gas (MMcf)	**358,608**	288,826	278,367	168,484	221,887
MBOE (6:1)	**194,746**	174,322	152,568	129,369	128,247
Carbon dioxide (MMcf) [5]	**5,641,054**	5,525,948	4,645,702	2,664,633	1,613,840
Consolidated Balance Sheet Data:					
Total assets	**$ 2,771,077**	$ 2,139,837	$ 1,505,069	$ 992,706	$ 982,621
Total long-term liabilities	**1,102,066**	833,380	617,343	368,128	434,845
Stockholders' equity [6]	**1,404,378**	1,106,059	733,662	541,672	421,202

(1) We sold Denbury Offshore, Inc. in July 2004.

(2) Effective January 1, 2006, we adopted Statement of Financial Accounting Standards No. 123(R), "Share Based Payment."

(3) In 2003, we recognized a gain of $2.6 million for the cumulative effect adoption of SFAS No. 143, "Accounting for Asset Retirement Obligations." The adoption of SFAS No. 143 increased basic and diluted net income per common share by $0.01. In April 2003, we recorded a pre-tax charge of $17.6 million associated with an early debt retirement.

(4) On December 5, 2007, and October 31, 2005, we split our common stock on a 2-for-1 basis. Information relating to all prior years' shares and earnings per share has been retroactively restated to reflect the stock splits.

(5) Based on a gross working interests basis and includes reserves dedicated to volumetric production payments of 182.3 Bcf at December 31, 2007, 210.5 Bcf at December 31, 2006, 237.1 Bcf at December 31, 2005, 178.7 Bcf at December 31, 2004, and 162.6 Bcf at December 31, 2003 (see Note 15 to the Consolidated Financial Statements).

(6) We have never paid any dividends on our common stock.

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

We are a growing independent oil and gas company engaged in acquisition, development and exploration activities in the U.S. Gulf Coast region. We are the largest oil and natural gas producer in Mississippi; own the largest carbon dioxide ("CO_2") reserves east of the Mississippi River used for tertiary oil recovery, and hold significant operating acreage in the Barnett Shale play near Fort Worth, Texas, onshore Louisiana and Alabama, and properties in Southeast Texas. Our goal is to increase the value of acquired properties through a combination of exploitation, drilling, and proven engineering extraction processes, including secondary and tertiary recovery operations. Our corporate headquarters are in Plano, Texas (a suburb of Dallas), and we have four primary field offices located in Laurel, Mississippi; McComb, Mississippi; Brandon, Mississippi; and Cleburne, Texas.

2007 Overview

Operating Results. During 2007, we set a corporate record for annual cash flow from operations of $570.2 million, a 23% increase over the $461.8 million of cash flow from operations generated during 2006. Our 2007 net income of $253.1 million was 25% higher than our $202.5 million of net income during 2006, even after including a $64.2 million decrease in pre-tax income between the respective periods from non-cash fair value adjustments associated with our commodity derivative contracts. Record high production levels, higher oil prices, and $25.8 million of incremental net cash receipts on our derivative contracts contributed to the positive results, partially offset by higher overall expenses, lower natural gas prices, and the effect of the $64.2 million differential in non-cash fair value adjustments associated with our commodity derivative contracts (see "Results of Operations – Oil and Natural Gas Revenues").

Our fourth quarter 2007 average production rate of 50,371 BOE/d and our 2007 average production of 44,115 BOE/d were Company quarterly and annual production records, with significant increases in our tertiary oil and Barnett Shale production, partially offset by production declines in our Louisiana onshore properties. Higher oil prices further improved 2007 results, as our average realized per BOE commodity price was 11% higher than during 2006, resulting in 13% higher revenues in 2007, together with 20% higher revenues due to higher production levels.

Excluding any impact of our commodity derivative income and expense items, our aggregate expenses increased 33% during 2007 as compared to expenses during 2006 due to (i) higher overall industry costs, (ii) a higher percentage of operations related to tertiary operations, which generally have higher operating costs per BOE (see "Results of Operations – CO_2 Operations" for a more thorough discussion), (iii) higher average debt levels to finance our $42 million acquisition on March 31, 2007 (see "2007 Acquisitions" below) and continued spending in excess of cash flow from operations (see "Capital Resources and Liquidity"), and (iv) higher compensation expense resulting from additional employees and increased salaries which we consider necessary in order to remain competitive in the industry, partially offset by approximately $6.0 million of non-recurring charges to earnings in 2006 related to the departure and retirement of two vice presidents.

As has been our practice for several years, we are reinvesting virtually all of our cash flow in new projects, with a desire to further increase our production and reserves. During 2007, our proved reserves increased from 174.3 MMBOE as of December 31, 2006, to 194.7 MMBOE as of December 31, 2007, replacing approximately 250% of our 2007 production, almost entirely from organic growth. The most significant reserve additions during 2007 were in the Barnett Shale (22.8 MMBOE) and in our tertiary operations (12.7 MMBOE). While we booked more proved tertiary reserves in 2007 than in 2006 (6.0 MMBOE), these reserve quantity additions were less than we expect to recognize during the next few years, presuming we have a production response from the tertiary floods we started in 2007 and expect to start in 2008 and 2009 (see "Results of Operations – Depletion, Depreciation and Amortization" for a review of our reserve changes during 2007 and a discussion of our proved tertiary reserves).

While overall costs were higher in the 2007 periods than in the comparable 2006 periods, during 2007 the rate of inflation in our industry appears to have moderated, and in some cases, we are beginning to see modest cost reductions. Likewise, although oilfield goods and services are still in tight supply, there have been signs of improvement in overall availability; but some supply issues persist, including long lead times for certain goods and services, such as compressors used in our tertiary recycling facilities and construction services for pipelines. It is difficult to forecast price trends and supply and service availability, which if adverse, can significantly impact both operating costs and capital expenditures, as well as cause delays in achieving our anticipated production targets.

Tertiary Operations. Having enough CO_2 to flood our tertiary oil fields is one of the most important ingredients, if not the key ingredient, to our tertiary operations. During 2007, we replaced 164% of our CO_2 production, increasing our proved CO_2 reserves slightly, from approximately 5.5 Tcf as of December 31, 2006 to approximately 5.6 Tcf as of December 31, 2007 (quantities are on a 100% working interest basis – see "CO_2 Operations – CO_2 Resources" for further information).

Oil production from our tertiary operations increased to an average of 14,767 BOE/d in 2007, a 47% increase over 2006 tertiary production level of 10,070 BOE/d, with fourth quarter 2007 tertiary production averaging 17,428 BOE/d. Production from our Phase II operations in Eastern Mississippi (Soso, Eucutta and Martinville Fields) contributed 2,888 BOE/d (approximately 61%) to the increase over the prior year's tertiary production level, with the balance of the increase coming from our Phase I fields, except for Little Creek Field which is on a gradual decline. In addition to further development of oil fields we already own and which are slated for tertiary flooding, we are continuing to buy additional oil fields that are candidates for future tertiary flood activity (see "2007 Acquisitions" below).

Please refer to the section entitled "CO_2 Operations" below for a discussion of these operations, their potential, and the ramifications of our continuing emphasis on these operations.

Sale of Louisiana Natural Gas Assets. In October 2007, we entered into an agreement to sell our Louisiana natural gas assets to a privately held company for approximately $180 million (before closing adjustments) plus any amounts received in the future from a net profits interest in a well. In late December 2007, we closed on approximately 70% of that sale with net proceeds of approximately $108.6 million (including estimated final purchase price adjustments), and closed on the remaining 30% on February 20, 2008, with net proceeds at the second closing of approximately $48.9 million. The operating net revenue, net of capital expenditures, between the August 1, 2007, effective date and the respective closing dates was an adjustment to the purchase price, along with other minor closing adjustments. The potential net profits interest relates to a well in the South Chauvin Field and is only earned if operating income from that well exceeds certain levels, which we believe could potentially increase the ultimate sales price by up to 10%.

Production attributable to the sold properties averaged approximately 30.6 MMcfe/d (82% natural gas) during the fourth quarter of 2007, representing approximately 10% of our total fourth quarter production and approximately 4% of our total proved reserve quantities as of December 31, 2006.

Genesis Transactions. On July 25, 2007, Genesis Energy, L.P. ("Genesis"), a master limited partnership of which Denbury is the general partner, closed on a previously announced acquisition in which they acquired several energy related businesses from the Davison family of Ruston, Louisiana, for total consideration of approximately $623 million (net of cash acquired at closing and subject to final purchase price adjustments). The acquisition agreement provided that Genesis deliver $560 million of consideration, half in common units at an agreed value of $20.8036 per unit (as compared to a value of $24.52 per unit for accounting purposes) and half in cash, subject to specified purchase price adjustments. In conjunction with that acquisition, we exercised our right to maintain our pro rata (7.4%) ownership of common units, acquiring 1,074,882 additional common units for approximately $22.4 million, in addition to our capital contribution of an additional $6.2 million as general partner to maintain our 2% general partner's interest.

In order to maintain our pro rata (7.4%) common unit ownership interest in Genesis, we acquired an additional 734,732 common units in a December 2007 Genesis public offering at $21.29 per unit, the public offering price of $22.00 per unit, less the underwriting discount. Our total cost for the units, including the 2% general partner portion of the offering, was $20.0 million.

The Company has reached substantial agreement and is in the process of finalizing the business issues with Genesis and its lenders as to the terms of the transactions with Genesis involving the Company's NEJD and Free State CO_2 Pipelines, including a long-term transportation service arrangement for the Free State line and a 20-year financing lease for the NEJD system. In these transactions, Denbury expects to receive from Genesis $225 million in cash and $25 million of Genesis common limited partnership units at the average closing price of the units on the thirty days prior to closing. The Company anticipates capitalizing these transactions for accounting purposes and currently projects that it will initially pay Genesis approximately $30 million per annum under the financing lease and transportation services agreement (and a lesser pro-rated amount for 2008), with future payments for the NEJD pipeline payments fixed at $20.7 million per year during the term of the financing lease, and the payments relating to the Free State Pipeline dependant on the volumes of CO_2 transported therein. While the business terms of the transactions have been substantially completed, closing remains subject to finalization of legal issues and completion and delivery of closing documentation. Currently, we will also consider similar transactions with Genesis for the new CO_2 pipeline we have constructed from Jackson Dome to Tinsley Field and are constructing from Tinsley Field to Delhi Field (the "Delta Pipeline"), once that pipeline is completed, forecasted at this time to be completed in late 2008 or early 2009, or potentially we could divide that pipeline into two segments and two separate transactions. If in future periods Genesis is able to complete additional acquisitions of non-Denbury related assets of sufficient size and with acceptable returns, we would consider additional dropdowns with Genesis of certain of our existing or planned assets provided that such transactions can generate "qualified income" for a master limited partnership, which may depend in part on the degree to which we ship man-made CO_2 on such lines and the status of man-made CO_2 as "qualified income."

2007 Acquisitions. On March 30, 2007, we completed an acquisition of six producing oil and natural gas fields, two of which are future potential CO_2 tertiary oil flood candidates, collectively called the Seabreeze Complex, located near Houston, Texas, at a cost of approximately $39.4 million. Tertiary operations are not expected to commence at these fields until 2010 or 2011, following anticipated completion of the 300 mile CO_2 pipeline from Louisiana to Hastings Field (also near Houston). The acquisition was funded with bank financing under our existing credit facility. At the time of acquisition, these fields had estimated proved conventional reserves of approximately 525 MBOE and produced an average of 759 BOE/d during the fourth quarter of 2007. We operate all of these fields and own the majority of the working interests.

We also purchased East and South Gillock Fields in 2007, small future CO_2 tertiary oil flood candidates, also located near Houston, Texas, at a cost of approximately $3.5 million. The conventional reserves and production associated with these fields was negligible at the time of the acquisition.

April 2007 Debt Issuance. On April 3, 2007, we issued $150 million of 7.5% Senior Subordinated Notes due 2015 as an additional issuance under our existing indenture governing our December 2005 sale of $150 million of 7.5% Senior Subordinated Notes due 2015. The notes were issued at 100.5% of par, which equates to an effective yield to maturity of 7.4%. The net proceeds from the issuance were approximately $149.2 million, which we used to repay a portion of the outstanding borrowings under our bank credit facility.

Capital Resources and Liquidity

Our current 2008 capital exploration and development budget is approximately $900 million, excluding any potential acquisitions. The current 2008 program includes an estimated $245 million to acquire pipe and right-of-ways for our proposed CO_2 pipeline from Louisiana to Texas (the "Green Pipeline") and another $80 million for the segment of the Delta CO_2 Pipeline from Tinsley to Delhi Fields. We expect to spend an additional $450 million constructing the Green Pipeline during 2009, making our current anticipated total cost for that line approximately $700 million. Currently, over 50% of the remaining portion of our 2008 budget is expected to be spent on other tertiary related operations, over 25% in the Barnett Shale area, and the balance in other areas. Based on oil and natural gas commodity futures prices as of late February 2008 and our current 2008 production forecasts, our 2008 capital budget is forecasted to be $125 million to $175 million greater than our anticipated cash flow from operations. We plan to fund most of this deficit with cash generated by the anticipated "drop-down" transaction with Genesis (see "2007 Overview – Genesis Transactions") and our recently completed sale of Louisiana natural gas assets (see "2007 Overview – Sale of Louisiana Natural Gas Assets"). We could potentially also generate additional funds of up to $150 million through transactions with Genesis whereby we could "drop-down" our Delta CO_2 Pipeline, or portions thereof, to Genesis (see "2007 Overview – Genesis Transactions").

If the Delta Pipeline "drop-down" to Genesis is not consummated, or if there is still a shortfall in excess of the cash generated by our recently completed Louisiana property sale and proposed "drop-down" of pipelines to Genesis described above, we would likely fund the deficit with bank debt. In addition, if commodity prices were to significantly decrease from current levels, we could also reduce our capital spending during 2008 commensurately, in addition to using bank debt to fund the deficit.

As of February 28, 2008, we had $111 million of bank debt outstanding on a $500 million borrowing base, leaving us significant incremental borrowing capacity, more than we currently plan or desire to use. Further, we believe that we could significantly increase our bank borrowing base if desired, and anticipate increasing it at our April 1, 2008 redetermination.

We monitor our capital expenditures on a regular basis, adjusting them up or down depending on commodity prices and the resultant cash flow. Therefore, during the last few years as commodity prices have increased, we have increased our capital budget throughout the year. As a result of cost inflation in our industry in recent years, many of our recent year budget increases have related to escalating costs rather than additional projects. Even though there are signs that the rate of this inflationary trend is subsiding, if costs do rise or we spend more than our estimated amounts, we will either have to increase our capital budget or consider deferring a portion of our planned projects.

We continue to pursue additional acquisitions of mature oil fields that we believe have potential as future tertiary flood candidates. These possible acquisitions are difficult to forecast and the purchase price can vary widely depending on the levels of existing production, conventional proved reserves and commodity prices. Any additional acquisitions would be funded, at least temporarily, with bank or other debt, although if significant, the acquisition would likely be ultimately funded with more permanent capital such as subordinated debt and/or additional equity.

Amendment to Our Bank Credit Facility. On March 31, 2007, we amended our Sixth Amended and Restated Credit Agreement with our nine banks, led by JPMorgan Chase Bank, N.A., as administrative agent. The amendment (i) increased the commitment amount that the banks are committed to fund from $250 million to $350 million, (ii) reconfirmed the borrowing base of $500 million, (iii) authorized last spring's $150 million subordinated debt offering (see "2007 Overview – April 2007 Debt Issuance"), and (iv) authorized us to enter into a sale-leaseback type transaction for our CO_2 pipelines, not to exceed $300 million, with Genesis, in the type of transaction contemplated and discussed above (see "2007 Overview – Genesis Transactions"). With regard to our bank credit facility, the borrowing base represents the amount that can be borrowed from a credit standpoint based on our assets, as confirmed by the banks, while the commitment amount is the amount the banks have committed to fund pursuant to the terms of the credit agreement. The banks have the option to participate in any borrowing request by us in excess of the commitment amount ($350 million), up to the borrowing base limit ($500 million), although the banks are not obligated to fund any amount in excess of the commitment amount. At February 28, 2008, we had outstanding $525 million (principal amount) of 7.5% subordinated notes and $111 million of bank debt.

Sources and Uses of Capital Resources

Capital Expenditure Summary

Amounts in thousands	Year Ended December 31, 2007	2006	2005
Oil and gas exploration and development			
Drilling	**$313,258**	$245,350	$147,773
Geological, geophysical and acreage	**22,829**	31,590	25,519
Facilities	**118,003**	98,890	65,018
Recompletions	**141,264**	120,438	70,056
Capitalized interest	**18,305**	11,059	—
Total oil and gas exploration and development expenditures	**613,659**	507,327	308,366
Oil and gas property acquisitions	**49,077**	319,000	70,870
Total oil and natural gas capital expenditures	**662,736**	826,327	379,236
CO_2 source field capital expenditures, including capitalized interest	**171,182**	63,586	78,726
Total	**$833,918**	$889,913	$457,962

Our 2007 capital expenditures have been funded with $570.2 million of cash flow from operations, $150.0 million from our issuance of subordinated debt in April, $135.8 million from sales proceeds, and $16.0 million of net bank borrowings, with the excess proceeds used for other purposes, including the $48.5 million incremental investment in Genesis.

Our 2006 expenditures were funded with $461.8 million of cash flow from operations, $139.8 million of equity issued and $134.0 million of net bank borrowings, and a $13.2 million increase in our accrued capital expenditures, with the balance funded with working capital, predominately cash from the December 2005 issuance of $150 million of subordinated debt.

Off-Balance Sheet Arrangements

Commitments and Obligations

At December 31, 2007, we have no off-balance sheet arrangements, special purpose entities, financing partnerships or guarantees, other than as disclosed in this section. We have no debt or equity triggers based upon our stock or commodity prices. Our dollar denominated payment obligations that are not on our balance sheet include our operating leases, which at year-end 2007 totaled $143.8 million (including $98.5 million of equipment costs) relating primarily to the lease financing of certain equipment for CO_2 recycling facilities at our tertiary oil fields. We also have several leases relating to office space and other minor equipment leases. Additionally, we have dollar related obligations that are not currently recorded on our balance sheet relating to various obligations for development and exploratory expenditures that arise from our normal capital expenditure program or from other transactions common to our industry. In addition, in order to recover our undeveloped proved reserves, we must also fund the associated future development costs forecasted in our proved reserve reports. For a further discussion of our future development costs and proved reserves, see "Results of Operations – Depletion, Depreciation and Amortization" below.

At December 31, 2007, we had a total of $10.5 million outstanding in letters of credit. Genesis Energy, Inc., our 100% owned subsidiary that is the general partner of Genesis, may, as general partner, be a potential guarantor of the bank debt of Genesis, which consists of $80.0 million in debt and $5.3 million in letters of credit at December 31, 2007. There were no guarantees by Denbury or any of its other subsidiaries of the debt of Genesis or of Genesis Energy, Inc. at December 31, 2007. We do not have any material transactions with related parties other than sales of production, transportation arrangements, capital leases with Genesis made in the ordinary course of business, and volumetric production payments of CO_2 ("VPP") sold to Genesis as discussed in Note 3 to our Consolidated Financial Statements. The anticipated conveyance of our CO_2 pipelines to Genesis would require payments over a minimum of 20 years and is not included in the commitment table below (see "2007 Overview – Genesis Transactions"). If consummated, we anticipate capitalizing these transactions for accounting purposes, and currently project that we will initially pay Genesis approximately $30 million per annum under the financing lease and transportation agreement (and a lesser pro-rated amount for 2008), with future payments for the NEJD Pipeline fixed at $20.7 million per year during the 20-year service term of the financing lease, and the payments relating to the Free State Pipeline dependant on the volumes of CO_2 transported thereon, with a minimum annual payment for the Free State Pipeline of $1.2 million.

We currently have long-term commitments to purchase manufactured CO_2 from three proposed gasification plants, if these plants are built, two proposed by the developers of Faustina Hydrogen Products LLC and another by Rentech Inc. If all three plants are built, these synthetic sources are currently anticipated to provide us with an aggregate of 750 MMcf/d to 850 MMcf/d of CO_2 by 2013. The base price of CO_2 per Mcf from these synthetic sources is currently expected to be 1.5 to 2.0 times higher than our most recent all-in cost of CO_2 from our natural sources (Jackson Dome) using current oil prices and assuming comparable compression levels. These predicted synthetic CO_2 prices are expected to be competitive with the cost of our natural CO_2 after adjusting for our share of potential carbon emissions credits using estimated current prices of CO_2 carbon credit futures. If all three plants are built, the aggregate purchase obligation for this CO_2 would be around $190 million per year, assuming a $90 per barrel oil price and comparable compression levels, before any potential savings from our share of carbon emissions credits. All of the contracts have price adjustments that fluctuate based on the price of oil. Construction has not yet commenced on any of these plants, and their construction is contingent on the satisfactory resolution of various issues, including financing; although based on their public representations, the initial Faustina plant is currently scheduled to begin construction during 2008, with completion scheduled in late 2010 or 2011. These amounts are not included in the table below as these payments are contingent on the plants being built.

A summary of our obligations at December 31, 2007, is presented in the following table:

	Payments Due by Period						
Amounts in Thousands	Total	2008	2009	2010	2011	2012	Thereafter
Contractual Obligations:							
Subordinated debt [a]	$ 525,000	$ —	$ —	$ —	$ —	$ —	$ 525,000
Senior Bank Loan [a]	150,000	—	—	—	150,000	—	—
Estimated interest payments on subordinated debt and Senior Bank Loan [a]	301,705	48,613	48,612	48,613	45,879	39,375	70,613
Operating lease obligations	143,768	17,580	17,128	16,745	16,185	14,957	61,173
Capital lease obligations [b]	8,738	1,291	1,529	1,291	1,291	1,242	2,094
Capital expenditure obligations [c]	166,041	113,628	50,658	1,755	—	—	—
Derivative contracts payment [d]	23,914	23,914	—	—	—	—	—
Hastings Field purchase option	5,000	5,000	—	—	—	—	—
Other Cash Commitments:							
Future development costs on proved oil and gas reserves, net of capital obligations [e]	530,778	179,033	143,053	103,168	41,940	21,250	42,334
Future development cost on proved CO_2 reserves, net of capital obligations [f]	133,894	46,794	11,000	—	—	—	76,100
Asset retirement obligations [g]	100,530	2,685	2,251	3,762	1,285	747	89,800
Total	$2,089,368	$438,538	$274,231	$175,334	$256,580	$ 77,571	$ 867,114

(a) These long-term borrowings and related interest payments are further discussed in Note 6 to the Consolidated Financial Statements. This table assumes that our long-term debt is held until maturity.

(b) Represents future minimum cash commitments of $7.0 million to Genesis under capital leases in place at December 31, 2007, primarily for transportation of crude oil and CO_2, $1.5 million for our office in Laurel, Mississippi, and auto leases for $0.2 million. Approximately $2.3 million of these payments represents interest.

(c) Represents future minimum cash commitments under contracts in place as of December 31, 2007, primarily for pipe, drilling rig services and well related costs. As is common in our industry, we commit to make certain expenditures on a regular basis as part of our ongoing development and exploration program. These commitments generally relate to projects that occur during the subsequent several months and are usually part of our normal operating expenses or part of our capital budget, which for 2008 is currently set at $900 million. In certain cases we have the ability to terminate contracts for equipment in which case we would only be liable for the cost incurred by the vendor up to that point; however, as we currently do not anticipate cancelling those contracts these amounts include our estimated payments under those contracts. We also have recurring expenditures for such things as accounting, engineering and legal fees, software maintenance, subscriptions, and other overhead type items. Normally these expenditures do not change materially on an aggregate basis from year to year and are part of our general and administrative expenses. We have not attempted to estimate the amounts of these types of recurring expenditures in this table as most could be quickly cancelled with regard to any specific vendor, even though the expense itself may be required for ongoing normal operations of the Company.

(d) Represents the estimated future payments under our oil and gas derivative contracts based on the futures market prices as of December 31, 2007. These amounts will change as oil and natural gas commodity prices change. The estimated fair market value of our oil and natural gas commodity derivatives at December 31, 2007, was a $23.3 million net liability. See further discussion of our derivative contracts and their market price sensitivities in "Market Risk Management" below in this Management's Discussion and Analysis of Financial Condition and in Note 10 to the Consolidated Financial Statements.

(e) Represents projected capital costs as scheduled in our December 31, 2007 proved reserve report that are necessary in order to recover our proved undeveloped oil and natural gas reserves. These are not contractual commitments and are net of any other capital obligations shown under "Contractual Obligations" in the table above.

(f) Represents projected capital costs as scheduled in our December 31, 2007 proved reserve report that are necessary in order to recover our proved undeveloped CO_2 reserves from our CO_2 source wells used to produce CO_2 for our tertiary operations. These are not contractual commitments and are net of any other capital obligations shown above.

(g) Represents the estimated future asset retirement obligations on an undiscounted basis. The present discounted asset retirement obligation is $41.3 million, as determined under SFAS No. 143, and is further discussed in Note 4 to the Consolidated Financial Statements.

During November 2006 we entered into an agreement that gives us an option on September 1, 2008, and September 1, 2009, to be effective on the following January 1st, to purchase an interest in Hastings Field, a strategically significant potential tertiary flood candidate located near Houston, Texas. The agreement provides for the parties to agree upon a purchase price for the conventional proved reserves at the time of the exercise of the option, which may be paid in cash or through a volumetric production payment; failing an agreement as to price, the price will be determined by a pre-designated independent petroleum engineering firm using specified criteria for calculation of the discounted present value of proved reserves at that time. As consideration for the option agreement, to date we have paid $45 million under this option and have a remaining payment due in November 2008 of $5.0 million. We can extend the option period beyond November 2009 for up to seven additional years at an incremental cost of $30 million per year. None of the option payment amounts will be credited against the purchase price if we exercise the option. If we exercise the option, we will be committed to make aggregate net capital expenditures in the field totaling approximately $175 million over the subsequent five years to develop the field for tertiary operations, with an obligation to commence CO_2 injections in the field within three years following the option exercise. The above table does not include the commitments related to Hastings Field if the purchase option is exercised by us, as the obligation is at our option. The above table does include the remaining $5.0 million due on the Hastings option payment.

Long-term contracts require us to deliver CO_2 to our industrial CO_2 customers at various contracted prices, plus we have a CO_2 delivery obligation to Genesis pursuant to three volumetric production payments ("VPP") entered into during 2003 through 2005. Based upon the maximum amounts deliverable as stated in the industrial contracts and the volumetric production payments, we estimate that we may be obligated to deliver up to 562 Bcf of CO_2 to these customers over the next 20 years; however, since the group as a whole has historically taken less CO_2 than the maximum allowed in their contracts, based on the current level of deliveries, we project that our commitment would likely be reduced to approximately 268 Bcf. The maximum volume required in any given year is approximately 142 MMcf/d, although based on our current level of deliveries this would likely be reduced to approximately 72 MMcf/d. Given the size of our proven CO_2 reserves at December 31, 2007 (approximately 5.6 Tcf before deducting approximately 182.3 Bcf for the three VPPs), our current production capabilities and our projected levels of CO_2 usage for our own tertiary flooding program, we believe that we will be able to meet these delivery obligations.

Results of Operations

CO_2 Operations

Overview. Since we acquired our first carbon dioxide tertiary flood in Mississippi in 1999, our interest in tertiary operations has increased to the point that approximately 72% of our current 2008 capital budget is dedicated to tertiary related operations. We particularly like this play as (i) it has a lower risk and is more predictable than most traditional exploration and development activities, (ii) it provides a reasonable rate of return at relatively low oil prices (generally around $30 a barrel at today's cost levels, depending on the specific field and area), and (iii) we have virtually no competition for this type of activity in our geographic area. Generally, from East Texas to Florida, there are no known significant natural sources of CO_2 except our own, and these large volumes of CO_2 that we own drive the play.

We talk about our tertiary operations by labeling operating areas or groups of fields as phases. Phase I is in Southwest Mississippi and includes several fields along our 183-mile NEJD CO_2 Pipeline that we acquired in 2001. The most significant fields in this area are Little Creek, Mallalieu, McComb and Brookhaven. Phase II, which began with the early 2006 completion of the Free State CO_2 Pipeline to East Mississippi, includes Eucutta, Soso, Martinville and Heidelberg Fields. Tinsley Field located northwest of Jackson, Mississippi, acquired in January 2006, is our Phase III and is serviced by that portion of the Delta CO_2 Pipeline completed in January 2008. Phase IV includes Cranfield and Lake St. John Fields, two fields near the Mississippi/Louisiana border located west of the Phase I fields, and Phase V is Delhi Field, a Louisiana field we acquired in 2006, located southwest of Tinsley Field. Flooding in Phase V will begin in 2009 upon completion of the Delta CO_2 Pipeline from Tinsley to Delhi. Citronelle Field in Southwest Alabama, another field acquired in 2006, is our Phase VI which will require an extension to the Free State CO_2 Pipeline, the timing of which is uncertain at this time. Our last two currently existing phases will require completion of our proposed Green Pipeline, a 300-mile CO_2 pipeline which will run from Southern Louisiana to near Houston, Texas, and is scheduled for completion in late 2009 or 2010. Hastings Field, a field on which we acquired a purchase option in late 2006 (see "Commitments and Contingencies"), is our Phase VII, and the Seabreeze Complex, acquired in 2007, will be our Phase VIII (see "2007 Overview – 2007 Acquisitions").

CO_2 Resources. Since we acquired the CO_2 source field located near Jackson, Mississippi, in 2001, we have continued to develop the field and have increased the proven CO_2 reserves from approximately 800 Bcf at the time of the acquisition to approximately 5.6 Tcf as of December 31, 2007. During 2007, our proven CO_2 reserves increased approximately 5%, or 295 Bcf (excluding 2007 production). The estimate of 5.6 Tcf of proved CO_2 reserves is based on 100% ownership of the CO_2 reserves, of which Denbury's net revenue interest ownership is approximately 4.5 Tcf. Both reserve estimates are included in the evaluation of proven CO_2 reserves prepared by DeGolyer and MacNaughton. In discussing the available CO_2 reserves, we make reference to the gross amount of proved reserves, as this is the amount that is available for Denbury's tertiary recovery programs, Genesis, and industrial users, as Denbury is responsible for distributing the entire CO_2 production stream for both of these uses. We currently estimate that it will take approximately 2.4 Tcf of CO_2 to develop and produce the proved tertiary recovery reserves we have recorded at December 31, 2007, in Phases I and II.

Today, we own every known producing CO_2 well in the region, providing us a significant strategic advantage in the acquisition of other properties in Mississippi and Louisiana that could be further exploited through tertiary recovery. As of February 20, 2008, we estimate that we are capable of producing approximately 700 MMcf/d of CO_2, over six times the rate that we were capable of producing at the time of our initial acquisition in 2001. We continue to drill additional CO_2 wells, with five more wells planned for 2008, in order to further increase our production capacity and potentially increase our proven CO_2 reserves. Our drilling activity at Jackson Dome will continue beyond 2008 as our current forecasts for the existing eight phases suggest that we will need approximately 1.4 Bcf/d of CO_2 production by 2012.

In addition to using CO_2 for our tertiary operations, we sell CO_2 to third party industrial users under long-term contracts. Most of these industrial contracts have been sold to Genesis along with the sale of a volumetric production payment for the CO_2. Our average daily CO_2 production during 2005, 2006 and 2007 was approximately 242 million, 342 million and 493 million cubic feet per day, respectively, of which approximately 73% in 2005, 75% in 2006 and 81% in 2007 was used in our tertiary recovery operations, with the balance delivered to Genesis under the volumetric production payments or sold to third party industrial users.

We spent approximately $0.21 per Mcf in operating expenses to produce our CO_2 during 2007, more than our 2006 average of $0.19 per Mcf and our 2005 average of $0.16 per Mcf, with the higher costs each year primarily due to higher oil costs, which impacts the amount we pay royalty owners for the CO_2, and higher operating costs. Our estimated total cost per thousand cubic feet of CO_2 during 2007 was approximately $0.29, after inclusion of depreciation and amortization expense related to the CO_2 production, as compared to approximately $0.28 during 2006 and $0.25 during 2005.

Man-Made CO_2 Sources. In addition to our natural source of CO_2, we are in discussions with the owners of several possible gasification plants which, if built, will convert coal or petroleum coke into various other fuels, with CO_2 being a significant by-product of the process. We expect these plants to provide us with significant additional sources of CO_2 in the future which would enable us to further expand our tertiary operations, although the earliest source of this manufactured CO_2 is not expected to be available to us until late 2010 or 2011. We have entered into long-term commitments to purchase manufactured CO_2 from three proposed plants (see "Commitments and Obligations"), which, if all three plants are built, are currently anticipated to provide us with an aggregate of 750 MMcf/d to 850 MMcf/d of CO_2 by 2013. While we are uncertain as to whether these three specific plants will be built, we anticipate that some gasification plants will be built within the next several years. If correct in our assumptions, we believe that we are a likely purchaser of CO_2 produced from such plants built in our area of operations because of the scale of our tertiary operations, the CO_2 pipeline infrastructure that we are continuing to develop, and the large natural source of CO_2 (Jackson Dome), which can act as a swing CO_2 producer if needed.

Overview of Tertiary Economics. When we began our tertiary operations several years ago, they were generally economic at oil prices below $20 per Bbl, although the economics varied by field. Our costs have escalated during the last few years due to general cost inflation in the industry, raising our current economic oil price to around $30 per Bbl, again dependent on the specific field. Our inception-to-date finding and development costs (including future development and abandonment costs but excluding expenditures on fields without proven reserves) for our tertiary oil fields through December 31, 2007, are approximately $9.75 per BOE. Currently, we forecast that these costs will range from $5 to $10 per BOE over the life of each field, depending on the state of a particular field at the time we begin operations, the amount of potential oil, the proximity to a pipeline or other facilities, etc. Our operating costs for tertiary operations are expected to range from $15.00 to $20.00 per BOE over the life of each field (at today's prices), again depending on the field itself.

While these economic factors have wide ranges, our rate of return from these operations has generally been better than our rate of return on traditional oil and gas operations, and thus our tertiary operations have become our single most important focus area. While it is extremely difficult to accurately forecast future production, we do believe that our tertiary recovery operations provide significant long-term production growth potential at reasonable rates of return, with relatively low risk, and thus will be the backbone of our Company's growth for the foreseeable future. Although we believe that our plans and projections are reasonable and achievable, there could be delays or unforeseen problems in the future that could delay or affect the economics of our overall tertiary development program. We believe that such delays or price effects, if any, should only be temporary.

Financial Statement Impact of CO_2 Operations. Our increasing emphasis on CO_2 tertiary recovery projects has significantly impacted and will continue to impact our financial results and certain operating statistics.

First, there is a significant delay between the initial capital expenditures on these fields and the resulting production increases, as we must build facilities before CO_2 flooding can commence, and it usually takes six to 12 months before the field responds to the injection of CO_2 (i.e., oil production commences). Further, we may spend significant amounts of capital before we can recognize any proven reserves from fields we flood (see "Analysis of CO_2 Tertiary Recovery Operating Activities" below). Even after a field has proven reserves, there will usually be significant amounts of additional capital required to fully develop the field.

Second, these tertiary projects are usually more expensive to operate than our other oil fields because of the cost of injecting and recycling the CO_2 (primarily due to the significant energy requirements to re-compress the CO_2 back into a near-liquid state for re-injection purposes). As commodity and energy prices increase, so do our operating expenses in these fields. Most of our CO_2 operating expenses are allocated to our oil fields and recorded as lease operating expenses on those fields at the time the CO_2 is injected. Since we expense all of the operating costs to produce and inject our CO_2, the operating costs per barrel will be higher at the inception of CO_2 injection projects because of little or minimal related oil production at that time. Commencing in 2008, we plan to capitalize the cost of CO_2 and related operating costs until production commences, which may slightly reduce our cost per BOE (see Note 1 to the Consolidated Financial Statements, "Significant Accounting Policies – Tertiary Injection Costs"). Our total corporate operating expenses on a per BOE basis will likely continue to increase as these operations constitute an increasingly larger percentage of our operations. Generally, these higher operating costs are somewhat offset by lower finding and development costs which helps to lower our overall depreciation and depletion rate (see also "Overview of Tertiary Economics" above and "Analysis of CO_2 Tertiary Recovery Operating Activities" below).

Analysis of CO_2 Tertiary Recovery Operating Activities. We currently have tertiary operations ongoing at almost all Phase I fields, and Soso, Martinville and Eucutta Fields in Phase II, and we are currently injecting CO_2 at Tinsley Field in Phase III. We project that our oil production from our CO_2 operations will increase substantially over the next several years as we continue to expand this program by adding additional projects and phases. As of December 31, 2007, we had approximately 69.5 MMBbls of proven oil reserves related to tertiary operations (48.3 MMBbls in Phase I and the balance in Phase II) and have identified and estimate significant additional oil potential in other fields that we own in this region.

We added 12.7 MMBbls of tertiary-related proved oil reserves during 2007, primarily initial proven tertiary oil reserves at Soso and Martinville Fields (Phase II). Prior to 2006, we booked most of our proven tertiary oil reserves near the start of a project as almost all the oil fields in Phase I were analogous to Little Creek Field (our first flood) and thus it was not necessary to have an oil production response to the CO_2 injections before they were considered proven. Conversely, our new floods (after Phase I) are not analogous (for the most part), as the tertiary floods will be in different geological formations. Therefore, for these new phases, there must be an oil production response to the CO_2 injections before we can recognize proven oil reserves, even though we believe that these formations have a similar risk profile. The magnitude of proven reserves that we can book in any given year will depend on our progress with new floods and the timing of the production response.

Our average annual oil production from our CO_2 tertiary recovery activities has increased during the last few years, from 3,970 Bbls/d in 2002 to 14,767 Bbls/d during 2007. Tertiary oil production represented approximately 53% of our total corporate oil production during 2007 and approximately 33% of our total corporate production of both oil and natural gas during the same period on a BOE basis. We expect that this tertiary related oil production will continue to increase, although the increases are not always predictable or consistent. While we may have temporary fluctuation in oil production related to tertiary operations, this does not indicate any issue with the proved and potential oil reserves recoverable with CO_2, because the historical correlation between oil production and CO_2 injections remains high. A detailed discussion of each of our tertiary oil fields and the development of each is included on pages 7 – 9 under "Our Tertiary Oil Fields With Proved Tertiary Reserves." Following is a chart with our tertiary oil production by field for 2005 and 2006, and by quarter for 2007. In 2007, we saw continued improved response from our newer Phase II floods at Martinville, Eucutta and Soso Fields, most of which were initiated during 2006. In addition, we continue to see improved response at most of our other floods in Phase I, except for Little Creek Field, which is a mature flood and is expected to continue to gradually decline over the next several years.

	Average Daily Production (BOE/d)						
					Year Ended December 31,		
Tertiary Oil Field	First Quarter 2007	Second Quarter 2007	Third Quarter 2007	Fourth Quarter 2007	2007	2006	2005
Phase I:							
Brookhaven	**1,422**	**1,794**	**2,452**	**2,507**	**2,048**	833	31
Little Creek area	**2,117**	**1,974**	**2,011**	**1,957**	**2,014**	2,739	3,529
Mallalieu area	**5,470**	**5,802**	**5,823**	**6,304**	**5,852**	5,210	4,739
McComb area	**1,811**	**1,884**	**1,853**	**2,096**	**1,912**	1,235	916
Phase II:							
Martinville	**320**	**521**	**1,101**	**883**	**709**	6	—
Eucutta	**614**	**1,338**	**2,035**	**2,572**	**1,646**	47	—
Soso	**25**	**370**	**826**	**1,109**	**586**	—	—
Total tertiary oil production	**11,779**	**13,683**	**16,101**	**17,428**	**14,767**	10,070	9,215

In addition to higher energy costs to operate our tertiary recycling facilities caused by higher commodity prices, we have experienced general cost inflation during the last few years. We also lease a portion of our recycling and plant equipment used in our tertiary operations, which further increases operating expenses. Over the last five years we have leased certain equipment that qualifies for operating lease treatment representing an underlying aggregate cost of approximately $98.5 million as of December 31, 2007. These leases have been an attractive method of financing due to their low imputed interest rates, which are fixed for seven to ten years. Also, the cost to produce our CO_2 has gradually increased (see "CO_2 Resources" above), all of which resulted in an increase in our tertiary operating cost per BOE from $12.00 per BOE during 2005, to $17.69 per BOE in 2006, to $19.77 per BOE in 2007. The absolute amount of operating expenses related to tertiary operations increased from $40.4 million during 2005, to $65.0 million during 2006, to $106.5 million during 2007.

Through December 31, 2007, we have invested a total of $1.0 billion on fields currently being flooded (including allocated acquisition costs) and have $250.8 million in unrecovered net cash flow (revenue less operating expenses and capital expenditures). Of this total, approximately $351.3 million (35%) was spent on fields which had little or no proved reserves at December 31, 2007 (i.e., fields for which significant incremental proved reserves are anticipated during 2008 and beyond). The proved oil reserves in our CO_2 fields have a PV-10 Value of $3.2 billion, using December 31, 2007, constant NYMEX pricing of $95.98 per Bbl. These amounts do not include the capital costs or related depreciation and amortization of our CO_2 producing properties, but do include CO_2 source field lease operating costs and transportation costs. Through December 31, 2007, we had a balance of approximately $371.0 million of unrecovered net cash flows for our CO_2 producing properties and CO_2 pipelines.

CO_2 Source-Related Capital Budget for 2008. Tentatively, we plan to spend approximately $90 million in 2008 in the Jackson Dome area with the intent to add additional CO_2 reserves and deliverability for future operations. Approximately $235 million in capital expenditures is budgeted in 2008 at the oil field level in Phases I through V, plus an additional $325 million for our Delta and Green CO_2 Pipelines, making our combined CO_2 related expenditures just over 72% of our $900 million 2008 capital budget.

Operating Results

Net income and cash flow from operations have increased each year during the last three years. Production increased 23% between 2005 and 2006, and 20% between 2006 and 2007, which, coupled with higher prices, resulted in record annual net income and cash flow.

	Year Ended December 31,		
Amounts in Thousands, Except Per Share Amounts	2007	2006	2005
Net income	**$253,147**	$202,457	$166,471
Net income per common share:			
Basic	**$ 1.05**	$ 0.87	$ 0.74
Diluted	**1.00**	0.82	0.70
Cash flow from operations	**$570,214**	$461,810	$360,960

Certain of our operating statistics for each of the last three years are set forth in the following chart:

	Year Ended December 31, 2007	2006	2005
Average daily production volumes			
Bbls/d	**27,925**	22,936	20,013
Mcf/d	**97,141**	83,075	58,696
BOE/d (1)	**44,115**	36,782	29,795
Operating revenues (in thousands)			
Oil sales	**$ 711,457**	$501,176	$367,414
Natural gas sales	**241,331**	215,381	181,641
Total oil and natural gas sales	**$ 952,788**	$716,557	$549,055
Oil and gas derivative contracts (in thousands) (2)			
Cash receipt (payment) on settlements of derivative contracts	**$ 20,480**	$ (5,302)	$ (16,761)
Non-cash fair value adjustment income (expense)	**(39,077)**	25,130	(12,201)
Total income (expense) from oil and gas derivative contracts	**$ (18,597)**	$ 19,828	$ (28,962)
Operating expenses (in thousands)			
Lease operating expenses	**$ 230,932**	$167,271	$108,550
Production taxes and marketing expenses (3)	**49,091**	36,351	27,582
Total production expenses	**$ 280,023**	$203,622	$136,132
Non-tertiary CO_2 operating margin (in thousands)			
CO_2 sales and transportation fees (4)	**$ 13,630**	$ 9,376	$ 8,119
CO_2 operating expenses	**4,214**	3,190	2,251
Non-tertiary CO_2 operating margin	**$ 9,416**	$ 6,186	$ 5,868
Unit sales price – including impact of derivative settlements (2)			
Oil price per Bbl	**$ 68.84**	$ 59.23	$ 50.30
Gas price per Mcf	**7.66**	7.10	7.70
Unit sales price – excluding impact of derivative settlements (2)			
Oil price per Bbl	**$ 69.80**	$ 59.87	$ 50.30
Gas price per Mcf	**6.81**	7.10	8.48
Oil and gas operating revenues and expenses per BOE (1)			
Oil and natural gas revenues	**$ 59.17**	$ 53.37	$ 50.49
Oil and gas lease operating expenses	**$ 14.34**	$ 12.46	$ 9.98
Oil and gas production taxes and marketing expenses	**3.05**	2.71	2.54
Total oil and gas production expenses	**$ 17.39**	$ 15.17	$ 12.52

(1) Barrel of oil equivalent using the ratio of one barrel of oil to six Mcf of natural gas (BOE).

(2) See also "Market Risk Management" below for information concerning the Company's derivative transactions. We do not apply hedge accounting for our oil and natural gas derivative contracts; see Note 10 to the Consolidated Financial Statements and "Critical Accounting Policies and Estimates – Oil and Gas Derivative Contracts" below.

(3) For 2007, 2006 and 2005, includes transportation expenses paid to Genesis of $6.0 million, $4.4 million and $4.0 million, respectively.

(4) For 2007, 2006 and 2005, includes deferred revenue of $4.4 million, $4.2 million and $3.1 million, respectively, associated with volumetric production payments and transportation income of $5.2 million, $4.6 million and $3.5 million, respectively, both from Genesis.

Production. Average daily production by area for 2005 and 2006, and each of the quarters of 2007 is listed in the following table (BOE/d).

	Average Daily Production (BOE/d)						
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Year Ended December 31,		
Operating Area	2007	2007	2007	2007	2007	2006	2005
Mississippi – CO_2 floods	**11,779**	**13,683**	**16,101**	**17,428**	**14,767**	10,070	9,215
Mississippi – non-CO_2 floods	**12,738**	**12,525**	**12,131**	**12,530**	**12,479**	12,743	12,072
Texas	**6,989**	**9,048**	**10,695**	**13,488**	**10,074**	4,868	2,145
Onshore Louisiana	**5,591**	**5,391**	**5,546**	**5,638**	**5,542**	7,937	6,164
Alabama and other	**1,208**	**1,269**	**1,247**	**1,287**	**1,253**	1,164	199
Total Company	**38,305**	**41,916**	**45,720**	**50,371**	**44,115**	36,782	29,795

As outlined in the above table, average production in 2007 increased 20% (7,333 BOE/d) over 2006 levels, and 2006 production increased 23% over average levels in 2005. The production increases in 2007 were primarily from increased oil production from our tertiary operations and increased production from the Barnett Shale, partially reduced by declines in production from our onshore Louisiana properties. During 2006, the most significant production increases were from the Barnett Shale and our acquisition of Tinsley and Citronelle Fields in January 2006, which contributed approximately 2,148 BOE/d of the increase (36%), with 1,122 BOE/d attributable to the Mississippi – non-CO_2 floods and 1,026 BOE/d to Alabama fields, although a small portion of that increase was from our internal development efforts following the acquisition.

Production in the Mississippi – non-CO_2 floods area decreased slightly each year from the prior year (before giving effect to the January 2006 acquisition related increase noted above), as this area is on a gradual decline from normal depletion, partially offset by drilling activity developing the Selma Chalk natural gas reservoir in the Heidelberg area.

See "CO_2 Operations" above for a discussion of the tertiary related production.

The general decrease in onshore Louisiana production in 2007 is due primarily to the expected relatively rapid depletion of wells in this area as we have focused less of our spending and activity in this area than we have historically. We closed on the divesture of these assets, excluding any oil fields that could have tertiary oil potential, in December 2007 and February 2008 (see "2007 Overview – Sale of Louisiana Natural Gas Assets"). The increase in production during 2006 in this area was a result of a higher level of activity during 2005 and early 2006 before the decision was made to sell the properties in this area.

Our production in the Barnett Shale area during 2007 increased 4,690 BOE/d (97% increase) over our 2006 level, and during 2006 increased 2,723 BOE/d (127% increase) over our 2005 level, primarily as a result of higher drilling activity levels than in 2005. We drilled and completed 45 wells during 2007 and 46 wells during 2006, as compared to 23 wells drilled during 2005, and plan to drill 45 to 50 wells during 2008. We had four rigs working in the area during most of the first quarter of 2007, but in the second quarter reduced our rig count in this area to three, which we retained for the remainder of 2007. During the fourth quarter of 2007, we processed our natural gas through a different gas plant, increasing the amount of liquids we recovered by 2,469 BOE/d, the primary reason for the increased production that quarter. We believe that our fourth quarter of 2007 production has peaked, or is near its peak, from this area, based on the anticipated level of future drilling activity. These wells are characterized by steep decline rates in their first year of production (typically 50% to 60%), followed by a gradual leveling-off of production and a resultant slow decline rate, giving them an overall long production life. The Texas property acquisition we made late in the first quarter of 2007 (see "2007 Overview – 2007 Acquisitions") contributed approximately 524 BOE/d to the 2007 average production from this area.

Our production for 2007 was 63% oil as compared to 62% during 2006 and 67% in 2005, as the recent increases in natural gas production in the Barnett Shale area and fluctuating natural gas production in Louisiana have generally been matched by increases in our tertiary oil production.

Oil and Natural Gas Revenues. Our oil and natural gas revenues have increased for each of the last two years, as both overall commodity prices and production were higher. The increase in production in 2007 increased oil and natural gas revenues by $142.9 million, or 20%, while the increase in overall commodity prices increased revenues by $93.4 million, or 13%, over the prior year's levels. The increase in production in 2006 increased oil and natural gas revenues by $128.8 million, or 23%, while the increase in overall commodity prices increased revenues by $38.7 million, or 6%, over the prior year's levels.

Excluding any impact of our derivative contracts, our net realized commodity prices and NYMEX differentials were as follows during 2007, 2006 and 2005:

	Year Ended December 31,		
	2007	2006	2005
Net Realized Prices:			
Oil price per Bbl	**$ 69.80**	$59.87	$ 50.30
Gas price per Mcf	**6.81**	7.10	8.48
Price per BOE	**59.17**	53.37	50.49
NYMEX Differentials:			
Oil per Bbl	**$ (2.65)**	$ (6.41)	$ (6.33)
Natural Gas per Mcf	**(0.28)**	0.13	(0.49)

Our oil NYMEX differential during 2007 was the lowest in our corporate history. The improved NYMEX differential during 2007 was related to higher prices received for both our light sweet barrels and our sour barrels primarily as a result of NYMEX (WTI) prices being depressed due to lack of available storage capacity in the mid-continent area, an oversupply of crude from Canada, capacity/transportation issues in moving crude oil out of the Cushing, Oklahoma, area and unanticipated refinery outages. This trend reversed itself by the fourth quarter of 2007, with average NYMEX oil differentials during that quarter of $(7.27) per Bbl, higher than our historical averages due to the significant increase in liquids extracted from our natural gas production in the Barnett Shale which is recorded as oil production, but sells at a significant discount to NYMEX (see also "Results of Operations - Production" above).

Our natural gas NYMEX differentials are generally caused by movement in the NYMEX natural gas prices during a month as most of our natural gas is sold on an index price that is set near the first of the month. While the percentage change in the above table is quite large, these differentials are very seldom more than a dollar above or below the NYMEX amount.

Oil and Natural Gas Derivative Contracts. During 2007, we had significant fluctuations in our pre-tax income related to non-cash fair value adjustments in our oil and natural gas derivative contracts (expense of $35.2 million in the first quarter, income of $13.3 million in the second quarter, expense of $5.4 million in the third quarter and expense of $11.8 million in the fourth quarter), while at the same time, during each quarter in 2007 we had net positive cash receipts on the settlements of our commodity derivative contracts, aggregating $20.5 million during the year, all related to our 2007 natural gas swaps, partially offset by payments on our oil swaps. In comparison, during 2006, we made payments on our derivative contracts of $5.3 million, related to oil swaps put in place in late 2005 to protect the rate of return on the fields acquired in January 2006. During 2005, we made payments on our derivative contracts of $16.8 million related to a natural gas collar.

Changing commodity prices cause fluctuations in the mark-to-market value adjustments of our derivative contracts. During 2007, we expensed $24.6 million related to our natural gas swaps, primarily offsetting the gain we recognized on the same swaps in late 2006 as the swaps had expired by the end of 2007. We also expensed $14.5 million related to our oil swaps as a result of the increasing oil price. We recognized a non-cash gain of $25.1 million in 2006 as a result of the decreasing prices, primarily related to the 75 MMcf/d of natural gas swaps for calendar 2007 that we entered into during December 2006. During 2005, because of our decision to abandon hedge accounting as of January 1, 2005, we recognized a non-cash expense of $12.2 million primarily related to the amortization of the fair value of the derivative contracts in place as of January 1, 2005, over the remaining life of the contracts, which was generally 2005. See also "Market Risk Management" and Note 10 to the Consolidated Financial Statements for more discussion of our oil and natural gas derivative contracts.

Operating Expenses. Our lease operating expenses have increased each year on both a per BOE basis and in absolute dollars primarily as a result of (i) our increasing emphasis on tertiary operations (see discussion of those expenses under "CO_2 Operations" above), (ii) higher overall industry costs, (iii) increased personnel and related costs, (iv) higher fuel and energy costs to operate our properties, and (v) increasing lease payments for certain of our tertiary operating facilities and equipment.

During 2007, operating costs averaged $14.34 per BOE, up from $12.46 per BOE during 2006, and $9.98 per BOE in 2005. Operating expenses for our tertiary operations were $106.5 million in 2007, up from $65.0 million during 2006, and $40.4 million during 2005, all as a result of increased tertiary activity. Tertiary operating expenses were particularly impacted by higher power and energy costs, higher costs for CO_2, and payments on leased facilities and equipment (see "CO_2 Operations" above). We expect this increase in tertiary operating costs to continue and to further increase our cost per BOE as these costs become a more significant portion of our total production and operations. Further, the sale of our Louisiana natural gas properties (see "2007 Overview – Sale of Louisiana Natural Gas Properties") will further increase our corporate average operating cost per BOE in the future. If the sold properties were excluded from our operating results for the entire year of 2007, our operating costs would have been approximately $15.47 per BOE, approximately $1.13 per BOE higher than as reported.

Production taxes and marketing expenses generally change in proportion to commodity prices and therefore have been higher in each of the last three years along with the increasing commodity prices. Transportation and plant processing fees were approximately $6.9 million higher in 2007 than in 2006 and approximately $0.8 million higher in 2006 than in 2005, largely associated with the incremental production and incremental plant processing fees related to our Barnett Shale production.

General and Administrative Expenses

During the last three years, general and administrative ("G&A") expenses have increased on a gross basis, while fluctuating on a per BOE basis as outlined below:

	Year Ended December 31,		
	2007	2006	2005
Net G&A expense (thousands)			
Gross G&A expense	**$ 115,519**	$ 96,479	$ 64,622
State franchise taxes	**2,915**	1,825	1,454
Operator labor and overhead recovery charges	**(59,145)**	(47,667)	(32,452)
Capitalized exploration and development costs	**(10,317)**	(7,623)	(5,084)
Net G&A expense	**$ 48,972**	$ 43,014	$ 28,540
Average G&A cost per BOE	**$ 3.04**	$ 3.20	$ 2.62
Employees as of December 31	**686**	596	460

Gross G&A expenses increased $19.0 million, or 20% between 2006 and 2007, and $31.9 million, or 49%, between 2005 and 2006. The increases are primarily due to higher compensation and personnel related costs caused by an increase in the number of employees, and higher wages as a result of average salary increases of between 5% and 10% during 2006 and 2007, which we consider necessary in order to remain competitive in our industry. During 2006, we increased our employee count by 30%, and we further increased our employee count 15% during 2007. Partially offsetting these overall compensation increases were $6.0 million of non-recurring charges related to the retirement and departure of two vice presidents during 2006. The adoption of SFAS No. 123(R) in January 2006 increased gross G&A expense by approximately $8.9 million during 2006, representing the non-cash charge for stock compensation (stock options and stock appreciation rights) pertaining to personnel charged to G&A. Stock compensation expense reflected in gross G&A was $12.2 million during 2007, $18.9 million during 2006 and $4.2 million during 2005.

Higher operator overhead recovery charges resulting from incremental activity helped to partially offset the increase in gross G&A. Our well operating agreements allow us, when we are the operator, to charge a well with a specified overhead rate during the drilling phase and also to charge a monthly fixed overhead rate for each producing well. As a result of the additional operated wells from acquisitions, additional tertiary operations, increased drilling activity and increased compensation expense (including the allocation of that portion of stock compensation charged to lease operating expense), the amount we recovered as operator labor and overhead charges increased by 24% between 2006 and 2007, and 47% between 2005 and 2006. Capitalized exploration and development costs increased each year primarily due to additional personnel and increased compensation costs, and the adoption of SFAS No. 123(R) in January 2006.

The net effect of the increases in gross G&A expenses, operator overhead recoveries and capitalized exploration costs was a 14% increase in net G&A expense between 2006 and 2007, and a 51% increase in net G&A expense between 2005 and 2006. On a per BOE basis, G&A decreased 5% in 2007 as compared to 2006 as the higher production more than offset the increase in gross costs, but G&A per BOE increased 22% in 2006 as compared to 2005 levels.

Interest and Financing Expenses

Amounts in thousands, except per BOE data	Year Ended December 31, 2007	2006	2005
Cash interest expense	**$ 49,205**	$ 33,787	$ 18,800
Non-cash interest expense	**2,010**	1,121	827
Less: Capitalized interest	**(20,385)**	(11,333)	(1,649)
Interest expense	**$ 30,830**	$ 23,575	$ 17,978
Interest and other income	**$ 5,532**	$ 6,379	$ 3,532
Average net cash interest expense per BOE (1)	**$ 1.43**	$ 1.26	$ 1.28
Average debt outstanding	**$672,376**	$455,603	$248,825
Average interest rate (2)	**7.3%**	7.4%	7.6%

(1) Cash interest expense less capitalized interest and other income on a BOE basis.

(2) Includes commitment fees but excludes amortization of debt issue costs.

Interest expense has increased each of the last two years corresponding to our increase in average debt levels as we used debt to fund a $250 million acquisition in January 2006, other lower cost acquisitions in 2006 and 2007, and to fund a portion of our capital spending, which in 2007 was significantly in excess of our cash flow from operations. These increases in cash interest have been partially offset by higher interest amounts capitalized on our significant unevaluated properties, primarily related to our 2006 acquisition, continued expansion of our tertiary operations and construction of our CO_2 pipelines. The average interest rate has been relatively unchanged because our subordinated debt, which was 89% of the total 2007 average debt, 82% of the total 2006 average debt, and 93% of the total 2005 average debt, is a fixed interest rate.

Depletion, Depreciation and Amortization ("DD&A")

Amounts in thousands, except per BOE data	Year Ended December 31, 2007	2006	2005
Depletion and depreciation of oil and natural gas properties	**$174,356**	$132,880	$ 88,949
Depletion and depreciation of CO_2 assets	**11,609**	8,375	5,334
Asset retirement obligations	**2,977**	2,389	1,682
Depreciation of other fixed assets	**6,958**	5,521	2,837
Total DD&A	**$195,900**	$149,165	$ 98,802
DD&A per BOE:			
Oil and natural gas properties	**$ 11.02**	$ 10.08	$ 8.34
CO_2 assets and other fixed assets	**1.15**	1.03	0.75
Total DD&A cost per BOE	**$ 12.17**	$ 11.11	$ 9.09

Our proved reserves increased from 152.6 MMBOE as of December 31, 2005, to 174.3 MMBOE as of December 31, 2006, and further increased to 194.7 MMBOE as of December 31, 2007. Reserve quantities and associated production are only one side of the DD&A equation, with capital expenditures less accumulated depletion, asset retirement obligations less related salvage value, and projected future development costs making up the remainder of the calculation.

We adjust our DD&A rate each quarter for significant changes in our estimates of oil and natural gas reserves and costs, and thus our DD&A rate could change significantly in the future. Our DD&A rate per BOE increased 10% between 2006 and 2007, and 22% between 2005 and 2006, primarily due to capital spending and increased costs. We added approximately 22.8 MMBOE and 17.8 MMBOE of reserves in the Barnett Shale and approximately 12.7 MMBOE and 6.0 MMBOE in our tertiary oil properties during 2007 and 2006, respectively, and only minor amounts elsewhere. Further, as a result of rising industry costs, we not only exceeded our cost estimates on our projects over the last two years, but also increased our future development costs on our proved undeveloped reserves to reflect these rising costs.

In general, 2006 was a transition year for us with regard to recording proved tertiary oil reserves. Prior to 2006, many of our tertiary floods could be considered proven near the start of a project as they were analogous to Little Creek Field (an already-producing tertiary flood) and thus it was not necessary to have a production response to CO_2 injections before we recognized proved reserves. Conversely, since that time, most of our new floods are not analogous and thus must have an oil production response to the CO_2 injections before we can recognize tertiary proved oil reserves in these fields, even though we believe there is a similar risk profile in flooding these fields. During 2006, two of our most significant new floods were Soso and Martinville Fields (Phase II), for which reserves were not booked until 2007 after we had a significant production response. During 2007, we initiated floods at Lockhart Crossing (Phase I), Tinsley (Phase III) and Cranfield (Phase IV) that will not result in additional proved reserves until we have a production response, which is expected in 2008. We expect this same delay factor to continue in the future with regard to recording most of our projected proved tertiary reserves, although we expect our proved reserves to increase more rapidly in the future because of the projected size and magnitude of the potential reserves from projects either started or planned.

We allocated approximately $33.9 million of the $39.4 million adjusted purchase price of our March 31, 2007 Seabreeze acquisition, $124 million of our $250 million January 2006 acquisition costs for Tinsley, Citronelle and South Cypress Creek Fields, and virtually all of the second quarter 2006 $50 million Delhi acquisition costs to unevaluated properties to reflect the significant potential reserves associated with future tertiary floods that we considered to be part of these acquisitions. As a result, these acquisitions did not materially impact our overall DD&A rate, as the amount included in our full cost pool was a cost per BOE relatively consistent with our overall DD&A rate.

Our DD&A rate for our CO_2 and other fixed assets increased in both 2006 and 2007 as a result of the building of our Free State CO_2 Pipeline to Eastern Mississippi, which went into service late in the first quarter of 2006, additional costs incurred drilling CO_2 wells during each year and higher associated future development costs, partially offset by an increase in CO_2 reserves from 4.6 Tcf as of December 31, 2005, to 5.5 Tcf as of December 31, 2006, and 5.6 Tcf as of December 31, 2007 (100% working interest basis before amounts attributable to Genesis volumetric production payments – see "CO_2 Operations – CO_2 Resources").

As part of the requirements of Statement of Financial Accounting Standards (SFAS) No. 143, Accounting for Asset Retirement Obligations, the fair value of a liability for an asset retirement obligation is recorded in the period in which it is incurred, discounted to its present value using our credit adjusted risk-free interest rate, with a corresponding capitalized amount. The liability is accreted each period, and the capitalized cost is depreciated over the useful life of the related asset. On an undiscounted basis, we estimated our retirement obligations as of December 31, 2005, to be $69.1 million ($27.1 million present value), with an estimated salvage value of $50.2 million. As of December 31, 2006, we estimated our retirement obligations to be $91.3 million ($41.1 million present value), with an estimated salvage value of $60.0 million, and as of December 31, 2007, we estimated our retirement obligations to be $100.6 million ($41.3 million present value), with an estimated salvage value of $67.3 million, the increase related to our recent acquisitions, increased activity and higher cost estimates due to the inflation in our industry, partially offset by a decrease in our obligation of approximately $9.4 million, ($9.2 million present value) related to the sale of most of our Louisiana natural gas properties in late 2007. DD&A is calculated on the increase in retirement obligations recorded as incremental oil and natural gas and CO_2 properties, net of its estimated salvage value. We also include the accretion of discount on the asset retirement obligation in our DD&A expense.

Under full cost accounting rules, we are required each quarter to perform a ceiling test calculation. We did not have any full cost pool ceiling test write-downs in 2005, 2006 or 2007.

Income Taxes

	Year Ended December 31,		
Amounts in thousands, except per BOE amounts	2007	2006	2005
Current income tax expense	**$ 30,074**	$ 19,865	$ 27,177
Deferred income tax provision	**110,193**	107,252	54,393
Total income tax provision	**$ 140,267**	$ 127,117	$ 81,570
Average income tax provision per BOE	**$ 8.71**	$ 9.47	$ 7.50
Effective tax rate	**35.7%**	38.6%	32.9%
Total net deferred tax asset (liability)	**$ (334,662)**	$ (229,925)	$ (129,474)

Our income tax provision was based on an estimated statutory rate of approximately 38% in 2007, and 39% in 2006 and 2005, adjusted for the impact of certain items such as compensation arising from incentive stock options that cannot be deducted for tax purposes in the same manner as book expense. The reduction in the estimated statutory rate to 38% in 2007 was a result of our sale of our Louisiana natural gas assets during the fourth quarter of 2007. For 2005, our net effective tax rate was lower than the statutory rate primarily due to the recognition of enhanced oil recovery credits ("EOR") which lowered our overall tax expense. For 2006 and 2007, we did not earn any additional EOR credits because of the high oil prices during 2005 and 2006, which completely phased out our ability to earn any additional credits.

In all three periods, the current income tax expense represents our anticipated alternative minimum cash taxes that we cannot offset with EOR credits. As of December 31, 2007, we had an estimated $37 million of EOR credit carryforwards that we can utilize to reduce a portion of our cash taxes. These EOR credits do not begin to expire until 2024. Since the ability to earn additional enhanced oil recovery credits is reduced or even eliminated based on the level of oil prices, we do not expect to earn any EOR credits in the future unless oil prices decrease significantly from current levels. Once our existing EOR credits are utilized, our cash taxes will also increase.

Results of Operations on a Per BOE Basis

The following table summarizes the cash flow, DD&A and results of operations on a per BOE basis for the comparative periods. Each of the individual components is discussed above.

	Year Ended December 31,		
Per BOE data	2007	2006	2005
Oil and natural gas revenues	**$ 59.17**	$ 53.37	$50.49
Gain (loss) on settlements of derivative contracts	**1.27**	(0.39)	(1.54)
Lease operating expenses	**(14.34)**	(12.46)	(9.98)
Production taxes and marketing expenses	**(3.05)**	(2.71)	(2.54)
Production netback	**43.05**	37.81	36.43
Non-tertiary CO_2 operating margin	**0.58**	0.46	0.54
General and administrative expenses	**(3.04)**	(3.20)	(2.62)
Net cash interest expense	**(1.43)**	(1.26)	(1.28)
Current income taxes and other	**(1.37)**	(0.41)	(1.50)
Changes in assets and liabilities relating to operations	**(2.38)**	1.00	1.62
Cash flow from operations	**35.41**	34.40	33.19
DD&A	**(12.17)**	(11.11)	(9.09)
Deferred income taxes	**(6.84)**	(7.99)	(5.00)
Non-cash commodity derivative adjustments	**(2.43)**	1.87	(1.12)
Changes in assets and liabilities and other non-cash items	**1.75**	(2.09)	(2.67)
Net income	**$ 15.72**	$ 15.08	$15.31

Market Risk Management

We finance some of our acquisitions and other expenditures with fixed and variable rate debt. These debt agreements expose us to market risk related to changes in interest rates. The following table presents the carrying and fair values of our debt, along with average interest rates. We had $150 million of bank debt outstanding as of December 31, 2007, and $111 million outstanding as of February 28, 2008. None of our existing debt has any triggers or covenants regarding our debt ratings with rating agencies. The fair value of the subordinated debt is based on quoted market prices.

Amounts in thousands	Expected Maturity Dates 2011	2013	2015	Carrying Value	Fair Value
Variable rate debt:					
Bank debt (weighted average interest rate of 6.2% at December 31, 2007)	$150,000	$ —	$ —	$150,000	$150,000
Fixed rate debt:					
7.5% subordinated debt due 2013 (fixed rate of 7.5%)	—	225,000	—	223,980	227,250
7.5% subordinated debt due 2015 (fixed rate of 7.5%)	—	—	300,000	300,685	303,000

From time to time, we enter into various derivative contracts to provide an economic hedge of our exposure to commodity price risk associated with anticipated future oil and natural gas production. We do not hold or issue derivative financial instruments for trading purposes. These contracts have consisted of price floors, collars and fixed price swaps. Historically, we hedged up to 75% of our anticipated production each year to provide us with a reasonably certain amount of cash flow to cover most of our budgeted exploration and development expenditures without incurring significant debt. Since 2005 and beyond, we have entered into fewer derivative contracts, primarily because of our strong financial position resulting from our lower levels of debt relative to our cash flow from operations. We did enter into natural gas derivative contracts in late 2006 and September 2007 as we believed that there is more risk with regard to natural gas prices and the fact that we planned to spend significantly more than our projected cash flow from operations during the ensuing year (see "Capital Resources and Liquidity"). In late 2006, we swapped 80% to 90% of our forecasted 2007 natural gas production at a weighted average price of $7.96 per Mcf, and in September 2007 we swapped 70% to 80% of our remaining forecasted 2008 natural gas production (after the sale of our Louisiana natural gas properties – see "2007 Overview – Sale of Louisiana Natural Gas Properties") at a weighted average price of $7.91 per Mcf.

When we make a significant acquisition, we generally attempt to hedge a large percentage, up to 100%, of the forecasted proved production for the subsequent one to three years following the acquisition in order to help provide us with a minimum return on our investment. As of December 31, 2007, we had derivative contracts in place related to our $250 million acquisition that closed on January 31, 2006, on which we entered into contracts to cover 100% of the estimated proved producing production at the time we signed the purchase and sale agreement. While these derivative contracts related to the acquisition represent between 5% and 6% of our estimated 2008 oil production, they are intended to help protect our acquisition economics related to the first three years of production from the proved producing reserves that we acquired. These swaps cover 2,000 Bbls/d for 2008 at a price of $57.34 per Bbl.

All of the mark-to-market valuations used for our oil and natural gas derivatives are provided by external sources and are based on prices that are actively quoted. We manage and control market and counterparty credit risk through established internal control procedures that are reviewed on an ongoing basis. We attempt to minimize credit risk exposure to counterparties through formal credit policies, monitoring procedures and diversification. For a full description of our derivative contract positions at year-end 2007, see Note 10 to the Consolidated Financial Statements.

Since January 1, 2005, for accounting purposes, we have elected to account for our oil and natural gas derivative contracts as speculative contracts. This means that any changes in the fair value of these derivative contracts will be charged to earnings on a quarterly basis instead of charging the effective portion to other comprehensive income and the ineffective portion to earnings. During 2005, we amortized the December 31, 2004, balance in Accumulated Other Comprehensive Loss to earnings as that was the remaining life of those contracts. Information regarding our current derivative contract positions and results of our historical derivative activity is included in Note 10 to the Consolidated Financial Statements.

At December 31, 2007, our derivative contracts were recorded at their fair value, which was a net liability of approximately $23.3 million, a decrease of $39.0 million from the $15.7 million fair value asset recorded as of December 31, 2006. This change is primarily related to the recognition of our natural gas hedges which expired during 2007, but were a significant asset at December 31, 2006 (see above), and higher oil prices which reduced the value of the remaining oil swaps. During 2007, we recognized total expenses related to our hedge contracts of $18.6 million, consisting of $20.5 million of net cash receipts on settlements of expired contracts and $39.1 million of expense relating to market-to-market non-cash adjustments.

Based on NYMEX crude oil futures prices at December 31, 2007, we would expect to make future cash payments of $26.3 million on our crude oil commodity derivative contracts. If crude oil futures prices were to decline by 10%, we would expect to make future cash payments on our crude oil commodity derivative contracts of $19.5 million, and if futures prices were to increase by 10% we would expect to pay $33.1 million. Based on NYMEX natural gas futures prices at December 31, 2007, we would expect to receive future cash payments of $2.4 million on our natural gas commodity hedges. If natural gas futures prices were to decline by 10%, the amount we would expect to receive under our natural gas commodity hedges would increase to $19.5 million, and if future prices were to increase by 10% we would expect to pay $14.7 million.

Critical Accounting Policies and Estimates

The preparation of financial statements in accordance with generally accepted accounting principles requires that we select certain accounting policies and make certain estimates and judgments regarding the application of those policies. Our significant accounting policies are included in Note 1 to the Consolidated Financial Statements. These policies, along with the underlying assumptions and judgments by our management in their application, have a significant impact on our consolidated financial statements. Following is a discussion of our most critical accounting estimates, judgments and uncertainties that are inherent in the preparation of our financial statements.

Full Cost Method of Accounting, Depletion and Depreciation and Oil and Natural Gas Reserves

Businesses involved in the production of oil and natural gas are required to follow accounting rules that are unique to the oil and gas industry. We apply the full-cost method of accounting for our oil and natural gas properties. Another acceptable method of accounting for oil and gas production activities is the successful efforts method of accounting. In general, the primary differences between the two methods are related to the capitalization of costs and the evaluation for asset impairment. Under the full cost method, all geological and geophysical costs, exploratory dry holes and delay rentals are capitalized to the full cost pool, whereas under the successful efforts method such costs are expensed as incurred. In the assessment of impairment of oil and gas properties, the successful efforts method follows the guidance of SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets," under which the net book value of assets are measured for impairment against the undiscounted future cash flows using commodity prices consistent with management expectations. Under the full cost method, the full cost pool (net book value of oil and gas properties) is measured against future cash flows discounted at 10% using commodity prices in effect at the end of the reporting period. The financial results for a given period could be substantially different depending on the method of accounting that an oil and gas entity applies.

In our application of full cost accounting for our oil and gas producing activities, we make significant estimates at the end of each period related to accruals for oil and gas revenues, production, capitalized costs and operating expenses. We calculate these estimates with our best available data, which includes, among other things, production reports, price posting, information compiled from daily drilling reports and other internal tracking devices, and analysis of historical results and trends. While management is not aware of any required revisions to its estimates, there will likely be future adjustments resulting from such things as changes in ownership interests, payouts, joint venture audits, re-allocations by the purchaser/pipeline, or other corrections and adjustments common in the oil and natural gas industry, many of which will require retroactive application. These types of adjustments cannot be currently estimated or determined and will be recorded in the period during which the adjustment occurs.

Under full cost accounting, the estimated quantities of proved oil and natural gas reserves used to compute depletion and the related present value of estimated future net cash flows therefrom used to perform the full cost ceiling test have a significant impact on the underlying financial statements. The process of estimating oil and natural gas reserves is very complex, requiring significant decisions in the evaluation of all available geological, geophysical, engineering and economic data. The data for a given field may also change substantially over time as a result of numerous factors, including additional development activity, evolving production history and continued reassessment of the viability of production under varying economic conditions. As a result, material revisions to existing reserve estimates may occur from time to time. Although every reasonable effort is made to ensure that the reported reserve estimates represent the most accurate assessments possible, including the hiring of independent engineers to prepare the report, the subjective decisions and variances in available data for various fields make these estimates generally less precise than other estimates included in our financial statement disclosures. Over the last four years, Denbury's annual revisions to its reserve estimates have averaged approximately 2.5% of the previous year's estimates and have been both positive and negative.

Changes in commodity prices also affect our reserve quantities. During 2005, 2006 and 2007, the change to reserve quantities related to commodity prices was relatively small, less than in prior years, as prices were relatively high each year-end. These changes in quantities affect our DD&A rate, and the combined effect of changes in quantities and commodity prices impacts our full cost ceiling test calculation. For example, we estimate that a 5% increase in our estimate of proved reserves quantities would have lowered our fourth quarter 2007 DD&A rate from $12.05 per Bbl to approximately $11.55 per Bbl, and a 5% decrease in our proved reserve quantities would have increased our DD&A rate to approximately $12.60 per Bbl. Also, reserve quantities and their ultimate values are the primary factors in determining the borrowing base under our bank credit facility and are determined solely by our banks.

There can also be significant questions as to whether reserves are sufficiently supported by technical evidence to be considered proven. In some cases our proven reserves are less than what we believe to exist because additional evidence, including production testing, is required in order to classify the reserves as proven. We have a corporate policy whereby we generally do not book proved undeveloped reserves unless the project has been committed to internally, which normally means it is scheduled within the subsequent three years (or at least the commencement of the project is scheduled in the case of longer-term multi-year projects such as waterfloods and tertiary recovery projects). Therefore, with regard to potential reserves, there is uncertainty as to whether the reserves should be included as proven or not. We also have a corporate policy whereby proved undeveloped reserves must be economic at long-term historical prices, which are usually significantly less than the year-end prices used in our reserve report. This also can have the effect of eliminating certain projects being included in our estimates of proved reserves, which projects would otherwise be included if undeveloped reserves were determined to be economic solely based on current prices in a high price environment, as was the case during the last three year-ends. (See "Depletion, Depreciation and Amortization" under "Results of Operations" above for further discussion.) All of these factors and the decisions made regarding these issues can have a significant effect on our proven reserves and thus on our DD&A rate, full cost ceiling test calculation, borrowing base and financial statements. See also discussion of requirements to book proven tertiary oil reserves at "Results of Operations – Depletion, Depreciation and Amortization."

Tertiary Injection Costs

Our tertiary operations are conducted in reservoirs that have already produced significant amounts of oil over many years; however, in accordance with the rules for recording proved reserves, we cannot recognize proved reserves associated with enhanced recovery techniques, such as injection, until there is a production response to the injected CO_2 or, unless the field is analogous to an existing flood. Our costs associated with the CO_2 we produce (or acquire) and inject are principally our costs of production, transportation and acquisition, or to pay royalties.

Prior to January 1, 2008, we expensed currently all costs associated with injecting CO_2 that we use in our tertiary recovery operations, even though some of these costs were incurred prior to any tertiary related oil production. Commencing January 1, 2008, we will begin capitalizing, as a development cost, injection costs in fields that are in their development stage, which means we have not yet seen incremental oil production due to the CO_2 injections (i.e. a production response). These capitalized development costs will be included in our unevaluated property costs within our full cost pool if there are not already proved tertiary reserves in that field. After we see a production response to the CO_2 injections (i.e. the production stage), injection costs will be expensed as incurred and any previously deferred unevaluated development costs will become subject to depletion upon recognition of proved tertiary reserves. Based upon the current status of some of our tertiary floods, this change in accounting will cause us to capitalize certain costs that we historically expensed. Had the new method of accounting for tertiary injectant costs been used in periods prior to January 1, 2008, the effect on our financial statements would have been immaterial for all periods presented.

Asset Retirement Obligations

We have significant obligations related to the plugging and abandonment of our oil, natural gas and CO_2 wells, the removal of equipment and facilities from leased acreage, and land restoration. SFAS No. 143 requires that we estimate the future cost of this obligation, discount it to its present value, and record a corresponding asset and liability in our Consolidated Balance Sheets. The values ultimately derived are based on many significant estimates, including the ultimate expected cost of the obligation, the expected future date of the required cash payment, and interest and inflation rates. Revisions to these estimates may be required based on changes to cost estimates, the timing of settlement, and changes in legal requirements. Any such changes that result in upward or downward revisions in the estimated obligation will result in an adjustment to the related capitalized asset and corresponding liability on a prospective basis and an adjustment in our DD&A expense in future periods. See Note 4 to our Consolidated Financial Statements for further discussion regarding our asset retirement obligations.

Income Taxes

We make certain estimates and judgments in determining our income tax expense for financial reporting purposes. These estimates and judgments occur in the calculation of certain tax assets and liabilities that arise from differences in the timing and recognition of revenue and expense for tax and financial reporting purposes. Our federal and state income tax returns are generally not prepared or filed before the consolidated financial statements are prepared; therefore, we estimate the tax basis of our assets and liabilities at the end of each period as well as the effects of tax rate changes, tax credits and, prior to year-end 2005, net operating loss carryforwards. Adjustments related to these estimates are recorded in our tax provision in the period in which we file our income tax returns. Further, we must assess the likelihood that we will be able to recover or utilize our deferred tax assets (primarily our enhanced oil recovery credits). If recovery is not likely, we must record a valuation allowance against such deferred tax assets for the amount we would not expect to recover, which would result in an increase to our income tax expense. As of December 31, 2007, we believe that all of our deferred tax assets recorded on our Consolidated Balance Sheet will ultimately be recovered. If our estimates and judgments change regarding our ability to utilize our deferred tax assets, our tax provision would increase in the period it is determined that recovery is not probable. A 1% increase in our effective tax rate would have increased our calculated income tax expense by approximately $3.9 million, $3.3 million and $2.5 million for the years ended December 31, 2007, 2006 and 2005, respectively. See Note 7 to the Consolidated Financial Statements for further information concerning our income taxes.

Oil and Natural Gas Derivative Contracts

We enter into oil and natural gas derivative contracts to mitigate our exposure to commodity price risk associated with future oil and natural gas production. These contracts have historically consisted of options, in the form of price floors or collars, and fixed price swaps. Under SFAS No. 133, every derivative instrument is required to be recorded on the balance sheet as either an asset or a liability measured at its fair value. If the derivative does not qualify as a hedge or is not designated as a hedge, the change in fair value of the derivative is recognized currently in earnings. If the derivative qualifies for cash flow hedge accounting, the change in fair value of the derivative is recognized in accumulated other comprehensive income (equity) to the extent that the hedge is effective, and in the income statement to the extent it is ineffective.

As of January 1, 2005, we abandoned hedge accounting. This means that any changes in the future fair value of these derivative contracts will be charged to earnings on a quarterly basis instead of charging the effective portion to other comprehensive income and the balance to earnings. While we may experience more volatility in our net income than if we had continued to apply hedge accounting treatment as permitted by SFAS No. 133, we believe that for us the benefits associated with applying hedge accounting do not outweigh the cost, time and effort to comply with hedge accounting. During 2007, 2006 and 2005, we recognized expense (income) of $39.1 million, ($25.1) million and $4.5 million, respectively, related to changes in the fair market value of our derivative contracts.

Stock Compensation Plans

Effective January 1, 2006, we adopted the fair value recognition provisions of SFAS No. 123(R), "Share-Based Payment" using the modified prospective application method described in the statement. Among other items, SFAS No. 123(R) eliminates the use of APB 25 and the intrinsic value method of accounting, and requires companies to recognize the cost of employee services received in exchange for awards of equity instruments, based on the grant date fair value of those awards, in the financial statements. Under the modified prospective application method, effective January 1, 2006, we began to recognize compensation expense for the unvested portion of awards outstanding as of December 31, 2005, over the remaining service periods, and for new awards granted or modified after January 1, 2006.

We estimate the fair value of stock option or stock appreciation right ("SAR") awards on the date of grant using the Black-Scholes option pricing model. The Black-Scholes option valuation model requires the input of somewhat subjective assumptions, including expected stock price volatility and expected term. Other assumptions required for estimating fair value with the Black-Scholes model are the expected risk-free interest rate and expected dividend yield of the Company's stock. The risk-free interest rates used are the U.S. Treasury yield for bonds matching the expected term of the option on the date of grant. Our dividend yield is zero, as Denbury does not pay a dividend. We utilize historical experience in arriving at our assumptions for volatility and expected term inputs.

We recognize the stock-based compensation expense on a straight-line basis over the requisite service period for the entire award. The expense we recognize is net of estimated forfeitures. We estimate our forfeiture rate based on prior experience and true it up for actual results as the awards vest. As of December 31, 2007, there was $9.8 million of total compensation cost to be recognized in future periods related to non-vested stock options and SARs. The cost is expected to be recognized over a weighted-average period of 1.2 years.

Use of Estimates

The preparation of financial statements requires us to make other estimates and assumptions that affect the reported amounts of certain assets, liabilities, revenues and expenses during each reporting period. We believe that our estimates and assumptions are reasonable and reliable, and believe that the ultimate actual results will not differ significantly from those reported; however, such estimates and assumptions are subject to a number of risks and uncertainties, and such risks and uncertainties could cause the actual results to differ materially from our estimates.

Recent Accounting Pronouncements

In September 2006, the FASB issued SFAS No. 157, "Fair Value Measurements." SFAS No. 157 defines fair value, establishes a framework for measuring fair value in accordance with United States generally accepted accounting principles, and expands disclosures about fair value measurements. SFAS No. 157 does not require any new fair value measurements, but provides guidance on how to measure fair value by providing a fair value hierarchy used to classify the source of the information. SFAS No. 157 is effective for fiscal years beginning after November 15, 2007. However, on February 12, 2008, the FASB issued FSP SFAS No. 157-2 which delays the effective date of SFAS No. 157 for all nonfinancial assets and nonfinancial liabilities, except those that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually). This FSP partially defers the effective date of SFAS No. 157 to fiscal years beginning after November 15, 2008, and interim periods within those fiscal years for items within the scope of this FSP. Effective for 2008, we will adopt SFAS No. 157 except as it applies to those nonfinancial assets and nonfinancial liabilities as noted in FSP SFAS No. 157-2. We have not yet determined the impact the partial adoption of SFAS No. 157 will have on the Company's financial condition or results of operations.

In February 2007, the FASB issued SFAS No. 159, "The Fair Value Option for Financial Assets and Financial Liabilities." SFAS No. 159 permits entities to choose to measure many financial instruments and certain other items at fair value, with the objective of improving financial reporting by giving entities the opportunity to mitigate volatility in reported earnings caused by measuring related assets and liabilities differently without having to apply complex hedge accounting provisions. The provisions of SFAS No. 159 are effective for us beginning January 1, 2008. We have not yet determined what impact, if any, this pronouncement will have on our financial condition or results of operations.

In December 2007, the FASB issued SFAS No. 141 (Revised 2007), "Business Combinations." SFAS No. 141(R) establishes principles and requirements for how an acquirer recognizes and measures in its financial statements the identifiable assets acquired, the liabilities assumed, any noncontrolling interest in the acquiree and the goodwill acquired. SFAS No. 141(R) also establishes disclosure requirements to enable the evaluation of the nature and financial effects of the business combination. This statement is effective for us beginning January 1, 2009. We have not yet determined what impact, if any, this pronouncement will have on our financial condition or results of operations.

In December 2007, the FASB issued SFAS No. 160, "Noncontrolling Interests in Consolidated Financial Statements an amendment of ARB No. 51." SFAS No. 160 establishes accounting and reporting standards for ownership interests in subsidiaries held by parties other than the parent, the amount of consolidated net income attributable to the parent and to the noncontrolling interest, changes in a parent's ownership interest, and the valuation of retained noncontrolling equity investments when a subsidiary is deconsolidated. SFAS No. 160 also establishes disclosure requirements that clearly identify and distinguish between the interests of the parent and the interests of the noncontrolling owners. This statement is effective for us beginning January 1, 2009. We have not yet determined what impact, if any, this pronouncement will have on our financial condition or results of operations.

Forward-Looking Information

The statements contained in this Annual Report on Form 10-K that are not historical facts, including, but not limited to, statements found in this Management's Discussion and Analysis of Financial Condition and Results of Operations, are forward-looking statements, as that term is defined in Section 21E of the Securities and Exchange Act of 1934, as amended, that involve a number of risks and uncertainties. Such forward-looking statements may be or may concern, among other things, forecasted capital expenditures, drilling activity or methods, acquisition plans and proposals and dispositions, development activities, cost savings, production rates and volumes or forecasts thereof, hydrocarbon reserves, hydrocarbon or expected reserve quantities and values, potential reserves from tertiary operations, hydrocarbon prices, pricing assumptions based on current and projected oil and gas prices, liquidity, regulatory matters, mark-to-market values, competition, long-term forecasts of production, finding cost, rates of return, estimated costs or changes in costs, future capital expenditures and overall economics and other variables surrounding our tertiary operations and future plans. Such forward-looking statements generally are accompanied by words such as "plan," "estimate," "expect," "predict," "anticipate," "projected," "should," "assume", "believe", "target" or other words that convey the uncertainty of future events or outcomes. Such forward-looking information is based upon management's current plans, expectations, estimates and assumptions and is subject to a number of risks and uncertainties that could significantly affect current plans, anticipated actions, the timing of such actions and the Company's financial condition and results of operations. As a consequence, actual results may differ materially from expectations, estimates or assumptions expressed in or implied by any forward-looking statements made by or on behalf of the Company. Among the factors that could cause actual results to differ materially are: fluctuations of the prices received or demand for the Company's oil and natural gas, inaccurate cost estimates, fluctuations in the prices of goods and services, the uncertainty of drilling results and reserve estimates, operating hazards, acquisition risks, requirements for capital or its availability, general economic conditions, competition and government regulations, and unexpected delays, as well as the risks and uncertainties inherent in oil and gas drilling and production activities or which are otherwise discussed in this annual report, including, without limitation, the portions referenced above, and the uncertainties set forth from time to time in the Company's other public reports, filings and public statements.

This Annual Report is not deemed to be soliciting material or to be filed with the Securities and Exchange Commission or subject to the liabilities of Section 18 of the Securities Act of 1934.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

The information required by Item 7A is set forth under Market Risk Management in "Management's Discussion and Analysis of Financial Condition and Results of Operations," appearing on pages 44 through 45.

Item 8. Financial Statements and Supplementary Data

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Our management, including the Chief Executive Officer and the Chief Financial Officer, is responsible for establishing and maintaining adequate internal controls over financial reporting, as defined in Rules 13a-15(f) and 15d-15(f) of the Securities Exchange Act of 1934, as amended. Our system of 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. Our internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the Company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the Company are being made only in accordance with authorizations of management and directors of the Company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the Company's assets that could have a material effect on the financial statements.

Internal control over financial reporting cannot provide absolute assurance of achieving financial reporting objectives because of its inherent limitations. Internal control over financial reporting is a process that involves human diligence and compliance and is subject to lapses in judgment and breakdowns resulting from human failures. Internal control over financial reporting also can be circumvented by collusion or improper management override. Because of such limitations, there is a risk that material misstatements may not be prevented or detected on a timely basis by internal control over financial reporting. However, these inherent limitations are known features of the financial reporting process. Therefore, it is possible to design into the process safeguards to reduce, though not eliminate, this risk.

Our management assessed the effectiveness of our internal control over financial reporting as of December 31, 2007. In making this assessment, our management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in *Internal Control – Integrated Framework*. Based on our management's assessment, we have concluded that our internal control over financial reporting was effective as of December 31, 2007, based on those criteria. The effectiveness of the Company's internal control over financial reporting as of December 31, 2007, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears herein.

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Stockholders of Denbury Resources Inc.:

In our opinion, the consolidated financial statements listed in the accompanying index present fairly, in all material respects, the financial position of Denbury Resources Inc. and its subsidiaries at December 31, 2007 and 2006, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2007 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2007, based on criteria established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express opinions on these financial statements and on the Company's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

As discussed in Note 1 to the consolidated financial statements, the Company changed the manner in which it accounts for stock-based compensation costs in 2006.

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

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

PricewaterhouseCoopers LLP

PricewaterhouseCoopers LLP

Dallas, Texas
February 28, 2008

Consolidated Balance Sheets

(In Thousands, Except Shares)	December 31, 2007	December 31, 2006
ASSETS		
Current Assets		
Cash and cash equivalents	**$ 60,107**	$ 53,873
Accrued production receivable	**136,284**	72,398
Trade and other receivables, net of allowance of $369 and $315	**28,977**	24,260
Derivative assets	**2,283**	26,883
Deferred tax assets	**12,708**	5,855
Total current assets	**240,359**	183,269
Property and Equipment		
Oil and natural gas properties (using full cost accounting)		
Proved	**2,682,932**	2,226,942
Unevaluated	**366,518**	293,657
CO_2 properties and equipment	**436,591**	267,483
Other	**50,116**	43,133
Less accumulated depletion and depreciation	**(1,143,282)**	(951,447)
Net property and equipment	**2,392,875**	1,879,768
Deposits on properties under option or contract	**49,097**	49,002
Other assets	**88,746**	27,798
Total Assets	**$ 2,771,077**	$2,139,837
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities		
Accounts payable and accrued liabilities	**$ 147,580**	$ 139,111
Oil and gas production payable	**84,150**	52,244
Derivative liabilities	**28,096**	4,302
Deferred revenue – Genesis	**4,070**	4,070
Short-term capital lease obligations	**737**	671
Total current liabilities	**264,633**	200,398
Long-term Liabilities		
Capital lease obligations	**5,665**	6,387
Long-term debt, net of discount or premium	**674,665**	507,786
Asset retirement obligations	**38,954**	39,331
Derivative liabilities	**—**	6,834
Deferred revenue – Genesis	**24,424**	28,843
Deferred tax liability	**347,370**	235,780
Other	**10,988**	8,419
Total long-term liabilities	**1,102,066**	833,380
Commitments and Contingencies (Note 11)		
Stockholders' Equity		
Preferred stock, $.001 par value, 25,000,000 shares authorized; none issued and outstanding	**—**	—
Common stock, $.001 par value, 600,000,000 shares authorized; 245,386,951 and 120,506,815 shares issued at December 31, 2007 and 2006, respectively	**245**	121
Paid-in capital in excess of par	**662,698**	616,046
Retained earnings	**751,179**	498,032
Accumulated other comprehensive loss	**(1,591)**	—
Treasury stock, at cost, 637,795 and 370,327 shares at December 31, 2007 and 2006, respectively	**(8,153)**	(8,140)
Total stockholders' equity	**1,404,378**	1,106,059
Total Liabilities and Stockholders' Equity	**$ 2,771,077**	$2,139,837

See Notes to Consolidated Financial Statements.

Consolidated Statements of Operations

(In Thousands, Except Per Share Data)	Year Ended December 31, 2007	2006	2005
Revenues			
Oil, natural gas and related product sales			
Unrelated parties	**$ 952,687**	$715,061	$544,408
Related party – Genesis	**101**	1,496	4,647
CO_2 sales and transportation fees	**13,630**	9,376	8,119
Interest income and other	**5,532**	6,379	3,532
Total revenues	**971,950**	732,312	560,706
Expenses			
Lease operating expenses	**230,932**	167,271	108,550
Production taxes and marketing expenses	**43,130**	31,993	23,553
Transportation expense – Genesis	**5,961**	4,358	4,029
CO_2 operating expenses	**4,214**	3,190	2,251
General and administrative	**48,972**	43,014	28,540
Interest, net of amounts capitalized of $20,385, $11,333 and $1,649 in 2007, 2006 and 2005, respectively	**30,830**	23,575	17,978
Depletion, depreciation and amortization	**195,900**	149,165	98,802
Commodity derivative expense (income)	**18,597**	(19,828)	28,962
Total expenses	**578,536**	402,738	312,665
Income Before Income Taxes	**393,414**	329,574	248,041
Income Tax Provision			
Current income taxes	**30,074**	19,865	27,177
Deferred income taxes	**110,193**	107,252	54,393
Net Income	**$ 253,147**	$202,457	$166,471
Net Income Per Share – Basic	**$ 1.05**	$ 0.87	$ 0.74
Net Income Per Share – Diluted	**$ 1.00**	$ 0.82	$ 0.70
Weighted Average Common Shares Outstanding			
Basic	**240,065**	233,101	223,485
Diluted	**252,101**	247,547	239,267

See Notes to Consolidated Financial Statements.

Consolidated Statements of Cash Flows

(In Thousands)	Year Ended December 31, 2007	2006	2005
Cash Flow from Operating Activities:			
Net income	**$ 253,147**	$ 202,457	$ 166,471
Adjustments needed to reconcile to net cash flow provided by operations:			
Depreciation, depletion and amortization	**195,900**	149,165	98,802
Deferred income taxes	**110,193**	107,252	54,393
Deferred revenue – Genesis	**(4,419)**	(4,180)	(3,080)
Stock based compensation	**10,595**	17,246	4,121
Non-cash fair value derivative adjustments	**38,952**	(25,129)	12,201
Income tax benefit from equity awards	**—**	—	9,218
Amortization of debt issue costs and other	**4,149**	1,603	1,257
Changes in assets and liabilities relating to operations:			
Accrued production receivable	**(63,886)**	(5,474)	(21,388)
Trade and other receivables	**(10,409)**	1,712	(14,924)
Other assets	**(819)**	(672)	129
Accounts payable and accrued liabilities	**1,576**	7,038	38,202
Oil and gas production payable	**31,906**	10,422	16,966
Other liabilities	**3,329**	370	(1,408)
Net Cash Provided by Operating Activities	**570,214**	461,810	360,960
Cash Flow Used for Investing Activities:			
Oil and natural gas expenditures	**(613,659)**	(507,327)	(308,366)
Acquisitions of oil and gas properties	**(49,077)**	(319,000)	(70,870)
Change in accrual for capital expenditures	**(421)**	13,195	18,196
Investment in Genesis	**(47,738)**	—	(4,257)
Acquisition of CO_2 assets and CO_2 capital expenditures	**(171,182)**	(63,586)	(78,726)
Net purchases of other assets	**(13,672)**	(10,531)	(6,441)
Deposits on properties under option or contract	**(7,595)**	(11,159)	(21,917)
Increase in restricted cash	**(1,836)**	(981)	(249)
Sales of short-term investments	**—**	—	57,133
Net proceeds from CO_2 production payment – Genesis	**—**	—	14,363
Net proceeds from other sales of properties and equipment	**142,667**	42,762	17,447
Net Cash Used for Investing Activities	**(762,513)**	(856,627)	(383,687)
Cash Flow from Financing Activities:			
Bank repayments	**(265,000)**	(249,000)	(64,800)
Bank borrowings	**281,000**	383,000	64,800
Payments on capital lease obligations	**(671)**	(580)	(521)
Income tax benefit from equity awards	**19,181**	16,575	—
Issuance of subordinated debt	**150,750**	—	150,000
Issuance of common stock	**18,222**	139,834	12,392
Purchase of treasury stock	**(2,960)**	(5,544)	(5,119)
Costs of debt financing	**(1,989)**	(684)	(1,975)
Net Cash Provided by Financing Activities	**198,533**	283,601	154,777
Net Increase (Decrease) in Cash and Cash Equivalents	**6,234**	(111,216)	132,050
Cash and cash equivalents at beginning of year	**53,873**	165,089	33,039
Cash and cash equivalents at end of year	**$ 60,107**	$ 53,873	$ 165,089

See Notes to Consolidated Financial Statements.

Consolidated Statements of Changes in Stockholders' Equity

(Dollar Amounts in Thousands)	Common Stock ($.001 Par Value) Shares	Common Stock ($.001 Par Value) Amount	Paid-In Capital in Excess of Par	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Treasury Stock (at cost) Shares	Treasury Stock (at cost) Amount	Total Stockholders' Equity
Balance – December 31, 2004	56,607,877	$ 57	$419,345	$129,104	$(4,788)	93,072	$(2,046)	$ 541,672
Repurchase of common stock	—	—	—	—	—	142,287	(5,119)	(5,119)
Issued pursuant to employee stock purchase plan	—	—	887	—	—	(80,869)	1,854	2,741
Issued pursuant to employee stock option plans	949,051	1	9,650	—	—	—	—	9,651
Issued pursuant to directors' compensation plan	3,502	—	119	—	—	—	—	119
Two-for-one stock split	57,468,101	57	(57)	—	—	185,847	—	—
Restricted stock grants	10,000	—	—	—	—	—	—	—
Stock-based compensation	—	—	4,121	—	—	—	—	4,121
Income tax benefit from equity awards	—	—	9,218	—	—	—	—	9,218
Derivative contracts, net	—	—	—	—	4,764	—	—	4,764
Unrealized gain on available-for-sale securities	—	—	—	—	24	—	—	24
Net income	—	—	—	166,471	—	—	—	166,471
Balance – December 31, 2005	115,038,531	115	443,283	295,575	—	340,337	(5,311)	733,662
Repurchase of common stock	—	—	—	—	—	167,255	(5,544)	(5,544)
Issued pursuant to employee stock purchase plan	—	—	1,245	—	—	(137,265)	2,715	3,960
Issued pursuant to employee stock option plan	2,012,472	2	11,018	—	—	—	—	11,020
Issued pursuant to directors' compensation plan	4,441	—	134	—	—	—	—	134
Restricted stock grants	129,987	—	—	—	—	—	—	—
Restricted stock grants – forfeited	(171,211)	—	—	—	—	—	—	—
Stock based compensation	—	—	18,941	—	—	—	—	18,941
Income tax benefit from equity awards	—	—	16,575	—	—	—	—	16,575
Issuance of common stock	3,492,595	4	124,850	—	—	—	—	124,854
Net income	—	—	—	202,457	—	—	—	202,457
Balance – December 31, 2006	120,506,815	121	616,046	498,032	—	370,327	(8,140)	1,106,059
Repurchase of common stock	—	—	—	—	—	**74,130**	**(2,960)**	**(2,960)**
Issued pursuant to employee stock purchase plan	—	—	**2,099**	—	—	**(149,360)**	**2,947**	**5,046**
Issued pursuant to employee stock option plan	**2,071,940**	**2**	**13,174**	—	—	—	—	**13,176**
Issued pursuant to directors' compensation plan	**3,981**	—	**136**	—	—	—	—	**136**
Two-for-one stock split	**122,626,451**	**122**	**(122)**	—	—	**342,698**	—	—
Restricted stock grants	**198,354**	—	—	—	—	—	—	—
Restricted stock grants – forfeited	**(20,590)**	—	—	—	—	—	—	—
Stock based compensation	—	—	**12,184**	—	—	—	—	**12,184**
Income tax benefit from equity awards	—	—	**19,181**	—	—	—	—	**19,181**
Derivative contracts, net	—	—	—	—	**(1,591)**	—	—	**(1,591)**
Net income	—	—	—	**253,147**	—	—	—	**253,147**
Balance – December 31, 2007	**245,386,951**	**$ 245**	**$662,698**	**$751,179**	**$(1,591)**	**637,795**	**$(8,153)**	**$1,404,378**

See Notes to Consolidated Financial Statements.

Consolidated Statements of Comprehensive Income

(In Thousands)	Year Ended December 31, 2007	2006	2005
Net Income	**$253,147**	$202,457	$166,471
Other comprehensive income (loss), net of tax:			
Change in fair value of derivative contracts designated as a hedge, net of tax of $1,017	**(1,591)**	—	—
Reclassification adjustments related to settlements of derivative contracts, net of tax of $2,920	**—**	—	4,764
Unrealized gain on securities available for sale, net of tax of $15	**—**	—	24
Comprehensive Income	**$251,556**	$202,457	$171,259

See Notes to Consolidated Financial Statements.

Note 1. Significant Accounting Policies

Organization and Nature of Operations

Denbury Resources Inc. is a Delaware corporation, organized under Delaware General Corporation Law, engaged in the acquisition, development, operation and exploration of oil and natural gas properties. We have one primary business segment, which is the exploration, development and production of oil and natural gas in the U.S. Gulf Coast region. We also own the rights to a natural source of carbon dioxide ("CO_2") reserves that we use for injection in our tertiary oil recovery operations. We also sell some of the CO_2 we produce to Genesis (see Note 3) and to third party industrial users.

Principles of Reporting and Consolidation

The consolidated financial statements herein have been prepared in accordance with generally accepted accounting principles ("GAAP") and include the accounts of Denbury and its subsidiaries, all of which are wholly owned. A Denbury subsidiary is the general partner and owns an aggregate 9.25% interest in Genesis Energy, L.P. ("Genesis"), a publicly traded master limited partnership. We account for our 9.25% ownership interest in Genesis under the equity method of accounting. Even though we have significant influence over the limited partnership in our role as general partner, because our control is limited by the Genesis limited partnership agreement we do not consolidate Genesis. See Note 3 for more information regarding our related party transactions with Genesis. All material intercompany balances and transactions have been eliminated. We have evaluated our consolidation of variable interest entities in accordance with FASB Interpretation No. 46, "Consolidation of Variable Interest Entities," and have concluded that we do not have any variable interest entities that would require consolidation.

Stock Splits

Stockholders of Denbury approved two 2-for-1 stock splits (described below) during the three-year period ended December 31, 2007. Information pertaining to shares and earnings per share has been retroactively adjusted in the accompanying financial statements and related notes thereto to reflect the stock splits, except for the share amounts included on our Consolidated Balance Sheets and Consolidated Statements of Changes in Stockholders' Equity, which reflect the actual shares outstanding at each period end.

On November 19, 2007, stockholders of Denbury Resources Inc. approved an amendment to our Restated Certificate of Incorporation to increase the number of shares of our authorized common stock from 250,000,000 shares to 600,000,000 shares and to split our common stock on a 2-for-1 basis. Stockholders of record on December 5, 2007, received one additional share of Denbury common stock for each share of common stock held at that time.

On October 19, 2005, stockholders of Denbury Resources Inc. approved an amendment to our Restated Certificate of Incorporation to increase the number of shares of our authorized common stock from 100,000,000 shares to 250,000,000 shares and to split our common stock on a 2-for-1 basis. Stockholders of record on October 31, 2005, received one additional share of Denbury common stock for each share of common stock held at that time.

Oil and Natural Gas Operations

Capitalized Costs. We follow the full cost method of accounting for oil and natural gas properties. Under this method, all costs related to acquisitions, exploration and development of oil and natural gas reserves are capitalized and accumulated in a single cost center representing our activities, which are undertaken exclusively in the United States. Such costs include lease acquisition costs, geological and geophysical expenditures, lease rentals on undeveloped properties, costs of drilling both productive and non-productive wells, and general and administrative expenses directly related to exploration and development activities, and do not include any costs related to production, general corporate overhead or similar activities. Proceeds received from disposals are credited against accumulated costs except when the sale represents a significant disposal of reserves, in which case a gain or loss is recognized.

Depletion and Depreciation. The costs capitalized, including production equipment, are depleted or depreciated on the unit-of-production method, based on proved oil and natural gas reserves as determined by independent petroleum engineers. Oil and natural gas reserves are converted to equivalent units based upon the relative energy content, which is six thousand cubic feet of natural gas to one barrel of crude oil. The depletion and depreciation rate associated with our oil and gas producing activities was $11.60 in 2007, $10.54 in 2006 and $8.69 in 2005.

Asset Retirement Obligations. In general, our future asset retirement obligations relate to future costs associated with plugging and abandonment of our oil, natural gas and CO_2 wells, removal of equipment and facilities from leased acreage, and returning such land to its original condition. The fair value of a liability for an asset retirement obligation is recorded in the period in which it is incurred, discounted to its present value using our credit adjusted risk-free interest rate, and a corresponding amount capitalized by increasing the carrying amount of the related long-lived asset. The liability is accreted each period, and the capitalized cost is depreciated over the useful life of the related asset. Revisions to estimated retirement obligations will result in an adjustment to the related capitalized asset and corresponding liability. If the liability is settled for an amount other than the recorded amount, the difference is recorded to the full cost pool, unless significant. See Note 4 for more information regarding our asset retirement obligations.

Ceiling Test. The net capitalized costs of oil and natural gas properties are limited to the lower of unamortized cost or the cost center ceiling. The cost center ceiling is defined as the sum of (i) the present value of estimated future net revenues from proved reserves before future abandonment costs (discounted at 10%), based on unescalated period-end oil and natural gas prices; (ii) plus the cost of properties not being amortized; (iii) plus the lower of cost or estimated fair value of unproved properties included in the costs being amortized, if any; (iv) less related income tax effects. The cost center ceiling test is prepared quarterly.

Joint Interest Operations. Substantially all of our oil and natural gas exploration and production activities are conducted jointly with others. These financial statements reflect only Denbury's proportionate interest in such activities, and any amounts due from other partners are included in trade receivables.

Proved Reserves. See Note 15 for information on our proved oil and natural gas reserves and the basis on which they are recorded.

Tertiary Injection Costs. Our tertiary operations are conducted in reservoirs that have already produced significant amounts of oil over many years; however, in accordance with the rules for recording proved reserves, we cannot recognize proved reserves associated with enhanced recovery techniques, such as CO_2 injection, until there is a production response to the injected CO_2 or, unless the field is analogous to an existing flood. Our costs associated with the CO_2 we produce (or acquire) and inject are principally our costs of production, transportation and acquisition, or to pay royalties.

Prior to January 1, 2008, we expensed currently all costs associated with injecting CO_2 that we use in our tertiary recovery operations, even though some of these costs were incurred prior to any tertiary related oil production. Commencing January 1, 2008, we will begin capitalizing, as a development cost, injection costs in fields that are in their development stage, which means we have not yet seen incremental oil production due to the CO_2 injections (i.e. a production response). These capitalized development costs will be included in our unevaluated property costs within our full cost pool if there are not already proved tertiary reserves in that field. After we see a production response to the CO_2 injections (i.e. the production stage), injection costs will be expensed as incurred and any previously deferred unevaluated development costs will become subject to depletion upon recognition of proved tertiary reserves. Based upon the current status of some of our tertiary floods, this change in accounting will cause us to capitalize certain costs that we historically expensed. Had the new method of accounting for tertiary injectant costs been used in periods prior to January 1, 2008, the effect on our financial statements would have been immaterial for all periods presented.

Property and Equipment – Other

Other property and equipment, which includes furniture and fixtures, vehicles, computer equipment and software, and capitalized leases, is depreciated principally on a straight-line basis over estimated useful lives. Estimated useful lives are generally as follows: vehicles and furniture and fixtures – 5 to 10 years; and computer equipment and software – 3 to 5 years.

Leased property meeting certain capital lease criteria is capitalized, and the present value of the related lease payments is recorded as a liability. Amortization of capitalized leased assets is computed using the straight-line method over the shorter of the estimated useful life or the initial lease term.

Revenue Recognition

Revenue is recognized at the time oil and natural gas is produced and sold. Any amounts due from purchasers of oil and natural gas are included in accrued production receivable.

We follow the sales method of accounting for our oil and natural gas revenue, whereby we recognize revenue on all oil or natural gas sold to our purchasers regardless of whether the sales are proportionate to our ownership in the property. A receivable or liability is recognized only to the extent that we have an imbalance on a specific property greater than the expected remaining proved reserves. As of December 31, 2007 and 2006, our aggregate oil and natural gas imbalances were not material to our consolidated financial statements.

We recognize revenue and expenses of purchased producing properties at the time we assume effective control, commencing from either the closing or purchase agreement date, depending on the underlying terms and agreements. We follow the same methodology in reverse when we sell properties by recognizing revenue and expenses of the sold properties until either the closing or purchase agreement date, depending on the underlying terms and agreements.

Derivative Instruments and Hedging Activities

We utilize oil and natural gas derivative contracts to mitigate our exposure to commodity price risk associated with our future oil and natural gas production. These derivative contracts have historically consisted of options, in the form of price floors or collars, and fixed price swaps. We have also used interest rate lock contracts to mitigate our exposure to interest rate fluctuations related to sale-leaseback financing of certain equipment used at our oilfield facilities. Our derivative financial instruments are recorded on the balance sheet as either an asset or a liability measured at fair value. Our recognition of the change in fair value depends on the designation of the derivative instrument. The changes in fair value of derivatives that are not designated as hedges under SFAS No. 133, as well as the ineffective portion of hedge derivatives, are recognized currently in earnings. Unrealized gains or losses on effective cash flow hedge derivatives, as well as any deferred gain or loss realized upon early termination of effective hedge derivatives, are recognized as a component of accumulated other comprehensive income. When the hedged transaction occurs, the realized gain or loss, as well as any deferred gain or loss, on the hedge derivative is transferred from accumulated other comprehensive income to earnings.

In order to qualify for hedge accounting, the relationship between the hedging instruments and the hedged items must be highly effective in achieving the offset of changes in fair values or cash flows attributable to the hedged risk, both at the inception of the hedge and on an ongoing basis. We measure hedge effectiveness on a quarterly basis. Hedge accounting is discontinued prospectively when a hedging instrument becomes ineffective. We assess hedge effectiveness based on total changes in the fair value of derivatives used in cash flow hedges rather than changes of intrinsic value only. As a result, changes in the entire fair value of derivative contracts are deferred in accumulated other comprehensive income, to the extent they are effective, until the hedged transaction is completed.

Effective January 1, 2005, we elected to discontinue hedge accounting for our oil and natural gas derivative contracts and accordingly de-designated our oil and gas derivative instruments from hedge accounting treatment. As a result of this change, we began accounting for our oil and natural gas derivative contracts as speculative contracts in the first quarter of 2005. As speculative contracts, the changes in the fair value of these instruments are recognized in income in the period of change. See Note 10 for further information on our derivative contracts.

Financial Instruments with Off-Balance-Sheet Risk and Concentrations of Credit Risk

Our financial instruments that are exposed to concentrations of credit risk consist primarily of cash equivalents, trade and accrued production receivables, and the derivative hedging instruments discussed above. Our cash equivalents represent high-quality securities placed with various investment-grade institutions. This investment practice limits our exposure to concentrations of credit risk. Our trade and accrued production receivables are dispersed among various customers and purchasers; therefore, concentrations of credit risk are limited. Also, most of our significant purchasers are large companies with excellent credit ratings. If customers are considered a credit risk, letters of credit are the primary security obtained to support lines of credit. We attempt to minimize our credit risk exposure to the counterparties of our derivative hedging contracts through formal credit policies, monitoring procedures and diversification. There are no margin requirements with the counterparties of our derivative contracts.

CO_2 Operations

We own and produce CO_2 reserves that are used for our own tertiary oil recovery operations, and in addition, we sell a portion to Genesis and to other third party industrial users. We record revenue from our sales of CO_2 to third parties when it is produced and sold. CO_2 used for our own tertiary oil recovery operations is not recorded as revenue in the Consolidated Statements of Operations. Expenses related to the production of CO_2 are allocated between volumes sold to third parties and volumes used for our own use. The expenses related to third party sales are recorded in "CO_2 operating expenses" and the expenses related to our own uses are recorded in "Lease operating expenses" in the Consolidated Statements of Operations or, effective January 1, 2008, are capitalized as oil and gas properties in our Consolidated Balance Sheets, depending on the status of floods that receive the CO_2 (see "Tertiary Injection Costs" on page 59 for further discussion). We capitalize acquisitions and the costs of exploring and developing CO_2 reserves. The costs capitalized are depleted or depreciated on the unit-of-production method, based on proved CO_2 reserves as determined by independent engineers. We evaluate our CO_2 assets for impairment by comparing our expected future revenues from these assets to their net carrying value.

Cash Equivalents

We consider all highly liquid investments to be cash equivalents if they have maturities of three months or less at the date of purchase.

Restricted Cash and Investments

At December 31, 2007 and 2006, we had approximately $9.5 million and $7.6 million, respectively, of restricted cash and investments held in escrow accounts for future site reclamation costs. These balances are recorded at cost and are included in "Other assets" in the Consolidated Balance Sheets. The estimated fair market value of these investments at December 31, 2007 and 2006, was virtually the same as amortized cost.

Net Income Per Common Share

Basic net income per common share is computed by dividing the net income attributable to common stockholders by the weighted average number of shares of common stock outstanding during the period. Diluted net income per common share is calculated in the same manner, but also considers the impact to net income and common shares for the potential dilution from stock options, stock appreciation rights ("SARs"), non-vested restricted stock and any other convertible securities outstanding.

All shares have been adjusted for our 2-for-1 stock splits. For each of the three years in the period ended December 31, 2007, there were no adjustments to net income for purposes of calculating basic and diluted net income per common share. In April 2006, we issued 6,985,190 shares (3,492,595 on a pre-split basis) of common stock in a public offering – See Note 8, "Stockholders' Equity."

The following is a reconciliation of the weighted average shares used in the basic and diluted net income per common share computations:

	Year Ended December 31,		
(In Thousands)	2007	2006	2005
Weighted average common shares – basic	**240,065**	233,101	223,485
Potentially dilutive securities:			
Stock options and SARs	**10,485**	12,376	13,862
Restricted stock	**1,551**	2,070	1,920
Weighted average common shares – diluted	**252,101**	247,547	239,267

The weighted average common shares – basic amount in 2007, 2006 and 2005 excludes 2.7 million, 2.8 million and 4.0 million shares of non-vested restricted stock, respectively, that is subject to future vesting over time. As these restricted shares vest, they will be included in the shares outstanding used to calculate basic net income per common share (although all restricted stock is issued and outstanding upon grant). For purposes of calculating weighted average common shares – diluted, the non-vested restricted stock is included in the computation using the treasury stock method, with the proceeds equal to the average unrecognized compensation during the period, adjusted for any estimated future tax consequences recognized directly in equity. The dilution impact of these shares on our earnings per share calculation may increase in future periods, depending on the market price of our common stock during those periods. Stock options and SARs to purchase approximately 130,000 shares in 2007, 256,000 shares in 2006 and 368,000 shares in 2005 were outstanding but excluded from the diluted net income per common share calculations, as their exercise prices exceeded the average market price of our common stock during the respective periods; therefore, their inclusion would be anti-dilutive to the calculations.

Stock-Based Compensation

In December 2004, the Financial Accounting Standards Board ("FASB") issued Statement of Financial Accounting Standard ("SFAS") No. 123(R), "Share Based Payment," which is a revision of SFAS No. 123, "Accounting for Stock-Based Compensation." SFAS No. 123(R) supersedes Accounting Principles Board Opinion 25 ("APB 25"), "Accounting for Stock Issued to Employees," and amends SFAS No. 95, "Statement of Cash Flows." Generally, the approach in SFAS No. 123(R) is similar to the approach described in SFAS No. 123. However, SFAS No. 123(R) requires all share-based compensation to employees, including grants of employee stock options, to be recognized in our consolidated financial statements based on estimated fair value.

We adopted SFAS No. 123(R) on January 1, 2006, using the modified prospective application method described in the statement. Under the modified prospective method, effective January 1, 2006, we began to recognize compensation expense for the unvested portion of awards outstanding as of December 31, 2005, over the remaining service periods, and for new awards granted or modified after January 1, 2006. See Note 9 for further discussion regarding our stock compensation plans.

Income Taxes

Income taxes are accounted for using the liability method under which deferred income taxes are recognized for the future tax effects of temporary differences between the financial statement carrying amounts and the tax basis of existing assets and liabilities using the enacted statutory tax rates in effect at year-end. The effect on deferred taxes for a change in tax rates is recognized in income in the period that includes the enactment date. A valuation allowance for deferred tax assets is recorded when it is more likely than not that the benefit from the deferred tax asset will not be realized.

Effective January 1, 2007 we adopted the provision of FASB Interpretation 48 ("FIN 48"), *Accounting for Uncertainties in Income Taxes* – an interpretation of FASB Statement No. 109, *Accounting for Income Taxes.* This interpretation addresses how tax benefits claimed or expected to be claimed on a tax return should be recorded in the financial statements. Under FIN 48, the Company may recognize the tax benefit from an uncertain tax position only if it is more likely than not that the tax position will be sustained on examination by the taxing authorities, based on the technical merits of the position. The tax benefits recognized in the financial statements from such a position should be measured based on the largest benefit that has a greater than fifty percent likelihood of being realized upon ultimate settlement. There was no material impact on our financial statements as the result of our adoption of FIN 48 in 2007. See Note 7, "Income Taxes," for further information regarding our income taxes and our adoption of FIN 48.

Use of Estimates

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amount of certain assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during each reporting period. Management believes its estimates and assumptions are reasonable; however, such estimates and assumptions are subject to a number of risks and uncertainties that may cause actual results to differ materially from such estimates. Significant estimates underlying these financial statements include (i) the fair value of financial derivative instruments, (ii) the estimated quantities of proved oil and natural gas reserves used to compute depletion of oil and natural gas properties, the related present value of estimated future net cash flows therefrom and ceiling test, (iii) accruals related to oil and gas production and revenues, capital expenditures and lease operating expenses, (iv) the estimated costs and timing of future asset retirement obligations, and (v) estimates made in the calculation of income taxes. While management is not aware of any significant revisions to any of its estimates, there will likely be future revisions to its estimates resulting from matters such as revisions in estimated oil and gas volumes, changes in ownership interests, payouts, joint venture audits, re-allocations by purchasers or pipelines, or other corrections and adjustments common in the oil and gas industry, many of which require retroactive application. These types of adjustments cannot be currently estimated and will be recorded in the period during which the adjustment occurs.

Reclassifications

Certain prior period amounts have been reclassified to conform with the current year presentation. Such reclassifications had no impact on our reported net income, current assets, total assets, current liabilities, total liabilities or stockholders' equity.

Recent Accounting Pronouncements

In September 2006, the FASB issued SFAS No. 157, "Fair Value Measurements." SFAS No. 157 defines fair value, establishes a framework for measuring fair value in accordance with United States generally accepted accounting principles, and expands disclosures about fair value measurements. SFAS No. 157 does not require any new fair value measurements, but provides guidance on how to measure fair value by providing a fair value hierarchy used to classify the source of the information. SFAS No. 157 is effective for fiscal years beginning after November 15, 2007. However, on February 12, 2008, the FASB issued FSP SFAS No. 157-2 which delays the effective date of SFAS No. 157 for all nonfinancial assets and nonfinancial liabilities, except those that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually). This FSP partially defers the effective date of SFAS No. 157 to fiscal years beginning after November 15, 2008, and interim periods within those fiscal years for items within the scope of this FSP. Effective for 2008, we will adopt SFAS No. 157 except as it applies to those nonfinancial assets and nonfinancial liabilities as noted in FSP SFAS No. 157-2. We have not yet determined the impact of the partial adoption of SFAS No. 157 will have on the Company's financial condition or results of operations.

In February 2007, the FASB issued SFAS No. 159, "The Fair Value Option for Financial Assets and Financial Liabilities." SFAS No. 159 permits entities to choose to measure many financial instruments and certain other items at fair value, with the objective of improving financial reporting by giving entities the opportunity to mitigate volatility in reported earnings caused by measuring related assets and liabilities differently without having to apply complex hedge accounting provisions. The provisions of SFAS No. 159 are effective for us beginning January 1, 2008. We have not yet determined what impact, if any, this pronouncement will have on our financial condition or results of operations.

In December 2007, the FASB issued SFAS No. 141 (Revised 2007), "Business Combinations." SFAS No. 141(R) establishes principles and requirements for how an acquirer recognizes and measures in its financial statements the identifiable assets acquired, the liabilities assumed, any noncontrolling interest in the acquiree and the goodwill acquired. SFAS No. 141(R) also establishes disclosure requirements to enable the evaluation of the nature and financial effects of the business combination. This statement is effective for us beginning January 1, 2009. We have not yet determined what impact, if any, this pronouncement will have on our financial condition or results of operations.

In December 2007, the FASB issued SFAS No. 160, "Noncontrolling Interests in Consolidated Financial Statements an amendment of ARB No. 51." SFAS No. 160 establishes accounting and reporting standards for ownership interests in subsidiaries held by parties other than the parent, the amount of consolidated net income attributable to the parent and to the noncontrolling interest, changes in a parent's ownership interest, and the valuation of retained noncontrolling equity investments when a subsidiary is deconsolidated. SFAS No. 160 also establishes disclosure requirements that clearly identify and distinguish between the interests of the parent and the interests of the noncontrolling owners. This statement is effective for us beginning January 1, 2009. We have not yet determined what impact, if any, this pronouncement will have on our financial condition or results of operations.

Note 2. Acquisitions and Divestitures

2007 Acquisition

On March 30, 2007, Denbury completed the acquisition of the Seabreeze Complex, which is composed of two significant fields and four smaller fields in the general area of Houston, Texas. At the time of acquisition these fields were producing approximately 400 BOE/d and had estimated current conventional proved reserves of approximately 525 MBOE. Two of these fields are future potential CO_2 tertiary flood candidates. Tertiary flooding at these fields is not expected to begin until 2010 or 2011, following completion of the proposed CO_2 pipeline from Louisiana to Hastings Field, near Houston, Texas.

The adjusted purchase price is approximately $39.4 million, after adjusting for interim net cash flow between the effective date and closing date of the acquisition, and minor purchase price adjustments. The purchase price was allocated between proved and unevaluated oil and natural gas properties based on a risk adjusted analysis of the total estimated value of the proved and probable reserves acquired. Based on this analysis, $5.5 million was assigned to proved properties and $33.9 million was assigned to unevaluated properties. The unevaluated costs are currently excluded from the amortization base and will be transferred to the amortization base as we develop and test the tertiary recovery projects planned in these fields.

2007 Divestiture

In October 2007, we entered into an agreement to sell our Louisiana natural gas assets to a privately held company for approximately $180 million (before closing adjustments) plus any amounts received from a net profits interest. In late December 2007, we closed on approximately 70% of that sale with net proceeds of approximately $108.6 million (including estimated final purchase price adjustments). The agreement has an effective date of August 1, 2007, and consequently operating net revenue after August 1, net of capital expenditures, along with any other minor closing items were adjustments to the purchase price. We closed on the remaining portion of the sale in February 2008 (see Note 14, "Subsequent Event"). The potential net profits interest relates to a well in the South Chauvin field and is only earned if operating income from that well exceeds certain levels, which we believe could potentially increase the ultimate sales price by up to 10%. The operating results of these sold properties are included in our financial statements through the December 19, 2007 closing date. We did not record any gain or loss on the sale in accordance with the full cost method of accounting.

2006 Acquisitions

On January 31, 2006, we completed an acquisition of three producing oil properties that are future potential CO_2 tertiary oil flood candidates: Tinsley Field approximately 40 miles northwest of Jackson, Mississippi; Citronelle Field in Southwest Alabama, and the smaller South Cypress Creek Field near the Company's Eucutta Field in Eastern Mississippi. The adjusted purchase price was approximately $250 million (including the $25 million deposited as earnest money as of December 31, 2005), of which $124 million was assigned to unevaluated properties.

During May 2006, we purchased the Delhi Holt-Bryant Unit ("Delhi") in Northern Louisiana for $50 million, plus a 25% reversionary interest to the seller after we have achieved $200 million in net operating revenue, as defined. Delhi is also a future potential CO_2 tertiary oil flood candidate. Approximately $49 million of the purchase price was assigned to unevaluated properties.

2006 Purchase Option Contract

During November 2006, we entered into an agreement with a subsidiary of Venoco, Inc. that gives us an option on September 1, 2008, or September 1, 2009, with an effective date of January 1 of the following year, to purchase their interest in Hastings Field, a strategically significant potential tertiary flood candidate located near Houston, Texas. The agreement provides for the parties to agree upon a purchase price at the time of the exercise of the option, which may be paid in cash or through a volumetric production payment; failing agreement as to price, the price will be determined by a pre-designated independent petroleum engineering firm using specified criteria for calculation of the discounted present value of the proved reserves at that time. As consideration for the option agreement, we made a payment of $37.5 million in November 2006, a payment of $7.5 million in 2007, and are required to make an additional payment of $5 million in 2008. We have recorded these payments and the discounted present value of the required additional payment, which total approximately $49 million, in "Deposits on properties under option or contract" in our December 31, 2007, Consolidated Balance Sheet. Upon exercise of the option to purchase Hastings Field, the deposit will be transferred to oil and natural gas properties. We will evaluate the option for impairment, and if circumstances arise that indicate the future acquisition will not occur, we will recognize expense for this option as appropriate.

2005 Acquisitions

Our acquisitions in 2005 included the purchase of additional interest and acreage in the Barnett Shale area ($34.2 million), additional interest in the Eucutta Field ($8.0 million), and the purchase of two oil fields that may be potential tertiary flood candidates in the future, Lake St. John ($16.1 million) and Cranfield ($1.1 million).

Note 3. Related Party Transactions – Genesis

Interest In and Transactions With Genesis

Denbury's subsidiary, Genesis Energy, Inc. is the general partner and owns an aggregate 9.25% interest in Genesis Energy, L.P. ("Genesis"), a publicly traded master limited partnership. Genesis' business is focused on the mid stream segment of the oil and gas industry in the Gulf Coast area of the United States, and its activities include gathering, marketing and transportation of crude oil and natural gas, refinery services, wholesale marketing of CO_2, and supply and logistic services.

We account for our 9.25% ownership in Genesis under the equity method of accounting as we have significant influence over the limited partnership; however, our control is limited under the limited partnership agreement and therefore we do not consolidate Genesis. Our investment in Genesis is included in "Other assets" in our Consolidated Balance Sheets. Denbury received cash distributions from Genesis of $1.7 million in 2007, $0.9 million in 2006, and $0.5 million in 2005. We also received $0.1 million in each of the last three years in directors' fees for certain officers of Denbury that are board members of Genesis. There are no guarantees by Denbury or any of our other subsidiaries of the debt of Genesis or of Genesis Energy, Inc.

On July 25, 2007, Genesis acquired several energy related businesses from the Davison family of Ruston, Louisiana, for total consideration of approximately $623 million (net of cash acquired at closing and subject to final purchase price adjustments). These businesses include a trucking operation for petroleum products and other bulk commodities, terminal storage of refined petroleum products, a refinery service operation which processes sour gas streams at several refining operations, and a wholesale petroleum products marketing business. Approximately one-half of the acquisition was funded by debt from Genesis' bank credit facility and approximately one-half through the issuance of Genesis common units to the seller. In conjunction with that acquisition, our subsidiary, Genesis Energy, Inc., exercised its right to maintain its pro rata (7.4%) ownership of common units, acquiring 1,074,882 additional common units for approximately $22.4 million, in addition to its capital contribution of an additional $6.2 million, as general partner, to maintain its 2% general partner's capital interest.

In December 2007, Genesis issued additional common units in a public offering. Our subsidiary, Genesis Energy, Inc., maintained its 2% general partner's interest and acquired 734,732 common units in this offering for $20 million, which maintained its same ownership interest of approximately 9.25%.

Our investment in Genesis of $60 million exceeded our percentage of net equity in the limited partnership at the time of acquisition by approximately $15.7 million, which represents goodwill and is not subject to amortization. The fair value of our investment in Genesis was in excess of $84.9 million at December 31, 2007, based on quoted market values of Genesis' publicly traded limited partnership units.

Oil Sales and Transportation Services

We utilize Genesis' trucking services and common carrier pipeline to transport certain of our crude oil production to sales points where it is sold to third party purchasers. We expensed $6.0 million in 2007, $4.4 million in 2006, and $4.0 million in 2005 for these transportation services.

Transportation Leases

In late 2004 and early 2005, we entered into pipeline transportation agreements with Genesis to transport our crude oil from certain of our fields in Southwest Mississippi, and to transport CO_2 from our main CO_2 pipeline to Brookhaven Field for our tertiary operations. We have accounted for these agreements as capital leases. The pipelines held under these capital leases are classified as property and equipment and are amortized using the straight-line method over the lease terms. Lease amortization is included in depreciation expense. The related obligations are recorded as debt. At December 31, 2007 and 2006, we had $5.2 million and $5.9 million, respectively, of capital lease obligations with Genesis recorded as liabilities in our Consolidated Balance Sheets, of which $0.7 million and $0.6 million, respectively, was current.

CO_2 Volumetric Production Payments

During 2003 through 2005, we sold 280.5 Bcf of CO_2 to Genesis under three separate volumetric production payment agreements. We have recorded the net proceeds of these volumetric production payment sales as deferred revenue and recognize such revenue as CO_2 is delivered under the volumetric production payments. At December 31, 2007 and 2006, $28.5 million and $32.9 million, respectively, was recorded as deferred revenue of which $4.1 million was included in current liabilities at both December 31, 2007 and 2006. We recognized deferred revenue of $4.4 million, $4.2 million and $3.1 million for the years ended December 31, 2007, 2006 and 2005, respectively, for deliveries under these volumetric production payments. We provide Genesis with certain processing and transportation services in connection with transporting CO_2 to their industrial customers for a fee of approximately $0.18 per Mcf of CO_2. For these services, we recognized revenues of $5.2 million, $4.6 million and $3.5 million for the years ended December 31, 2007, 2006 and 2005, respectively.

At December 31, 2007 and 2006, we had a net receivable from Genesis of $0.1 million, in both periods associated with all of the transactions described above.

Note 4. Asset Retirement Obligations

In general, our future asset retirement obligations relate to future costs associated with plugging and abandonment of our oil, natural gas and CO_2 wells, removal of equipment and facilities from leased acreage and land restoration. The fair value of a liability for an asset retirement is recorded in the period in which it is incurred, discounted to its present value using our credit adjusted risk-free interest rate, and a corresponding amount capitalized by increasing the carrying amount of the related long-lived asset. The liability is accreted each period, and the capitalized cost is depreciated over the useful life of the related asset.

The following table summarizes the changes in our asset retirement obligations for the years ended December 31, 2007 and 2006.

(In Thousands)	Year Ended December 31, 2007	2006
Beginning asset retirement obligation	**$41,107**	$27,088
Liabilities incurred and assumed during period	**6,530**	10,159
Revisions in estimated cash flows	**1,165**	2,791
Liabilities settled during period	**(1,302)**	(1,320)
Accretion expense	**2,976**	2,389
Sales	**(9,218)**	—
Ending asset retirement obligation	**$41,258**	$41,107

At December 31, 2007 and 2006, $2.3 million and $1.8 million, respectively, of our asset retirement obligation were classified in "Accounts payable and accrued liabilities" under current liabilities in our Consolidated Balance Sheets. Liabilities sold in 2007 were associated with the sale of our Louisiana natural gas properties in December 2007. The reversal of this asset retirement obligation, which was assumed by the purchaser, was recorded as an adjustment to the full cost pool with no gain or loss recognized in accordance with the full cost method of accounting. Liabilities incurred and assumed during 2007 and 2006 are primarily for properties acquired. We have escrow accounts that are legally restricted for certain of our asset retirement obligations. The balances of these escrow accounts were $9.5 million at December 31, 2007, and $7.6 million at December 31, 2006, and are included in "Other assets" in our Consolidated Balance Sheets.

Note 5. Property and Equipment

(In Thousands)	December 31, 2007	2006
Oil and Natural Gas Properties:		
Proved properties	**$ 2,682,932**	$2,226,942
Unevaluated properties	**366,518**	293,657
Total	**3,049,450**	2,520,599
Accumulated depletion and depreciation	**(1,081,909)**	(907,911)
Net Oil and Natural Gas Properties	**1,967,541**	1,612,688
CO_2 properties and equipment	**269,335**	205,235
Accumulated depletion and depreciation	**(34,676)**	(23,492)
Net CO_2 Properties	**234,659**	181,743
CO_2 pipelines	**167,256**	62,248
Accumulated depletion and depreciation	**(3,340)**	(1,505)
Net CO_2 Pipelines	**163,916**	60,743
Capital leases	**7,985**	7,985
Accumulated depletion and depreciation	**(2,482)**	(1,631)
Net Capital Leases	**5,503**	6,354
Other	**42,131**	35,148
Accumulated depletion and depreciation	**(20,875)**	(16,908)
Net Other	**21,256**	18,240
Net Property and Equipment	**$ 2,392,875**	$1,879,768

At December 31, 2007 and 2006, we had $106.2 million and $7.9 million of costs, respectively, included in "CO_2 Pipelines" above related to construction in progress. These costs were not being depreciated at December 31, 2007 or December 31, 2006. Depreciation will commence when the pipelines are placed into service. The Company capitalizes interest on its CO_2 pipelines during the construction period. Interest capitalized on these CO_2 pipelines was $2.1 million in 2007 and $0.3 million in 2006.

Unevaluated Oil and Natural Gas Properties Excluded From Depletion

Under full cost accounting, we may exclude certain unevaluated costs from the amortization base pending determination of whether proved reserves can be assigned to such properties. We allocate the purchase price of oil and natural gas properties we acquire between proved and unevaluated properties based on a risk adjusted analysis of the total estimated value of the proved, probable and possible reserves acquired. The costs classified as unevaluated are transferred to the full cost amortization base as the properties are developed, tested and evaluated. A summary of the unevaluated properties excluded from oil and natural gas properties being amortized at December 31, 2007 and 2006, and the year in which they were incurred follows:

	December 31, 2007			
	Costs Incurred During:			
(In Thousands)	2007	2006	2005	Total
Property acquisition costs	**$ 40,889**	**$184,407**	**$4,567**	**$229,863**
Exploration and development	**95,246**	**13,638**	**23**	**108,907**
Capitalized interest	**17,501**	**10,247**	**—**	**27,748**
Total	**$153,636**	**$208,292**	**$4,590**	**$366,518**

	December 31, 2006			
	Costs Incurred During:			
(In Thousands)	2006	2005	Prior	Total
Property acquisition costs	$193,554	$ 11,906	$1,655	$207,115
Exploration and development	70,624	1,657	3,202	75,483
Capitalized interest	11,059	—	—	11,059
Total	$275,237	$ 13,563	$4,857	$293,657

Property acquisition costs for 2007 are primarily for CO_2 tertiary oil field candidates acquired in the Seabreeze Complex acquisition, and for 2006 are primarily associated with our acquisitions of four CO_2 tertiary oil field candidates: Tinsley Field, Citronelle Field, South Cypress Creek Field and Delhi Field. See Note 2 – "Acquisitions and Divestitures." Exploration and development costs for 2007 are primarily associated with our CO_2 tertiary oil fields that are under development and did not have proved reserves at December 31, 2007. Costs are transferred into the amortization base on an ongoing basis as the projects are evaluated and proved reserves established or impairment determined. We review the excluded properties for impairment at least annually. We currently estimate that evaluation of most of these properties and the inclusion of their costs in the amortization base is expected to be completed within five years. Until we are able to determine whether there are any proved reserves attributable to the above costs, we are not able to assess the future impact on the amortization rate.

Note 6. Notes Payable and Long-Term Indebtedness

(In Thousands)	December 31, 2007	2006
7.5% Senior Subordinated Notes due 2015	**$ 300,000**	$150,000
Premium on Senior Subordinated Notes due 2015	**685**	—
7.5% Senior Subordinated Notes due 2013	**225,000**	225,000
Discount on Senior Subordinated Notes due 2013	**(1,020)**	(1,214)
Senior bank loan	**150,000**	134,000
Capital lease obligations – Genesis	**5,238**	5,869
Capital lease obligations	**1,164**	1,189
Total	**681,067**	514,844
Less current obligations	**737**	671
Long-term debt and capital lease obligations	**$ 680,330**	$514,173

7.5% Senior Subordinated Notes due 2015

On April 3, 2007, we issued $150 million of Senior Subordinated Notes due 2015 as an additional issuance under our existing indenture governing our December 2005 sale of $150 million of 7.5% Senior Subordinated Notes due 2015 ("2015 Notes"). The notes, which carry a coupon rate of 7.5%, were sold at 100.5% of par, which equates to an effective yield to maturity of approximately 7.4%. Net proceeds from the sale were approximately $149.2 million. The net proceeds were used to repay a portion of the outstanding borrowings under our bank credit facility.

The $150 million of 2015 Notes issued on December 21, 2005, were priced at par, and we used the $148.0 million of net proceeds from the offering to fund a portion of the $250 million oil and natural gas property acquisition, which closed in January 2006 (see Note 2, "Acquisitions and Divestitures").

The 2015 Notes mature on December 15, 2015, and interest on the 2015 Notes is payable each June 15 and December 15. We may redeem the 2015 Notes at our option beginning December 15, 2010, at the following redemption prices: 103.75% after December 15, 2010, 102.5% after December 15, 2011, 101.25%, after December 15, 2012, and 100% after December 15, 2013. In addition, prior to December 15, 2008, we may at our option on one or more occasions redeem up to 35% of the 2015 Notes at a redemption price of 107.5% with the net cash proceeds from a stock offering. The indenture contains certain restrictions on our ability to incur additional debt, pay dividends on our common stock, make investments, create liens on our assets, engage in transactions with our affiliates, transfer or sell assets, consolidate or merge, or sell substantially all of our assets. The 2015 Notes are not subject to any sinking fund requirements. All of our significant subsidiaries fully and unconditionally guarantee this debt.

7.5% Senior Subordinated Notes due 2013

On March 25, 2003, we issued $225 million of 7.5% Senior Subordinated Notes due 2013 ("2013 Notes"). The 2013 Notes were priced at 99.135% of par, and we used most of our $218.4 million of net proceeds from the offering, after underwriting and issuance costs, to retire our then existing $200 million of 9% Senior Subordinated Notes due 2008, including the Series B notes.

The 2013 Notes mature on April 1, 2013, and interest on the 2013 Notes is payable each April 1 and October 1. We may redeem the 2013 Notes at our option beginning April 1, 2008, at the following redemption prices: 103.75% after April 1, 2008, 102.5% after April 1, 2009, 101.25% after April 1, 2010, and 100% after April 1, 2011, and thereafter. The indenture contains certain restrictions on our ability to incur additional debt, pay dividends on our common stock, make investments, create liens on our assets, engage in transactions with our affiliates, transfer or sell assets, consolidate or merge, or sell substantially all of our assets. The 2013 Notes are not subject to any sinking fund requirements. All of our significant subsidiaries fully and unconditionally guarantee this debt.

In connection with our internal reorganization to a holding-company organizational structure, we entered into a First Supplemental Indenture dated December 29, 2003, which did not require the consent of the holders of the 2013 Notes. The supplemental indenture made Denbury Resources Inc. and Denbury Onshore, LLC, co-obligors of this debt. All of our significant subsidiaries continue to fully and unconditionally guarantee this debt. There were no other significant changes as part of the amendment.

Senior Bank Loan

On March 31, 2007, we amended our Sixth Amended and Restated Credit Agreement, the instrument governing our senior bank loan. The amendment (i) increased the commitment amount that the banks are committed to fund from $250 million to $350 million, (ii) reconfirmed the borrowing base of $500 million, (iii) authorized the $150 million subordinated debt offering, and (iv) authorized us to enter into a sale-leaseback type transaction for our CO_2 pipelines, not to exceed $300 million, with Genesis Energy, L.P. The borrowing base represents the amount that can be borrowed from a credit standpoint based on our assets, as confirmed by the banks, while the commitment amount is the amount the banks have committed to fund pursuant to the terms of the credit agreement. The banks have the option to participate in any borrowing request we make in excess of the commitment amount ($350 million), up to the borrowing base limit ($500 million), although the banks are not obligated to fund any amount in excess of the commitment amount. The credit agreement maintains the structure of semi-annual reviews of the borrowing base and commitment amount on April 1 and October 1.

The bank credit facility is secured by substantially all of our producing oil and natural gas properties, and contains several restrictions including, among others: (i) a prohibition on the payment of dividends, (ii) a requirement to maintain positive working capital, as defined, (iii) a minimum interest coverage test, and (iv) a prohibition of most debt and corporate guarantees. Additionally, there is a limitation on the aggregate amount of forecasted production that can be economically hedged with oil or natural gas derivative contracts. We were in compliance with all of our bank covenants as of December 31, 2007. Borrowings under the credit facility are generally in tranches that can have maturities up to one year. Interest on any borrowings is based on the Prime Rate or LIBOR rate plus an applicable margin as determined by the borrowings outstanding. The facility matures in September 2011.

As of December 31, 2007, we had $150.0 million of outstanding borrowings under the facility and $10.5 million in letters of credit secured by the facility. The weighted average interest rate on these outstanding borrowings was 6.2% at December 31, 2007. The next scheduled redetermination of the borrowing base will be as of April 1, 2008, based on December 31, 2007 assets and proved reserves.

Indebtedness Repayment Schedule

At December 31, 2007, our indebtedness, excluding the discount and premium on our senior subordinated debt, is repayable over the next five years and thereafter as follows:

(In Thousands)

2008	$ 737
2009	1,031
2010	890
2011	150,978
2012	1,027
Thereafter	526,739
Total indebtedness	$ 681,402

Note 7. Income Taxes

Our income tax provision is as follows:

(In Thousands)	Year Ended December 31, 2007	2006	2005
Current income tax expense:			
Federal	**$ 21,948**	$ 16,033	$26,659
State	**8,126**	3,832	518
Total current income tax expense	**30,074**	19,865	27,177
Deferred income tax expense (benefit):			
Federal	**113,868**	97,902	44,191
State	**(3,675)**	9,350	10,202
Total deferred income tax expense	**110,193**	107,252	54,393
Total income tax expense	**$140,267**	$127,117	$81,570

At December 31, 2007, we have no net operating loss carryforwards. As of December 31, 2007, we have an estimated $37 million of enhanced oil recovery credits to carry forward related to our tertiary operations. These credits will begin to expire in 2024.

Deferred income taxes relate to temporary differences based on tax laws and statutory rates in effect at the December 31, 2007 and 2006, balance sheet dates. We believe that we will be able to realize all of our deferred tax assets at December 31, 2007, and therefore have provided no valuation allowance against our deferred tax assets.

At December 31, 2007 and 2006, our deferred tax assets and liabilities were as follows:

(In Thousands)	December 31, 2007	2006
Deferred tax assets:		
Loss carryforwards – state	**$ —**	$ 792
Tax credit carryover	**15,631**	14,103
Enhanced oil recovery credit carryforwards	**37,257**	41,856
Other	**19,950**	7,791
Total deferred tax assets	**72,838**	64,542
Deferred tax liabilities:		
Property and equipment	**(406,632)**	(283,983)
Derivative hedging contracts	**(868)**	(10,484)
Total deferred tax liabilities	**(407,500)**	(294,467)
Total net deferred tax liability	**$(334,662)**	$(229,925)

Our income tax provision varies from the amount that would result from applying the federal statutory income tax rate to income before income taxes as follows:

	Year Ended December 31,		
(In Thousands)	2007	2006	2005
Income tax provision calculated using the federal statutory income tax rate	**$137,695**	$115,351	$ 86,814
State income taxes	**11,536**	13,183	9,922
Estimated statutory rate change	**(7,351)**	—	—
Enhanced oil recovery credits	**—**	—	(17,142)
Other	**(1,613)**	(1,417)	1,976
Total income tax expense	**$140,267**	$127,117	$ 81,570

Uncertain Tax Positions

We adopted the provisions of FIN 48 as of January 1, 2007. As a result of the implementation, we determined that approximately $4.0 million of tax benefits previously recognized were considered uncertain tax positions, as the timing of these deductions may not be sustained upon examination by taxing authorities. As such, upon adoption of FIN 48, we recorded income taxes payable of $4.3 million (including $0.3 million in estimated interest) which was offset by a corresponding reduction of the deferred tax liability of $4.1 million for the tax position that we believe will ultimately be sustained. At January 1, 2007, the total amount of unrecognized tax benefits was $4.5 million, exclusive of interest.

There was no cumulative adjustment made to the opening balance of retained earnings at January 1, 2007. Our uncertain tax positions relate primarily to timing differences, and we do not believe any of such uncertain tax positions will materially impact our effective tax rate in future periods. The amount of unrecognized tax benefits are expected to change over the next 12 months; however, such change is not expected to have a significant impact on our results of operations or financial position.

We file consolidated and separate income tax returns in the U.S. federal jurisdiction and in many state jurisdictions. We are currently under examination by the Internal Revenue Service and different state authorities. The Internal Revenue Service concluded its examination of our 2004 tax year during the third quarter of 2007 and began an examination of our 2005 tax year during the fourth quarter of 2007. The state of Mississippi concluded its audit of tax years 1998 through 2000 during the third quarter of 2007 and is currently examining years 2001 through 2004. Neither of the concluded examinations by the Internal Revenue Service and the state of Mississippi resulted in any material assessments. As a result of the examinations concluded during the third quarter, we decreased our total amount of unrecognized tax benefits from $4.5 million to $3.5 million. These adjustments all related to temporary timing differences and did not have any impact on our effective tax rate.

The following table summarizes the changes in our liability for unrecognized tax benefits for the year ended December 31, 2007:

(In Thousands)	
Unrecognized tax benefit at January 1, 2007	**$ 4,462**
Settlements	**(1,005)**
Unrecognized tax benefit at December 31, 2007	**$ 3,457**

We have not paid any significant interest or penalties associated with our income taxes, but classify both interest expense and penalties as part of our income tax expense.

Note 8. Stockholders' Equity

Authorized

We are authorized to issue 600 million shares of common stock, par value $.001 per share, and 25 million shares of preferred stock, par value $.001 per share. The preferred shares may be issued in one or more series with rights and conditions determined by the Board of Directors.

Stock Splits

Stockholders of Denbury approved two 2-for-1 stock splits (described below) during the three-year period ended December 31, 2007. Information pertaining to shares and earnings per share has been retroactively adjusted in the accompanying financial statements and related notes thereto to reflect the stock splits, except for the share amounts included on our Consolidated Balance Sheets and Consolidated Statements of Changes in Stockholders' Equity, which reflect the actual shares outstanding at each period end.

On November 19, 2007, stockholders of Denbury Resources Inc. approved an amendment to our Restated Certificate of Incorporation to increase the number of shares of our authorized common stock from 250,000,000 shares to 600,000,000 shares and to split our common stock on a 2-for-1 basis. Stockholders of record on December 5, 2007, received one additional share of Denbury common stock for each share of common stock held at that time.

On October 19, 2005, stockholders of Denbury Resources Inc. approved an amendment to our Restated Certificate of Incorporation to increase the number of shares of our authorized common stock from 100,000,000 shares to 250,000,000 shares and to split our common stock on a 2-for-1 basis. Stockholders of record on October 31, 2005, received one additional share of Denbury common stock for each share of common stock held at that time.

Stock Issuance

On April 25, 2006, we sold 6,985,190 shares (3,492,595 on a pre-split basis) of common stock in a public offering for $125 million (net to Denbury). We used the net proceeds from the offering to repay then current borrowings under our bank credit facility, which were $120 million as of April 25, 2006, the majority of which was incurred to partially fund our $250 million acquisition of three properties in January 2006.

Stock Repurchases

In 2006 and 2007, all of our share repurchases were from employees of Denbury that delivered shares to the Company to satisfy their minimum tax withholding requirements as provided for under Denbury's stock compensation plans and were not part of a formal stock repurchase plan.

Employee Stock Purchase Plan

We have an Employee Stock Purchase Plan that is authorized to issue up to 7,400,000 shares of common stock. As of December 31, 2007, there were 779,093 authorized shares remaining to be issued under the plan. In accordance with the plan, eligible employees may contribute up to 10% of their base salary and Denbury matches 75% of their contribution. The combined funds are used to purchase previously unissued Denbury common stock or treasury stock purchased by the Company in the open market for that purpose, in either case, based on the market value of Denbury's common stock at the end of each quarter. We recognize compensation expense for the 75% company match portion, which totaled $2.2 million, $1.7 million and $1.2 million for the years ended December 31, 2007, 2006 and 2005, respectively. This plan is administered by the Compensation Committee of Denbury's Board of Directors.

401(k) Plan

Denbury offers a 401(k) Plan to which employees may contribute tax deferred earnings subject to Internal Revenue Service limitations. Up to 3% of an employee's compensation, as defined by the plan, is matched by Denbury at 100%, and an employee's contribution between 3% and 6% of compensation is matched by Denbury at 50%. Effective January 1, 2008, Denbury increased its match to 100% of an employee's contribution, up to 6% of compensation. Denbury's match is vested immediately. During 2007, 2006 and 2005, Denbury's matching contributions were approximately $2.2 million, $1.6 million and $1.2 million, respectively, to the 401(k) Plan.

Note 9. Stock Compensation Plans

Stock Incentive Plans

Denbury has two stock compensation plans. The first plan has been in existence since 1995 (the "1995 Plan") and expired in August 2005 (although options granted under the 1995 Plan prior to that time can remain outstanding for up to 10 years). The 1995 Plan only provided for the issuance of stock options, and in January 2005, we issued stock options under the 1995 Plan that utilized substantially all of the remaining authorized shares. The second plan, the 2004 Omnibus Stock and Incentive Plan (the "2004 Plan"), has a 10-year term and was approved by the stockholders in May 2004. In May 2007, shareholders approved an increase to the number of shares that may be used under our 2004 Plan, from 10.0 million to 14.0 million shares. The 2004 Plan provides for the issuance of incentive and non-qualified stock options, restricted stock awards, stock appreciation rights ("SARs") settled in stock, and performance awards that may be issued to officers, employees, directors and consultants. Awards covering a total of 14.0 million shares of common stock are authorized for issuance pursuant to the 2004 Plan, of which awards covering no more than 6.7 million shares may be issued in the form of restricted stock or performance vesting awards. At December 31, 2007, a total of 5,168,519 shares were available for future issuance of awards, of which only 1,580,684 shares may be in the form of restricted stock or performance vesting awards.

Denbury has historically granted incentive and non-qualified stock options to its employees. Effective January 1, 2006, we completely replaced the use of stock options for employees with SARs settled in stock, as SARs are less dilutive to our stockholders while providing an employee with essentially the same economic benefits as stock options. The stock options and SARs generally become exercisable over a four-year vesting period with the specific terms of vesting determined at the time of grant based on guidelines established by the Board of Directors. The stock options and SARs expire over terms not to exceed 10 years from the date of grant, 90 days after termination of employment, and 90 days or one year after permanent disability, depending on the plan, or one year after the death of the optionee. The stock options and SARs are granted at the fair market value at the time of grant, which is defined in the 2004 Plan as the closing price on the NYSE on the date of grant. The plan is administered by the Compensation Committee of Denbury's Board of Directors.

In 2004, Denbury began the use of restricted stock awards for its officers and independent directors, all granted under the 2004 Plan. The holders of these shares have all of the rights and privileges of owning the shares (including voting rights) except that the holders are not entitled to delivery of a portion thereof until certain requirements are met. With respect to the restricted stock granted to officers of Denbury in 2004, the vesting restrictions on those shares are as follows: i) 65% of the awards vest 20% per year over five years, and ii) 35% of the awards vest upon retirement, as defined in the 2004 Plan. With respect to the 65% of the awards that vest over five years, on each annual vesting date, 66-2/3% of the vested shares may be delivered to the holder with the remaining 33-1/3% retained and held in escrow until the holder's separation from the Company. With respect to the restricted shares issued to Denbury's independent board members, the shares vest 20% per year over five years. For these directors' shares, on each annual vesting date, 40% of such vested shares may be delivered to the holder with the remaining 60% retained and held in escrow until the holder's separation from the Company.

In the second quarter of 2006, our Senior Vice President of Operations departed Denbury. The Board of Directors modified certain of his outstanding long-term equity incentives awarded to him during 2003 and 2004. As a result of the modification, compensation cost of approximately $5.3 million was included in "General and administrative expenses" in the Consolidated Statement of Operations for the year ended December 31, 2006. During the third quarter of 2006, our Vice President of Marketing announced his retirement and departed the Company on August 31, 2006, in connection with which we expensed approximately $750,000 related to options and restricted stock that he held.

Total compensation expense charged against income for stock-based compensation was $10.6 million and $17.2 million (including the $5.3 million resulting from modification of equity awards discussed above) for the years ended December 31, 2007 and 2006, respectively. Part of this expense, $1.5 million in each year, was included in "Lease operating expenses" for stock compensation expense associated with our field employees, and the remaining amount recognized in "General and administrative expenses" in the Consolidated Statements of Operations. The total income tax benefit recognized in the Consolidated Statements of Operations for share-based compensation arrangements was $4.1 million and $4.6 million for the years ended December 31, 2007 and 2006, respectively. Share-based compensation capitalized as part of "Oil and Natural Gas Properties" was $1.6 million and $1.7 million for the years ended December 31, 2007 and 2006, respectively.

Effective January 1, 2006, we adopted SFAS No. 123(R) to account for our employee stock based compensation. Prior to 2006, we accounted for stock-based compensation utilizing the recognition and measurement principles of Accounting Principles Board Opinion 25 ("APB 25"), "Accounting for Stock Issued to Employees," and its related interpretations. Under these principles, no compensation expense for stock options was reflected in net income as long as the stock options had an exercise price equal to the quoted market price of the underlying common stock on the date of grant. For restricted stock grants, we recognize compensation expense equal to the intrinsic value of the stock on the date of grant over the applicable vesting periods. The following table illustrates the effect on net income and net income per common share for 2005 as if we had applied the fair value recognition and measurement provisions of SFAS No. 123, as amended by SFAS No. 148, in accounting for our stock-based compensation.

Amounts in thousands, except per share amounts	Year Ended December 31, 2005
Net income, as reported	$166,471
Add: stock-based compensation included in reported net income, net of related tax effects	2,765
Less: stock-based compensation expense applying fair value based method, net of related tax effects	8,425
Pro-forma net income	$160,811
Net income per common share	
As reported:	
Basic	$ 0.74
Diluted	0.70
Pro forma:	
Basic	$ 0.72
Diluted	0.68

Prior to the adoption of SFAS No. 123(R) on January 1, 2006, we did not assume the capitalization of any stock-based compensation in our SFAS No. 123 pro forma net income. As a result, no stock-based compensation expense is reflected as being capitalized in the table above. Beginning in 2006, an appropriate portion of stock-based compensation associated with our employees involved in our exploration and drilling activities has been capitalized as part of our "Oil and Natural Gas Properties" in the Consolidated Balance Sheet. The effect of applying SFAS No. 123(R) during the years ended December 31, 2007 and 2006, was to decrease net income by approximately $3.5 million and $6.4 million, respectively, for stock compensation expense that would only have been presented in footnote disclosures under the old requirements of SFAS No. 123. The effect on earnings per share for the year ended December 31, 2007 and 2006, was a decrease of $0.01 and $0.03, respectively, per both basic and diluted share. Additionally, cash flow from operations was lower and cash flow from financing activities was higher by approximately $19.2 million and $16.6 million for the years ended December 31, 2007 and 2006, respectively, associated with the tax benefit for tax deductions in excess of recognized compensation expenses that is now required to be reported as a financing cash flow.

Stock Options and SARs

The fair value of each stock option or SAR award is estimated on the date of grant using the Black-Scholes option pricing model with the assumptions noted in the following table. The risk-free rate for periods within the contractual life of the option is based on the U.S. Treasury yield curve in effect at the time of grant. The expected life of stock options and SARs granted was derived from examination of our historical option grants and subsequent exercises. The contractual terms (4-year cliff vesting and 4-year graded vesting) are evaluated separately for the expected life, as the exercise behavior for each is different. Expected volatilities are based on the historical volatility of our stock. Implied volatility was not used in this analysis as our tradable call option terms are short and the trading volume is low. Our dividend yield is zero, as Denbury does not pay a dividend.

	2007	2006	2005
Weighted average fair value of options granted	**$6.90**	$6.32	$3.47
Risk free interest rate	**4.54%**	4.52%	3.80%
Expected life	**4.6 to 6.4 years**	4.9 to 6.9 years	5 years
Expected volatility	**38.3%**	41.1%	42.6%
Dividend yield	**—**	—	—

The following is a summary of our stock option and SARs activity.

	Year Ended December 31,					
	2007		2006		2005	
	Number of Options	Weighted Average Price	Number of Options	Weighted Average Price	Number of Options	Weighted Average Price
Outstanding at beginning of year	**14,964,920**	**$ 4.96**	18,812,144	$ 4.04	17,760,628	$ 2.63
Granted	**873,649**	**16.34**	1,034,310	13.58	4,966,508	8.15
Exercised	**(4,054,844)**	**3.44**	(4,032,652)	2.77	(3,594,292)	2.69
Forfeited	**(320,440)**	**7.90**	(848,882)	5.53	(320,700)	4.43
Outstanding at end of year	**11,463,285**	**6.28**	14,964,920	4.96	18,812,144	4.04
Exercisable at end of year	**3,969,466**	**$ 3.26**	4,739,104	$ 2.66	5,019,270	$ 2.25

The total intrinsic value of stock options and SARs exercised during the years ended December 31, 2007, 2006 and 2005, was approximately $60.3 million, $49.3 million and $24.8 million, respectively. The total grant-date fair value of stock options and SARs vested during the years ended December 31, 2007, 2006 and 2005, was approximately $6.8 million, $6.0 million and $3.4 million, respectively. The aggregate intrinsic value of stock options and SARs outstanding at December 31, 2007, was approximately $269.1 million, and these options and SARs have a weighted-average remaining contractual life of 6.1 years. The aggregate intrinsic value of options exercisable at December 31, 2007, was approximately $105.1 million, and these stock options and SARs have a weighted-average remaining contractual life of 4.2 years.

A summary of the status of our non-vested stock options and SARs as of December 31, 2007, and the changes during the year ended December 31, 2007, is presented below:

Non-Vested Stock Options and SARs	Shares	Weighted Average Grant-Date Fair Value
Non-vested at January 1, 2007	**10,225,816**	**$ 2.71**
Granted	**873,649**	**6.90**
Vested	**(3,285,206)**	**2.06**
Forfeited	**(320,440)**	**3.39**
Non-vested at December 31, 2007	**7,493,819**	**3.45**

As of December 31, 2007, there was $9.8 million of total compensation cost to be recognized in future periods related to non-vested stock option and SAR share-based compensation arrangements. The cost is expected to be recognized over a weighted-average period of 1.2 years. Cash received from stock option exercises under share-based payment arrangements for the years ended December 31, 2007, 2006 and 2005, was $13.1 million, $11.1 million and $9.7 million, respectively. The tax benefit realized from the exercises of stock options and SARs totaled $18.7 million for 2007, $14.7 million for 2006, and $8.6 million for 2005.

Restricted Stock

As of December 31, 2007, we had issued 5,267,082 shares of restricted stock pursuant to the 2004 Plan and have recorded deferred compensation expense of $32.6 million, the fair market value of the shares on the grant dates, net of estimated forfeitures of $1.2 million. This expense is amortized over the applicable five-year, four-year, or retirement date vesting periods. As of December 31, 2007, there was $14.2 million of unrecognized compensation expense related to non-vested restricted stock grants. This unrecognized compensation cost is expected to be recognized over a weighted-average period of 2.5 years.

A summary of the status of our non-vested restricted stock grants and the changes during the year ended December 31, 2007, is presented below:

Non-Vested Restricted Stock Grants	Shares	Weighted-Average Grant Date Fair Value
Non-vested at beginning of year	2,887,922	$ 5.90
Granted	367,108	17.67
Vested	(531,402)	6.02
Forfeited	(21,180)	7.70
Non-vested at end of year	2,702,448	7.46

The total vesting date fair value of restricted stock vested during the years ended December 31, 2007, 2006 and 2005 was $10.7 million, $17.4 million and $7.1 million, respectively.

Performance Equity Awards

On January 2, 2007, the Board of Directors awarded performance equity awards to the officers of Denbury. These performance-based shares will vest on March 31, 2010, when the Company's various financial and operational results for 2009 will have been finalized. The number of performance-based shares that will be earned (and eligible to vest) during the performance period will depend on the Company's level of success in achieving four specifically identified performance targets. Generally, one-half of the shares earnable under the performance-based shares will be earned for performance at the designated target levels (100% target vesting levels) or upon any earlier change of control, and twice the number of shares will be earned if the higher maximum target levels are met. If performance is below designated minimum levels for all performance targets, no performance-based shares will be earned. Any portion of the performance shares that are not earned by the end of the three year measurement period will be forfeited. In certain change of control events, one-half (i.e. the target level amount) of the performance-based shares would vest.

The number of performance-based shares (at the 100% targeted vesting level) granted to the Company's executive officers is 107,918 shares. The actual number of shares to be delivered pursuant to the performance-based shares could range from zero to 200% (215,836 shares) of the stated 100% targeted amount. These performance-based share awards have a grant date fair value of $13.90 per share. The Company recognizes compensation expense when it becomes probable that the performance criteria specified in the plan will be achieved. We currently estimate that the 100% targeted vesting level amount is probable. During the year ended December 31, 2007, we recorded $0.4 million of expense in "General and administrative expenses" in our Consolidated Statement of Operations for these performance-based awards.

Note 10. Derivative Instruments and Hedging Activities

Oil and Gas Derivative Contracts

Effective January 1, 2005, we elected to discontinue hedge accounting treatment for financial statement purposes for our oil and natural gas derivative contracts and accordingly de-designated our derivative instruments from hedge accounting treatment in accordance with SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activites." As a result of this change, we began accounting for our oil and natural gas derivative contracts as speculative contracts in the first quarter of 2005. As speculative contracts, the changes in the fair value of these instruments are recognized in income in the period of change. Additionally, the balance remaining in "Accumulated Comprehensive Loss" at December 31, 2004, related to the de-designated derivative contracts, was amortized over the remaining life of the contracts, all of which expired in 2005.

From time to time, we enter into various derivative contracts to economically hedge our exposure to commodity price risk associated with anticipated future oil and natural gas production. We do not hold or issue derivative financial instruments for trading purposes. These contracts have consisted of price floors, collars and fixed price swaps. Historically, prior to 2005, we hedged up to 75% of our anticipated production each year to provide us with a reasonably certain amount of cash flow to cover most of our budgeted exploration and development expenditures without incurring significant debt. Since 2005 and beyond, we have entered into fewer derivative contracts, primarily because of our strong financial position resulting from our lower levels of debt relative to our cash flow from operations. We did enter into natural gas contracts in late 2006 and September 2007 as we believed that there is more risk with regard to natural gas prices and the fact that we planned to spend significantly more than our expected cash flow in the ensuing year. In late 2006, we swapped 80% to 90% of our forecasted 2007 natural gas production at a weighted average price of $7.96 per Mcf, and in September 2007, we swapped 70% to 80% of our 2008 natural gas production (after the sale of our Louisiana natural gas properties) at a weighted average price of $7.91 per Mcf.

When we make a significant acquisition, we generally attempt to hedge a large percentage, up to 100%, of the forecasted production for the subsequent one to three years following the acquisition in order to help provide us with a minimum return on our investment. As of December 31, 2007, we had derivative contracts in place related to the $250 million acquisition that closed January 31, 2006, on which we entered into contracts to cover 100% of the estimated proved production for three years at the time we signed the purchase and sale agreement.

All of the mark-to-market valuations used for our financial derivatives are provided by external sources and are based on prices that are actively quoted. We manage and control market and counterparty credit risk through established internal control procedures, which are reviewed on an ongoing basis. We attempt to minimize credit risk exposure to counterparties through formal credit policies, monitoring procedures and diversification.

The following is a summary of "Commodity derivative (expense) income," included in our Consolidated Statements of Operations:

	Year Ended December 31,		
(In Thousands)	2007	2006	2005
Receipt (payment) on settlements of derivative contracts – oil	**$ (9,833)**	$ (5,302)	$ —
Receipt (payment) on settlements of derivative contracts – gas	**30,313**	—	(16,761)
Reclassification of accumulated other comprehensive income balance	**—**	—	(7,684)
Fair value adjustments to derivative contracts – income (expense)	**(39,077)**	25,130	(4,517)
Commodity derivative (expense) income	**$(18,597)**	$19,828	$(28,962)

Oil and Natural Gas Derivative Contracts at December 31, 2007:

Crude Oil Contracts:

	NYMEX Contract Prices Per Bbl		Estimated Fair Value Asset (Liability) at December 31, 2007 (In Thousands)
Type of Contract and Period	Bbls/d	Swap Price	
Swap Contracts			
Jan. 2008 – Dec. 2008	**2,000**	**$ 57.34**	**$ (25,614)**

Natural Gas Contracts:

	NYMEX Contract Prices Per MMBtu		Estimated Fair Value Asset (Liability) at December 31, 2007 (In Thousands)
Type of Contract and Period	MMBtu/d	Swap Price	
Swap Contracts			
Jan. 2008 – Dec. 2008	**20,000**	**$ 7.89**	**$ 594**
Jan. 2008 – Dec. 2008	**20,000**	**7.91**	**737**
Jan. 2008 – Dec. 2008	**20,000**	**7.94**	**952**

At December 31, 2007, our derivative contracts were recorded at their fair value, which was a net liability of $23.3 million.

Interest Rate Lock Derivative Contracts

In January 2007, we entered into interest rate lock contracts to remove our exposure to possible interest rate fluctuations related to our commitment to the sale-leaseback financing of certain equipment for CO_2 recycling facilities at our tertiary oil fields. We are applying hedge accounting to these contracts as provided under SFAS No. 133. For these instruments designated as interest rate hedges, changes in fair value, to the extent the hedge is effective, are recognized in other comprehensive income (loss) until the hedged item is recognized in earnings. Amounts representing hedge ineffectiveness are recorded in earnings. Hedge effectiveness is assessed quarterly based on the total change in the contract's fair value.

At December 31, 2007, the interest rate lock contracts had a fair value liability of approximately $2.5 million that was recorded in our December 31, 2007, Consolidated Balance Sheet. This $2.5 million liability includes approximately $1 million related to the contracts that settled on December 31, 2007 (payment made to the counterparty in January 2008 in this amount), which were designated as a hedge of our equipment leases which also closed on December 31, 2007. We recorded $1.6 million (net of taxes of $1.0 million) in accumulated other comprehensive income in our December 31, 2007, Consolidated Balance Sheet and the ineffectiveness totaling $0.1 million was recognized as income in our Consolidated Statement of Operations for the year ended December 31, 2007.

Note 11. Commitments and Contingencies

We have operating leases for the rental of equipment, office space and vehicles that totaled $143.8 million, $101.4 million and $37.2 million as of December 31, 2007, 2006 and 2005, respectively. During the last five years, we entered into lease financing agreements for equipment at certain of our oil and natural gas properties and CO_2 source fields. These lease financings totaled $27.1 million during 2007, $41.1 million during 2006, and $17.3 million during 2005 with associated required monthly payments of $257,000 for the 2007 leases, $431,000 for the 2006 leases, and $223,000 for the 2005 leases. Leases entered into prior to 2006 have seven-year terms, and the leases entered into in 2006 and 2007 have 10-year terms. Rental expense for operating leases totaled $23.4 million in 2007, $14.1 million in 2006, and $8.2 million in 2005.

In 2005 and 2006, we entered into three agreements with Genesis to transport crude oil and CO_2. These agreements are accounted for as capital leases and are discussed in detail in Note 3.

At December 31, 2007, long-term commitments for these items require the following future minimum rental payments:

(In Thousands)	Capital Leases	Operating Leases
2008	$ 1,291	$ 17,580
2009	1,529	17,128
2010	1,291	16,745
2011	1,291	16,185
2012	1,242	14,957
Thereafter	2,094	61,173
Total minimum lease payments	8,738	$143,768
Less: Amount representing interest	(2,336)	
Present value of minimum lease payments	$ 6,402	

Long-term contracts require us to deliver CO_2 to our industrial CO2 customers at various contracted prices, plus we have a CO_2 delivery obligation to Genesis related to three CO_2 volumetric production payments ("VPPs") (see Note 3). Based upon the maximum amounts deliverable as stated in the industrial contracts and the volumetric production payments, we estimate that we may be obligated to deliver up to 562 Bcf of CO_2 to these customers over the next 20 years, with a maximum volume required in any given year of approximately 142 MMcf/d. However, since the group as a whole has historically purchased less CO_2 than the maximum allowed in their contracts, based on the current level of deliveries, we project that the amount of CO_2 that we will ultimately be required to deliver will be significantly less than the contractual commitment. Given the size of our proven CO_2 reserves at December 31, 2007 (approximately 5.6 Tcf before deducting approximately 182.3 Bcf for the VPPs with Genesis), our current production capabilities and our projected levels of CO_2 usage for our own tertiary flooding program, we believe that we can meet these contractual delivery obligations.

We currently have long-term commitments to purchase manufactured CO_2 from three proposed gasification plants, if these plants are built, two proposed by the developers of Faustina Hydrogen Products LLC and another by Rentech Inc. If all three plants are built, these synthetic sources are currently anticipated to provide us with an aggregate of 750 MMcf/d to 850 MMcf/d of CO_2 by 2013. The base price of CO_2 per Mcf from these synthetic sources is currently expected to be 1.5 to 2.0 times higher than our most recent all-in cost of CO_2 from our natural sources (Jackson Dome) using current oil prices and assuming comparable compression levels. These predicted synthetic CO_2 prices are expected to be competitive with the cost of our natural CO_2 after adjusting for our share of potential carbon emissions credits using estimated current prices of CO_2 carbon credit futures. If all three plants are built, the aggregate purchase obligation for this CO_2 would be around $190 million per year, assuming a $90 per barrel oil price and comparable compression levels, before any potential savings from our share of carbon emissions credits. All of the contracts have price adjustments that fluctuate based on the price of oil. Construction has not yet commenced on any of these plants, and their construction is contingent on the satisfactory resolution of various issues, including financing; although based on their public representations, the initial Faustina plant is currently scheduled to begin construction during 2008, with completion scheduled in late 2010 or 2011. We have invested a total of $8.6 million during 2006 and 2007 in preferred stock of the Faustina plant. All of our investment may later be redeemed, with a return, or converted to equity after construction financing for the project has been obtained, currently expected to occur some time during 2008. We have recorded our investment in this debt security at cost and classified it as held-to-maturity, since we have the intent and ability to hold it until it is redeemed. The investment is included in "Other assets" in our Consolidated Balance Sheets.

Denbury is subject to various possible contingencies that arise primarily from interpretation of federal and state laws and regulations affecting the oil and natural gas industry. Such contingencies include differing interpretations as to the prices at which oil and natural gas sales may be made, the prices at which royalty owners may be paid for production from their leases, environmental issues and other matters. Although management believes that it has complied with the various laws and regulations, administrative rulings and interpretations thereof, adjustments could be required as new interpretations and regulations are issued. In addition, production rates, marketing and environmental matters are subject to regulation by various federal and state agencies.

Litigation

We are involved in various lawsuits, claims and regulatory proceedings incidental to our businesses. While we currently believe that the ultimate outcome of these proceedings, individually and in the aggregate, will not have a material adverse effect on our financial position or overall trends in results of operations or cash flows, litigation is subject to inherent uncertainties. If an unfavorable ruling were to occur, there exists the possibility of a material adverse impact on our net income in the period in which the ruling occurs. We provide accruals for litigation and claims if we determine that we may have a range of legal exposure that would require accrual.

Note 12. Supplemental Information

Significant Oil and Natural Gas Purchasers

Oil and natural gas sales are made on a day-to-day basis or under short-term contracts at the current area market price. The loss of any purchaser would not be expected to have a material adverse effect upon our operations. For the year ended December 31, 2007, we had three significant purchasers that each accounted for 10% or more of our oil and natural gas revenues: Marathon Ashland Petroleum LLC (43%), Hunt Crude Oil Supply Co. (19%) and Crosstex Energy Field Services Inc. (16%). For the year ended December 31, 2006, two purchasers each accounted for 10% or more of our oil and natural gas revenues: Marathon Ashland Petroleum LLC (28%) and Hunt Crude Oil Supply Co. (18%). For the year ended December 31, 2005, we had three significant purchasers that each accounted for 10% or more of our oil and natural gas revenues: Marathon Ashland Petroleum LLC (28%), Hunt Crude Oil Supply Co. (20%) and Sunoco, Inc. (13%).

Accounts Payable and Accrued Liabilities

(In Thousands)	December 31, 2007	December 31, 2006
Accounts payable	**$ 59,076**	$ 57,637
Accrued exploration and development costs	**36,409**	36,830
Accrued lease operating expense	**10,114**	8,178
Hastings purchase option – current	**4,709**	6,794
Accrued compensation	**10,872**	6,361
Accrued interest	**5,716**	5,233
Taxes payable	**8,103**	4,447
Asset retirement obligations – current	**2,304**	1,776
Other	**10,277**	11,855
Total	**$147,580**	$139,111

Supplemental Cash Flow Information

(In Thousands)	Year Ended December 31, 2007	2006	2005
Interest paid, net of amounts capitalized	**$ 27,892**	$ 21,514	$ 16,622
Interest capitalized	**20,385**	11,333	1,649
Income taxes paid	**10,277**	4,210	21,000

During 2007 and 2006, we capitalized $18.3 million and $11.0 million of interest, respectively, on our significant unevaluated properties, primarily related to our CO_2 tertiary floods without proved reserves. Additionally, we capitalized $2.1 million in 2007, $0.3 million in 2006, and $1.6 million in 2005 of interest relating to the construction of our CO_2 pipelines. We recorded a non-cash increase to property and debt in the amount of $1.2 million in 2006, and $2.4 million in 2005, related to capital leases. In 2007, we issued 367,108 shares of restricted stock with a market value of $6.5 million on the date of grant. In 2006, we issued 259,974 shares of restricted stock with a market value of $3.8 million on the date of grant. In 2005, we issued 40,000 shares of restricted stock with a market value of $0.3 million on the date of grant. See Note 9, "Stock Compensation Plans - Restricted Stock."

In November 2006, we entered into an agreement for the option to purchase an oil property for an upfront payment of $37.5 million, plus required additional payments totaling $12.5 million during the following two years. In 2006, we accrued the discounted present value of these required additional payments and recorded this amount plus the upfront payment in "Deposits on properties under option or contract" on our December 31, 2006, Consolidated Balance Sheet. The upfront payment of $37.5 million in 2006 and the $7.5 million payment we made in 2007 are recorded on our Consolidated Statements of Cash Flow under "Investing Activities."

Fair Value of Financial Instruments

(In Thousands)	December 31, 2007 Carrying Amount	2007 Estimated Fair Value	2006 Carrying Amount	2006 Estimated Fair Value
7.5% Senior Subordinated Notes due 2013	**$223,980**	**$227,250**	$223,786	$227,250
7.5% Senior Subordinated Notes due 2015	**300,685**	**303,000**	150,000	152,250
Senior Bank Loan	**150,000**	**150,000**	134,000	134,000

The fair values of our senior subordinated notes are based on quoted market prices. The carrying value of our Senior Bank Loan is approximately fair value based on the fact that it is subject to short-term floating interest rates that approximate the rates available to us for those periods. We have other financial instruments consisting primarily of cash, cash equivalents, short-term receivables and payables that approximate fair value due to the nature of the instrument and the relatively short maturities.

Note 13. Condensed Consolidating Financial Information

Our subordinated debt is fully and unconditionally guaranteed jointly and severally by all of Denbury Resources Inc.'s subsidiaries other than minor subsidiaries, except that with respect to our $225 million of 7.5% Senior Subordinated Notes due 2013, Denbury Resources Inc. and Denbury Onshore, LLC are co-obligors. Except as noted in the foregoing sentence, Denbury Resources Inc. is the sole issuer and Denbury Onshore, LLC is a subsidiary guarantor. The results of our equity interest in Genesis are reflected through the equity method by one of our subsidiaries, Denbury Gathering & Marketing. Each subsidiary guarantor and the subsidiary co-obligor are 100% owned, directly or indirectly, by Denbury Resources Inc. The following is condensed consolidating financial information for Denbury Resources Inc., Denbury Onshore, LLC, and subsidiary guarantors:

Condensed Consolidating Balance Sheets

	December 31, 2007				
(In Thousands)	Denbury Resources Inc. (Parent and Co-Obligor)	Denbury Onshore, LLC (Issuer and Co-Obligor)	Guarantor Subsidiaries	Eliminations	Denbury Resources Inc. Consolidated
Assets					
Current assets	**$ 430,518**	**$ 237,273**	**$ 7,263**	**$ (434,695)**	**$ 240,359**
Property and equipment	**—**	**2,392,865**	**10**	**—**	**2,392,875**
Investment in subsidiaries (equity method)	**1,018,397**	**—**	**905,796**	**(1,924,193)**	**—**
Other assets	**312,556**	**78,230**	**113,633**	**(366,576)**	**137,843**
Total assets	**$ 1,761,471**	**$ 2,708,368**	**$ 1,026,702**	**$ (2,725,464)**	**$ 2,771,077**
Liabilities and Stockholders' Equity					
Current liabilities	**$ —**	**$ 691,062**	**$ 8,266**	**$ (434,695)**	**$ 264,633**
Long-term liabilities	**300,686**	**1,111,510**	**39**	**(310,169)**	**1,102,066**
Stockholders' equity	**1,460,785**	**905,796**	**1,018,397**	**(1,980,600)**	**1,404,378**
Total liabilties and stockholders' equity	**$ 1,761,471**	**$ 2,708,368**	**$ 1,026,702**	**$ (2,725,464)**	**$ 2,771,077**

	December 31, 2006				
(In Thousands)	Denbury Resources Inc. (Parent and Co-Obligor)	Denbury Onshore, LLC (Issuer and Co-Obligor)	Guarantor Subsidiaries	Eliminations	Denbury Resources Inc. Consolidated
Assets					
Current assets	$ 392,372	$ 180,476	$ 3,662	$ (393,241)	$ 183,269
Property and equipment	—	1,879,742	26	—	1,879,768
Investment in subsidiaries (equity method)	709,611	—	698,380	(1,407,991)	—
Other assets	154,076	64,391	10,794	(152,461)	76,800
Total assets	$1,256,059	$2,124,609	$ 712,862	$(1,953,693)	$ 2,139,837
Liabilities and Stockholders' Equity					
Current liabilities	$ —	$ 590,602	$ 3,037	$ (393,241)	$ 200,398
Long-term liabilities	150,000	835,627	214	(152,461)	833,380
Stockholders' equity	1,106,059	698,380	709,611	(1,407,991)	1,106,059
Total liabilties and stockholders' equity	$1,256,059	$2,124,609	$ 712,862	$(1,953,693)	$ 2,139,837

Condensed Consolidating Statements of Operations

	Year Ended December 31, 2007				
(In Thousands)	Denbury Resources Inc. (Parent and Co-Obligor)	Denbury Onshore, LLC (Issuer and Co-Obligor)	Guarantor Subsidiaries	Eliminations	Denbury Resources Inc. Consolidated
Revenues	**$ 19,594**	**$ 953,398**	**$ 18,552**	**$ (19,594)**	**$ 971,950**
Expenses	**20,046**	**554,540**	**23,544**	**(19,594)**	**578,536**
Income before the following:	**(452)**	**398,858**	**(4,992)**	**—**	**393,414**
Equity in net earnings of subsidiaries	**253,970**	**—**	**257,554**	**(511,524)**	**—**
Income before income taxes	**253,518**	**398,858**	**252,562**	**(511,524)**	**393,414**
Income tax provision (benefit)	**371**	**141,305**	**(1,409)**	**—**	**140,267**
Net income	**$ 253,147**	**$ 257,553**	**$ 253,971**	**$ (511,524)**	**$ 253,147**

	Year Ended December 31, 2006				
(In Thousands)	Denbury Resources Inc. (Parent and Co-Obligor)	Denbury Onshore, LLC (Issuer and Co-Obligor)	Guarantor Subsidiaries	Eliminations	Denbury Resources Inc. Consolidated
Revenues	$ 11,219	$ 731,516	$ 796	$ (11,219)	$ 732,312
Expenses	11,581	400,657	1,719	(11,219)	402,738
Income before the following:	(362)	330,859	(923)	—	329,574
Equity in net earnings of subsidiaries	202,749	—	203,669	(406,418)	—
Income before income taxes	202,387	330,859	202,746	(406,418)	329,574
Income tax provision (benefit)	(70)	127,189	(2)	—	127,117
Net income	$202,457	$ 203,670	$ 202,748	$ (406,418)	$ 202,457

	Year Ended December 31, 2005				
(In Thousands)	Denbury Resources Inc. (Parent and Co-Obligor)	Denbury Onshore, LLC (Issuer and Co-Obligor)	Guarantor Subsidiaries	Eliminations	Denbury Resources Inc. Consolidated
Revenues	$ 313	$ 560,079	$ 314	$ —	$ 560,706
Expenses	485	310,974	1,206	—	312,665
Income before the following:	(172)	249,105	(892)	—	248,041
Equity in net earnings of subsidiaries	166,576	—	167,064	(333,640)	—
Income before income taxes	166,404	249,105	166,172	(333,640)	248,041
Income tax provision (benefit)	(67)	82,041	(404)	—	81,570
Net income	$166,471	$ 167,064	$ 166,576	$ (333,640)	$ 166,471

Condensed Consolidating Statements of Cash Flows

(In Thousands)	Year Ended December 31, 2007 Denbury Resources Inc. (Parent and Co-Obligor)	Denbury Onshore, LLC (Issuer and Co-Obligor)	Guarantor Subsidiaries	Eliminations	Denbury Resources Inc. Consolidated
Cash flow from operations	**$ 33**	**$ 570,098**	**$ 83**	**$ —**	**$ 570,214**
Cash flow from investing activities	**(183,204)**	**(762,513)**	**—**	**183,204**	**(762,513)**
Cash flow from financing activities	**183,204**	**198,533**	**—**	**(183,204)**	**198,533**
Net increase in cash	**33**	**6,118**	**83**	**—**	**6,234**
Cash, beginning of period	**1**	**52,225**	**1,647**	**—**	**53,873**
Cash, end of period	**$ 34**	**$ 58,343**	**$ 1,730**	**$ —**	**$ 60,107**

(In Thousands)	Year Ended December 31, 2006 Denbury Resources Inc. (Parent and Co-Obligor)	Denbury Onshore, LLC (Issuer and Co-Obligor)	Guarantor Subsidiaries	Eliminations	Denbury Resources Inc. Consolidated
Cash flow from operations	$ —	$ 460,841	$ 969	$ —	$ 461,810
Cash flow from investing activities	(150,864)	(856,625)	(2)	150,864	(856,627)
Cash flow from financing activities	150,864	283,601	—	(150,864)	283,601
Net increase (decrease) in cash	—	(112,183)	967	—	(111,216)
Cash, beginning of period	1	164,408	680	—	165,089
Cash, end of period	$ 1	$ 52,225	$ 1,647	$ —	$ 53,873

(In Thousands)	Year Ended December 31, 2005 Denbury Resources Inc. (Parent and Co-Obligor)	Denbury Onshore, LLC (Issuer and Co-Obligor)	Guarantor Subsidiaries	Eliminations	Denbury Resources Inc. Consolidated
Cash flow from operations	$ (5,298)	$ 365,714	$ 544	$ —	$ 360,960
Cash flow from investing activities	(150,000)	(383,666)	(21)	150,000	(383,687)
Cash flow from financing activities	155,298	149,479	—	(150,000)	154,777
Net increase in cash	—	131,527	523	—	132,050
Cash, beginning of period	1	32,881	157	—	33,039
Cash, end of period	$ 1	$ 164,408	$ 680	$ —	$ 165,089

Note 14. Subsequent Event

On February 20, 2008, we closed on the remaining portion of our Louisiana natural gas asset sale. We received net proceeds of approximately $48.9 million related to this portion of the asset sale (see Note 2, "Acquisition and Divestitures – 2007 Divestiture").

Note 15. Supplemental Oil and Natural Gas Disclosures (unaudited)

Costs Incurred

The following table summarizes costs incurred and capitalized in oil and natural gas property acquisition, exploration and development activities. Property acquisition costs are those costs incurred to purchase, lease, or otherwise acquire property, including both undeveloped leasehold and the purchase of reserves in place. Exploration costs include costs of identifying areas that may warrant examination and examining specific areas that are considered to have prospects containing oil and natural gas reserves, including costs of drilling exploratory wells, geological and geophysical costs and carrying costs on undeveloped properties. Development costs are incurred to obtain access to proved reserves, including the cost of drilling development wells, and to provide facilities for extracting, treating, gathering and storing the oil and natural gas, and the cost of improved recovery systems.

The Company capitalizes interest on unevaluated oil and gas properties that have on-going development activities. Included in the cost incurred below are capitalized interest of $18.3 million in 2007 and $11.0 million in 2006. Costs incurred also include new asset retirement obligations established, as well as changes to asset retirement obligations resulting from revisions in cost estimates or abandonment dates. Asset retirement obligations included in the table below were $7.5 million in 2007, $12.8 million in 2006 and $4.6 million in 2005 (see Note 4, "Asset Retirement Obligations").

Costs incurred in oil and natural gas activities were as follows:

	Year Ended December 31,		
(In Thousands)	2007	2006	2005
Property acquisitions:			
Proved	**$ 15,531**	$147,655	$ 64,791
Unevaluated	**60,079**	205,506	32,874
Exploration	**42,726**	43,564	45,652
Development	**553,315**	443,866	240,478
Total costs incurred [1]	**$ 671,651**	$840,591	$ 383,795

(1) Capitalized general and administrative costs that directly relate to exploration and development activities were $10.3 million, $7.6 million and $5.1 million for the years ended December 31, 2007, 2006 and 2005, respectively.

Oil and Natural Gas Operating Results

Results of operations from oil and natural gas producing activities, excluding corporate overhead and interest costs, were as follows:

	Year Ended December 31,		
(In Thousands, Except Per BOE Data)	2007	2006	2005
Oil, natural gas and related product sales	**$ 952,788**	$716,557	$549,055
Lease operating costs	**230,932**	167,271	108,550
Production taxes and marketing expenses	**49,091**	36,351	27,582
Depletion, depreciation and amortization	**177,333**	135,269	90,631
CO_2 depletion, depreciation and amortization [1]	**9,403**	6,281	3,894
Commodity derivative expense (income)	**18,597**	(19,828)	28,962
Net operating income	**467,432**	391,213	289,436
Income tax provision	**177,624**	151,008	95,224
Results of operations from oil and natural gas producing activities	**$ 289,808**	$240,205	$194,212
Depletion, depreciation and amortization per BOE	**$ 11.60**	$ 10.54	$ 8.69

(1) Represents an allocation of the depletion, depreciation and amortization of our CO_2 properties associated with our tertiary oil producing activities.

Oil and Natural Gas Reserves

Net proved oil and natural gas reserve estimates for all years presented were prepared by DeGolyer and MacNaughton, independent petroleum engineers located in Dallas, Texas. The reserves were prepared in accordance with guidelines established by the Securities and Exchange Commission and, accordingly, were based on existing economic and operating conditions. Oil and natural gas prices in effect as of the reserve report date were used without any escalation. (See "Standardized Measure of Discounted Future Net Cash Flows and Changes Therein Relating to Proved Oil and Natural Gas Reserves" below for a discussion of the effect of the different prices on reserve quantities and values.) Operating costs, production and ad valorem taxes and future development costs were based on current costs with no escalation.

There are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting the future rates of production and timing of development expenditures. The following reserve data represents estimates only and should not be construed as being exact. Moreover, the present values should not be construed as the current market value of our oil and natural gas reserves or the costs that would be incurred to obtain equivalent reserves. All of our reserves are located in the United States.

Estimated Quantities of Reserves

	Year Ended December 31,					
	2007		2006		2005	
	Oil (MBbl)	Gas (MMcf)	Oil (MBbl)	Gas (MMcf)	Oil (MBbl)	Gas (MMcf)
Balance at beginning of year	**126,185**	**288,826**	106,173	278,367	101,287	168,484
Revisions of previous estimates	**(1,601)**	**1,478**	4,351	(22,279)	(3,613)	(12,047)
Revisions due to price changes	**1,538**	**(355)**	(2)	(3,116)	872	1,268
Extensions and discoveries	**6,887**	**131,451**	4,587	65,582	1,214	117,512
Improved recovery [1]	**12,376**	**—**	5,044	—	13,276	—
Production	**(10,193)**	**(35,456)**	(8,372)	(30,322)	(7,305)	(21,424)
Acquisition of minerals in place	**405**	**1,935**	14,424	643	442	24,574
Sales of minerals in place	**(619)**	**(29,271)**	(20)	(49)	—	—
Balance at end of year	**134,978**	**358,608**	126,185	288,826	106,173	278,367
Proved Developed Reserves:						
Balance at beginning of year	**83,703**	**176,648**	59,640	151,681	55,998	94,573
Balance at end of year	**97,005**	**226,271**	83,703	176,648	59,640	151,681

(1) Improved recovery additions result from the application of secondary recovery methods such as water-flooding or tertiary recovery methods such as CO_2 flooding.

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

The Standardized Measure of Discounted Future Net Cash Flows and Changes Therein Relating to Proved Oil and Natural Gas Reserves ("Standardized Measure") does not purport to present the fair market value of our oil and natural gas properties. An estimate of such value should consider, among other factors, anticipated future prices of oil and natural gas, the probability of recoveries in excess of existing proved reserves, the value of probable reserves and acreage prospects, and perhaps different discount rates. It should be noted that estimates of reserve quantities, especially from new discoveries, are inherently imprecise and subject to substantial revision.

Under the Standardized Measure, future cash inflows were estimated by applying year-end prices to the estimated future production of year-end proved reserves. The product prices used in calculating these reserves have varied widely during the three-year period. These prices have a significant impact on both the quantities and value of the proven reserves as reductions in oil and gas prices can cause wells to reach the end of their economic life much sooner and can make certain proved undeveloped locations uneconomical, both of which reduce the reserves. The following representative oil and natural gas year-end prices were used in the Standardized Measure. These prices were adjusted by field to arrive at the appropriate corporate net price.

	December 31, 2007	2006	2005
Oil (NYMEX)	**$95.98**	$61.05	$61.04
Natural Gas (Henry Hub)	**6.80**	5.63	10.08

Future cash inflows were reduced by estimated future production, development and abandonment costs based on year-end costs to determine pre-tax cash inflows. Future income taxes were computed by applying the statutory tax rate to the excess of pre-tax cash inflows over our tax basis in the associated proved oil and natural gas properties. Tax credits and net operating loss carryforwards were also considered in the future income tax calculation. Future net cash inflows after income taxes were discounted using a 10% annual discount rate to arrive at the Standardized Measure.

(In Thousands)	December 31, 2007	2006	2005
Future cash inflows	**$14,082,865**	$ 8,185,682	$ 8,197,957
Future production costs	**(3,687,197)**	(2,697,206)	(2,069,015)
Future development costs	**(605,638)**	(565,488)	(525,877)
Future income taxes	**(3,283,702)**	(1,519,179)	(1,944,430)
Future net cash flows	**6,506,328**	3,403,809	3,658,635
10% annual discount for estimated timing of cash flows	**(2,966,711)**	(1,566,468)	(1,574,186)
Standardized measure of discounted future net cash flows	**$ 3,539,617**	$ 1,837,341	$ 2,084,449

The following table sets forth an analysis of changes in the Standardized Measure of Discounted Future Net Cash Flows from proved oil and natural gas reserves:

(In Thousands)	Year Ended December 31, 2007	2006	2005
Beginning of year	**$1,837,341**	$2,084,449	$1,129,196
Sales of oil and natural gas produced, net of production costs	**(672,765)**	(512,935)	(412,923)
Net changes in sales prices	**2,346,008**	(552,772)	1,261,231
Extensions and discoveries, less applicable future development and production costs	**344,615**	124,787	461,936
Improved recovery (1)	**513,840**	117,342	204,116
Previously estimated development costs incurred	**192,696**	124,207	110,424
Revisions of previous estimates, including revised estimates of development costs, reserves and rates of production	**(214,994)**	(324,608)	(261,730)
Accretion of discount	**269,520**	321,548	164,329
Acquisition of minerals in place	**32,212**	182,374	44,807
Sales of minerals in place	**(121,209)**	(222)	—
Net change in income taxes	**(987,647)**	273,171	(616,937)
End of year	**$3,539,617**	$1,837,341	$2,084,449

(1) Improved recovery additions result from the application of secondary recovery methods such as water flooding or tertiary recovery methods such as CO_2 flooding.

CO_2 Reserves

Based on engineering reports prepared by DeGolyer and MacNaughton, our CO_2 reserves, on a 100% working interest basis, were estimated at approximately 5.6 Tcf at December 31, 2007 (includes 182.3 Bcf of reserves dedicated to three volumetric production payments with Genesis), 5.5 Tcf at December 31, 2006 (includes 210.5 Bcf of reserves dedicated to three volumetric production payments with Genesis), and 4.6 Tcf at December 31, 2005 (includes 237.1 Bcf of reserves dedicated to three volumetric production payments with Genesis). We make reference to the gross amount of proved reserves as that is the amount that is available both for Denbury's tertiary recovery programs and for industrial users who are customers of Denbury and others, as we are responsible for distributing the entire CO_2 production stream for both of these purposes.

Note 16. Unaudited Quarterly Information

In Thousands, Except Per Share Amounts	March 31	June 30	September 30	December 31
2007				
Revenues	**$ 174,155**	**$ 222,510**	**$ 253,509**	**$ 321,776**
Expenses	**146,907**	**120,033**	**142,296**	**169,300**
Net income	**16,616**	**62,567**	**67,988**	**105,976**
Net income per share (1):				
Basic	**0.07**	**0.26**	**0.28**	**0.44**
Diluted	**0.07**	**0.25**	**0.27**	**0.42**
Cash flow from operations	**93,345**	**102,252**	**169,214**	**205,403**
Cash flow used for investing activities (2)	**(215,615)**	**(205,404)**	**(231,045)**	**(110,449)**
Cash flow provided by (used for) financing activities (3)	**103,404**	**100,722**	**68,668**	**(74,261)**
2006				
Revenues	$ 179,146	$ 193,566	$ 192,201	$ 167,399
Expenses	107,398	119,978	97,237	78,125
Net income	43,778	44,262	59,294	55,123
Net income per share (1):				
Basic	0.19	0.19	0.25	0.23
Diluted	0.18	0.18	0.24	0.22
Cash flow from operations	102,512	106,417	135,365	117,516
Cash flow used for investing activities (4)	(347,684)	(205,495)	(143,349)	(160,099)
Cash flow provided by financing activities (5)	110,067	99,906	6,096	67,532

(1) Per share amounts for all periods reflect the impact of a 2-for-1 split on December 5, 2007.

(2) In December 2007, we received cash proceeds of $115.4 million for the sale of our Louisiana natural gas assets. (See Note 2, "Acquisitions and Divestitures.")

(3) In the second quarter of 2007, we issued $150 million of 7.5% Senior Subordinated Notes due 2015 (See Note 6, "Notes Payable and Long-Term Indebtedness.") Also during 2007, we had net borrowings of $96 million in the first quarter and $60 million in the third quarter, and net repayments of $60 million in the second quarter and $80 million in the fourth quarter, all under our senior bank loan.

(4) In January 2006, we acquired three oil properties for approximately $250 million (including the $25 million of earnest money paid in the fourth quarter of 2005). In May 2006, we acquired an oil property for $50 million, plus a reversionary interest. In November 2006, we entered into an agreement for the option to purchase an oil property for an upfront payment of $37.5 million, plus required additional payments totaling $12.5 million. (See Note 2, "Acquisitions and Divestitures.")

(5) In April 2006, we sold $125 million (net to Denbury) of common stock in a public offering (see Note 8, "Stockholders' Equity – Stock Issuance"). We had net borrowings of $100 million and $64 million in the first and fourth quarters of 2006, respectively, and net repayments of $30 million in the second quarter of 2006, all under our senior bank loan.

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

None.

Item 9A. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

Under the supervision and with the participation of our management, including our President and Chief Executive Officer and our Chief Financial Officer, we evaluated the effectiveness of our disclosure controls and procedures as of the end of the period covered by this report. Based upon that evaluation, our President and Chief Executive Officer and our Chief Financial Officer concluded that our disclosure controls and procedures were effective to provide reasonable assurance that we record, process, summarize and report the information we must disclose in reports that we file or submit under the Securities Exchange Act of 1934, as amended, within the time periods specified in the SEC's rules and forms.

Evaluation of Changes in Internal Control over Financial Reporting

Under the supervision and with the participation of our management, including our President and Chief Executive Officer and our Chief Financial Officer, we have determined that, during the fourth quarter of fiscal 2007, there were no changes in our internal control over financial reporting that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Management's Report on Internal Control over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rules 13a-15(f) and 15(d)-15(f) of the Securities Exchange Act of 1934, as amended. Under the supervision and with the participation of our management, including our President and Chief Executive Officer and our Chief Financial Officer, we assessed the effectiveness of our internal control over financial reporting as of the end of the period covered by this report based on the framework in "Internal Control — Integrated Framework" issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on that assessment, our President and Chief Executive Officer and our Chief Financial Officer concluded that our internal control over financial reporting was effective to provide reasonable assurance regarding the reliability of our financial reporting and the preparation of our financial statements for external purposes in accordance with U.S. generally accepted accounting principles.

The effectiveness of the Company's internal control over financial reporting as of December 31, 2007, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears herein.

Important Considerations

The effectiveness of our disclosure controls and procedures and our internal control over financial reporting is subject to various inherent limitations, including cost limitations, judgments used in decision making, assumptions about the likelihood of future events, the soundness of our systems, the possibility of human error, and the risk of fraud. Moreover, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions and the risk that the degree of compliance with policies or procedures may deteriorate over time. Because of these limitations, there can be no assurance that any system of disclosure controls and procedures or internal control over financial reporting will be successful in preventing all errors or fraud or in making all material information known in a timely manner to the appropriate levels of management.

Item 9B. Other Information

None.

Item 10. Directors, Executive Officers and Corporate Governance

Except as disclosed below, information as to Item 10 will be set forth in the Proxy Statement ("Proxy Statement") for the Annual Meeting of Shareholders to be held May 15, 2008, ("Annual Meeting") and is incorporated herein by reference.

Code of Ethics

We have adopted a Code of Ethics for Senior Financial Officers and the Principal Executive Officer. This Code of Ethics, including any amendments or waivers, is posted on our website at www.denbury.com.

Item 11. Executive Compensation

Information as to Item 11 will be set forth in the Proxy Statement for the Annual Meeting and is incorporated herein by reference.

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

Information as to Item 12 will be set forth in the Proxy Statement for the Annual Meeting and is incorporated herein by reference.

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

Information as to Item 13 will be set forth in the Proxy Statement for the Annual Meeting and is incorporated herein by reference.

Item 14. Principal Accountant Fees and Services

Information as to Item 14 will be set forth in the Proxy Statement for the Annual Meeting and is incorporated herein by reference.

Item 15. Exhibits and Financial Statement Schedules

Financial Statements and Schedules. Financial statements and schedules filed as a part of this report are presented on page 53. All financial statement schedules have been omitted because they are not applicable or the required information is presented in the financial statements or the notes to consolidated financial statements.

Exhibits. The following exhibits are filed as part of this report.

Exhibit No.	Exhibit
3(a)	Restated Certificate of Incorporation of Denbury Resources Inc. filed with the Delaware Secretary of State on December 29, 2003 (incorporated by reference as Exhibit 3.1 of our Form 8-K filed December 29, 2003).
3(b)	Certificate of Amendment of Restated Certificate of Incorporation of Denbury Resources Inc. filed with the Delaware Secretary of State on October 20, 2005 (incorporated by reference as Exhibit 3(a) of our Form 10-Q filed November 8, 2005).
3(c)*	Certificate of Amendment of Restated Certificate of Incorporation of Denbury Resources Inc. filed with the Delaware Secretary of State on November 21, 2007.
3(d)	Bylaws of Denbury Resources Inc., a Delaware corporation, adopted December 29, 2003 (incorporated by reference as Exhibit 3.2 of our Form 8-K filed December 29, 2003).
4(a)	Indenture for $150 million of 7.5% Senior Subordinated Notes due 2015 among Denbury Resources Inc., certain of its subsidiaries, and JP Morgan Chase Bank, as trustee (incorporated by reference as Exhibit 4.1 of our Form 8-K filed December 9, 2005).
4(b)	Indenture for $225 million of 7.5% Senior Subordinated Notes due 2013 among Denbury Resources Inc., certain of its subsidiaries and JP Morgan Chase Bank as trustee, dated March 25, 2003 (incorporated by reference as Exhibit 4(a) to our Registration Statement No. 333-105233-04 on Form S-4, filed May 14, 2003).
4(c)	First Supplemental Indenture for $225 million of 7.5% Senior Subordinated Notes due 2013 dated as of December 29, 2003, among Denbury Resources Inc., certain of its subsidiaries, and the JP Morgan Chase Bank, as trustee (incorporated by reference as Exhibit 4.1 of our Form 8-K filed December 29, 2003).
4(d)	First Supplemental Indenture for 7.5% Senior Subordinated Notes due 2015, dated April 3, 2007, between Denbury Resources Inc., as issuer, and The Bank of New York Trust Company, N.A., as Trustee (incorporated by reference as Exhibit 4.1 of our Form 8-K filed April 3, 2007).
10(a)	Sixth Amended and Restated Credit Agreement among Denbury Onshore, LLC, as Borrower, Denbury Resources Inc., as Parent Guarantor and JPMorgan Chase Bank, N.A., as Administrative Agent, and certain other financial institutions, dated September 14, 2006 (incorporated by reference as Exhibit 10.1 of our Form 8-K filed September 19, 2006).
10(b)	Amendment for Increased Commitment from $150 million to $250 million to Sixth Amended and Restated Credit Agreement among Denbury Onshore, LLC, as Borrower, Denbury Resources Inc, as Parent Guarantor, Bank One, N.A. as Administrative Agent, and certain other financial institutions dated as of December 22, 2006 (incorporated by reference as Exhibit 10(c) of our Form 10-K for the year ended December 31, 2007).
10(c)	First Amendment to 6th Amended and Restated Credit Agreement among Denbury Onshore, LLC, as Borrower, Denbury Resources Inc., as Parent Guarantor, JPMorgan Chase Bank, N.A., as Administrative Agent and certain other financial institutions effective March 31, 2007 (incorporated by reference as Exhibit 10 in our Form 10-Q for the quarter ended March 31, 2007).
10(d)	Amendment for Increased Commitment from $250 million to $350 million to Sixth Amended and Restated Credit Agreement among Denbury Onshore, LLC, as Borrower, and JPMorgan Chase Bank, N.A., as Administrative Agent, and certain other financial institutions dated as of March 31, 2007 (incorporated by reference as Exhibit 10 in our Form 10-Q for the quarter ended March 31, 2007).

Exhibit No.	Exhibit
10(e)**	Denbury Resources Inc. Amended and Restated Stock Option Plan as of December 5, 2007 (incorporated by reference as Exhibit 99.2 of our Form 8-K, filed December 11, 2007).
10(f)**	Denbury Resources Inc. Stock Purchase Plan, as amended and restated December 5, 2007 (incorporated by reference as Exhibit 99.4 of our Form 8-K, filed December 11, 2007).
10(g)**	Form of indemnification agreement between Denbury Resources Inc. and its officers and directors (incorporated by reference as Exhibit 10 of our Form 10-Q for the quarter ended June 30, 1999).
10(h)**	Denbury Resources Inc. Directors Compensation Plan (incorporated by reference as Exhibit 4 of our Registration Statement on Form S-8, No. 333-39172, filed June 13, 2000, amended March 2, 2001 and May 11, 2005).
10(i)**	Denbury Resources Severance Protection Plan, as amended and restated effective December 5, 2007 (incorporated by reference as Exhibit 99.3 of our Form 8-K, filed December 11, 2007).
10(j)**	Denbury Resources Inc. 2004 Omnibus Stock and Incentive Plan, as amended and restated effective December 5, 2007 (incorporated by reference as Exhibit 99.1 of our Form 8-K, filed December 11, 2007).
10(k)**	2004 form of restricted stock award that vests 20% per annum, for grants to officers pursuant to 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc. (incorporated by reference as Exhibit 10(k) of our Form 10-K for the year ended December 31, 2004).
10(l)**	2004 form of restricted stock award that vests on retirement, for grants to officers pursuant to 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc. (incorporated by reference as Exhibit 10(l) of our Form 10-K for the year ended December 31, 2004).
10(m)**	2004 form of restricted stock award that vests 20% per annum, for grants to directors pursuant to 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc. (incorporated by reference as Exhibit 10(m) of our Form 10-K for the year ended December 31, 2004).
10(n)**	2005 form of incentive stock option agreement that vests 25% per annum, for grants to new employees and officers on their hire date pursuant to 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc. (incorporated by reference as Exhibit 10(n) of our Form 10-K for the year ended December 31, 2004).
10(o)**	2005 form of incentive stock option agreement that cliff vests 100% four years from the date of grant, for grants to employees and officers pursuant to 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc. (incorporated by reference as Exhibit 10(o) of our Form 10-K for the year ended December 31, 2004).
10(p)**	2005 form of non-qualified stock option agreement that vests 25% per annum, for grants to new employees and officers on their hire date pursuant to 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc. (incorporated by reference as Exhibit 10(p) of our Form 10-K for the year ended December 31, 2004).
10(q)**	2005 form of non-qualified stock option agreement that cliff vests 100% four years from the date of grant, for grants to employees, officers and directors pursuant to 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc. (incorporated by reference as Exhibit 10(q) of our Form 10-K for the year ended December 31, 2004).
10(r)**	2006 form of stock appreciation rights agreement that vests 25% per annum, for grants to new employees and officers on their hire date pursuant to 2004 Omnibus and Incentive Plan for Denbury Resources Inc. (incorporated by reference as Exhibit 10(v) of our Form 10-K for the year ended December 31, 2005).

Exhibit No.	Exhibit
10(s)**	2006 form of stock appreciation rights agreement that vests 100% four years from the date of grant, for grants to employees and officers pursuant to 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc. (incorporated by reference as Exhibit 10(w) of our Form 10-K for the year ended December 31, 2005).
10(t)**	2006 form of stock appreciation rights agreement that cliff vests 100% four years from the date of grant, for grants to directors pursuant to 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc. (incorporated by reference as Exhibit 10(x) of our Form 10-K for the year ended December 31, 2005).
10(u)**	2006 form of restricted stock award that vests 25% per annum, for grants to new employees and officers on their hire date pursuant to 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc. (incorporated by reference as Exhibit 10(y) of our Form 10-K for the year ended December 31, 2005).
10(v)**	2006 form of restricted stock award that cliff vests 100% four years from the date of grant for grants to employees and officers pursuant to 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc. (incorporated by reference as Exhibit 10(z) of our Form 10-K for the year ended December 31, 2005).
10(w)**	2007 form of restricted stock award to officers that cliff vests on March 31, 2010 pursuant to 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc. (incorporated by reference as Exhibit 10(y) of our Form 10-K for the year ended December 31, 2007).
10(x)**	2007 form of performance share awards to officers pursuant to 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc. (incorporated by reference as Exhibit 10(z) of our Form 10-K for the year Ended December 31, 2007).
10(y)**	2007 form of restricted stock award to directors that cliff vests after three years pursuant to 2004 Omnibus Stock and Incentive Plan (incorporated by reference as Exhibit 10(cc) of our Form 10-K for the year ended December 31, 2007).
10(z)* **	2007 form of restricted stock award to new directors that vest 20% per annum.
10(aa)**	Form of deferred payment cash award that cliff vests 100% four years from the date of grant for grants to employees and officers (incorporated by reference as exhibit 10(bb) of our Form 10-K for the year ended December 31, 2005).
10(bb)**	Form of deferred payment cash award that vests 25% per annum, for grants to new employees and officers on their date of hire (incorporated by reference as Exhibit 10(aa) of our Form 10-K for the year ended December 31, 2005).
21*	List of subsidiaries of Denbury Resources Inc.
23(a)*	Consent of PricewaterhouseCoopers LLP.
23(b)*	Consent of DeGolyer and MacNaughton.
31(a)*	Certification of Chief Executive Officer Pursuant to Section 302 of Sarbanes-Oxley Act of 2002.
31(b)*	Certification of Chief Financial Officer Pursuant to Section 302 of Sarbanes-Oxley Act of 2002.
32*	Certification of Chief Executive Officer and Chief Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
99*	The summary of DeGolyer and MacNaughton's Report as of December 31, 2007, on oil and gas reserves (SEC Case) dated February 11, 2008.

** Filed herewith.*

*** Compensation arrangements.*

Copies of the above exhibits not contained herein are available to any security holder upon request to the Secretary, Denbury Resources Inc., 5100 Tennyson Pkwy., Suite 1200, Plano, TX 75024.

SIGNATURES

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

DENBURY RESOURCES INC.

/s/ Phil Rykhoek February 28, 2008

Phil Rykhoek Sr. Vice President and Chief Financial Officer

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

/s/ Gareth Roberts February 28, 2008

Gareth Roberts Director, President and Chief Executive Officer
(Principal Executive Officer)

/s/ Phil Rykhoek February 28, 2008

Phil Rykhoek Sr. Vice President and Chief Financial Officer
(Principal Financial Officer)

/s/ Mark C. Allen February 28, 2008

Mark C. Allen Vice President and Chief Accounting Officer
(Principal Accounting Officer)

/s/ Ron Greene February 28, 2008

Ron Greene Director

/s/ David I. Heather February 28, 2008

David I. Heather Director

/s/ Randy Stein February 28, 2008

Randy Stein Director

/s/ Wieland Wettstein February 28, 2008

EXHIBIT 21

List of Subsidiaries

Name of Subsidiary	Jurisdiction of Incorporation	Status
Denbury Gathering & Marketing, Inc.	Delaware	Wholly owned subsidiary of Denbury Resources Inc. – parent company of Genesis Energy, Inc.
Genesis Energy, Inc.	Delaware	Wholly owned subsidiary of Denbury Gathering & Marketing, Inc. – holds 2.0% general partner interest of Genesis Energy LP, .01% general partner interest of Genesis Crude Oil LP, and 7.396% limited partner interest of Genesis Energy LP
Denbury Operating Company	Delaware	Wholly owned subsidiary of Denbury Resources Inc. – operating holding company of limited liability companies
Denbury Onshore, L.L.C.	Delaware	Wholly owned subsidiary of Denbury Operating Company – onshore oil and gas properties
Denbury Marine, L.L.C.	Louisiana	Wholly owned subsidiary of Denbury Operating Company – marine company
Tuscaloosa Royalty Fund L.L.C.	Delaware	Wholly owned subsidiary of Denbury Operating Company
Denbury New Frontiers, L.L.C.	Delaware	Wholly owned subsidiary of Denbury Operating Company

EXHIBIT 23(a)

Consent of Independent Registered Public Accounting Firm

We hereby consent to the incorporation by reference in the Registration Statements on Form S-8 (Nos. 333-1006, 333-27995, 333-55999, 333-70485, 333-39172, 333-39218, 333-63198, 333-90398, 333-106253, 333-116249 and 333-143848) of Denbury Resources Inc. of our report dated February 28, 2008 relating to the financial statements and the effectiveness of internal control over financial reporting, which appears in this Form 10K.

/s/ PricewaterhouseCoopers LLP February 28, 2008

Dallas, Texas

Exhibit 31 (a)

Certification Under Section 302 of the Sarbanes-Oxley Act of 2002

I, Gareth Roberts, certify that:

1. I have reviewed this report on Form 10-K of Denbury Resources Inc. (the registrant);
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/s/ Gareth Roberts February 28, 2008

Gareth Roberts
President and Chief Executive Officer

Exhibit 31(b)

Certification Under Section 302 of the Sarbanes-Oxley Act of 2002

I, Phil Rykhoek, certify that:

1. I have reviewed this report on Form 10-K of Denbury Resources Inc. (the registrant);
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/s/ Phil Rykhoek February 28, 2008

Phil Rykhoek
Sr. Vice President and Chief Financial Officer

Exhibit 32

Certification of Chief Executive Officer and Chief Financial Officer
Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

In connection with the accompanying Annual Report on Form 10-K for the year ended December 31, 2007 (the Report) of Denbury Resources Inc. (Denbury) as filed with the Securities and Exchange Commission on February 28, 2008, each of the undersigned, in his capacity as an officer of Denbury, hereby certifies pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to his knowledge:

1. The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Denbury.

/s/ Gareth Roberts February 28, 2008

Gareth Roberts
President and Chief Executive Officer

/s/ Phil Rykhoek February 28, 2008

Phil Rykhoek
Sr. Vice President and Chief Financial Officer

Board of Directors

Ronald G. Greene
Chairman of the Board
Principal
Tortuga Investment Corp.
Calgary Alberta

Michael Beatty
Chairman & C.E.O.
Beatty & Wozniak, P.C.
Denver, Colorado

Mike Decker
Principal
Wingate Partners
Dallas, Texas

David I. Heather
Director
The Scotia Group
Dallas, Texas

Greg McMichael
Independent Consultant
Denver, Colorado

Gareth Roberts
President & C.E.O.
Denbury Resources Inc.
Dallas, Texas

Randy Stein
Independent Consultant
Denver, Colorado

Wieland F. Wettstein
President
Finex Financial
Corporation, Ltd.
Calgary Alberta

Officers

Gareth Roberts
President & C.E.O.

Robert Cornelius
Senior Vice President
Operations

Tracy Evans
Senior Vice President
Reservoir Engineering

Phil Rykhoek
Senior Vice President and
Chief Financial Officer

Mark Allen
Vice President and
Chief Accounting Officer

Dan Cole
Vice President
Marketing

Brad Cox
Vice President
Business Development

Ray Dubuisson
Vice President
Land

Charlie Gibson
Vice President
Reservoir Engineering

Barry Schneider
Vice President
Production and Operations

Corporate Headquarters

Denbury Resources Inc.
5100 Tennyson Pkwy, Ste. 1200
Plano, Texas 75024
T: 972.673.2000
F: 972.673.2150

Register and Transfer Agent

American Stock Transfer
and Trust Company
New York, NY

Legal Counsel

Baker & Hostetler LLP

Bankers

JP Morgan (Agent)

Auditors

PricewaterhouseCoopers LLP

Evaluation Engineers

DeGolyer & MacNaughton

Stock Exchange

New York Stock Exchange
Trading Symbol: DNR

Annual Meeting

The annual meeting of stockholders will be held on May 15, 2008, at 3:00 P.M., local time, at the Westin Stonebriar Hotel located at:
1549 Legacy Drive
Frisco, Texas

All stockholders are encouraged to attend, but if unable should complete and return the proxy card.

For Further Information

Contact Gareth Roberts or Phil Rykhoek at Corporate Headquarters. We have listed on our website at www.denbury.com, our corporate governance guidelines, as well as the charters for our nominating/governance committee, our compensation committee, and our audit committee. The website also contains other corporate governance information such as our code of ethics for our directors, officers and employees, our hotline number to report any abnormalities, and other data.

You may contact our board members by addressing a letter to: Denbury Resources Inc. Attn: Corporate Secretary, or by e-mail to secretary@denbury.com.

Our Form 10-K filed with the SEC is included herein, excluding all exhibits other than our Section 302, 404, and 906 certifications by the CEO and CFO. We will send shareholders our Form 10-K exhibits and any of our corporate governance documents, without charge, upon request to Laurie Burkes at the Company's headquarters. This report can also be accessed at our website, www.denbury.com.

In May 2007, the Company submitted its written affirmation and annual Chief Executive Officer certification pursuant to Section 303A of the New York Stock Exchange regulations without qualifications.

The cover and narrative section of this annual report are printed on Coronado Infinite White Super Smooth Text and the cover is on Coronado Infinite White Stipple. The financial section is printed on Cougar Astropaque.

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