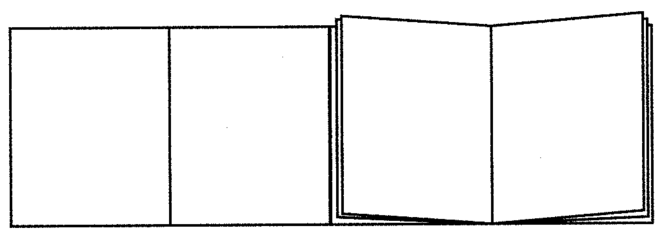
Denbury Resources Inc. 2008 Annual Report

Defining Denbury



This year's annual report graphically highlights our strategy in four steps. We have illustrated these steps on a fold-out chart so shareholders can appreciate the whole picture while reading the details in each section.

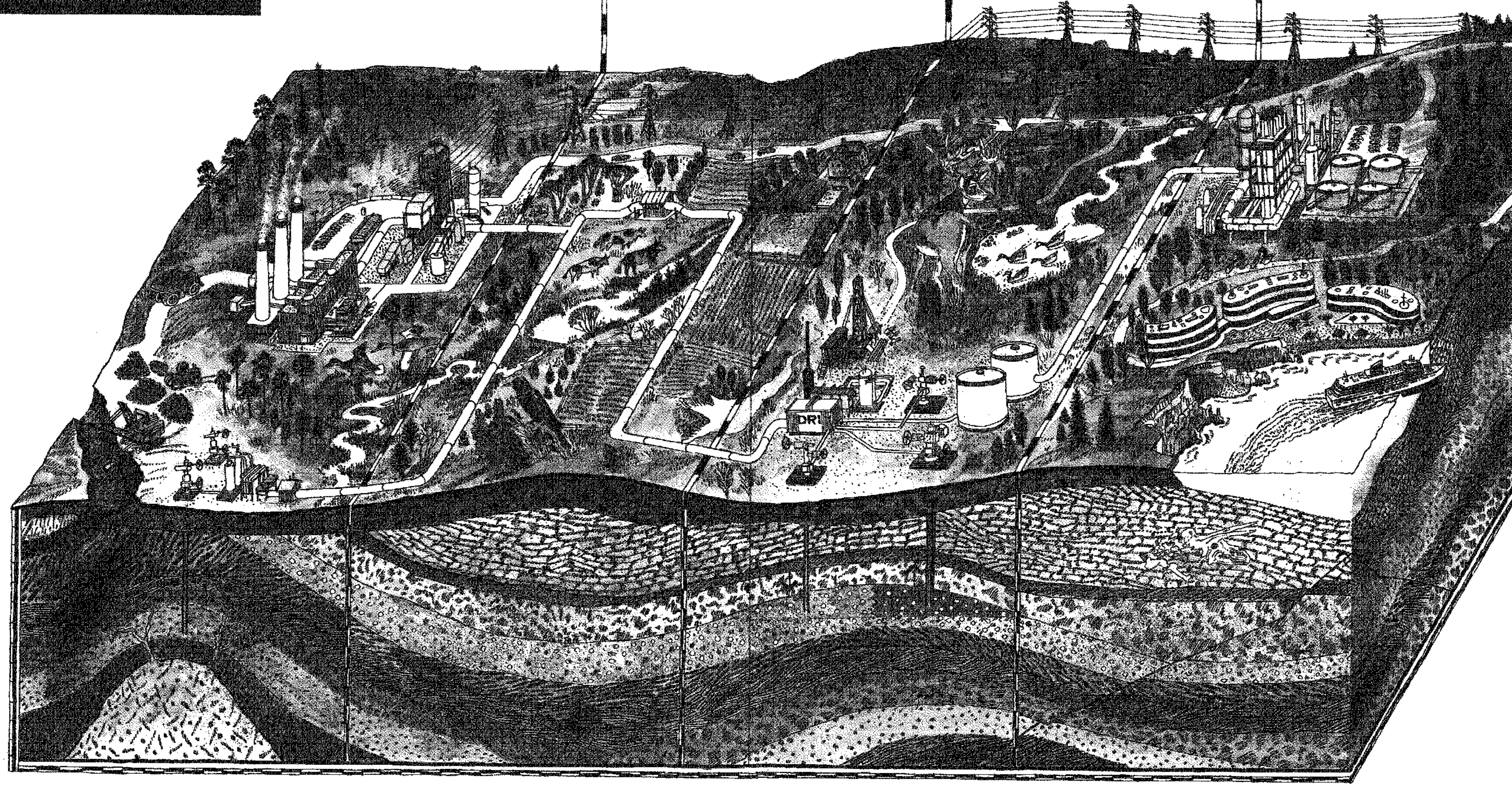
Our CO_2 cycle consists of the four steps outlined below. Denbury captures carbon dioxide (CO_2) and transports it to mature oil fields to increase production and create numerous economic and social benefits.

CO_2 Sources & Capture

CO_2 Transportation

CO_2 Enhanced Oil Recovery & Storage

CO_2 Strategy Benefits



1 Step 1: CO_2 Sources & Capture
Denbury has its own natural source of CO_2 at Jackson Dome in Mississippi and intends to capture man-made volumes from power plants or industrial sources. CO_2 capture occurs when natural or man-made CO_2 is purified and dried for transportation to oil fields.

2 Step 2: CO_2 Transportation
Denbury currently operates or controls over 420 miles of CO_2 pipelines, which distribute CO_2 from Jackson Dome to our oil fields. We are currently building the 320-mile Green Pipeline to Texas, which will allow us to potentially capture man-made volumes of CO_2 in the Gulf Coast area.

3 Step 3: CO_2 Enhanced Oil Recovery & Storage
Our CO_2 enhanced oil recovery (CO_2 EOR) operations have demonstrated the ability to recover significant amounts of additional oil, and also provide a promising method to sequester man-made volumes of CO_2 in depleted oil reservoirs.

4 Step 4: CO_2 Strategy Benefits
After the CO_2 EOR process is completed, the CO_2 is left sequestered in the geological formation that trapped the oil originally. Oil production in these domestic fields enriches the local economy, royalty owners and Denbury shareholders while reducing the need for imported oil.

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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 following section of this annual report, such as probable and potential reserves or production forecasts derived from such probable and potential reserves, that the SEC's guidelines strictly prohibit us from including in filings with the SEC.

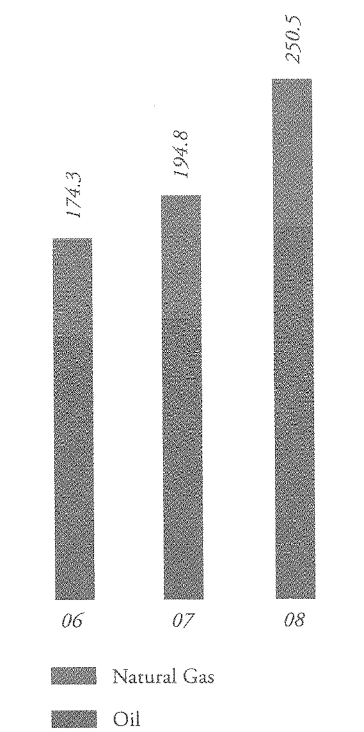
Forward-Looking Statements

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.

As a feature of this year's annual report, we have tried to illustrate graphically our strategy of combining CO_2 capture with incremental oil production. Our CO_2 enhanced oil recovery operations not only increase domestic oil production, but also improve the local economies in which we operate, provide a promising method to sequester industrial CO_2 volumes, and help reduce our nation's need for imported oil.

We added 88.9 MMBOE of proved reserves, including 63.4 MMBOE in our CO_2 tertiary floods, primarily at Heidelberg, Tinsley and Lockhart Crossing Fields.

Proved Reserves
MMBOE



Dear Shareholders:

Last year was definitively a year of extremes with record high oil prices topping $145 per barrel mid-year, then dropping below $40 per barrel late in 2008. Our stock price vacillated along with the price of oil, trading as high as $40 per share during the period of high oil prices, and trading as low as one-eighth of that price when oil prices declined. The continuing low commodity and equity prices in early 2009 reflect the impact of a growing global recession.

Along with high oil prices, which steadily increased until mid-year 2008, we faced escalating operating and capital costs, project delays and a shortage of trained personnel, which together created significant compensation inflation in our industry. One favorable aspect of the declining oil prices in the second half of the year is that costs have begun to come down, and we have been able to fill most of our needs for personnel. For example, our tertiary operating costs decreased 18% sequentially between the third and fourth quarters of 2008, from $26.81 per BOE in the third quarter to $21.86 per BOE in the fourth. We expect these costs to be further reduced in 2009, potentially to the upper teens if oil prices stay below $50 per barrel, as a significant portion of these costs track commodity prices. On the capital side, we commit to significant expenditures as far as two years in advance. So, while we are seeing cost reductions in some areas, it will take a little longer to fully recognize the full measure of material savings in our capital costs.

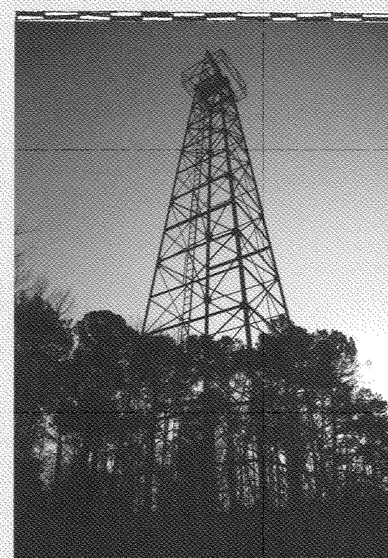
On the personnel front, recently we have been able to selectively add key personnel, and we continue to improve the training and experience of our operational staff. The past few years have reinforced how important our personnel are to our success, and how qualified personnel shortages can be a limiting factor to rapid growth.

Despite the distractions of a collapsing economy, 2008 was a good year for us in many ways.

- We added 88.9 MMBOE of proved reserves (before netting out 2008 production, property sales and reserve revisions due to pricing), including 63.4 MMBOE in our CO_2 tertiary floods, primarily at Heidelberg, Tinsley and Lockhart Crossing Fields. Our finding and development costs, all-in (including the changes in future development costs) were $12.23 per BOE, not only an excellent result when compared to others in our industry, but one which should improve over time as we add probable reserves from these same fields in the future. Using the more common "short-cut" method of computing finding costs, which excludes the changes in future development costs and unevaluated properties, our 2008 finding costs would be less than $7.00 per BOE.

- The Delta Pipeline was completed as far as Tinsley Field (Phase III) in early 2008, allowing us to increase our CO_2 injection rates as development of the field progressed. Substantial progress was made on the 81-mile portion of the Delta Pipeline from Tinsley to Delhi Field (Phase V), and this portion of the pipeline is expected to be ready for service by mid-2009.
- Tinsley Field responded to CO_2 injection in April 2008 with production increasing steadily since that time to a fourth quarter average of 1,832 Bbls/d. We expect production from this field, our largest tertiary flood to date, to increase further in 2009.
- We began injection at our first tertiary flood in Louisiana, Lockhart Crossing Field (Phase I), in December 2007, with our first oil production response early in the third quarter of 2008. Production at this field averaged 555 Bbls/d in the fourth quarter of 2008.
- We completed the conversion of a natural gas line to CO_2 service mid-year and began injecting CO_2 at Cranfield (Phase IV). First oil production response occurred in early 2009.
- Overall, our tertiary oil production increased to an annual average of 19,377 Bbls/d in 2008, a 31% increase over 2007 tertiary production levels, the primary driver for our record annual production level of 46,343 BOE/d.
- Production from the Barnett Shale area in Texas was relatively flat throughout the year, averaging 12,699 BOE/d, about the same level as fourth quarter 2007 production. This area did, however, produce our second largest increase in proved reserves. We added approximately 19.5 MMBOE (117 Bcfe) of reserves here during 2008. We drilled 38 wells in this area during 2008, but due to lower natural gas prices, we have substantially curtailed drilling activity in this area for 2009.
- We began construction of the 320-mile Green Pipeline late in 2008 after almost two years of planning. This line will run from Donaldsonville, Louisiana, southeast of Baton Rouge, to the recently acquired Hastings Field south of Houston, Texas, and will interconnect with the NEJD Pipeline. We expect this pipeline to cost around $730 million, of which we have spent

We are one of the few companies currently capable of taking large volumes of man-made CO_2 and safely sequestering it in underground reservoirs.



This is an old-fashioned oil derrick located at our Tinsley Field. This field responded to CO_2 injection in April 2008 with production increasing steadily since that time. We expect production from Tinsley Field, our largest tertiary flood to date, to increase further in 2009.

We will ultimately need more CO_2 to continue our growth, and others will need a way to sequester their CO_2 emissions.

$230 million and expect to spend approximately $430 million during 2009. By late 2009 or early 2010, we expect to finish the line from Donaldsonville, Louisiana, to the east shore of Galveston Bay, with plans to finish the line to Hastings Field by the end of 2010. Initially we anticipate transporting CO_2 from our natural source at Jackson Dome on this line, but ultimately expect that the Green Pipeline will be used to ship predominately man-made (anthropogenic) sources of CO_2. We believe that this line will be a major strategic asset for us for years to come.

- Lastly, we have put Denbury into a position to weather the economic conditions we find ourselves in. We have significantly improved our liquidity with our recent $420 million subordinated debt offering, coupled with the other steps taken during the last six months, which included a $400 million increase in our bank commitment amount, cancellation of the $600 million acquisition of Conroe Field, purchase of oil derivative contracts for 30,000 Bbls/d during 2009 with a floor price of $75 / Bbl, and a reduction of our 2009 capital budget. We will continue to monitor our progress and look for additional ways to maintain our liquidity, lower our costs and improve our efficiencies.

We began construction of the 320-mile Green Pipeline late in 2008. This line will run from Donaldsonville, Louisiana, southeast of Baton Rouge, to the recently acquired Hastings Field south of Houston, Texas, and will interconnect with the NEJD Pipeline. We believe that this line will be a major strategic asset for us for years to come.

Lower oil prices have reduced our cash flow and will require us to slow our development pace, but it will not deter us from our favorable strategy. The new administration in Washington has stated that they want to reduce CO_2 emissions, which is likely to be part of any new climate legislation. This legislation would likely be either a cap and trade system or a carbon tax, either of which would provide an economic incentive to capture CO_2 from existing and future industrial plants. We could potentially benefit from any such legislation, as we are one of the few companies currently capable of taking large volumes of man-made CO_2 and safely sequestering it in underground reservoirs. We will ultimately need more CO_2 to continue our growth, and others will need a way to sequester their CO_2 emissions. Potentially, both needs can be met through the same solution.

As a feature of this year's annual report, we have tried to illustrate graphically our strategy of combining CO_2 capture with incremental oil production. By increasing domestic oil production, we reduce the need for imported oil, the real villain behind the United States' trade deficit, whilst benefiting local and state governments, local employment, mineral owners, and ultimately, Denbury shareholders.

Denbury is in excellent shape to carry out this strategy, better than any time in the 20 years since it was founded in my living room! Therefore, I have decided that this is an appropriate time to let the experienced team at the head of the Company take more responsibility, while I take a turn at the back of the peloton (to use a cycling analogy). I intend to step down as President and CEO on June 30th, but I will continue as Co-Chairman of the Board and retain an active role in the Company's strategic planning.

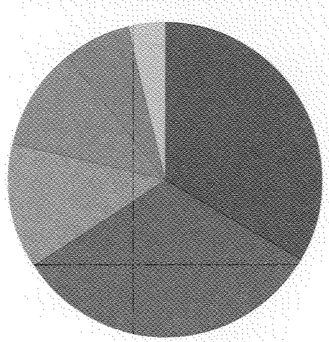
The new team will be led by Phil Rykhoek as CEO and Tracy Evans as President and COO, but our Investment Committee approach, where decisions are made by consensus amongst senior management, will remain and ensure our continuity.

We look forward to a successful 2009 and beyond.

Gareth Roberts
President and Chief Executive Officer
March 6, 2009

By increasing domestic oil production, we reduce the need for imported oil, the real villain behind the United States' trade deficit, whilst benefiting local and state governments, local employment, mineral owners, and ultimately, Denbury shareholders.

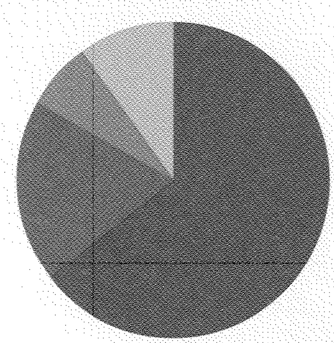
2008 Capital Expenditures[1]
$1.02 Billion



in millions

- CO_2 Pipelines $343
- Tertiary Floods $332
- Barnett Shale $131
- Jackson Dome CO_2 $108
- MS - Non CO_2 $73
- Other $38

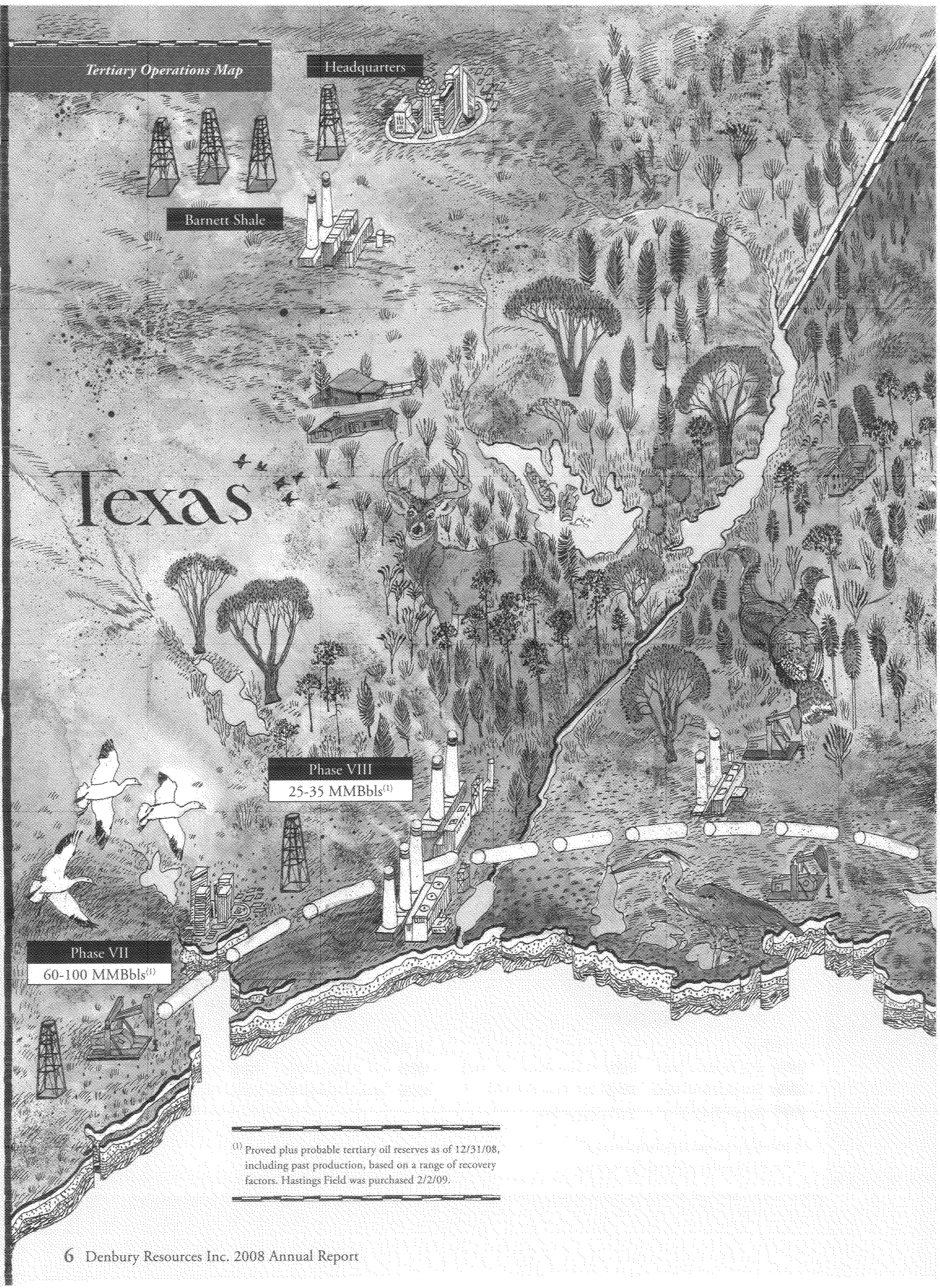
Projected 2009 Capital Budget[1]
$750 Million



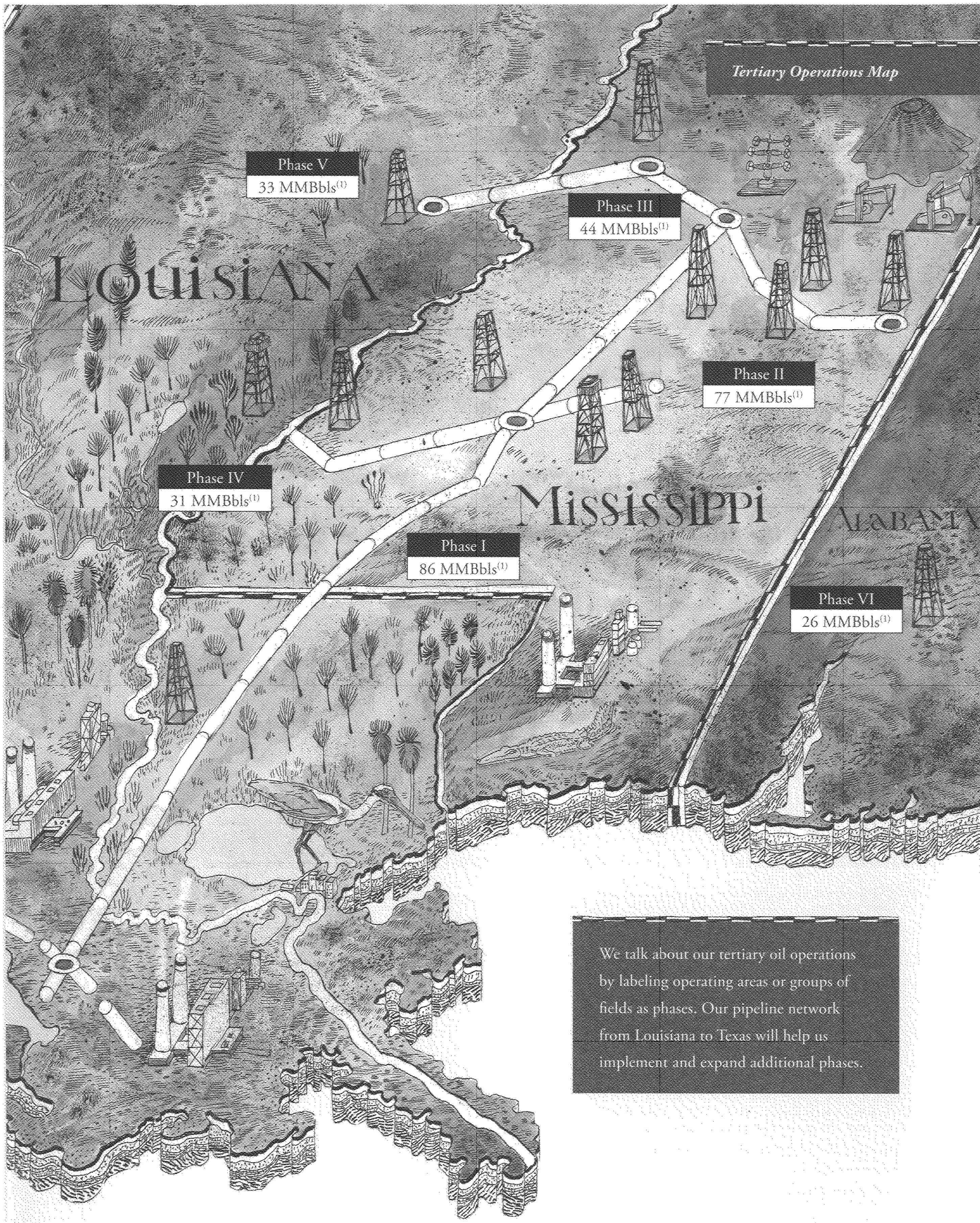
in millions

- CO_2 Pipelines $485
- Tertiary Floods[2] $138
- Jackson Dome CO_2 $52
- Other $75

[1] Excludes acquisitions and capitalized interest.
[2] Net of $100 million of assumed lease financing.



(1) Proved plus probable tertiary oil reserves as of 12/31/08, including past production, based on a range of recovery factors. Hastings Field was purchased 2/2/09.



We talk about our tertiary oil operations by labeling operating areas or groups of fields as phases. Our pipeline network from Louisiana to Texas will help us implement and expand additional phases.

Financial Highlights

Amounts in thousands, unless otherwise noted	Year Ended December 31, 2008	2007	2006[2]	2005	2004[3]	Average Annual Growth[1]
Consolidated Statements of Operations Data:						
Revenues	$ 1,365,702	$ 973,060	$ 731,536	$ 560,392	$ 382,972	37%
Net income[4]	388,396	253,147	202,457	166,471	82,448	47%
Net income per common share[5]:						
Basic	1.59	1.05	0.87	0.74	0.38	43%
Diluted	1.54	1.00	0.82	0.70	0.36	44%
Weighted average number of common shares outstanding[5]:						
Basic	243,935	240,065	233,101	223,485	219,482	3%
Diluted	252,530	252,101	247,547	239,267	229,206	2%
Consolidated Statements of Cash Flow Data:						
Cash provided by (used by):						
Operating activities	$ 774,519	$ 570,214	$ 461,810	$ 360,960	$ 168,652	46%
Investing activities	(994,659)	(762,513)	(856,627)	(383,687)	(93,550)	81%
Financing activities	177,102	198,533	283,601	154,777	(66,251)	– %
Production (daily):						
Oil (Bbls)	31,436	27,925	22,936	20,013	19,247	13%
Natural gas (Mcf)	89,442	97,141	83,075	58,696	82,224	2%
BOE (6:1)	46,343	44,115	36,782	29,795	32,951	9%
Unit Sales Price (excluding hedges):						
Oil (per Bbl)	$ 92.73	$ 69.80	$ 59.87	$ 50.30	$ 36.46	26%
Natural gas (per Mcf)	8.56	6.81	7.10	8.48	6.24	8%
Unit Sales Price (including hedges):						
Oil (per Bbl)	$ 90.04	$ 68.84	$ 59.23	$ 50.30	$ 27.36	35%
Natural gas (per Mcf)	7.74	7.66	7.10	7.70	5.57	9%
Costs per BOE:						
Lease operating expenses	$ 18.13	$ 14.34	$ 12.46	$ 9.98	$ 7.22	26%
Production taxes and marketing expenses	3.76	3.05	2.71	2.54	1.55	25%
General and administrative	3.56	3.04	3.20	2.62	1.78	19%
Depletion, depreciation and amortization	13.08	12.17	11.11	9.09	8.09	13%
Proved Reserves:						
Oil (MBbls)	179,126	134,978	126,185	106,173	101,287	15%
Natural gas (MMcf)	427,955	358,608	288,826	278,367	168,484	26%
MBOE (6:1)	250,452	194,746	174,322	152,568	129,369	18%
Carbon dioxide (MMcf)[6]	5,612,167	5,641,054	5,525,948	4,645,702	2,664,633	20%
Consolidated Balance Sheet Data:						
Total assets	$ 3,589,674	$ 2,771,077	$ 2,139,837	$ 1,505,069	$ 992,706	38%
Total long-term liabilities	1,363,539	1,102,066	833,380	617,343	368,128	39%
Stockholders' equity[7]	1,840,068	1,404,378	1,106,059	733,662	541,672	36%

[1] Four-year compounded average annual growth rate computed using 2004 as a base year.

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

[3] We sold Denbury Offshore, Inc. in July 2004.

[4] In 2008, we had a full cost ceiling test write-down of $226 million ($140.1 million net of tax) and pretax expense of $30.6 million associated with a cancelled acquisition. These charges were partially offset by pretax income of $200.1 million on our commodity derivative contracts.

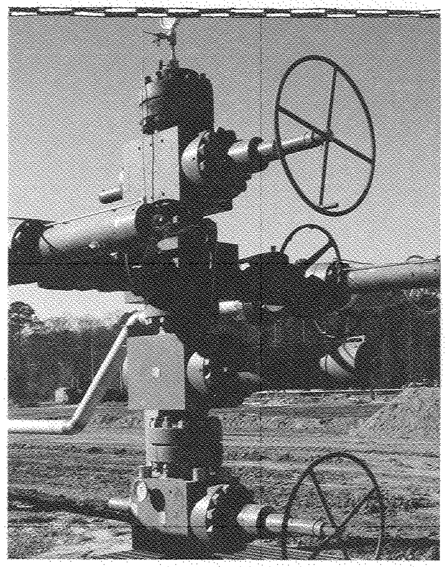
[5] On December 5, 2007, and October 31, 2005, we split our common stock on a 2-for-1 basis. Information relating to all prior years' shares and earnings per share has been retroactively restated to reflect the stock splits.

[6] Based on a gross working interest basis and includes reserves dedicated to volumetric production payments of 153.8 Bcf at December 31, 2008, 182.3 Bcf at December 31, 2007, 210.5 Bcf at December 31, 2006, 237.1 Bcf at December 31, 2005 and 178.7 Bcf at December 31, 2004 (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 table of contents page regarding cautionary notes about forward-looking statements and unproved reserves referenced herein.



This is a CO_2 production well at Jackson Dome. Production wells, such as this one, produce oil, water and CO_2. The CO_2 is later recycled.

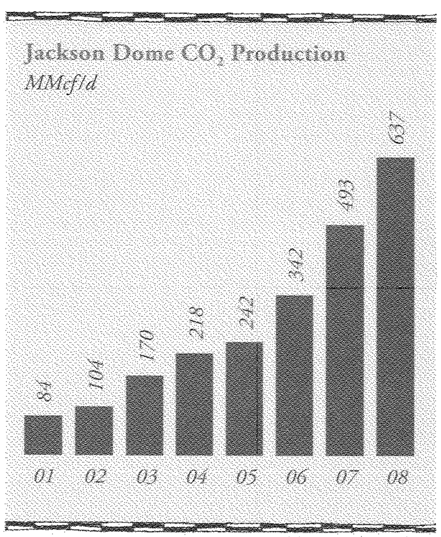
Natural CO_2 Source

Denbury uses carbon dioxide (CO_2) to extract additional amounts of oil from reservoirs in mature, depleted oil fields. This process, referred to as tertiary or CO_2 enhanced oil recovery, requires large volumes of nearly pure CO_2. We currently obtain this CO_2 from our natural source at Jackson Dome which is associated with an old volcano. Such natural sources are rare, and to our knowledge, we have the only large natural source of CO_2 in the Gulf Coast region. In the future, we also plan to use man-made CO_2 from industrial sources. We transport our CO_2 in a compressed state via pipelines, as CO_2 acts like a liquid (the so-called dense phase) at pressures in excess of 1,100 pounds per square inch ("psi").

At Jackson Dome, we produce CO_2 from formations that are between 14,000 and 16,000 feet underground. This CO_2 was originally discovered by companies looking for oil and gas in the 1960's and 1970's, and was initially thought to have little commercial value. However, following the oil crisis of the 1970's, several oil companies experimented with CO_2 for enhanced oil recovery, and by the 1980's, Shell Oil Company had started a project to produce CO_2 at Jackson Dome for this purpose. Low oil prices in the ensuing years thwarted this effort, and in 2001, Denbury acquired most of the assets that remained from this early effort, including producing CO_2 wells, facilities and a CO_2 pipeline.

Since 2001, we have steadily expanded the productive capacity at Jackson Dome, increasing production of CO_2 from 55 MMcf/d at the time we acquired the property, to an average of 767 MMcf/d during the fourth quarter of 2008. In 2009, we expect the productive capacity of our CO_2 wells to increase to over 1 Bcf/d.

Likewise, our proved reserves of CO_2 have increased from 0.8 Tcf at the time of Jackson Dome's acquisition to 5.6 Tcf as of December 31, 2008. We now own 26 producing wells, three dehydration facilities and a large number of gathering pipelines around Jackson Dome. We estimate that Denbury now injects more CO_2 per day (new or additional volumes, excluding recycled volumes) into its active CO_2 enhanced oil recovery projects than any other company in the world.

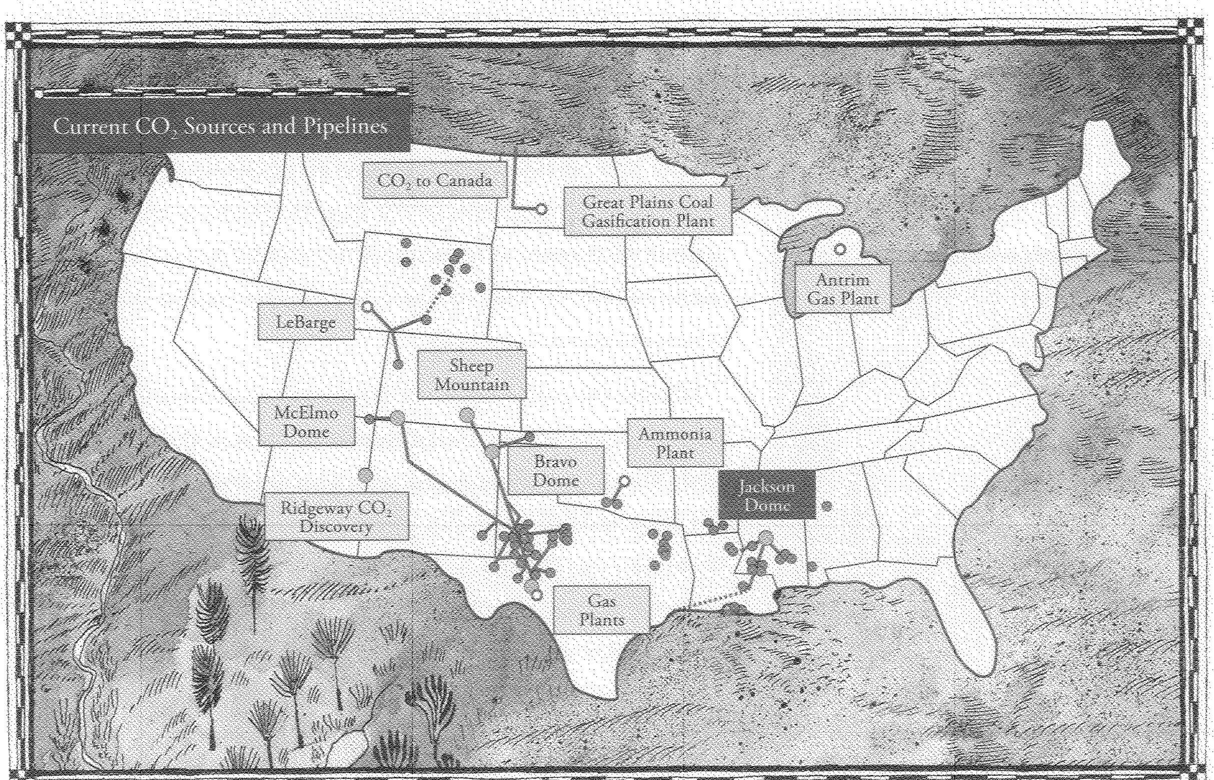


Man-made Sources

Many industrial activities produce large volumes of CO_2, particularly power plants, chemical plants and refineries. In these plants, carbon in the form of coal, oil or natural gas is combusted, which produces CO_2. Most of this CO_2 is released into the air, resulting in increasing amounts of CO_2 in our atmosphere. It has been proposed by those concerned about atmospheric CO_2 levels, that these emissions be reduced by some means; the only practical method at this time would be to capture this CO_2 and store it in underground reservoirs. Our CO_2 enhanced oil recovery operations provide a promising method to sequester these CO_2 volumes in oil reservoirs while simultaneously increasing domestic supplies of oil.

Denbury's CO_2 enhanced oil recovery operations provide a promising method to sequester CO_2 volumes in oil reservoirs while simultaneously increasing domestic supplies of oil.

We have entered into four contracts with owners of potential sources of CO_2 and have signed Letters of Intent or Memoranda of Understanding ("MOU") with numerous other project owners. These contracts are possible because of our pipeline systems and the presence of Jackson Dome CO_2 volumes to buffer the inherent imbalances between



The above map illustrates the current natural and industrial CO_2 sources and pipelines in the United States. Denbury owns its own natural source of CO_2 at Jackson Dome. Such natural sources are rare, and to our knowledge, we have the only large natural source of CO_2 in the Gulf Coast region.

The CO_2 Cycle

Over the past one billion years the earth has continually replenished the CO_2 in the atmosphere by volcanic activity. Much of the CO_2 is original mantle CO_2, but gradually the source of CO_2 has increasingly been the recycling of subducted limestones via volcanic eruptions. CO_2 concentrations in the air have varied over the past billion years, but have generally been much higher than the current concentration of around 300 parts per million ("ppm"). About 70 million years ago the amount of CO_2 in the atmosphere increased from an apparent increase in volcanic activity, allowing deposits of large volumes of limestones in the form of chalk. One of these CO_2-rich volcanoes was located near the site of present-day Jackson Dome in Mississippi. During its eruption, some of that CO_2 was trapped in adjacent sedimentary rocks, which today form the current producing zones for our CO_2 wells.

industrial supplies and our oil fields' demands. Generally, the current signed contracts and MOUs are for proposed plants which would employ gasification, none of which are currently under construction.

Gasification which burns carbon in the form of lignite, coal or petroleum coke, in pure oxygen, allows for the production of syngas, which can then be used in power plants and industrial processes as a natural gas substitute. The syngas can be converted into synthetic natural gas (CH_4) and transported along with natural gas for chemical or power purposes. The gasification process produces a near pure stream of CO_2 which can be easily diverted into a pipeline system and sequestered as part of our CO_2 enhanced oil recovery operations. These gasification plants are generally referred to as pre-combustion capture projects.

Existing emitters of CO_2, such as conventional power plants, are considering capturing the CO_2 emissions after combustion (post-combustion capture). We are in discussions with several potential post-combustion capture projects, but no firm contracts have been executed.

It seems likely that legislation targeting CO_2 emissions will be forthcoming shortly. We believe this will increase the quantities of CO_2 available to us, allowing us to grow and expand our CO_2 enhanced oil recovery operations to additional oil fields.

Currently Denbury operates or controls over 420 miles of CO_2 pipelines and has approximately 400 miles of pipeline under construction. These pipelines stretch from Jackson Dome to our producing regions in Mississippi, Louisiana and Texas.

CO_2 Transportation

One of the key properties of CO_2 is its ability to become a super critical fluid (the so-called dense phase) at a pressure of 1,100 psi, thus allowing it to be transported by pipeline. This is far more efficient than transporting CO_2 as a gas and allows Denbury to transport large volumes of CO_2 over hundreds of miles.

Currently Denbury operates or controls over 420 miles of CO_2 pipelines and has approximately 400 miles of pipeline under construction. These pipelines stretch from Jackson Dome to our producing regions in Mississippi, Louisiana and Texas. Our CO_2 is dehydrated and 98% pure, making it transportable using carbon steel pipe. Our pipelines operate at pressures ranging from 1,200 psi to 2,200 psi, and we can increase capacity by increasing the pipeline operating pressure (assuming the pipeline is capable of sustaining the higher pressure), as we have recently done with our NEJD Pipeline.

We are in the process of building the Green Pipeline, which will run from the end of our NEJD Pipeline near Donaldsonville, Louisiana, southeast of Baton Rouge, Louisiana, westward to our Hastings field, south of Houston, Texas. This pipeline is a key element to our expansion strategy and will not only allow us to send Jackson Dome CO_2 to fields in Texas, but will also allow us to gather man-made sources of CO_2 from the many power plants and industrial facilities along its route.

CO_2 pipelines have been operating in the U.S. for over 30 years and have a remarkable history of safety. There have been few unplanned releases of CO_2 and no fatalities associated with its use. CO_2 is a non-toxic, non-explosive, non-flammable gas which humans consume in soft drinks and exhale into the environment as they breathe. The primary risk with CO_2 is that it can displace oxygen if allowed to accumulate in a confined space and cause suffocation. Normally however, CO_2 rapidly disperses in air.

We are in the process of building the Green Pipeline, which will run from the end of our NEJD Pipeline near Donaldsonville, Louisiana, southeast of Baton Rouge, Louisiana, westward to our Hastings Field, south of Houston, Texas. This pipeline is a key element to our expansion strategy and will not only allow us to send Jackson Dome CO_2 to fields in Texas, but will also allow us to capture man-made sources of CO_2 from the many power plants and industrial facilities along its route. Potentially, these man-made sources could provide volumes several times greater than the volumes of CO_2 we expect to transport from Jackson Dome. Therefore, even a small percentage of these volumes would significantly enhance our ability to initiate CO_2 enhanced oil recovery projects in new oil fields. Today there are no significant volumes of man-made CO_2 being captured and sequestered in the Gulf Coast area. It will likely require either (i) an economic incentive such as a cap and trade system or a carbon tax to encourage carbon capture of existing emissions or (ii) an improvement in the overall economy and increased availability of capital to fund construction of new facilities. In either case, we will be ready and will have a significant strategic advantage following the completion of our CO_2 pipelines already in progress and the tie-in of these new lines with our existing infrastructure. All of our pipeline infrastructure will be connected with the CO_2 being produced from Jackson Dome, which potentially allows us to use Jackson Dome as a swing producer. Since the CO_2 emitters need someone to reliably take their gas 24 hours a day, 365 days a year, our unique flexibility allows us to contract for man-made volumes for long periods of time, as much as 15 to 20 years.

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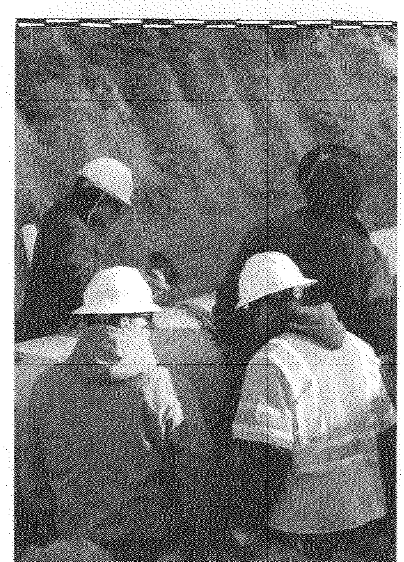


Construction of our Delta Pipeline will be completed in the first half of 2009. This pipeline runs from Tinsley Field (Phase III) to our Delhi Field (Phase V).

Denbury's ownership of the only known large natural CO_2 source in the area and our pipeline system infrastructure provide us with a significant competitive advantage. We are able to acquire depleted fields in our areas of operation with significant CO_2 enhanced oil recovery potential, and ultimately produce the oil that would not otherwise be recoverable.

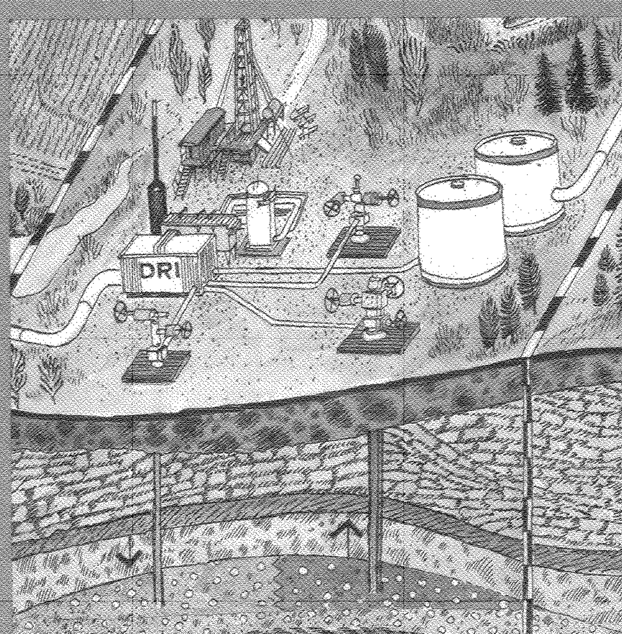
CO_2 Enhanced Oil Recovery

Our strategy of CO_2 capture and transportation is to provide sufficient volumes to pursue the Company's ultimate goal of increasing oil production and reserves in depleted reservoirs through CO_2 enhanced oil recovery ("CO_2 EOR").

The Gulf Coast region originally contained approximately 70 billion barrels of oil in place. Assuming that sufficient supplies of CO_2 are captured and delivered to the oil fields in the region, several billion barrels of oil could be recovered through CO_2 enhanced oil recovery projects. The United States Department of Energy commissioned, and subsequently released, a study of the top 200 reservoirs in the Gulf Coast region. This study estimated that an additional 3 to 5 billion barrels of oil could be recovered through CO_2 enhanced oil recovery methods. Denbury's ownership of the only natural CO_2 source in the area and our CO_2 pipeline system infrastructure provide us with a significant competitive advantage. We are able to acquire depleted fields in our areas of operation with significant CO_2 enhanced oil recovery potential, and ultimately produce the oil that would not otherwise be recoverable.

CO_2 EOR Process

CO_2 injected into a reservoir through an injection well acts as a kind of super solvent as it passes through the oil reservoir. The CO_2 dissolves into the oil that it contacts, decreasing the oil's viscosity and surface tension, allowing the oil to be extracted through producing wells. Exploration and production activity in most oil reservoirs results in the recovery of only a portion (30-60%) of the original oil in place, leaving a significant amount of oil that can be recovered using CO_2 enhanced oil recovery. Our CO_2 enhanced oil recovery efforts have demonstrated our ability to recover on average an additional 17% of the original oil in place, and in some cases, we are exceeding 17%.



Denbury has planned the development of our oil fields over a series of eight phases, each phase representing a group of nearby fields. In some cases, the fields are large enough to be a phase by themselves (e.g. Tinsley Field). Typically, we acquire these fields two to five years ahead of our planned CO_2 flood, with our latest acquisition being Hastings Field (Phase VII) purchased in February 2009.

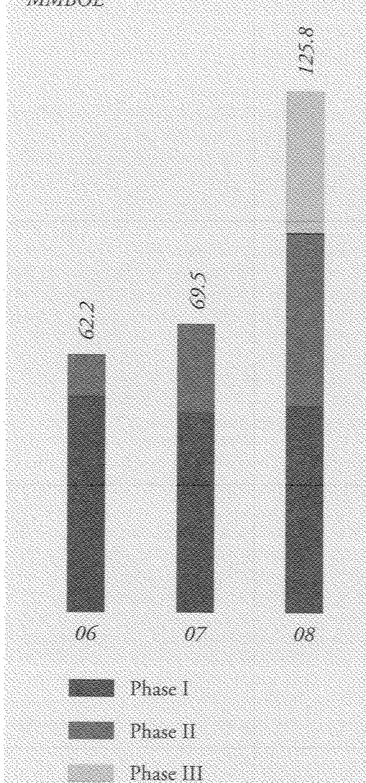
In the fourth quarter of 2008, Denbury produced an average of 21,874 Bbls/d from 16 fields in Phases I, II and III. Our longest active CO_2 enhanced oil recovery projects are located in Phase I (Southwest Mississippi), where we currently operate 12 floods, including our largest producing field, Mallalieu Field. Phase II was initiated following the construction and commissioning of the Free State Pipeline in 2006. We currently operate three producing CO_2 enhanced oil recovery projects within Phase II and have recently initiated CO_2 injections at our fourth (Heidelberg Field), our largest field in the area. CO_2 enhanced oil recovery operations at Tinsley Field (Phase III) were initiated in 2007 with our first oil response occurring in early 2008. Production continued to increase throughout 2008 and has grown to an average daily production of 1,832 Bbls in the fourth quarter of 2008. Our Phase IV CO_2 enhanced oil recovery project at Cranfield was initiated in the second half of 2008, with first oil production response during the first quarter of 2009.

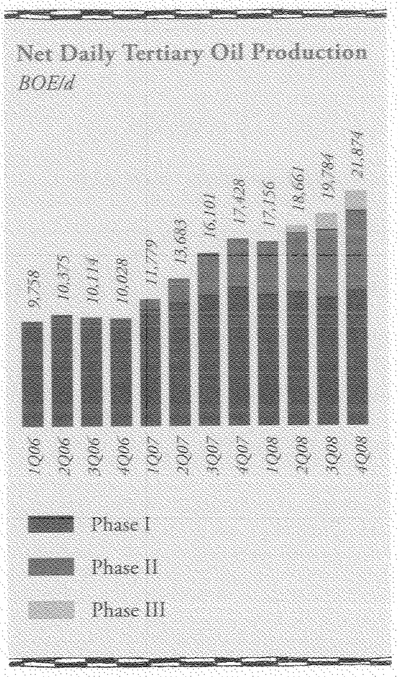
In 2009, we plan to initiate CO_2 enhanced oil recovery operations at Delhi Field (Phase V) upon completion of the Delta Pipeline from Tinsley Field to Delhi Field. We also plan to complete construction of the first phase of our newest CO_2 pipeline, the Green Pipeline, from Donaldsonville, Louisiana, to Galveston Bay in Southeast Texas. The completion of this portion of the Green Pipeline will allow us to initiate CO_2 enhanced oil recovery operations in the Seabreeze Area (Phase VIII) in 2010. Following the completion of the remaining portion of our Green Pipeline across Galveston Bay and on to Hastings Field, we plan to initiate CO_2 injections in Hastings Field (Phase VII). We expect the Green Pipeline to be completed to Hastings Field late in 2010 and injections to commence in early 2011.

In 2008, we were able to book additional CO_2 tertiary oil reserves of 63.4 MMBbls, which increased our tertiary reserves to 125.8 MMBbls, now about half of our total proved reserves on a BOE basis. The 2008 tertiary proved reserve additions were primarily at Tinsley, Heidelberg and Lockhart Crossing Fields. In order to recognize proved reserves, we must

In 2008, we were able to book additional CO_2 tertiary oil reserves of 63.4 MMBbls, which increased our tertiary reserves to 125.8 MMBbls, now about half of our total proved reserves on a BOE basis.

Tertiary Oil Reserves
MMBOE





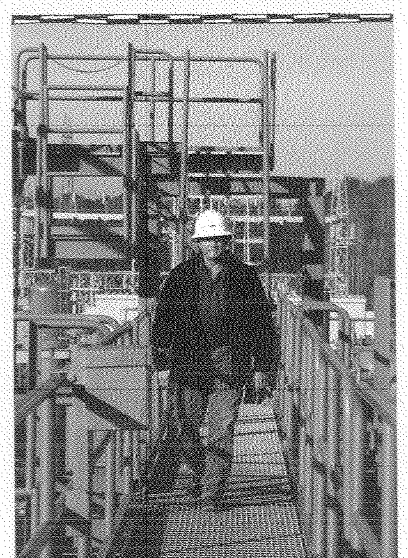
either have an oil production response from CO_2 injections or the field must be analogous to another producing tertiary oil field in the same area.

The main features of our tertiary flooding program are low cost reserve additions and steady production growth. We estimate that in addition to our 125.8 MMBbls of proved oil reserves from CO_2 enhanced oil recovery operations, our eight phases contain 254 MMBbls of probable reserves for a total of approximately 380 MMBbls. We estimate that proved CO_2 reserves at Jackson Dome are nearly sufficient to recover these proved and probable oil reserves. Our business model provides for the development of additional potential CO_2 reserves over the next five years or so, and we expect our tertiary oil production to increase over that period of time by an average of 10% to 20% per year. This forecast is dependent, however, on our capability to invest capital dollars in our projects which is highly dependent on the level of commodity prices.

Man-made CO_2 Volumes

Our strategy is to augment our natural CO_2 volumes with man-made volumes from power or industrial plants. As we discussed earlier, our ability to do this is largely dependent on the construction of new gasification facilities, or CO_2 capture facilities, at existing sites. The timing of this construction is uncertain, but we anticipate that it is at least three or four years away. This timing could be ideal for us as it would allow us to expand our CO_2 enhanced oil recovery operations beyond our current phases, and give us the impetus to continue our growth beyond the currently scheduled projects.

We believe that we offer industrial users the most practical and economical way to sequester CO_2 as we can permanently store the CO_2 underground in depleted oil reservoirs. As we have in the past, we are continuing to work with the appropriate government entities to certify our oil fields as permanent sequestration sites so that we are able to utilize any tax credits or carbon credits that may become available. In summary, we believe that we can create value from a product like CO_2, which others view as a waste or liability.



Donnie Dubois, Lead Operator, at our Lockhart Crossing CO_2 Facility. CO_2 injection began at our Lockhart Crossing Field in December 2007, with first oil production in June 2008.

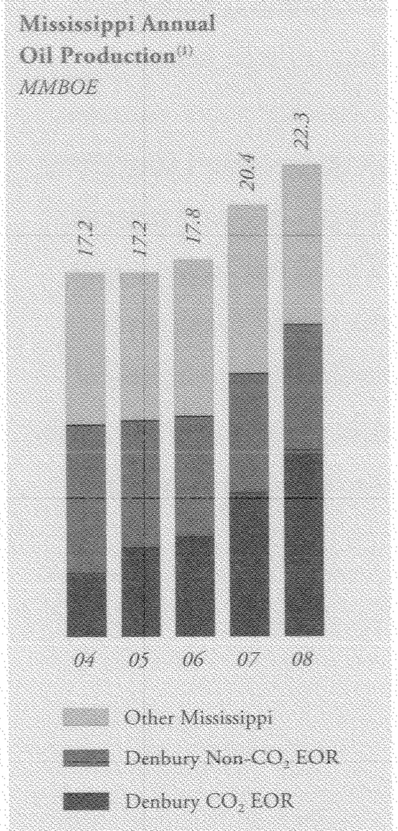
Benefits of Denbury's Strategy

At the current time, we have virtually no competition for CO_2 enhanced oil recovery projects in the areas that we operate, because of our ownership of both CO_2 reserves and related CO_2 pipeline infrastructure. As a result, we expect to grow our reserves and production for several years at a reasonable cost, and believe we can make a profit with oil prices as low as $40 to $50 a barrel. Long term, we believe that oil will become relatively more valuable as easy-to-find sources of supply become scarcer. We do not believe that the world is close to finding an economical substitute for crude oil in our modern economy.

Denbury's ability to sequester significant volumes of CO_2 from industrial sources appears to be very timely in view of our government's stated goal to tax or cap CO_2 emissions. Our current CO_2 EOR projects inject from 0.52 to 0.64 metric tons of CO_2 for every recovered barrel of oil (the burning of which releases approximately 0.42 metric tons of CO_2), storing 24% to 52% more CO_2 than the recovered oil produces. Not all of the oil that we produce is consumed in such a way that creates CO_2 — at least 20% goes to produce valuable products like plastics which are used to produce products vital to the modern economy. In any event, oil produced from this method is certainly more beneficial than imported oil which sequesters no CO_2 volumes.

Long term, we believe that oil will become relatively more valuable as easy-to-find sources of supply become scarcer. We do not believe that the world is close to finding an economical substitute for crude oil in our modern economy.

Denbury's New Green Building: The expansion of our corporate offices in Plano, Texas, was completed in 2008. Our new building is LEED (Leadership in Energy and Environmental Design) certified, which provides that it is environmentally responsible and a healthy place to work.



(1) Source: Mississippi Oil & Gas Board for state total annual oil production amounts

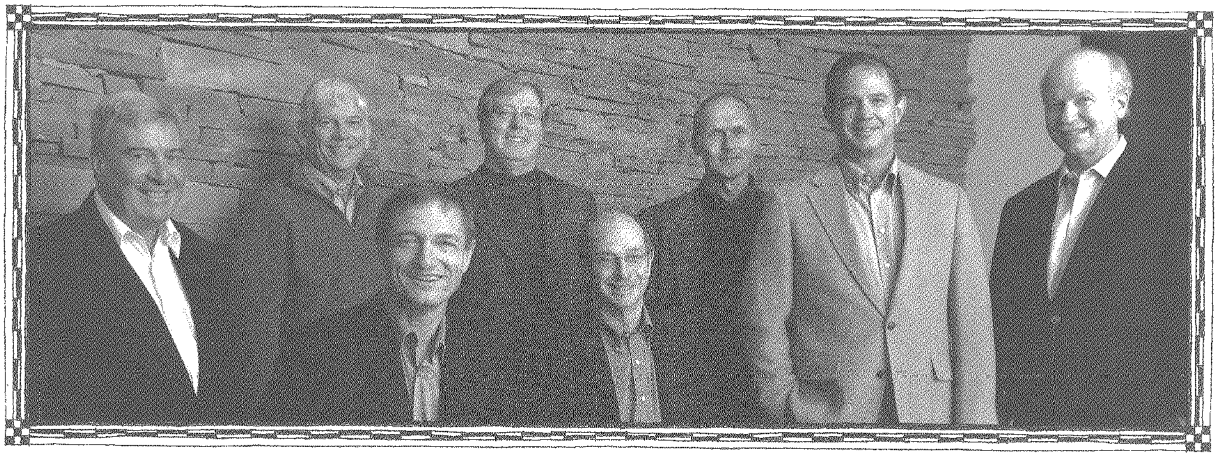
The benefits of producing a barrel of oil domestically are very significant to the local and federal economy. In Mississippi, we expect that approximately half of the state's total 2009 production of oil will come from CO_2 EOR. Both our capital expenditures ($1.02 billion in 2008) and operating expenditures ($308 million in 2008) are spent in the local communities where we work and invest, and we contribute to the local and state economies through the various taxes that we pay. Contrast this to the economic benefits of imported oil which provides none of these benefits. In fact, it has been estimated by some that considering the trade imbalance effect along with the lack of the benefits of taxes and reinvestment, a domestic barrel of oil selling for $60 is the equivalent of paying $220 for an imported barrel.

Denbury has enjoyed being a part of the communities in which we work. We contribute annually to various charities and causes, including our donations and sponsorship of the Mississippi Multiple Sclerosis (MS) Society Bike Tour, and unanticipated needs such as those created in the aftermath of Hurricane Katrina. We continue to improve the training, safety and operating conditions for our employees, and we are making a major effort to improve the impact our on-going operations have on the communities where we work. To this latter end, during 2009 we will be initiating and addressing the sustainability of your company's operations, and we will be reporting this annually going forward.

Mississippi MS150

Denbury has been a sponsor of the MS150 Bike Tour in Mississippi for the past five years, two of which were as title sponsor. We put a team together each year, because we know that riding 150 miles is nowhere near as difficult as confronting a lifetime with multiple sclerosis. In 2008, Denbury raised approximately $155,000 during the October MS Bike Tour in Mississippi. We had 25 Denbury employees join the ride and 15 Denbury volunteers.

The National Multiple Sclerosis Society gives us all reason to hope. In addition to supporting novel research projects around the globe, they also provide much needed education, programs, and services to everyone who is affected by MS — including those diagnosed, their friends and families, and the healthcare professionals who work with them.



Board of Directors
(from left to right)

David I. Heather
Independent Consultant
Dallas, Texas

Michael L. Beatty
Chairman and Chief Executive Officer
Beatty & Wozniak, P.C.
Denver, Colorado

Wieland F. Wettstein
Chairman of the Board
President
Finex Financial Corporation, Ltd.
Calgary Alberta

Gareth Roberts
President and Chief Executive Officer
Denbury Resources Inc.
Plano, Texas

Ronald G. Greene
Principal
Tortuga Investment Corp.
Calgary Alberta

Michael B. Decker
Principal
Wingate Partners
Dallas, Texas

Randy Stein
Independent Consultant
Denver, Colorado

Gregory L. McMichael
Independent Consultant
Denver, Colorado

Investment Committee
(from left to right)

Ronald T. Evans
Senior Vice President, Reservoir Engineering

Gareth Roberts
President and Chief Executive Officer

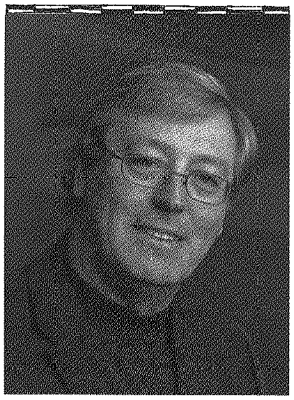
Phil Rykhoek
Senior Vice President and Chief Financial Officer

Mark C. Allen
Vice President and Chief Accounting Officer

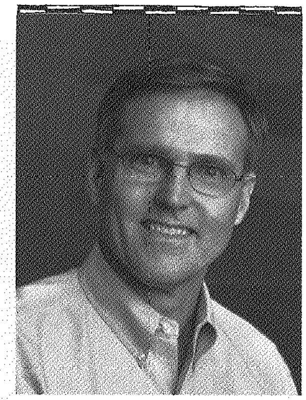
Robert Cornelius
Senior Vice President, Operations

Our corporate governance guidelines, as well as the charters for our nominating/governance committee, compensation committee, and audit committee are listed on the Company website at www.denbury.com. 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.

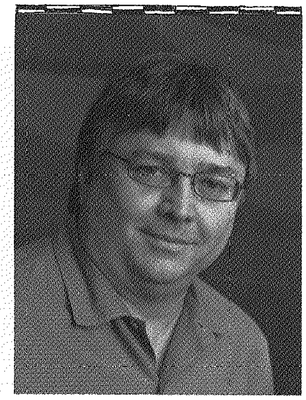
You may contact our board members by addressing a letter to: Denbury Resources Inc. Attn: Corporate Secretary, or by email to secretary@denbury.com.



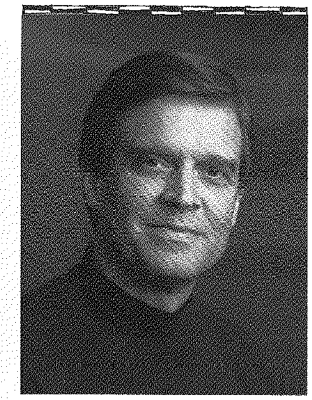
Gareth Roberts
President and Chief Executive Officer



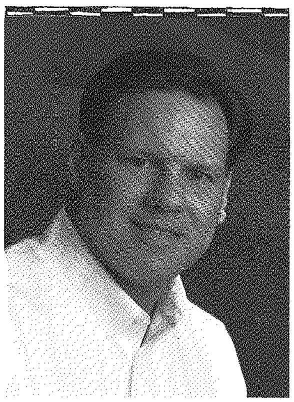
Robert Cornelius
Senior Vice President, Operations



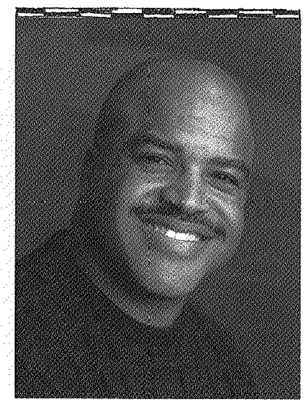
Ronald T. Evans
Senior Vice President, Reservoir Engineering



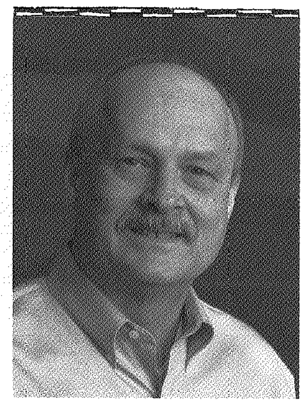
Phil Rykhoek
Senior Vice President and Chief Financial Officer



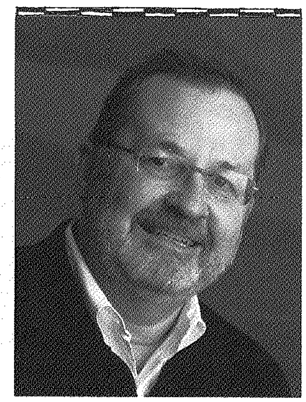
Mark C. Allen
Vice President and Chief Accounting Officer



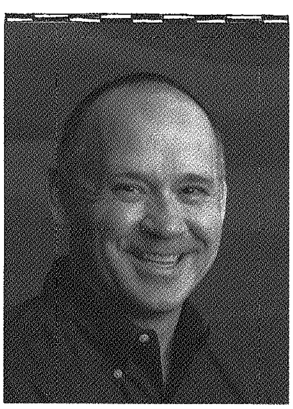
Jerome C. Ballard, Sr.
Vice President, Human Resources



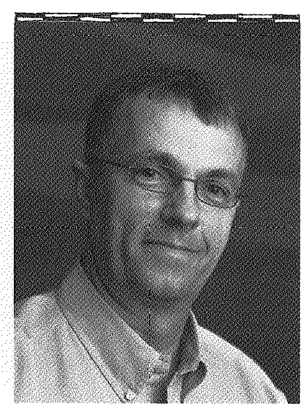
Ray Dubuisson
Vice President, Land



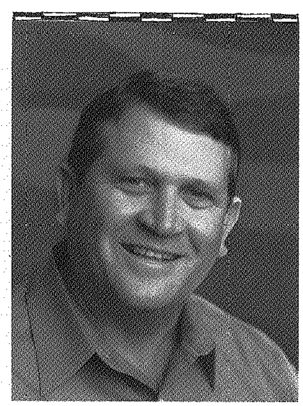
Dan E. Cole
Vice President, Marketing



Bradley A. Cox
Vice President, Business Development



Charlie Gibson
Vice President, Reservoir Engineering



Barry Schneider
Vice President, Production and Operations

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

2008 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, 2008
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 small reporting company. See definition of "large accelerated filer," "accelerated filer," and "small reporting company" in Rule 12-b2 of the Exchange Act.
Large accelerated filer X Accelerated filer ___ Non-accelerated filer ___ 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 $6,251,312,368.

The number of shares outstanding of the registrant's Common Stock as of January 31, 2009, was 248,411,326.

DOCUMENTS INCORPORATED BY REFERENCE

Document:	Incorporated as to:
1. Notice and Proxy Statement for the Annual Meeting of Shareholders to be held May 13, 2009.	*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 20.
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. For the complete definition see: http://ecfr.gpoaccess.gov/cgi/t/text/text-idx?c=ecfr&sid=20c66c74f60c4bb8392bcf9ad6fccea3&rgn=div5&view=text&node=17:2.0.1.1.8&idno=17#17:2.0.1.1.8.0.21.43

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, 2008, we had 797 employees, 493 of whom were employed in field operations or at the field offices. Our employee count does not include the approximately 610 employees of Genesis Energy, LLC as of December 31, 2008, 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 where we have a competitive advantage as a result of our CO_2 reserves and expanding infrastructure, or where we believe we can ultimately obtain it;
- acquire properties where we believe additional value can be created through tertiary recovery operations and a combination of other exploitation, development, exploration and marketing techniques;
- 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 controlling 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

Overview. Since we acquired our first carbon dioxide tertiary flood in Mississippi in 1999, we have gradually increased our emphasis on these types of operations. During this time, we have learned a considerable amount about tertiary operations and working with carbon dioxide. Our tertiary operations have grown to the point that approximately 50% of our December 31, 2008 proved reserves are proved tertiary oil reserves, almost 50% of our forecasted 2009 production is expected to come from tertiary oil operations (on a BOE basis), and almost all of our 2009 capital expenditures are related to our current or future tertiary 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 (we estimate our economic per barrel dollar cost on these projects at current oil prices is in the range of the mid-twenties, 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. In addition, we are pursuing anthropogenic (man-made) sources of CO_2 to use in our tertiary operations, which we believe will not only help us recover additional oil, but will provide an economical way to sequester CO_2. We have acquired several old oil fields in our areas of operations with potential for tertiary recovery and plan to acquire additional fields, and we are continuing to expand our CO_2 pipeline infrastructure to transport CO_2.

During 2008, we added 63.4 MMBbls of tertiary-related proved oil reserves, primarily initial proven tertiary oil reserves at Heidelberg Field (Phase II), Tinsley Field (Phase III) and Lockhart Crossing Field (Phase I) (see discussion of the individual fields below), increasing our proved tertiary oil reserves from 69.5 MMBbls at December 31, 2007 to 125.8 MMBbls as of December 31, 2008. In order to recognize proved tertiary oil reserves, we must either have an oil production response to the CO_2 injections or the field must be analogous to an existing tertiary flood. The magnitude of proved reserves that we can book in any given year will depend on our progress with new floods and the timing of the associated production response.

We believe that 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 5% 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 proved 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, followed by our acquisition of Jackson Dome CO_2 reserves and NEJD 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 enhanced oil play.

Tertiary Recovery Phases. We categorize our tertiary operations by labeling operating areas or groups of fields as phases. Phase I includes several fields along our 183-mile NEJD CO_2 Pipeline that runs through southwest Mississippi and into Louisiana. The most significant fields in this area are Little Creek, Mallalieu, McComb, and Brookhaven Fields, all fields which have been producing oil for some time, and one of our newest enhanced oil fields, Lockhart Crossing Field. We saw our first tertiary oil production from Lockhart Crossing Field, located in South Louisiana, during 2008. Lockhart Crossing, although a relatively small field, is the first of three fields we plan to CO_2 flood in Louisiana and is 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, and Martinville Fields which have been producing oil for over two years, and Heidelberg Field where we started injecting CO_2 in

December 2008. 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. Tinsley Field had its first oil production response in the second quarter of 2008. Phase IV includes Cranfield, where we began CO_2 injection operations during July 2008 and had our first oil production response in the first quarter of 2009, and Lake St. John Field, a project currently scheduled to commence in 2011, both fields located near the Mississippi/Louisiana border west of the Phase I fields. Phase V is Delhi Field, a Louisiana field acquired in 2006, located southwest of Tinsley Field. CO_2 injection in Phase V will begin in 2009 upon completion of the Delta CO_2 Pipeline, an 81-mile pipeline from Tinsley to Delhi. Citronelle Field in Southwest Alabama, another field acquired in 2006, is our Phase VI. Citronelle will require an extension to the Free State CO_2 Pipeline in order to commence this project, the timing of which is uncertain at this time. Our last two currently existing phases will require completion of our 320-mile Green Pipeline, which will run from Southern Louisiana to Hastings Field, south of Houston, Texas, scheduled for completion in 2010. Hastings Field, a field on which we acquired a purchase option in late 2006 and purchased in February 2009, 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 wells and drilled 20 additional CO_2 producing wells, significantly increasing our estimated proved CO_2 reserves to approximately 5.6 Tcf as of December 31, 2008, 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.

Today, we own every producing CO_2 well in the region. Although our current proved 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 continued our exploration efforts by completing a 136 square mile 3-dimensional seismic program during 2008. The 3-D seismic program was located west of the DRI Ice Field over existing known CO_2 fields and adjacent lead areas. The seismic data will be evaluated during 2009 with anticipated exploratory drilling in future years. During 2008 we drilled and completed five CO_2 production wells. These wells added 360 MMcf/d of CO_2 production capacity which increased the Jackson Dome total CO_2 production capacity to between 900 MMcf/d and 1.0 Bcf/d. During the fourth quarter 2008, production averaged 767 MMcf/d of CO_2, a 44% increase over levels in the fourth quarter 2007. In addition to expanding our production capacity, during 2008 we completed the installation and startup of a second train at the Barksdale dehydration facility at Jackson Dome. This expansion added 300 MMcf/d of CO_2 dehydration capacity, which increased the Jackson Dome total CO_2 dehydration capacity to approximately 1.1 Bcf/d. We also installed a pump station in Brandon, Mississippi, to boost NEJD pipeline pressure and increase CO_2 deliverability capacity in that pipeline to approximately 515 MMcf/d. In order to ensure future production rates, processing capabilities and deliverability to the main transportation pipelines, during 2009 we are constructing a 150 MMcf/d Trace Dehydration Facility, installing additional pump capacity at the Brandon Pump Station and constructing a 13-mile pipeline from the Barksdale dehydration facility to the Brandon Pump Station. This pipeline will provide additional capacity to the NEJD line by bypassing a majority of the industrial users.

During 2008, we sold an average of 89 MMcf/d of CO_2 to commercial users, and we used an average of 548 MMcf/d for our tertiary activities. We are continuing to increase our CO_2 production, averaging 767 MMcf/d during the fourth quarter of 2008. We estimate that our planned tertiary operations will not require any significant additional deliverability through 2010.

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. If built, these plants could 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 2013. These plants have all been delayed due to current economic conditions and it is uncertain when, if ever, these plants will be built. We have entered into long-term commitments to purchase manufactured CO_2 from four proposed plants, which, if all four plants are built, could potentially provide us with an aggregate of 1.0 Bcf/d of CO_2, commencing in 2013. In addition to the proposed gasification plants, we have ongoing discussions underway regarding existing plants of various types that emit CO_2 and we may be able to purchase their volumes. In order to capture such volumes, we (or the plant owner) would need to install additional equipment, which include at a minimum, compression facilities. Most of these existing plants emit relatively small volumes of CO_2, generally less than the proposed gasification plants, but such volumes may still be attractive if the source is located near our proposed Green CO_2 pipeline. 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 in the next few years Congress could enact legislation to address climate change by capping or taxing U.S. CO_2 emissions, which could ultimately increase the supply and lower our cost of man-made CO_2 for our operations by creating economic penalties for the emission of CO_2. Further, we see these sources as a possible expansion of our natural Jackson Dome source, assuming they are economic, and we believe that our potential ability to tie these sources together with pipelines will give us a significant competitive advantage over our competitors in our geographic area in acquiring additional oil fields and future potential man-made sources of CO_2. We believe that we are a likely purchaser of CO_2 produced 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 source to balance our CO_2 supplies and demand.

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 four existing Phase II tertiary fields in East Mississippi (Eucutta, Soso, Martinville and Heidelberg) and will also be used for our proposed projects at South Cypress Creek and other fields in Phase II.

During 2008, 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 (31 miles), which significantly increased the transportation capacity of CO_2 to that field. We also reconditioned and converted the natural gas pipeline we acquired from Southern Natural Gas Company in 2007 to CO_2 service, which we are currently using to transport CO_2 to our first Phase IV field, Cranfield Field. During 2008, we started construction to further extend our Delta Pipeline with a 24" 68-mile extension from Tinsley Field to Delhi Field. Completion of this segment is expected during the second quarter of 2009.

In late 2006, we purchased an option to acquire Hastings Field, a potential tertiary flood located near Houston, Texas, which we subsequently acquired in February 2009. In order to flood Hastings Field, we are building a CO_2 pipeline from the southern end of our existing NEJD CO_2 Pipeline that terminates near Donaldsonville, Louisiana, to Hastings Field, estimated to be approximately 320 miles. Based on our latest estimates, this pipeline is expected to cost between $700 million and $750 million. During 2007, we committed to the manufacture of the 24" pipe and thereby locked-in the pipe purchase price, and acquired approximately 100-plus miles of the necessary 320 miles of right-of-way. Our efforts during 2008 were focused on engineering design, pipe manufacturing and right-of-way acquisitions. Construction of the pipeline began during November 2008 and will continue through 2010. This multi-year project is underway and in 2009 we expect elevated activity and elevated spending (especially during the first half of the year) as crews work to complete the pipeline and its connecting line to Oyster Bayou Field, east of Galveston Bay, by late 2009 or early 2010 and on to the Hastings Field by year-end 2010. 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 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, but we expect them to be reduced to an economic break-even dollar cost on these projects in the mid-twenties per barrel if oil prices remain at their current reduced level, 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 proved reserves) for our tertiary oil fields through December 31, 2008, are approximately $11.30 per BOE. Currently, we forecast that our finding and development costs for most of our tertiary projects will average less than $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, and other factors, as the finding and development costs to date do not include significant unproved potential reserves in most of the fields. Our operating costs for tertiary operations are highly dependent on commodity prices and could range from $15 to $25 per BOE over the life of each field, 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.

Tentatively, we plan to spend approximately $52 million in 2009 in the Jackson Dome area with the intent to add additional CO_2 deliverability for future operations. Approximately $138 million in capital expenditures is budgeted in 2009 at the oil field level in Phases I through V, plus an additional $485 million for our Delta and Green CO_2 Pipelines, making our combined CO_2 related expenditures just over 90% of our projected $750 million 2009 capital budget.

Our Tertiary Oil Fields with Proved Tertiary Reserves

On December 31, 2008, we had total tertiary-related proved oil reserves of approximately 125.8 MMBbls, consisting of 3.2 MMBbls at Little Creek Field (and surrounding smaller fields), 11.8 MMBbls at Mallalieu Field, 13.7 MMBbls at McComb and Smithdale Fields, 17.3 MMBbls at Brookhaven Field, 9.1 MMBbls at Eucutta Field, 9.0 MMBbls at Soso Field, 0.8 MMBbls at Martinville Field, 34.4 MMBbls at Tinsley, 4.0 MMBbls at Lockhart, and 22.4 MMBbls at Heidleberg. 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 21,874 Bbls/d during the fourth quarter of 2008. We expect this production to continue to increase for several years as we expand our tertiary operations to additional fields.

Phase I Fields

Mallalieu Field. Mallalieu Field consists of two units, West Mallalieu Unit and the smaller East Mallalieu Unit. Combined they are our most prolific tertiary flood in terms of production, producing 5,056 Bbls/d during the fourth quarter 2008. In contrast to many of our existing fields, Mallalieu Field was not waterflooded prior to CO_2 injection. Therefore, we estimate 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 2007, we increased our proved reserves in this area, raising our estimated recovery factor from 17% to 20% for this field, based on production performance to date. A total of $11.3 million was invested in this field during 2008 to drill, re-enter or recomplete wells in efforts to improve production. During the fourth quarter of 2008, we began an expansion of the central processing facility in this field, which is expected to be completed in July, 2009. The expansion of the facility will allow CO_2 recycle rates to increase from the current 160 MMcf/d to 230 MMcf/d.

From inception through December 31, 2008, we had net positive cash flow (revenue less operating expenses and capital expenditures, including the acquisition cost) from Mallalieu Field of $421.0 million.

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 generally increased since that time, averaging 1,563 Bbls/d in the fourth quarter of 2008. During 2008, we expanded the number of injection wells and increased injection pressures, resulting in significant increases in our CO_2 injections at McComb Field. The field continues to present challenges to the technical team, but we are improving our understanding of the reservoir. The technical team is working to further improve production rates by monitoring injection patterns, reworking producing wells, and using injection surveys for conformance issues within the reservoir.

In early 2008, we had a mechanical failure in one of our best wells at Smithdale, causing a temporary decline in production. The well was redrilled and oil production was restored, averaging 529 Bbls/d in the fourth quarter of 2008. The reservoir at Smithdale is a channel and thus our drilling was based on the completion of our 2007 3-D seismic survey covering the McComb and Smithdale Fields. By utilizing the 3-D seismic data, our geoscientists are able to put our wells in optimal positions within the channels at Smithdale to maximize the aerial coverage and sweep of the CO_2 injected.

From inception through December 31, 2008, 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 $101.2 million.

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 generally increase throughout 2006 and 2007 as additional injection patterns have been developed. Brookhaven Field has three discrete reservoirs that are being simultaneously CO_2 flooded. Our oil production here during the fourth quarter of 2008 averaged 3,178 Bbls/d.

During 2008, oil production increased from 3,000 to 4,500 barrels of oil per day as a result of expanded development of the CO_2 flood. Also, detailed production and reservoir evaluations identified certain areas of high permeability within the Tuscaloosa Reservoir that act as "thief zones" and take a disproportionate volume of CO_2 from the injection wells. Polymer treatments designed to reduce CO_2 injection into these "thief zones" were pumped successfully on two wells. The polymer treatments are designed to alter the injection profiles and improve the reservoir sweep efficiencies in the first and second development areas of Brookhaven Field. The injection and offsetting production results of these treatments are encouraging enough that additional treatments are planned in 2009.

From inception through December 31, 2008, we had net positive cash flow (revenue less operating expenses and capital expenditures, including the acquisition cost) from Brookhaven of $4.6 million.

Little Creek Area. The Little Creek area fields, Denbury's most mature enhanced oil recovery project, were acquired in 1999. During the fourth quarter of 2008, production averaged 1,706 Bbls/d from the Little Creek area, which includes Lazy Creek. Production at Little Creek Field began declining during 2006 and is expected to gradually decline in the future, even though 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.

A project was initiated in 2008 between Denbury, Mississippi State University, and the U.S. Department of Energy. The group is studying the process of alternating CO_2 injection with nutrient-enriched water in a CO_2 injection well to stimulate the growth and development of microbes in the reservoir. The one-year project will monitor injection pressures and offset oil samples for evidence of improved sweep efficiencies within the reservoir as a result of the growth of the microbes. If successful, the technique could be expanded to other portions of the field.

From inception through December 31, 2008, 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 $183.5 million.

Lockhart Crossing Field. Lockhart Crossing, located in Livingston Parish, Louisiana is our first CO_2 project outside of Mississippi. Lockhart Crossing produces from the Wilcox formation at an average depth of 10,200' and has similar reservoir characteristics to the Tuscaloosa formation which had great success to tertiary flooding at Little Creek and Mallalieu Fields.

We initiated CO_2 injections during December 2007 after completing the six mile supply line connecting Lockhart Crossing to the NEJD Pipeline. We saw our first tertiary production in July 2008. By the end of 2008, we had completed two of the five development phases in the field and we are using 3-D seismic data to assist us with the remaining development.

From inception through December 31, 2008, 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 costs) from this field of $59.5 million.

Phase II Fields

Eucutta Field. The oil production 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. The initial tertiary oil production occurred in the fourth quarter of 2006. During 2008, oil production continued to increase as the Eutaw Reservoir was more fully developed, averaging 3,538 Bbls/d during the fourth quarter of 2008. Our plans for 2009 include the development of the remaining injection patterns, along with an expansion and upgrade of the CO_2 facility. This work will be completed in early 2009, with an anticipated increase in oil production thereafter.

At December 31, 2008, we had 9.1 MMBbls of proved reserves in the Eucutta Field attributable to the CO_2 flood 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, 2008, we had net positive cash flow (revenue less operating expenses and capital expenditures, including the acquisition cost) from Eucutta of $3.9 million.

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 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, we had our initial response from the Rodessa combined with continued response from the Bailey. In addition, a pilot CO_2 flood was initiated in the Cotton Valley Sand. We made significant additions to the CO_2 recycle facility during 2008, increasing the CO_2 purchase capacity. During the fourth quarter of 2008, production at Soso had increased to 2,704 Bbls/d.

From inception through December 31, 2008, 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 $67.6 million.

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 completed the development of the Mooringsport formation during 2006. During 2008, an additional producing well was drilled to expand the development of the Rodessa sand. A Lower Hosston "huff and puff" project was also initiated. The Lower Hosston project consists of injecting a predetermined volume of CO_2 into the reservoir, allowing the CO_2 time to disperse and contact oil, then flowing the well back and producing the oil that contacted the CO_2. Numerous cycles of injection and production are planned. We are currently in the first injection cycle on this project. During the fourth quarter of 2008 production at Martinville averaged 1,213 Bbls/d, almost all of which is from the Mooringsport.

Although we booked minimal proved reserves in 2006 from the one responding well in the Mooringsport, in 2007 and 2008 we booked additional reserves, approximately 1.5 MMBbls and 0.8 MMBbls, respectively, 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, 2008, 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 $6.2 million.

The Martinville Field Wash Fred 8500' reservoir development continues to evolve. The Wash Fred formation 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 low 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 with 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.

Heidelberg Field. Our 2008 capital program included $43.4 million for construction of the CO_2 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 will be conducted in the West Heidelberg (WHEOUP) Unit. 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 similar to the results at Eucutta Field. During the first half of 2008, the Heidelberg central processing and CO_2 recycle facility surface site was secured, cleared, and prepared for construction and facility construction began during the third quarter of the year. The first phase well work was completed in the fourth quarter with the conversion of seventeen producers and eight CO_2 injectors. As of year end, we were injecting approximately 40 MMcf/d of CO_2 into the Eutaw formation in the southern end of West Heidelberg Field. During 2009, we will add eight new injection patterns and expand the central processing facility. Oil production response to the CO_2 injection is expected during the second half of 2009. Four phases are planned for West Heidelberg Field before moving EOR operations into East Heidelberg.

Due to Heidelberg being an analogy to Eucutta, we were able to book proved tertiary oil reserves at Heidelberg Field at December 31, 2008. Although similar in many respects, the Eutaw reservoir at Heidelberg contains two to three times the potential oil reserves as the Eutaw formation at Eucutta Field.

Phase III Field

Tinsley Field. Tinsley Field was acquired in January 2006 and is the largest oil field in the state of Mississippi. As is the case with the majority of fields in Mississippi, Tinsley produces from multiple reservoirs. Our primary target in Tinsley for CO_2 enhanced oil recovery operations is the Woodruff formation. A prior operator 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 crude 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 reconditioned the pipeline for CO_2 service and initiated limited CO_2 injection in Tinsley Field in January 2007. During 2008 the 24" Delta Pipeline was completed and placed in service between Jackson Dome and the Tinsley CO_2 recycle facility, allowing us to transport and inject significantly larger volumes of CO_2. We had our first tertiary oil production commencing in April 2008. By July 2008, all of the tertiary wells in the first two phases were responding to CO_2 injection and producing oil. During the fourth quarter of 2008, the average oil production was 1,832 Bbls/d. We also had non-CO_2 oil production during this same period of 736 Bbls/d.

From inception through December 31, 2008, 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 Tinsley of $213.8 million.

Our Tertiary Oil Fields Without Proved Tertiary Reserves

Cranfield. Cranfield development accelerated during 2008 as we increased the well count to 11 CO_2 injectors and 11 producers. Reconditioning of the CO_2 pipeline and the initial phase of the production facility were completed in the third quarter of 2008, which allowed us to commence CO_2 injection into the Lower Tuscaloosa reservoir. The CO_2 injection increased reservoir pressure to a level that caused most of the wells to begin flowing water by late 2008. We had our first minor amounts of tertiary oil production in January 2009. At Cranfield, we have participated with the Bureau of Economic Geology (BEG) from the University of Texas as they study CO_2 injection and sequestration to better define and understand the movement of CO_2 through the reservoir. The results of this study could lead to a greater recovery of the oil in the reservoir.

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 income. In 2008, eight wells were re-completed to be utilized in the Delhi flood patterns. We also finalized the development plans to complete two CO_2 flood patterns in the Paluxy formation and one pattern in the Tuscallousa formation. The surveying and permitting process for wells, flowlines and facilities are expected to be completed during the first quarter of 2009. The Delta Pipeline (Tinsley to Delhi) is expected to be delivering CO_2 to Delhi Field by the end of the second quarter of 2009. The CO_2 processing facility engineering will be completed during 2009 and construction of the CO_2 facility will begin, with first enhanced oil production anticipated in 2010. As of December 31, 2008, 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 gave us an option to purchase their interest in Hastings Field, a strategically significant potential tertiary flood candidate located near Houston, Texas. We exercised the purchase option prior to September 2008, and closed the $201 million acquisition during February 2009. As consideration for the option agreement, we made total payments of $50 million.

The purchase price of $201 million included approximately $4.9 million for certain surface land, oilfield equipment and other related assets. Under the terms of the agreement, Venoco, Inc., the seller, retained a 2% override and reversionary interest of approximately 25% following payout, as defined in the option agreement. The Hastings Complex is currently producing approximately 2,400 BOE/d, net to the acquired interest, with conventional proved reserves of approximately 5.8 MMBOE using year-end 2008 prices. The Hastings proved reserves were not included in the Company's year-end proved reserves. We plan to commence flooding the field with CO_2 beginning in 2011, after completion of our Green CO_2 Pipeline currently under construction, and construction of field CO_2 recycling facilities.

As part of the agreement, we are required to spend an aggregate of approximately $179 million over a five year period to develop the field for tertiary operations (commencing in 2010), with an obligation to commence CO_2 injections in the field by late 2012.

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 started construction of the Green Pipeline during November 2008 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 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 on or close to the planned route of the 24" Green Pipeline. We acquired the majority interest in Oyster Bayou Field and a relatively small interest in Fig Ridge Field. We plan to start the unitization hearings required at Oyster Bayou Field during 2009. 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. During 2008 we initiated those discussions.

Our acquisitions in Gillock Field include an acquisition of almost all of the South Gillock Unit, 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 Green Pipeline.

Overall Tertiary Economics to Date. Through December 31, 2008, we have invested a total of $1.4 billion on tertiary oil fields (including the allocated acquisition costs), and received $1.3 billion in net operating income (revenue less operating expenses), or net unrecovered cash flow of $105.3 million, the deficit primarily due to the significant funds expended on acquisitions during 2006. Of our total spending, approximately $229.6 million was invested to date on fields that had little or no proved reserves at December 31, 2008 (i.e., significant incremental proved reserves are anticipated in future years). 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 $816.7 million as of December 31, 2008, including $525.7 million associated with CO_2 pipelines. At year-end 2008, the proved oil reserves in our tertiary recovery oil fields had a PV-10 Value of approximately $1.0 billion, using December 31, 2008, NYMEX pricing of $44.60 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 20,441 gross acres and 19,457 net acres in the Barnett Shale area in North Central Texas. We acquired our initial acreage in this area in 2001 and did only limited development until 2005. Through December 31, 2008, we have invested a total of $552.3 million on the Barnett Shale area (including acquisition costs) and have received $403.0 million in net operating income (revenue less operating expenses), or net negative cash flow of $149.3 million. At December 31, 2008, we had approximately 458 Bcfe of proved reserves in the Barnett Shale area with a PV-10 Value of approximately $430.0 million, using December 31, 2008, Henry Hub indicative cash pricing of $5.71 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 2008, we drilled and completed 38 horizontal wells which kept our production from this area about the same throughout the year, averaging approximately 73 MMcfe/d during the fourth quarter of 2008.

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 were 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 development well locations that could be drilled. Our year-end reserves included 77 proved undeveloped locations, plus we have an additional 64 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 are inconclusive at this time. We have drilled two 250' spaced wells. These wells have produced volumes at or above that which an average conventionally spaced well would have produced at this time in their production life. If our testing of the Barnett Shale on tighter well spacing continues to be successful, it would significantly increase our number of future locations. We expect production in the Barnett Shale to decline during 2009, as we are planning on drilling only six wells during the year due to reduction of our overall capital expenditure program because of the significant decline in commodity prices during the last half of 2008. Our planned 2009 capital expenditures in the Barnett Shale area are estimated to be approximately $25 million.

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 2008 averaged approximately 12,150 BOE/d from this area (25% of our Company total), and we had proved reserves of 40.1 MMBOE as of December 31, 2008 (16% 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 four currently have tertiary operations (Soso, Martinville, Eucutta and Heidleberg Fields). Production from our conventional and secondary recovery operations in our East Mississippi fields has been relatively consistent over the last three years, averaging 12,743 BOE/d in 2006, 12,479 BOE/d in 2007 and 11,897 BOE/d during 2008.

Heidelberg Field. The largest field in the region and one of our largest fields corporately is Heidelberg Field, which for the fourth quarter of 2008 produced an average of 7,482 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. Most of the past and current production comes from the Eutaw, Selma Chalk and Christmas sands at depths from 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, other than our tertiary operations, 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 19.4 MMcf/d in the fourth quarter of 2008. 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 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 during 2008, we drilled 10 horizontal Selma Chalk wells, three of which were located in West Heidelberg. Similar to the Barnett Shale, we have severely curtailed capital expenditures on this field in 2009 as a result of lower commodity prices.

FIELD SUMMARIES

Denbury operates in five primary areas: Eastern Mississippi, Western Mississippi, Texas, Alabama and Louisiana. Our 17 largest fields (listed below) constitute approximately 97% of our total proved reserves on a BOE basis, and 96% of our total proved reserves on a PV-10 Value basis. Within these 17 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; Jackson, Mississippi; and Aledo, Texas.

	Proved Reserves as of December 31, 2008[1]					2008 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)	Avg NRI
Tertiary Oil Fields								
Tinsley	34,440	—	34,440	13.8%	$ 224,812	1,010	—	75.6%
Heidelberg	22,394	—	22,394	8.9%	22,948	—	—	77.3%
Brookhaven	17,330	—	17,330	6.9%	213,816	2,826	—	79.2%
McComb Area	13,688	—	13,688	5.5%	101,106	1,901	—	78.9%
Mallalieu	11,790	—	11,790	4.7%	161,077	5,686	—	76.6%
Eucutta	9,147	—	9,147	3.7%	135,975	3,109	—	83.5%
Soso	9,024	—	9,024	3.6%	91,089	2,111	—	77.2%
Lockhart Crossing	3,970	—	3,970	1.6%	35,502	186	—	58.0%
Little Creek & Lazy Creek	3,213	—	3,213	1.3%	40,758	1,683	—	83.2%
Martinville	839	—	839	0.3%	7,700	865	—	78.1%
Total Tertiary Oil Fields	125,835	—	125,835	50.3%	1,034,783	19,377	—	78.7%
Mississippi								
Heidelberg	17,066	63,637	27,672	11.0%	276,199	4,505	17,663	77.3%
Sharon	16	24,458	4,092	1.6%	54,930	13	8,222	83.6%
Eucutta	1,140	—	1,140	0.5%	14,346	309	3	67.3%
Summerland	1,044	—	1,044	0.4%	7,524	373	—	74.4%
S. Cypress Creek	937	17	940	0.4%	9,523	190	20	83.0%
Other Mississippi	4,777	2,807	5,245	2.1%	53,816	2,012	1,065	21.4%
Total Mississippi	24,980	90,919	40,133	16.0%	416,338	7,402	26,973	48.4%
Texas								
Newark (Barnett Shale)	20,865	332,502	76,282	30.5%	429,961	2,887	58,874	79.9%
Other Texas	343	553	435	0.1%	3,059	266	1,488	64.6%
Total Texas	21,208	333,055	76,717	30.6%	433,020	3,153	60,362	78.8%
Louisiana and Other								
Various Fields	417	3,912	1,069	0.4%	17,786	310	1,312	56.7%
Louisiana Sold[3]	—	—	—	—	—	15	518	49.0%
Total Louisiana and Other	417	3,912	1,069	0.4%	17,786	325	1,830	55.4%
Alabama								
Citronelle	6,686	—	6,686	2.7%	24,906	1,176	—	63.3%
Other Alabama	—	69	12	—	22	3	277	1.8%
Total Alabama	6,686	69	6,698	2.7%	24,928	1,179	277	29.5%
Company Total	179,126	427,955	250,452	100.0%	$1,926,855	31,436	89,442	64.9%

(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, 2008. The prices at that date were a NYMEX oil price of $44.60 per Bbl adjusted to prices received by field and a Henry Hub natural gas cash price of $5.71 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 $1,415,498 at December 31, 2008. A comparison of PV-10 to the Standardized Measure is included in the table on page 20 as well as further information regarding our use of this non-GAAP measure.

(3) Production in the Louisiana sold category is 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, 2008:

	Developed		Undeveloped		Total	
	Gross	Net	Gross	Net	Gross	Net
Mississippi	153,080	108,720	248,227	32,036	401,307	140,756
Louisiana	35,863	34,162	4,559	3,882	40,422	38,044
Texas	37,691	34,324	7,229	3,814	44,920	38,138
Alabama	19,429	15,218	68,697	11,755	88,126	26,973
Other	6,852	855	38,711	9,686	45,563	10,541
Total	252,915	193,279	367,423	61,173	620,338	254,452

Denbury's net undeveloped acreage that is subject to expiration over the next three years, if not renewed, is approximately 25% in 2009, 22% in 2010 and 45% in 2011.

Productive Wells

The following table sets forth our gross and net productive oil and natural gas wells at December 31, 2008:

	Producing Oil Wells		Producing Natural Gas Wells		Total	
	Gross	Net	Gross	Net	Gross	Net
Operated Wells:						
Mississippi	585	558.3	220	200.0	805	758.3
Louisiana	25	18.8	9	9.0	34	27.8
Texas	27	23.1	199	192.6	226	215.7
Alabama	151	120.3	7	3.1	158	123.4
Total	788	720.5	435	404.7	1,223	1,125.2
Non-Operated Wells:						
Mississippi	39	3.8	20	4.6	59	8.4
Louisiana	—	—	1	—	1	—
Texas	1	—	4	0.5	5	0.5
Alabama	—	—	3	0.6	3	0.6
Other	4	—	—	—	4	—
Total	44	3.8	28	5.7	72	9.5
Total Wells:						
Mississippi	624	562.1	240	204.6	864	766.7
Louisiana	25	18.8	10	9.0	35	27.8
Texas	28	23.1	203	193.1	231	216.2
Alabama	151	120.3	10	3.7	161	124.0
Other	4	—	—	—	4	—
Total	832	724.3	463	410.4	1,295	1,134.7

Drilling Activity

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

	Year Ended December 31,					
	2008		2007		2006	
	Gross	Net	Gross	Net	Gross	Net
Exploratory Wells:[1]						
Productive[2]	—	—	9	6.2	10	8.5
Non-productive[3]	1	1.0	4	3.4	8	6.8
Development Wells:[1]						
Productive[2]	102	98.3	101	96.8	90	82.7
Non-productive[3][4]	1	0.7	—	—	—	—
Total	104	100.0	114	106.4	108	98.0

(1) An exploratory well is a well drilled either in search of a new, as yet undiscovered, oil or natural 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 2008, 2007 and 2006, an additional 33, 23, and 14 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, 2008, we had three significant purchasers that each accounted for 10% or more of our oil and natural gas revenues: Marathon Petroleum Company LLC (49%), Hunt Crude Oil Supply Co. (20%) and Crosstex Energy Field Services Inc. (14%). For the year ended December 31, 2007, three purchasers each accounted for 10% or more of our oil and natural gas revenues: Marathon Petroleum Company 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 significant purchasers that each accounted for 10% or more of our oil and natural gas revenues: Marathon Petroleum Company LLC (28%) and Hunt Crude Oil Supply Co. (18%).

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 tertiary 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, 2008, the discount for our oil production from Heidelberg Field averaged $15.65 per Bbl and for our Eastern Mississippi properties as a whole the discount averaged $13.64 per Bbl relative to NYMEX oil prices. For our Phase I tertiary fields in Southwest Mississippi, we averaged a premium of $3.75 per Bbl over NYMEX oil prices during 2008. For our Phase II tertiary fields, we averaged a discount of $6.61 per Bbl below NYMEX oil prices during 2008. Our Texas Barnett Shale properties averaged $43.74 per Bbl below NYMEX prices during 2008, largely because the reported oil sales are mostly natural gas liquids, which typically sell at much lower prices 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 in Mississippi. For the year ended December 31, 2008, we averaged $0.35 above NYMEX prices for our Mississippi natural gas production. However, in the Barnett Shale area in Texas, due primarily to its location, the price we received averaged $0.74 below NYMEX prices.

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 and Climate Change Legislation

In October 2008, as part of the Emergency Economic Stabilization Act, Congress included a new tax credit for carbon capture and sequestration, including that achieved through enhanced oil recovery, as further modified by the American Recovery and Reinvestment Act of 2009, passed in February 2009. In future periods Congress may decide to revisit legislation introduced in prior sessions 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 impose a tax or other economic penalty on the production of fossil fuels that, when used, ultimately release CO_2, and 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. At the same time, legislation to reduce the emissions of carbon dioxide or other gases could also create economic incentives for technologies and practices that reduce or avoid such emissions, including processes that sequester CO_2 in geologic formations such as oil and gas reservoirs.

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 or could result in the imposition of economic penalties on the production of fossil fuels that, when used, ultimately release CO_2; (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 NATURAL 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, 2008, 2007 and 2006. The reserve estimates were prepared using constant prices and costs in accordance with the guidelines of Statement of Financial Accounting Standards ("SFAS") No. 69. 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 2008, we provided oil and gas reserve estimates for 2007 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, 2007.

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 90% 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 94% of our proved undeveloped natural gas reserves. Due to the curtailment of our capital spending for 2009, our current plans include drilling only six new wells in the Barnett Shale during 2009.

	December 31, 2008	2007	2006
Estimated Proved Reserves:			
Oil (MBbls)	179,126	134,978	126,185
Natural gas (MMcf)	427,955	358,608	288,826
Oil equivalent (MBOE)	250,452	194,746	174,322
Percentage of Total MBOE:			
Proved producing	47%	56%	48%
Proved non-producing	11%	13%	17%
Proved undeveloped	42%	31%	35%
Representative Oil and Natural Gas Prices:(1)			
Oil – NYMEX	$ 44.60	$ 95.98	$ 61.05
Natural gas – Henry Hub	5.71	6.80	5.63
Present Values (thousands):(2)			
Discounted estimated future net cash flow before income taxes ("PV-10 Value") (3)	$1,926,855	$5,385,123	$2,695,199
Standardized measure of discounted estimated future net cash flow after income taxes	1,415,498	3,539,617	1,837,341

(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 (in thousands), was $511,357 at December 31, 2008, $1,845,506 at December 31, 2007, and $857,858 at December 31, 2006. 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 90% of our 2009 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, have been particularly volatile over the last six months, and likely will continue to be volatile in the future, especially given current world geopolitical conditions. As a result of the low oil and natural gas prices at December 31, 2008, we recorded a $226.0 million full cost ceiling test write-down. Subsequent to December 31, 2008, oil and natural gas prices have continued their volatility and are currently at levels lower than at year-end 2008. If oil and natural gas prices remain at these lower levels through March 31, 2009, or subsequent periods, we may be required to record additional full cost ceiling test write-downs in the first quarter of 2009, or in subsequent periods. The amount of any future write-down is difficult to predict and will depend upon the oil and natural gas prices at the end of each period, the incremental proved reserves that might be added during each period and additional capital spent.

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 72% of our December 31, 2008 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. 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 until mid-2008, albeit with fluctuations. For 2008, NYMEX oil prices increases throughout the first six months, averaging approximately $111.03 per Bbl for the first six months of 2008. During the last half of 2008, oil prices declined substantially, ending the year at a NYMEX price of $44.60 per Bbl. Since we have acquired oil commodity derivative contracts with a NYMEX floor price of $75 per barrel covering approximately 80% of our 2009 forecasted oil production, we are relatively insensitive to lower oil prices during 2009. We currently do not have any oil or natural gas commodity derivative contracts in place for subsequent years, and therefore oil prices could decline to a level that makes our tertiary projects uneconomic. If that were to happen, we may decide to suspend future expansion projects and if prices were to drop below the cash break-even point for an extended period of time, we may decide to shut-in existing production, either of which would have a material adverse effect on our operations. Since our operating costs have not decreased as quickly as commodity prices, it is difficult to determine a precise break-even point for our tertiary projects. Based on prior history, we estimate that our economic break-even point for these types of projects would approximate per barrel dollar costs in the range of the mid-twenties, and our operating cash break-even point would be between $15 and $20 of cost per barrel if commodity prices remain at current levels for sustained periods.

The prices we receive for our crude oil do not always correlate with NYMEX prices. Our NYMEX differentials over the last few years have ranged from a low of approximately $1.50 per Bbl to a high of almost $10.00 per Bbl. These variances have been due to various factors and are difficult to forecast or anticipate but have a direct impact on the net oil price we receive.

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 $6.97 per MMBtu during 2006, $7.09 per MMBtu during 2007, and $8.89 per MMBtu during 2008, and ended 2008 at $5.62 per MMBtu.

The current financial crisis may have effects on our liquidity, business and financial condition that we cannot predict.

Liquidity is essential to our business. Our liquidity could be substantially negatively affected by an inability to raise funding in the long-term or short-term debt capital markets or equity capital markets or an inability to access bank financing. The continued credit crisis and related turmoil in the global financial system is likely to continue to materially affect our liquidity, business and our financial condition. Our ability to access the capital markets has been restricted as a result of this crisis and may be restricted in the future when we would like, or need, to raise capital. The economic situation could also adversely affect the collectability of our trade receivables or performance by our suppliers and cause our commodity hedging arrangements to be ineffective if our counterparties are unable to perform their obligations or seek bankruptcy protection. Additionally, the current economic situation could lead to reduced demand for oil and gas, or lower prices for oil and gas, or both, which could have a negative impact on our revenues.

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

As of February 27, 2009, we had outstanding $525 million (principal amount) of 7.5% subordinated notes, $420 million (principal amount) of 9.75% Senior Subordinated Notes, and $60 million of bank debt. At that time, we had approximately $690 million available on our bank credit line. We currently have a bank borrowing base of $1.0 billion, with a commitment amount of $750 million. The borrowing base represents the amount that can be borrowed from a credit standpoint, while the commitment amount is the amount the banks have committed to fund pursuant to the terms of the credit agreement. The next semi-annual redetermination of the borrowing base for our bank credit facility will be on April 1, 2009. 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 as our projected 2009 capital expenditures, excluding acquisitions, are between $200 million and $300 million higher than our projected 2009 cash flow from operations. Further, our cash flow from operations is highly dependent on the prices that we receive for oil and natural gas, which in the latter part of 2008, declined significantly. If oil and natural gas prices remain depressed 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;
- as a result of the discretionary nature of the setting of our bank borrowing base and its being highly dependent on current commodity prices, if commodity prices were to further decrease, our banks could reduce our borrowing base so that we could not borrow additional funds or to a level below our outstanding debt that would require us to repay any deficit (between the borrowing base and the outstanding bank debt) over a six month period;
- 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 be greater as a result of our level of indebtedness, 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.

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.

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 3,926 BOE/d net to the acquired interests during the fourth quarter of 2008, and have proved reserves of approximately 42.8 MMBOEs as of December 31, 2008. During 2008, we recognized approximately 34.8 MMBOE of proven tertiary reserves at Tinsley Field, but have yet to recognize any tertiary oil reserves at Citronelle or South Cypress Creek Fields. In February 2009, we closed on the acquisition of Hastings field located near Houston, Texas. Hastings is also a potential tertiary oil field and it will be supplied CO_2 by the Green Pipeline, which is currently under construction. The purchase price, including option payments, was approximately $250 million. 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 these specific acquisitions, 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.

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.

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, 2008, three purchasers each accounted for more than 10% of our oil and natural gas revenues and in the aggregate, for 83% 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 flows 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, 2008, approximately 42% 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.

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

None.

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. As of February 23, 2009, based on information from the Company's transfer agent, American Stock Transfer and Trust Company, the number of holders of record of Denbury's common stock was 1,066. On February 25, 2009, the last reported sale price of Denbury's common stock, as reported on the NYSE, was $12.88 per share.

	2008		2007	
	High	Low	High	Low
First Quarter	$33.640	$21.760	$15.310	$12.980
Second Quarter	40.320	27.280	19.380	14.835
Third Quarter	37.240	16.110	23.380	18.275
Fourth Quarter	18.860	5.590	30.560	22.405

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 2008.

Purchases of Equity Securities by the Issuer and Affiliated Purchasers

ISSUER PURCHASES OF EQUITY SECURITIES

Period	(a) Total Number of Shares Purchased	(b) Average Price Paid per Share	(c) Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	(d) Maximum Number of Shares that May Purchased Under Plan or Programs
October 1 through 31, 2008	3,475	$15.44	—	—
November 1 through 30, 2008	398	10.33	—	—
December 1 through 31, 2008	—	—	—	—
Total	3,873	14.91	—	—

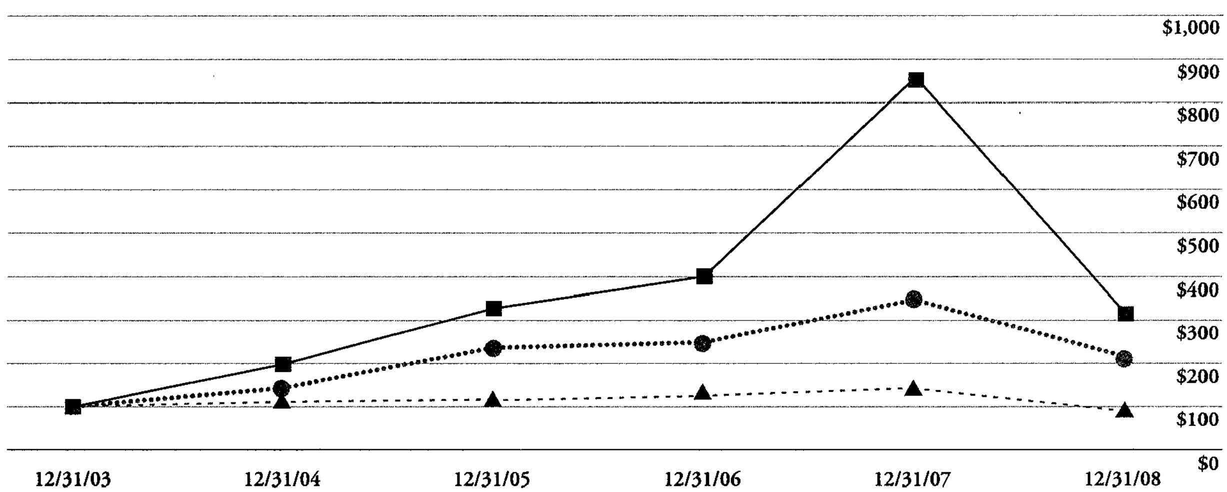
These shares were purchased from employees of Denbury who delivered shares to the company to satisfy their minimum tax withholding requirements related to the vesting of restricted shares.

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, 2008, 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, 2003, and that dividends were reinvested.

CUMULATIVE TOTAL RETURN ON $100 INVESTMENT



	December 31,					
	2003	2004	2005	2006	2007	2008
Denbury Resources Inc.	100.00	197.34	327.53	399.57	855.50	314.02
S&P 500	100.00	110.88	116.33	134.70	142.10	89.53
Dow Jones US Exploration and Production	100.00	141.87	234.54	247.14	355.06	212.61

Item 6. Selected Financial Data

(In thousands, unless otherwise noted)	Year Ended December 31, 2008	2007	2006[1]	2005	2004[2]
Consolidated Statements of Operations Data:					
Revenues	$1,365,702	$ 973,060	$ 731,536	$ 560,392	$382,972
Net income [3]	388,396	253,147	202,457	166,471	82,448
Net income per common share [4]:					
Basic	1.59	1.05	0.87	0.74	0.38
Diluted	1.54	1.00	0.82	0.70	0.36
Weighted average number of common shares outstanding [4]:					
Basic	243,935	240,065	233,101	223,485	219,482
Diluted	252,530	252,101	247,547	239,267	229,206
Consolidated Statements of Cash Flow Data:					
Cash provided by (used by):					
Operating activities	$ 774,519	$ 570,214	$ 461,810	$ 360,960	$168,652
Investing activities	(994,659)	(762,513)	(856,627)	(383,687)	(93,550)
Financing activities	177,102	198,533	283,601	154,777	(66,251)
Production (daily):					
Oil (Bbls)	31,436	27,925	22,936	20,013	19,247
Natural gas (Mcf)	89,442	97,141	83,075	58,696	82,224
BOE (6:1)	46,343	44,115	36,782	29,795	32,951
Unit Sales Price (excluding impact of derivative settlements):					
Oil (per Bbl)	$ 92.73	$ 69.80	$ 59.87	$ 50.30	$ 36.46
Natural gas (per Mcf)	8.56	6.81	7.10	8.48	6.24
Unit Sales Price (including impact of derivative settlements):					
Oil (per Bbl)	$ 90.04	$ 68.84	$ 59.23	$ 50.30	$ 27.36
Natural gas (per Mcf)	7.74	7.66	7.10	7.70	5.57
Costs per BOE:					
Lease operating expenses	$ 18.13	$ 14.34	$ 12.46	$ 9.98	$ 7.22
Production taxes and marketing expenses	3.76	3.05	2.71	2.54	1.55
General and administrative	3.56	3.04	3.20	2.62	1.78
Depletion, depreciation and amortization	13.08	12.17	11.11	9.09	8.09
Proved Reserves:					
Oil (MBbls)	179,126	134,978	126,185	106,173	101,287
Natural gas (MMcf)	427,955	358,608	288,826	278,367	168,484
MBOE (6:1)	250,452	194,746	174,322	152,568	129,369
Carbon dioxide (MMcf)[5]	5,612,167	5,641,054	5,525,948	4,645,702	2,664,633
Consolidated Balance Sheet Data:					
Total assets	$3,589,674	$2,771,077	$2,139,837	$1,505,069	$992,706
Total long-term liabilities	1,363,539	1,102,066	833,380	617,343	368,128
Stockholders' equity [6]	1,840,068	1,404,378	1,106,059	733,662	541,672

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

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

(3) In 2008, we had a full cost ceiling test write-down of $226.0 million ($140.1 million net of tax) and pre-tax expense of $30.6 million associated with a cancelled acquisition. These charges were partially offset by pre-tax income of $200.1 million on our commodity derivative contracts.

(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 153.8 Bcf at December 31, 2008, 182.3 Bcf at December 31, 2007, 210.5 Bcf at December 31, 2006, 237.1 Bcf at December 31, 2005, and 178.7 Bcf at December 31, 2004. (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

The following discussion and analysis should be read in conjunction with our Consolidated Financial Statements and Notes thereto included in Item 8, "Financial Statements and Supplementary Data." Our discussion and analysis includes forward looking information that involves risks and uncertainties and should be read in conjunction with "Risk Factors" under Item 1A of this report, along with "Forward Looking Statements" at the end of this section for information on the risks and uncertainties that could cause our actual results to be materially different than our forward looking statements.

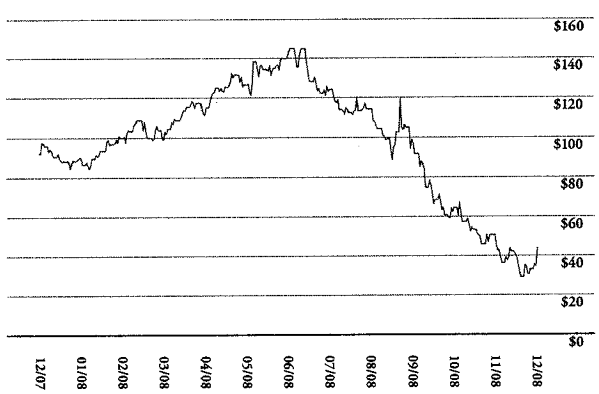
OVERVIEW

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 reserves of carbon dioxide ("CO_2") used for tertiary oil recovery east of the Mississippi River, and significant operating acreage in the Barnett Shale play near Fort Worth, Texas, and also hold 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, with our most significant emphasis relating to 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; Jackson, Mississippi; and Aledo, Texas.

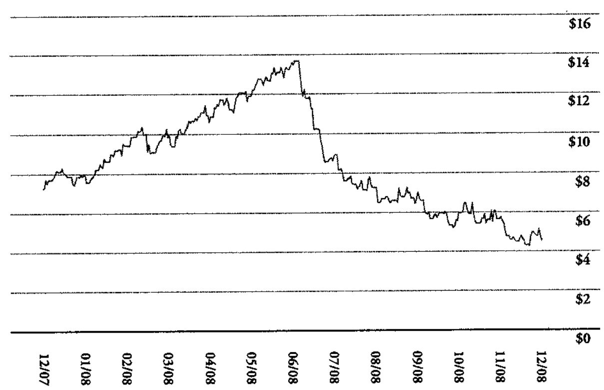
Liquidity. During the last six months, we have taken several steps to improve our liquidity as a result of the deterioration in the capital markets and the decrease in oil and natural gas prices (see "Capital Resources and Liquidity").

2008 Operating Highlights. Oil and natural gas prices were extremely volatile during 2008, with NYMEX oil prices setting a record high of approximately $145 per Bbl around mid-year, followed by a rapid drop during the second half of the year to below $40 per Bbl, a price level not seen since 2004, finishing the year at $44.60 per Bbl. Natural gas prices followed a similar trend in 2008, beginning the year at $7.48 per Mcf, increasing to approximately $13.60 per Mcf in mid-2008, and then ending 2008 at slightly under $6.00 per Mcf. See the charts below for further information on the fluctuations in oil and natural gas prices during 2008.

2008 NYMEX Oil Prices per Barrel



2008 NYMEX Natural Gas Prices per Mcf



In spite of the commodity price volatility, our average revenue per BOE for the year was $79.42, approximately 34% higher than 2007's average of $59.17 per BOE. These higher prices were a significant contributor to our record cash flow and earnings. Our 2008 cash flow from operations was $774.5 million, a 36% increase over our 2007 annual cash flow from operations of $570.2 million, and our 2008 net income of $388.4 million was 53% higher than our $253.1 million of net income during 2007. In addition to higher commodity prices during 2008, we had record high production levels, partially offset by higher operating costs and a $30.6 million charge related to the cancellation of the Conroe Field acquisition in early October (see also "Capital Resources and Liquidity" below). During 2008, we also had two significant non-cash operational items, (i) a net gain of $257.6 million ($159.7 million net of tax) associated with our fair value adjustments on our derivative contracts, the majority of which were related to the 2009 oil price collars acquired in October 2008, and (ii) a full cost ceiling write-down at December 31, 2008, of $226.0 million ($140.1 million net of tax) incurred because of the significant decrease in oil and natural gas prices during the latter part of 2008.

During 2008 our oil and natural gas production averaged 46,343 BOE/d, an 18% increase over our 2007 average production (after adjusting for the sale of our Louisiana natural gas properties in December 2007 and February 2008), with growth primarily from our tertiary oil operations and Barnett Shale, partially offset by modest declines in our East Mississippi non-tertiary production. Our average tertiary oil production increased to 19,377 BOE/d in 2008, a 31% increase over our 2007 tertiary oil production levels, and our average Barnett Shale production increased to 12,699 BOE/d, a 33% increase year-over-year. (See "Results of Operations – Operating Results – Production" for more information). Our oil and natural gas revenues increased 41% in 2008, with 5% of the increase associated with the higher production levels and 36% of the increase due to higher oil and natural gas commodity prices.

Our operating costs have gradually increased over the last few years along with commodity prices; the cost inflation caused by a corresponding increase in the demand for goods and services in our business as a result of commodity price escalation. While we recognized some cost savings during the last quarter of 2008 following the sharp decline in commodity prices during the second half of the year, operating costs have not decreased at the same rate as commodity prices. Therefore on average, virtually all of our expenses increased on both an absolute and per BOE basis during 2008. This continued a trend that we have experienced over the last several years as our costs have been increasing, due to (i) higher overall industry costs, (ii) a higher percentage of operations related to tertiary operations (which have higher operating costs per BOE), and (iii) higher compensation expense resulting from additional employees and increased salaries, which we consider necessary in order to remain competitive in the industry. We expect to see further cost reductions in 2009, as we believe that lower spending levels in the industry will reduce demand for goods and services and eventually lower costs, but it is uncertain how quickly costs will come down and by how much.

We invested approximately $1.1 billion in capital projects and minor acquisitions during 2008, of which approximately $462.9 million was spent on CO_2 pipelines, facilities and drilling. During 2008 our proved oil and natural gas reserves increased from 194.7 MMBOE as of December 31, 2007 to 250.5 MMBOE at December 31, 2008, replacing approximately 525% of our 2008 production, almost entirely from organic growth. The most significant reserve additions during 2008 were approximately 63.4 MMBbls added in our tertiary oil operations, primarily associated with the booking of proved tertiary reserves at Tinsley, Heidelberg and Lockhart Crossing Fields, and 19.5 MMBOE added in our Barnett Shale operations.

Genesis Transactions. On May 30, 2008, we closed two transactions with Genesis Energy, L.P. ("Genesis") involving our Northeast Jackson Dome ("NEJD") and Free State CO_2 Pipelines, which included a long-term transportation service arrangement for the Free State Pipeline and a 20-year financing lease for the NEJD system. We received from Genesis $225 million in cash and $25 million of Genesis common units (1,199,041 units at an average price of $20.85 per unit). These transactions were treated as financing leases for accounting purposes, with the assets and liabilities recorded on our balance sheet. We currently project that we will initially pay Genesis approximately $30 million per annum under the financing lease and transportation services agreement, with future payments for the NEJD pipeline fixed at $20.7 million per year during the term of the financing lease, and the payments relating to the Free State Pipeline dependent on the volumes of CO_2 transported therein, with a minimum annual payment thereon of $1.2 million.

Change in Tax Accounting Method for Certain Tertiary Costs. During the third quarter of 2008, we obtained approval from the Internal Revenue Service ("IRS") to change our method of tax accounting for certain assets used in our tertiary oilfield recovery operations. Previously, we had capitalized and depreciated these costs, but now we can deduct these costs once the assets are placed into service. As a result, we expect to receive tax refunds of approximately $10.6 million for tax years through 2007, along with other tax benefits, and we have reduced our current income tax expense and increased our deferred income tax expense in 2008 to adjust for the impact of this change. This change is not expected to have a significant impact on our overall tax rate; however, it will allow for a quicker deduction of costs for tax purposes.

This change in tax treatment impacts the overall economics of certain financing-type transactions we have historically utilized, primarily equipment lease financing and certain transactions with Genesis. Following the favorable ruling, we initially discontinued our leasing program and pipeline financings with Genesis, but with the recent downturn in commodity prices, we anticipate that our cash income taxes for 2009 will be minimal, minimizing the effect of this change in tax accounting. With lower projected cash income taxes expected for the near future, and given the generally advantageous interest rate inherent in equipment lease transactions, and their being an alternative source of liquidity, we plan to resume our equipment leasing program in 2009 and budgeted $100 million of leasing in 2009, but if possible, we would like to lease as much as $150 million. Because of the uncertainties that exist in the capital markets, we cannot be certain of the dollar amount, pricing or availability of such equipment financing leases.

The economic impact of our acceleration of tax deductions will also affect how we view future asset transactions with Genesis. Transactions which are not sales for tax purposes, such as the $175 million financing lease on the NEJD CO_2 Pipeline (see "Overview – Genesis Transactions" above) would not be affected provided that they meet other necessary tax criteria. Those transactions which constitute a sale for tax purposes, such as the $75 million sale and associated long-term transportation service agreement entered into with Genesis on our Free State CO_2 Pipeline (see "Overview – Genesis Transactions" above), will be less advantageous from a tax perspective.

Sale of Louisiana Natural Gas Assets. In February 2008, we received the $48.9 million remaining portion (30%) of the proceeds from the sale of our Louisiana natural gas assets, the prior 70% of which closed in December 2007. Production attributable to the sold properties averaged 302 BOE/d (approximately 81% natural gas) during the first quarter of 2008, representing production prior to the closing date for the portion of the sale that closed in February.

Recent 2009 Transactions

Purchase of Hastings Field. On February 2, 2009, we closed the $201 million acquisition of the Hastings Field, which is located near Houston, Texas, and is a potential tertiary oil field to be supplied by the Green CO_2 Pipeline which has commenced construction. In August 2008, we exercised our option with a subsidiary of Venoco, Inc. ("Venoco") to purchase Hastings Field, and in consideration of our exercising the option in 2008 rather than 2009, Venoco agreed to extend the deadlines for capital expenditures, commencement of CO_2 injections and certain other contractual requirements by one year.

Management Succession Plan. On February 5, 2009, our Board of Directors adopted a management succession plan under which our current executive officers will assume new roles on or about June 30, 2009. Gareth Roberts, the Company's founder, will relinquish his position as President and CEO and become Co-Chairman of the Board of Directors and will assume a non-officer role as the Company's Chief Strategist. Phil Rykhoek, currently Senior Vice President and Chief Financial Officer, will become CEO; Tracy Evans, currently Senior Vice President – Reservoir Engineering, will become President and Chief Operating Officer; and Mark Allen, currently Vice President and Chief Accounting Officer, will become Senior Vice President and Chief Financial Officer.

Subordinated Debt Issuance. On February 13, 2009, we issued $420 million of 9.75% Senior Subordinated Notes due 2016 (the "Notes"). The Notes were sold to the public at 92.816% of par, plus accrued interest from February 13, 2009, which equates to an effective yield to maturity of approximately 11.25% (before offering expenses). Interest on the Notes will be paid on March 1 and September 1 of each year, beginning September 1, 2009. The Notes will mature on March 1, 2016. We used the net proceeds from the offering of approximately $381 million to repay most of the then outstanding debt on our bank credit facility.

CAPITAL RESOURCES AND LIQUIDITY

During the last six months, we have taken several steps to improve our liquidity as a result of the deterioration in the capital markets and the decrease in oil and natural gas commodity prices. These included a $400 million increase to our bank commitment amount (see "Increased Bank Credit Line" below for more details), cancellation of the $600 million acquisition of Conroe Field, purchase of oil derivative contracts covering approximately 80% of our currently estimated 2009 oil production, and reduction of our capital budget for 2009. Also, in February 2009, we issued $420 million of Senior Subordinated Notes (see "Overview – Recent 2009 Transactions – Subordinated Debt Issuance").

Prior to the decline in economic conditions, we had intended, in a tax free exchange, to exchange the Barnett Shale properties for the Conroe and Hastings Fields, both of which are future tertiary flood candidates located near Houston, Texas. However, because of the deterioration in capital market conditions, we believed that the sale of our Barnett Shale properties at a price that we would consider reasonable was doubtful, and without the certainty of a Barnett Shale property sale, we did not feel comfortable increasing our leverage. As such, we cancelled our $600 million contract to purchase Conroe Field, forfeiting a $30 million non-refundable deposit which we expensed in the third quarter. To further protect our liquidity in the event that commodity prices continued to decline, in October 2008 we purchased oil derivative contracts for 2009 with a floor price of $75 / Bbl and a ceiling price of $115 / Bbl for total consideration of $15.5 million. The collars cover 30,000 Bbls/d representing approximately 80% of our currently anticipated 2009 oil production. See "Oil and Natural Gas Derivative Contracts" below in this section for information regarding the counterparties for these collars. We further significantly increased our liquidity in February 2009 by issuing $420 million of subordinated debt. We used net proceeds from that offering ($381 million) to repay most of our then outstanding bank debt, freeing-up most of our bank credit line for future capital needs, as our total bank commitment amount of $750 million was not reduced because of the offering.

We currently estimate that our 2009 total capital spending will be approximately $750 million, plus the already closed Hastings acquisition of $201 million. Our current 2009 capital budget includes approximately $485 million relating to our CO_2 pipelines, the majority of which is to build the Green CO_2 Pipeline. The budget also assumes that we fund approximately $100 million of budgeted equipment purchases with operating leases, a practice we had discontinued in the last half of 2008 as a result of our favorable tax ruling (see "Overview – Change in Tax Accounting Method for Certain Tertiary Costs"). Use of these operating leases is dependent upon being able to secure acceptable financing, and as of February 27, 2009, we had not yet secured most of this financing. The 2009 budget incorporates significantly reduced spending in the Barnett Shale and in other conventional areas such as the Heidelberg Selma Chalk, and a slower development program for our tertiary operations. Based on our current cash flow projections, using $50.00 per barrel for oil and $5.00 per Mcf for natural gas prices and including our expected oil derivative contract settlements, we anticipate that our capital expenditures could exceed projected cash flow by $400 million to $500 million, including the Hastings acquisition.

We anticipate funding this shortfall during 2009 with the proceeds from our February 2009 subordinated debt issuance and our bank credit line, and expect to have a total bank debt balance by the end of 2009 of $150 million to $250 million, leaving us $500 million to $600 million of availability on our $750 million bank commitment amount. We anticipate that this credit line will be sufficient to fund our 2009 plans and do not expect our bank credit line to be reduced by our banks unless commodity prices were to further decrease significantly from current levels. We may raise additional capital during 2009 if it is possible to do so in a reasonably economic manner. Such additional capital sources could include the sale or joint venture of assets, a volumetric production payment, additional operating leases, or other options that become available during the year. We will also continually monitor our capital expenditures on a regular basis, adjusting them up or down depending on commodity prices and the resultant cash flow. Therefore, should our cash flow be less than expected, we would plan to reduce our capital expenditures to the extent possible during the year, which could in turn, have the impact of reducing our anticipated production levels in future years. For 2009, we have contracted for certain capital expenditures, including construction of most of the Green Pipeline already in progress and two drilling rigs, and therefore the portion of capital that we could eliminate without significant penalty is limited (see also "Off-Balance Sheet Arrangements – Commitments and Obligations").

Based on our long-term models, we expect our future capital spending needs to be less in the future than they have been in recent years, excluding any potential acquisitions. Therefore, if commodity prices remain at current levels after 2009, we anticipate that we will be able to match our capital spending with our projected cash flow from operations and preserve our liquidity to the extent that we deem necessary, although any such spending reductions would most likely lower our anticipated rate of production growth.

Increased Bank Credit Line. In early October 2008, we amended our bank credit facility, which increased the banks' commitment amount from $350 million to $750 million, maintained our borrowing base at $1.0 billion, modified the commitment fees and pricing grid for the loan, raising the pricing grid by 25 basis points, and provided for other transactions, such as the acquisition of Conroe Field, which were not consummated. The borrowing base represents the amount that can be borrowed from a credit standpoint while the commitment amount is the amount the banks have committed to fund pursuant to the terms of the credit agreement. We further amended our bank credit facility in February 2009 to allow us to issue the subordinated debt at an interest rate higher than the previously allowed 10% (see "Overview – Recent 2009 Transactions – Subordinated Debt Issuance").

While bank borrowing bases in our industry are likely to be reduced in the future to reflect the reduction in commodity prices, with $250 million of cushion between our borrowing base and commitment amount and the incremental value added by retaining our Barnett Shale properties, currently we do not expect our bank commitment level to be reduced below $750 million unless prices were to further decrease significantly from current strip prices of approximately $45.00 per barrel for oil and $5.00 per Mcf for natural gas. As of February 27, 2009, we had outstanding $525 million (principal amount) of 7.5% subordinated notes, $420 million (principal amount) of 9.75% Senior Subordinated Notes and $60 million of bank debt.

Although we remain interested in acquiring mature oil fields that we believe have potential as future tertiary flood candidates, with the general lack of liquidity in the capital markets, our ability to fund any significant acquisitions will be limited and are not likely to be material unless we are able to obtain additional capital.

Sources and Uses of Capital Resources

Capital Expenditure Summary

Amounts in thousands	Year Ended December 31, 2008	2007	2006
Capital expenditures			
Oil and gas exploration and development			
Drilling	$ 244,841	$313,258	$245,350
Geological, geophysical and acreage	18,183	22,829	31,590
Facilities	170,263	118,003	98,890
Recompletions	140,451	141,264	120,438
Capitalized interest	17,627	18,305	11,059
Total oil and gas exploration and development expenditures	591,365	613,659	507,327
Oil and natural gas property acquisitions	31,367	49,077	319,000
Total oil and natural gas capital expenditures	622,732	662,736	826,327
CO_2 capital expenditures, including capitalized interest	462,889	171,182	63,586
Total	$1,085,621	$833,918	$889,913

Our 2008 capital expenditures were funded with $774.5 million of cash flow from operations, $225 million from the drop-down of CO_2 pipelines to Genesis, and $51.7 million from property sales proceeds.

Our 2007 capital expenditures were funded with $570.2 million of cash flow from operations, $150.0 million from the April 2007 issuance of subordinated debt, $135.8 million from property sales proceeds, and $16.0 million of net bank borrowings.

Our 2006 expenditures were funded with $461.8 million of cash flow from operations, $139.8 million of equity issued, $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, 2008, our dollar denominated payment obligations that are not on our balance sheet include our operating leases, which at year-end 2008 totaled $128.6 million (including $104.5 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. At December 31, 2008, we had a total of $10.5 million of letters of credit outstanding under our bank credit agreement. Additionally, we have dollar denominated 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.

Genesis Energy, LLC, our subsidiary that is the general partner of Genesis (a limited partnership), could under certain circumstances become liable, in its capacity as general partner, for debts and obligations of Genesis. There were no guarantees by Denbury or any of its other subsidiaries of the debt of Genesis or of Genesis Energy, LLC at December 31, 2008. During the second quarter of 2008, we entered into transactions with Genesis relating to two of our CO_2 pipelines (see "Overview – Genesis Transactions" above). As a result of these two transactions, we currently project that we will initially pay Genesis approximately $30 million per annum under the financing lease and transportation services agreement (a pro-rated total of $15.4 million during 2008), with future payments for the NEJD pipeline fixed at $20.7 million per year during the term of the financing lease, and the payments relating to the Free State Pipeline dependent on the volumes of CO_2 transported therein, with a minimum annual payment thereon of $1.2 million.

We currently have long-term commitments to purchase CO_2 from four proposed gasification plants, two of which are in the Gulf Coast region and two in the Midwest region (Illinois / Kentucky area) of the United States. The Midwest plants are not only conditioned on those specific plants being constructed, but also upon Denbury contracting additional volumes of CO_2 for purchase in the general area of the proposed plants that would provide an acceptable economic return on the CO_2 pipeline that we would need to construct to transport these volumes to our existing CO_2 pipeline system. If all four plants are built, these CO_2 sources are currently anticipated to provide us with aggregate CO_2 volumes of around 1 Bcf/d. Due to the current economic conditions, the earliest we would expect any plant to be completed and provide CO_2 would be 2013, and there is some doubt as to whether they will be constructed at all. The base price of CO_2 per Mcf from these CO_2 sources varies by plant and location, but is generally higher than our most recent all-in cost of CO_2 from our natural sources (Jackson Dome) using current oil prices. Prices for CO_2 delivered from these projects are expected to be competitive with the cost of our natural CO_2 after adjusting for our share of potential carbon emissions reduction credits using estimated futures prices of carbon emissions reduction credits. If all four plants are built, the aggregate purchase obligation for this CO_2 would be around $135 million per year, assuming a $50 per barrel oil price, before any potential savings from our share of carbon emissions reduction 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. While it is likely that not every plant currently under contract will be constructed, there are several other plants under consideration that could provide CO_2 to us that would either supplement or replace the CO_2 volumes from the four proposed plants that we currently have contracts with. We are having ongoing discussions and negotiations with several of these other potential sources. We have not included any financial commitment attributable to the existing contracts or other potential sources in the commitment table below as all such payments are contingent on the plants being built.

A summary of our obligations at December 31, 2008, is presented in the following table:

	Payments Due by Period						
Amounts in thousands	Total	2009	2010	2011	2012	2013	Thereafter
Contractual Obligations:							
Subordinated debt [a]	$ 525,000	$ —	$ —	$ —	$ —	$225,000	$ 300,000
Senior Bank Loan [a]	75,000	—	—	75,000	—	—	—
Estimated interest payments on subordinated debt and Senior Bank Loan [a]	234,096	41,588	41,588	40,933	39,375	26,661	43,951
Pipeline financing lease obligations [b]	588,414	29,358	31,759	33,205	33,438	33,518	427,136
Operating lease obligations	128,606	17,938	17,351	16,571	15,199	12,510	49,037
Capital lease obligations [c]	9,219	2,120	1,882	1,882	1,242	700	1,393
Capital expenditure obligations [d]	376,827	367,980	8,847	—	—	—	—
Other Cash Commitments:							
Future development costs on proved oil and gas reserves, net of capital obligations [e]	890,262	97,048	312,069	188,275	115,605	61,921	115,344
Future development cost on proved CO_2 reserves, net of capital obligations [f]	116,792	18,792	—	22,000	—	—	76,000
Asset retirement obligations [g]	106,413	2,154	1,321	1,288	722	1,013	99,915
Total	$3,050,629	$576,978	$414,817	$379,154	$205,581	$361,323	$1,112,776

(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. On February 13, 2009 we issued $420 million of 9.75% Senior Subordinated Notes at a discount, 92.816% of par, for which the obligations related thereto are not included in the above table. See Note 14 to the Consolidated Financial Statements.

(b) Represents estimated future cash payments under a long-term transportation service agreement for the Free State Pipeline, and future minimum cash payments in a 20-year financing lease for the NEJD pipeline system. Both transactions with Genesis were entered into in 2008 and are being accounted for as financing leases. The payment required for the Free State Pipeline is variable based upon the amount of the CO_2 we ship through the pipeline and the commitment amounts disclosed above for that line are computed based upon our internal forecasts. Approximately $338.2 million of these payments represent interest. See Note 3 to Consolidated Financial Statements.

(c) Represents future minimum cash commitments of $5.9 million to Genesis under capital leases in place at December 31, 2008, primarily for transportation of crude oil and CO_2, and $3.3 million for office space and rental equipment. Approximately $2.0 million of these payments represents interest.

(d) Represents future cash commitments under contracts in place as of December 31, 2008, primarily for pipe, pipeline construction contracts, drilling rig services and well related costs, including approximately $311.2 million for our Green CO_2 Pipeline. 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 2009 is currently set at $750 million, exclusive of acquisitions. 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.

(e) Represents projected capital costs as scheduled in our December 31, 2008 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, 2008 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 $45.1 million, as determined under SFAS No. 143, and is further discussed in Note 4 to the Consolidated Financial Statements.

During February 2009, we closed our $201 million purchase of Hastings Field (see "Recent 2009 Transactions – Purchase of Hastings Field" above). Under the agreement, we are required to make aggregate net capital expenditures in this field of approximately $179 million over the next six years as follows (the following amounts representing cumulative amounts required by that date): $26.8 million by December 31, 2010, $71.5 million by December 31, 2011, $107.2 million by December 31, 2012, $142.9 million by December 31, 2013, and $178.7 million by December 31, 2014. If we fail to spend the required amounts by the due dates, we are required to make a cash payment equal to 10% of the cumulative shortfall at each applicable date. Further, we are committed to injecting at least an average of 50 MMcf/day of CO_2 (total of purchased and recycled) in the West Hastings Unit for the 90 day period prior to January 1, 2013. If such injections do not occur, we must either (1) relinquish our rights to initiate (or continue) tertiary operations and reassign to Venoco all assets previously purchased for the value of such assets at that time based upon the discounted value of the field's proved reserves using a 20% discount rate, or (2) make an additional payment of $20 million in January 2013, less any payments made for failure to meet the capital spending requirements as of December 31, 2012, and a $30 million payment for each subsequent year (less amounts paid for capital expenditure shortfalls) until the CO_2 injection in the Hastings Field equals or exceeds the minimum required injection rate.

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 512 Bcf of CO_2 on a cumulative basis to these customers over the next 19 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 254 Bcf. The maximum volume required in any given year is approximately 136 MMcf/d, although based on our current level of deliveries this would likely be reduced to approximately 78 MMcf/d. Given the size of our proven CO_2 reserves at December 31, 2008 (approximately 5.6 Tcf before deducting approximately 153.8 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, we have gradually increased our emphasis on these types of operations. During this time, we have learned a considerable amount about tertiary operations and working with carbon dioxide. Our tertiary operations have grown to the point that approximately 50% of our December 31, 2008 proved reserves are proved tertiary oil reserves, almost 50% of our forecasted 2009 production is expected to come from tertiary oil operations (on a BOE basis), and almost all of our 2009 capital expenditures are related to our current or future tertiary 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 (we estimate our economic break-even per barrel dollar cost on these projects at current oil prices is in the range of the mid-twenties, 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. In addition, we are pursuing anthropogenic (man-made) sources of CO_2 to use in our tertiary operations, which we believe will not only help us recover additional oil, but will provide an economical way to sequester CO_2. We have acquired several old oil fields in our areas of operations with potential for tertiary recovery and plan to acquire additional fields, and we are continuing to expand our CO_2 pipeline infrastructure to transport CO_2.

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 is anticipated to 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 320-mile CO_2 pipeline which will run from Southern Louisiana to near Houston, Texas, and is scheduled for completion in 2010. Hastings Field, a field which we purchased in February 2009 (see "Commitments and Contingencies"), is our Phase VII, and the Seabreeze Complex, acquired in 2007, will be our Phase VIII.

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, 2008. During 2008, the increase in our proven CO_2 reserves was offset by the 233 Bcf of CO_2 production during the year. 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 all of these uses. We currently estimate that it will take approximately 1.8 Tcf of CO_2 to develop and produce the proved tertiary recovery reserves we have recorded at December 31, 2008, in Phases I, II and III.

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, Louisiana and Texas that could be further exploited through tertiary recovery. As of February 27, 2009, we estimate that we are capable of producing between 900 MMcf/d and 1 Bcf/d of CO_2, over eight 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 one more well planned for 2009, in order to further increase our production capacity. Our drilling activity at Jackson Dome will continue beyond 2009 as our current forecasts for the existing eight phases suggest that we will need approximately 1.4 Bcf/d of CO_2 production by 2013.

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 volumetric production payments for the CO_2. Our average daily CO_2 production during 2006, 2007 and 2008 was approximately 342 MMcf/d, 493 MMcf/d and 637 MMcf/d, respectively, of which approximately 75% in 2006, 81% in 2007 and 86% in 2008 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 \$0.22 per Mcf in operating expenses to produce our CO_2 during 2008, more than our 2007 average of \$0.21 per Mcf and our 2006 average of \$0.19 per Mcf, with the higher costs each year primarily due to higher average oil costs, which is the basis upon which we pay royalty owners for the CO_2, and higher operating costs. Our CO_2 costs peaked at \$0.27 per Mcf in the second quarter of 2008, corresponding to the peak in oil prices, but decreased during the fourth quarter of 2008 to an average of approximately \$0.15 per Mcf as a result of the decline in oil prices. Our estimated total cost per thousand cubic feet of CO_2 during 2008 was approximately \$0.30, after inclusion of depreciation and amortization expense related to the CO_2 production, as compared to approximately \$0.29 per Mcf during 2007 and \$0.28 per Mcf during 2006.

Man-Made CO_2 Sources. In addition to our natural source of CO_2, we are in discussions with the owners of several proposed solid carbon gasification plants which, if constructed, will convert coal or petroleum coke into various other products, with CO_2 being a significant by-product of the process. If built, these plants could 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 date this CO_2 is expected to be available to us is in 2013. These plants have all been delayed due to current economic conditions and it is uncertain, when, if ever, these plants will be built. We have entered into long-term commitments to purchase CO_2 from four proposed plants (see "Commitments and Obligations"), which, if all four plants are built, are currently anticipated to provide us with an aggregate of approximately 1 Bcf/d of CO_2. In addition to the proposed gasification plants, we have ongoing discussions with existing plants of various types that emit CO_2 and we may be able to purchase their volumes. In order to capture such volumes, we (or the plant owner) would need to install additional equipment, which include at a minimum, compression and dehydration facilities. Most of these existing plants emit relatively small volumes of CO_2, generally less than the proposed gasification plants, but such volumes may still be attractive if the source is located near our Green CO_2 Pipeline. The capture of CO_2 could also be influenced by anticipated federal legislation, which could impose economic penalties for the emission of CO_2. We believe that we are a likely purchaser of CO_2 produced in our area of operations because of the scale of our tertiary operations, our CO_2 pipeline infrastructure, and the large natural source of CO_2 (Jackson Dome), which can act as a swing CO_2 source to balance CO_2 supplies and demands.

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, but we expect them to be reduced during 2009, and to be at economic break-even dollar costs in the mid-twenties per barrel if oil prices remain at their current reduced level, 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, 2008, are approximately $11.30 per BOE. Currently, we forecast that most of these costs will average less than $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, and other factors, as the finding and development costs to date do not include significant unproven potential reserves in most of the fields. Our operating costs for tertiary operations are highly dependent on commodity prices and could range from $15 to $25 per BOE over the life of each field, 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 can be 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). Since a significant portion of our operating costs vary along with commodity and electrical prices, these costs are highly variable and will increase in a high commodity price environment and decrease in a low price environment. As an example (as discussed above), during 2008, the cost of our CO_2 varied from $0.15 per Mcf to $0.27 per Mcf. Most of our CO_2 operating costs are allocated to our tertiary oil fields and recorded as lease operating expenses or capitalized to those fields at the time the CO_2 is injected, and these costs have historically represented over 25% of the total operating costs for a tertiary operation. Since we expense all of the operating costs to produce and inject our CO_2 (following the commencement of tertiary oil production), the operating costs per barrel will be higher at the inception of CO_2 injection projects because of minimal related oil production at that time.

Analysis of CO_2 Tertiary Recovery Operating Activities. We currently have tertiary operations ongoing at almost all Phase I fields, at Soso, Martinville, Eucutta and Heidelberg Fields in Phase II, Tinsley Field in Phase III, and Cranfield (Phase IV). 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, 2008, we had approximately 125.8 MMBbls of proven oil reserves related to tertiary operations (50.0 MMBbls in Phase I, 41.4 MMBbls in Phase II and 34.4 MMBbls in Phase III) representing about 50% of our total corporate proved reserves, and have identified and estimate significant additional oil potential in other fields that we own in this region.

We added 63.4 MMBbls of tertiary-related proved oil reserves during 2008, primarily initial proven tertiary oil reserves at Heidelberg Field (Phase II), Tinsley Field (Phase III) and Lockhart Crossing Field (Phase I). In order to recognize proved tertiary oil reserves, we must either have an oil production response to the CO_2 injections or the field must be analogous to an existing tertiary flood. 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 19,377 Bbls/d during 2008 (21,874 Bbls/d during the fourth quarter of 2008). Tertiary oil production represented approximately 62% of our total corporate oil production during 2008 and approximately 42% 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 usually 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 8-11 under "Our Tertiary Oil Fields With Proved Tertiary Reserves."

Following is a chart with our tertiary oil production by field for 2006 and 2007, and by quarter for 2008. In 2008, we had initial production response from our tertiary floods at Lockhart Crossing Field and Tinsley Field, and we saw continued improved response from our newer Phase II floods at Martinville, Eucutta and Soso Fields, most of which were initiated during 2006. We initiated CO_2 injections at Cranfield Field in July 2008 and at Heidelberg Field in December 2008. We anticipate our first response and sales from the Cranfield CO_2 injections in the first quarter of 2009 and from the Heidelberg Field injections in the second half of 2009. One of our Phase I fields, Little Creek, is a mature flood and is expected to continue its gradual decline over the next several years. Production at another Phase I field, Mallalieu, appears to have plateaued and is not expected to increase during 2009.

	Average Daily Production (BOE/d)						
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Year Ended December 31,		
Tertiary Oil Field	2008	2008	2008	2008	2008	2007	2006
Phase I:							
Brookhaven	2,638	2,714	2,772	3,178	2,826	2,048	833
Little Creek area	1,807	1,661	1,556	1,706	1,683	2,014	2,739
Mallalieu area	6,099	6,260	5,339	5,056	5,686	5,852	5,210
McComb area	1,632	1,818	2,061	2,092	1,901	1,912	1,235
Lockhart Crossing	—	—	182	555	186	—	—
Phase II:							
Martinville	793	715	736	1,213	865	709	6
Eucutta	2,699	2,933	3,262	3,538	3,109	1,646	47
Soso	1,488	1,885	2,358	2,704	2,111	586	—
Phase III:							
Tinsley	—	675	1,518	1,832	1,010	—	—
Total tertiary oil production	17,156	18,661	19,784	21,874	19,377	14,767	10,070

In addition to higher electrical 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 six years we have leased certain equipment that qualifies for operating lease treatment representing an underlying aggregate cost of approximately $104.5 million as of December 31, 2008. 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 gradually increased through mid-2008, as oil prices increased (see "CO_2 Resources" above), with all of these items causing our lease operating expense for our tertiary operations to peak at $26.81 per Bbl in the third quarter of 2008, before declining along with the drop in oil prices in the latter part of 2008 to an average of $21.86 per Bbl during the fourth quarter of 2008. Our total tertiary operating expenses and cost per barrel for each of the last three years are set forth in the following table:

	Year Ended December 31,		
	2008	2007	2006
Tertiary operating expenses (thousands)	$167,156	$106,541	$65,028
Tertiary operating expenses per Bbl	23.57	19.77	17.69

Through December 31, 2008, we have invested a total of $1.4 billion in tertiary fields (including allocated acquisition costs) and have only $105.3 million in unrecovered net cash flow (revenue less operating expenses and capital expenditures). Of this total invested amount, approximately $229.6 million (17%) was spent on fields which had little or no proved reserves at December 31, 2008 (i.e., fields for which significant incremental proved reserves are anticipated during 2009 and beyond). The proved oil reserves in our CO_2 fields have a PV-10 Value of $1.0 billion, using December 31, 2008, constant NYMEX pricing of $44.60 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.

CO_2 Source Field-Related Capital Budget for 2009. Tentatively, we plan to spend approximately $52 million in 2009 in the Jackson Dome area with the intent to add deliverability for future operations. Approximately $138 million in capital expenditures is budgeted in 2009 at the oil field level in Phases I through V, plus an additional $485 million for our Delta and Green CO_2 Pipelines, making our combined CO_2 related expenditures just over 90% of our $750 million 2009 capital budget (excluding the Hastings Field purchase).

Operating Results

Net income and cash flow from operations have increased each year during the last three years. Production increased 5% between 2007 and 2008 (net of the production that was sold), 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	2008	2007	2006
Net income	$388,396	$253,147	$202,457
Net income per common share:			
Basic	$ 1.59	$ 1.05	$ 0.87
Diluted	1.54	1.00	0.82
Cash flow from operations	$774,519	$570,214	$461,810

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

	Year Ended December 31,		
	2008	2007	2006
Average daily production volumes			
Bbls/d	31,436	27,925	22,936
Mcf/d	89,442	97,141	83,075
BOE/d[1]	46,343	44,115	36,782
Operating revenues (in thousands)			
Oil sales	$1,066,917	$711,457	$501,176
Natural gas sales	280,093	241,331	215,381
Total oil and natural gas sales	$1,347,010	$952,788	$716,557
Oil and natural gas derivative contracts (in thousands)[2]			
Cash receipt (payment) on settlements of derivative contracts	$ (57,553)	$ 20,480	$ (5,302)
Non-cash fair value adjustment income (expense)	257,606	(39,077)	25,130
Total income (expense) from oil and natural gas derivative contracts	$ 200,053	$ (18,597)	$ 19,828
Operating expenses (in thousands)			
Lease operating expenses	$ 307,550	$230,932	$167,271
Production taxes and marketing expenses[3]	63,752	49,091	36,351
Total production expenses	$ 371,302	$280,023	$203,622
Non-tertiary CO_2 operating margin (in thousands)			
CO_2 sales and transportation fees[4]	$ 13,858	$ 13,630	$ 9,376
CO_2 operating expenses	4,216	4,214	3,190
Non-tertiary CO_2 operating margin	$ 9,642	$ 9,416	$ 6,186
Unit sales price – including impact of derivative settlements[2]			
Oil price per Bbl	$ 90.04	$ 68.84	$ 59.23
Gas price per Mcf	7.74	7.66	7.10
Unit sales price – excluding impact of derivative settlements[2]			
Oil price per Bbl	$ 92.73	$ 69.80	$ 59.87
Gas price per Mcf	8.56	6.81	7.10
Oil and natural gas operating revenues and expenses per BOE[1]			
Oil and natural gas revenues	$ 79.42	$ 59.17	$ 53.37
Oil and natural gas lease operating expenses	$ 18.13	$ 14.34	$ 12.46
Oil and natural gas production taxes and marketing expenses	3.76	3.05	2.71
Total oil and natural gas production expenses	$ 21.89	$ 17.39	$ 15.17

(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.

(3) For 2008, 2007 and 2006, includes transportation expenses paid to Genesis of $8.0 million, $6.0 million and $4.4 million, respectively.

(4) For 2008, 2007 and 2006, includes deferred revenue of $4.5 million, $4.4 million and $4.2 million, respectively, associated with volumetric production payments and transportation income of $5.5 million, $5.2 million and $4.6 million, respectively, both from Genesis.

Production. Average daily production by area for 2006 and 2007, and each of the quarters of 2008 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	2008	2008	2008	2008	2008	2007	2006
Tertiary oil fields	17,156	18,661	19,784	21,874	19,377	14,767	10,070
Mississippi – non-CO_2 floods	12,128	11,617	11,694	12,150	11,897	12,479	12,743
Texas	13,522	14,068	12,701	12,576	13,214	10,074	4,868
Onshore Louisiana	905	663	512	418	624	5,542	7,937
Alabama and other	1,189	1,296	1,222	1,219	1,231	1,253	1,164
Total Company	44,900	46,305	45,913	48,237	46,343	44,115	36,782

Average daily production during 2008 increased 18% (7,047 BOE/d) over 2007 levels after adjusting for the sale of our Louisiana natural gas assets in December 2007 and February 2008. The production increases in 2008 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 Mississippi – non-CO_2 floods. Production increases from the Barnett Shale contributed approximately 3,149 BOE/d of the increase and our tertiary operations contributed 4,610 BOE/d of the increase, partially offset by decreases of 582 BOE/d at our Mississippi – non-CO_2 fields.

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

Production in the Mississippi – non-CO_2 floods area decreased slightly each year from the prior year 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.

Our production in the Barnett Shale area in Texas increased 3,149 BOE/d (33%) during 2008 over our 2007 level, and during 2007 increased 4,690 BOE/d (97%) over our 2006 level there. We drilled and completed 38 wells during 2008, 45 wells during 2007 and 46 wells drilled during 2006, and plan to drill 6 wells during 2009. We have severely curtailed our spending plans in this area for 2009 in an effort to prioritize and reduce our overall capital expenditures. We expect our Barnett Shale production to gradually decrease throughout 2009 based on our reduced level of future drilling activity. These wells are characterized by steep decline rates in their first year of production, 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, the Seabreeze Complex, contributed approximately 506 BOE/d to our 2008 average production, approximately the same as the 524 BOE/d produced during 2007.

The decrease in onshore Louisiana production in 2008 is due to the December 2007 and February 2008 divesture of these assets, excluding any oil fields that could have tertiary oil potential (see "2008 Overview – Sale of Louisiana Natural Gas Assets").

Our production for 2008 was 68% oil as compared to 63% during 2007 and 62% in 2006. This increase is due to the sale of our Louisiana natural gas assets in December 2007 and February 2008, and to the increase 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 due to increases in both overall commodity prices and production, as seen in the following table:

	Year Ended December 31,			
	2008 vs. 2007		2007 vs. 2006	
Amounts in thousands	Increase in Revenues	Percentage Increase in Revenues	Increase in Revenues	Percentage Increase in Revenues
Change in revenues due to:				
Increase in production	$ 50,845	5%	$ 142,860	20%
Increase in commodity prices	343,377	36%	93,371	13%
Total increase in revenues	$ 394,222	41%	$ 236,231	33%

Excluding any impact of our derivative contracts, our net realized commodity prices and NYMEX differentials were as follows during 2008, 2007 and 2006:

	Year Ended December 31,		
	2008	2007	2006
Net Realized Prices:			
Oil price per Bbl	$92.73	$69.80	$59.87
Gas price per Mcf	8.56	6.81	7.10
Price per BOE	79.42	59.17	53.37
NYMEX Differentials:			
Oil per Bbl	$ (7.02)	$ (2.65)	$ (6.41)
Natural Gas per Mcf	(0.33)	(0.28)	0.13

Our oil NYMEX differential peaked during 2008 in the second quarter at $(9.64), corresponding to the peak in oil prices. Differentials have decreased since that time along with the decline in oil prices, averaging $(3.59) during the fourth quarter of 2008, a relatively low differential based on our historical averages, but not as low as they were during 2007. 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 had reversed itself by the fourth quarter of 2007, with average NYMEX oil differentials during that quarter of $(7.27) per Bbl.

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

	Year Ended December 31,					
	2008		2007		2006	
	Non-Cash Fair Value Adjustment	Cash Settlements	Non-Cash Fair Value Adjustment	Cash Settlements	Non-Cash Fair Value Adjustment	Cash Settlements
Amounts in thousands	Income/ (expense)	Receipt/ (payment)	Income/ (expense)	Receipt/ (payment)	Income/ (expense)	Receipt/ (payment)
First quarter	$ (38,733)	$ (8,048)	$(35,158)	$ 8,251	$(10,862)	$ (768)
Second quarter	(30,223)	(28,594)	13,330	1,719	(9,317)	(2,212)
Third quarter	86,079	(24,072)	(5,441)	9,414	14,582	(2,207)
Fourth quarter	240,483	3,161	(11,808)	1,096	30,727	(115)
Total	$257,606	$(57,553)	$(39,077)	$20,480	$ 25,130	$(5,302)

During 2008, we had significant fluctuations in our pre-tax income related to non-cash fair value adjustments in our oil and natural gas derivative contracts due to fluctuating oil and natural gas prices. During 2008 we made cash payments of $57.5 million on the settlements of our commodity derivative contracts, with $26.5 million related to our 2008 natural gas swaps, and $31.0 million related to payments on our oil swaps. During 2007, we had settlements on our commodity derivative contracts of $20.5 million, all related to our natural gas swaps, partially offset by payments on our oil swaps. 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 fields acquired in January 2006.

Changing commodity prices cause fluctuations in the mark-to-market value adjustments of our derivative contracts. The most significant adjustment made in 2008 was for oil derivative contracts purchased in October 2008 covering 30,000 Bbls/d during calendar year 2009. These contracts have a floor price of $75 per Bbl and a ceiling price of $115 per Bbl, and were purchased for $15.5 million. As oil prices declined significantly after we purchased these contracts, we recognized $234.3 million of non-cash fair value income on these contracts during the fourth quarter of 2008. The estimated fair value of these contracts recognized as a current asset on our Consolidated Balance Sheet at December 31, 2008, was $249.7 million. Further, significant fluctuations in oil commodity prices during 2009 may result in corresponding significant fluctuations in our 2009 quarterly pretax income due to market value changes in these outstanding contracts. The remaining $23.3 million of net non-cash fair value income during 2008 was primarily associated with our oil swap contracts that settled during 2008. During 2007, we expensed $24.6 million related to mark-to-market value adjustments of 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 in 2007, as a result of the increasing oil price. We recognized a non-cash gain of $25.1 million in 2006 as a result of decreasing prices, primarily related to the 75 MMcf/d of natural gas swaps for calendar 2007 that we entered into during December 2006.

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 electrical costs to operate our properties, and (v) increasing lease payments for certain of our tertiary operating facilities and equipment.

During 2008, operating costs averaged $18.13 per BOE, up from $14.34 per BOE during 2007, and $12.46 per BOE in 2006. On a sequential quarterly basis during 2008, our operating costs per BOE averaged $16.15, $18.23, $20.20, and finally $17.90 for the fourth quarter, generally following the changes in oil prices. Operating expenses for our tertiary operations were $167.2 million in 2008, up from $106.5 million during 2007, and $65.0 million during 2006, all as a result of increased tertiary activity. Tertiary operating expenses were particularly impacted by higher electrical costs during 2007 and the first half of 2008, higher costs for CO_2, and payments on leased facilities and equipment (see "CO_2 Operations" above). As discussed under "CO_2 Operations", we expect our tertiary operating costs to partially correlate with oil prices. They have steadily risen during the last few years as oil prices have generally gone up, but with the recent drop in oil prices, these costs are expected to decrease. The sale of our Louisiana natural gas properties (see "2008 Overview – Sale of Louisiana Natural Gas Properties") also increased our corporate average operating cost per BOE in 2008. 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 increasing commodity prices. Transportation and plant processing fees were approximately $8.4 million higher in 2008 than in 2007 and approximately $6.9 million higher in 2007 than in 2006, 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,		
	2008	2007	2006
Net G&A expense (thousands)			
Gross G&A expense	$137,979	$115,519	$96,479
State franchise taxes	3,415	2,915	1,825
Operator labor and overhead recovery charges	(68,556)	(59,145)	(47,667)
Capitalized exploration and development costs	(12,464)	(10,317)	(7,623)
Net G&A expense	$ 60,374	$ 48,972	$43,014
Average G&A cost per BOE	$ 3.56	$ 3.04	$ 3.20
Employees as of December 31	797	686	596

Gross G&A expenses increased $22.5 million, or 19% between 2007 and 2008, and $19.0 million, or 20%, between 2006 and 2007. The increases are primarily due to higher compensation and personnel related costs caused by an increase in the number of employees and higher wages which we consider necessary in order to remain competitive in our industry. During 2007, we increased our employee count by 15%, and we further increased our employee count 16% during 2008. Stock compensation expense reflected in gross G&A was $16.2 million during 2008, $12.2 million during 2007 and $18.9 million during 2006. The 2006 amount included $6.0 million of non-recurring charges related to the retirement and departure of two vice presidents during 2006.

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 16% between 2007 and 2008, and 24% between 2006 and 2007. Capitalized exploration and development costs increased each year primarily due to additional personnel and increased compensation costs.

The net effect of the increases in gross G&A expenses, operator overhead recoveries and capitalized exploration costs was a 23% increase in net G&A expense between 2007 and 2008, and a 14% increase in net G&A expense between 2006 and 2007. On a per BOE basis, G&A increased 17% in 2008 as compared to 2007 but G&A per BOE decreased 5% in 2007 as compared to 2006 levels as higher production more than offset the increase in gross costs.

Interest and Financing Expenses

	Year Ended December 31,		
Amounts in thousands, except per BOE data	2008	2007	2006
Cash interest expense	$ 59,955	$ 49,205	$ 33,787
Non-cash interest expense	1,802	2,010	1,121
Less: Capitalized interest	(29,161)	(20,385)	(11,333)
Interest expense	$ 32,596	$ 30,830	$ 23,575
Interest and other income	$ 4,834	$ 6,642	$ 5,603
Average net cash interest expense per BOE (1)	$ 1.59	$ 1.43	$ 1.26
Average debt outstanding	$735,288	$672,376	$455,603
Average interest rate (2)	8.2%	7.3%	7.4%

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

(2) Includes commitment fees but excludes amortization of discount, premium and debt issue costs.

Interest expense increased $1.8 million, or 6%, between 2007 and 2008, and $7.3 million, or 31%, between 2006 and 2007, primarily as a result of higher debt levels in the 2007 and 2008 periods, partially offset by higher capitalized interest during the 2007 and 2008 periods. Interest expense increased significantly during 2008 as a result of the two transactions with Genesis which were recorded as financing leases (see "Overview – Genesis Transactions") and which carry a higher imputed rate of interest. The higher rate of interest is partially offset by the cash distributions that we receive from Genesis, which have increased from $1.7 million in 2007 to $7.1 million during 2008. However, the cash receipts related to distributions from Genesis are not recognized in our income statement but rather as an adjustment to our investment account.

Our interest capitalization increased in 2008 because of our growing balance of unevaluated property expenditures, expenditures on our CO_2 pipeline projects and higher overall interest rates.

Depletion, Depreciation and Amortization ("DD&A") and Full Cost Ceiling Test Write-down

	Year Ended December 31,		
Amounts in thousands, except per BOE data	2008	2007	2006
Depletion and depreciation of oil and natural gas properties	$192,791	$174,356	$132,880
Depletion and depreciation of CO_2 assets	15,644	11,609	8,375
Asset retirement obligations	3,048	2,977	2,389
Depreciation of other fixed assets	10,309	6,958	5,521
Total DD&A	$221,792	$195,900	$149,165
DD&A per BOE:			
Oil and natural gas properties	$ 11.55	$ 11.02	$ 10.08
CO_2 assets and other fixed assets	1.53	1.15	1.03
Total DD&A cost per BOE	$ 13.08	$ 12.17	$ 11.11
Full cost ceiling test write-down	$226,000	$ —	$ —

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, before the $226.0 million ($140.1 million net of tax) full cost ceiling write-down in 2008, increased 7% between 2007 and 2008, and 10% between 2006 and 2007, primarily due to capital spending and increased costs. Our proved reserves increased from 174.3 MMBOE as of December 31, 2006, to 194.7 MMBOE as of December 31, 2007, and further increased to 250.5 MMBOE as of December 31, 2008. Our 2008 year-end proved reserve quantities represent a 29% increase over proved reserves at the end of 2007, in spite of an estimated 13.8 MMBOE that were excluded as a result of the lower commodity prices at the end of 2008.

We added a total of 88.9 MMBOE of proved reserves during 2008 (before netting out 2008 production, property sales and downward reserve revisions due to pricing), replacing approximately 525% of our 2008 production. The most significant reserve additions during 2008 were approximately 63.4 MMbbls added in our tertiary oil operations and approximately 117 Bcfe (19.5 MMBOE) in the Barnett Shale, both before netting out 2008 production. Our tertiary-related oil reserves added during the year were primarily at Tinsley Field in Phase III (34.8 MMBOE), Heidelberg Field in Phase II (22.4 MMBOE) and Lockhart Crossing Field in Phase I (4.0 MMBOE). Even though the additional proved reserves were significant, at the same time that we recognize incremental proved tertiary oil reserves, we move any related costs for that field from unevaluated properties into the full cost pool. Usually, these unevaluated costs are significant and when combined with the estimated future development costs, the net impact of the DD&A rate is usually minimal, and in some cases, increases the rate. Further, we generally do not initially recognize all of the potential tertiary oil reserves that we believe are recoverable, and therefore we expect to recognize incremental proved reserves at each of these tertiary fields in the future. These potential future reserves will have little or no cost associated with the incremental barrels; therefore, as these potential future reserves are recognized they will reduce the average ultimate cost per barrel.

Approximately $76.6 million of our 2008 capital expenditures were incurred on properties for which there were no proved reserves at year-end 2008 (primarily our new tertiary floods), and as such, were classified as unevaluated costs and did not affect our DD&A rate. As part of the initial recognition of proved reserves at Tinsley, Heidelberg and Lockhart Crossing Fields during 2008, approximately $284.6 million of previously unevaluated costs were moved to the full cost pool.

Our DD&A rate during the fourth quarter of 2008 was also negatively impacted by the exclusion of approximately 13.8 MMBOE due to the decrease in commodity prices. Had these reserves been included, the DD&A rate on oil and gas properties for the fourth quarter of 2008 would have been approximately $11.32 per BOE, rather than the $11.92 per BOE that was reported.

Our DD&A rate for our CO_2 and other fixed assets increased in both 2007 and 2008 as a result of the Free State CO_2 Pipeline that was placed into service in 2006, the Lockhart Crossing CO_2 pipeline placed into service during 2007, the Tinsley and Heidelberg CO_2 pipelines placed into service during 2008, drilling costs for additional CO_2 wells, and the expansion of our corporate office space during 2008.

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, 2006, to be $91.3 million ($41.1 million present value), with an estimated salvage value of $60.0 million. 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, and as of December 31, 2008, we estimated our retirement obligations to be $106.4 million ($45.1 million present value), with an estimated salvage value of $76.4 million, the increase related to 2008 activity and higher cost estimates due to the inflation in our industry, partially offset by a decrease in our obligation of approximately $9.5 million, ($9.3 million present value) related to the sale of most of our Louisiana natural gas properties in late 2007 and early 2008. 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 have not had any full cost pool ceiling test write-downs since 1998. However, during 2008, commodity prices were volatile, with oil NYMEX prices moving from $95.98 per Bbl at December 31, 2007 to $140.00 per Bbl at June 30, 2008 then down to $44.60 per Bbl at December 31, 2008. Likewise, natural gas NYMEX prices went from $7.48 per Mcf as of December 31, 2007 to $13.35 per Mcf at June 30, 2008 and down to $5.62 per Mcf as of December 31, 2008. Because of the 54% decrease in NYMEX oil price and 25% decrease in NYMEX natural gas price between year-end 2007 and year-end 2008, we recognized a full cost pool ceiling test write-down at December 31, 2008 of $226.0 million, or $13.32 per BOE. Subsequent to December 31, 2008, oil and natural gas prices have continued their volatility and are currently at levels lower than at year-end 2008. If oil and natural gas prices remain at these lower levels through March 31, 2009, or subsequent periods, we may be required to record additional write-downs under the full cost ceiling test in the first quarter of 2009, or in subsequent periods. The amount of any future write-down is difficult to predict and will depend upon the oil and natural gas prices at the end of each period, the incremental proved reserves that might be added during each period and additional capital spent.

Income Taxes

	Year Ended December 31,		
Amounts in thousands, except per BOE amounts and tax rates	2008	2007	2006
Current income tax expense	$ 40,812	$ 30,074	$ 19,865
Deferred income tax expense	195,020	110,193	107,252
Total income tax expense	$ 235,832	$ 140,267	$ 127,117
Average income tax expense per BOE	$ 13.90	$ 8.71	$ 9.47
Effective tax rate	37.8%	35.7%	38.6%
Total net deferred tax asset (liability)	$(522,234)	$(334,662)	$(229,925)

Our income tax provision was based on an estimated statutory rate of approximately 38% in 2008 and 2007 and 39% in 2006. Our effective tax rate has generally been less than our estimated statutory rate due to the impact of certain items such as our domestic production activities deduction, partially offset by 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 2008 and 2007 was a result of our sale of our Louisiana natural gas assets during the fourth quarter of 2007. In 2008, we received permission from the IRS to change our method of tax accounting for certain assets used in our tertiary recovery operations (see "Overview—Change in Tax Accounting Method for Certain Tertiary Costs").

In all three periods, the current income tax expense represents our anticipated alternative minimum cash taxes that we cannot offset with enhanced oil recovery ("EOR") credits. As of December 31, 2008, we had an estimated $44 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 2022. Since the ability to earn additional enhanced oil recovery credits is based upon the level of oil prices, we may earn EOR credits again in the future if oil prices remain at their currently depressed levels.

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	2008	2007	2006
Oil and natural gas revenues	$ 79.42	$ 59.17	$ 53.37
Gain (loss) on settlements of derivative contracts	(3.40)	1.27	(0.39)
Lease operating expenses	(18.13)	(14.34)	(12.46)
Production taxes and marketing expenses	(3.76)	(3.05)	(2.71)
Production netback	54.13	43.05	37.81
Non-tertiary CO_2 operating margin	0.57	0.58	0.46
General and administrative expenses	(3.56)	(3.04)	(3.20)
Net cash interest expense	(1.59)	(1.43)	(1.26)
Abandoned acquistion costs	(1.80)	—	—
Current income taxes and other	(1.78)	(1.37)	(0.41)
Changes in assets and liabilities relating to operations	(0.31)	(2.38)	1.00
Cash flow from operations	45.66	35.41	34.40
DD&A	(13.08)	(12.17)	(11.11)
Write-down of oil and natural gas properties	(13.32)	—	—
Deferred income taxes	(11.50)	(6.84)	(7.99)
Non-cash commodity derivative adjustments	15.19	(2.43)	1.87
Changes in assets and liabilities and other non-cash items	(0.05)	1.75	(2.09)
Net income	$ 22.90	$ 15.72	$ 15.08

MARKET RISK MANAGEMENT

Debt

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. We had $75 million of bank debt outstanding as of December 31, 2008, and $60 million outstanding as of February 27, 2009. The carrying value of our bank debt 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 adjusted the estimated fair value measurement of our bank debt at December 31, 2008 in accordance with SFAS No. 157 for estimated nonperformance risk. This estimated nonperformance risk totaled approximately $11.0 million and was determined utilizing industry credit default swaps. None of our existing debt has any triggers or covenants regarding our debt ratings with rating agencies, although under the NEJD financing lease with Genesis (see "2008 Overview – Genesis Transactions") in the event of significant downgrades of our corporate credit rating by the rating agencies, Genesis can require certain credit enhancements from us, and possibly other remedies under the lease. The fair value of the subordinated debt is based on quoted market prices. The following table presents the carrying and fair values of our debt, along with average interest rates at December 31, 2008.

Amounts in thousands	Expected Maturity Dates 2011	2013	2015	Carrying Value	Fair Value
Variable rate debt:					
Bank debt (weighted average interest rate of 2.95% at December 31, 2008)	**$75,000**	**$ —**	**$ —**	**$ 75,000**	**$ 64,000**
Fixed rate debt:					
7.5% subordinated debt due 2013 (fixed rate of 7.5%)	**—**	**225,000**	**—**	**224,174**	**171,000**
7.5% subordinated debt due 2015 (fixed rate of 7.5%)	**—**	**—**	**300,000**	**300,599**	**213,000**

Oil and Natural Gas Derivative Contracts

From time to time, we enter into various oil and natural gas 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. The production that we hedge has varied from year to year depending on our levels of debt and financial strength and expectation of future commodity prices. Historically, we hedged up to 80% of our anticipated production 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. 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 "2008 Overview – Sale of Louisiana Natural Gas Assets") at a weighted average price of $7.91 per Mcf. We cancelled the December 2008 natural gas swaps in the third quarter of 2008 because of our plans at that time to sell our Barnett Shale properties, receiving approximately $61,000 from the cancellation.

As a result of the current economic conditions and in order to protect our liquidity in the event that commodity prices continue to decline, during early October 2008, we purchased oil derivative contracts for 2009 with a floor price of $75 / Bbl and a ceiling price of $115 / Bbl for total consideration of $15.5 million. The collars cover 30,000 Bbls/d representing approximately 80% of our currently anticipated 2009 oil production. These 2009 contracts were entered into with the following counterparties: JPMorgan Chase Bank (10,000 Bbls/d), Wells Fargo Bank (7,500 Bbls/d), Keybank (5,000 Bbls/d), Fortis Energy Marketing and Trading GP (5,000 Bbls/d) and Comerica Bank (2,500 Bbls/d).

Historically, when we made a significant acquisition, we generally attempted 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. For 2008, 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 first three years of estimated proved producing production at the time we signed the purchase and sale agreement. These swaps covered 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. We have included an estimate of nonperformance risk in the fair value measurement of our oil derivative contracts as required by SFAS No. 157. At December 31, 2008, all of our oil derivative contracts are in an asset position. Therefore, in assessing the nonperformance risk of the counterparties to these contracts, we have measured the risk by using credit default swaps as we believe this data is the most responsive to current market events. If a counter-party did not have credit default swaps associated with that specific entity, we utilized industry credit default swaps as an estimate of the fair value of this risk associated with that entity. At December 31, 2008, the fair value of our oil derivative contracts was reduced by $3.7 million for the estimated nonperformance risk of our counterparties.

For accounting purposes, we do not apply hedge accounting for our oil and natural gas derivative 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. 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, 2008, our derivative contracts were recorded at their fair value, which was a net asset of approximately $249.7 million, an increase of $273.0 million from the $23.3 million fair value liability recorded as of December 31, 2007. This change is primarily related to the declining oil prices which significantly increased the value of our 2009 oil collars, and the expiration of our natural gas hedges during 2008. During 2008, we recognized total income related to our hedge contracts of $200.1 million, consisting of $57.5 million of net cash payments on settlements of expired contracts, and $257.6 million of income relating to mark-to-market non-cash adjustments.

Based on NYMEX crude oil futures prices at December 31, 2008, we would expect to receive future cash payments of $229.8 million on our crude oil commodity derivative contracts. If crude oil futures prices were to decline by 10%, we would expect to receive future cash payments on our crude oil commodity derivative contracts of $289.0 million, and if futures prices were to increase by 10% we would expect to receive $170.7 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. Further, we do not designate our oil and natural gas derivative contracts as hedge instruments for accounting purposes under SFAS No. 133, and as a result, these contracts are not considered in the full cost ceiling test.

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 3.3% of the previous year's estimates and have been both positive and negative.

Changes in commodity prices also affect our reserve quantities. During 2006 and 2007, the change to reserve quantities related to commodity prices was relatively small as prices were relatively high each year-end; however, at December 31, 2008 the lower commodity prices lowered our proved reserves by 13.8 MMBOE. 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 2008 DD&A rate from $13.72 per BOE to approximately $13.17 per BOE, and a 5% decrease in our proved reserve quantities would have increased our DD&A rate to approximately $14.33 per BOE. 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.

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 2006 or 2007. However, during 2008, commodity prices were volatile, with oil NYMEX prices moving from $95.98 per Bbl at December 31, 2007 to $140.00 per Bbl at June 30, 2008 then down to $44.60 per Bbl at December 31, 2008. Likewise, natural gas NYMEX prices went from $7.48 per Mcf as of December 31, 2007 to $13.35 per Mcf at June 30, 2008 and down to $5.62 per Mcf as of December 31, 2008. Because of the 54% decrease in NYMEX oil price and 25% decrease in NYMEX natural gas price between year-end 2007 and year-end 2008, we recognized a full cost pool ceiling test write-down during 2008 of $226.0 million, or $13.32 per BOE. Commodity prices have historically been volatile and are expected to be in the future. If oil and natural gas prices remain at these lower levels through March 31, 2009, or subsequent periods, we may be required to record additional write-downs due to the full cost ceiling test in the first quarter of 2009, or in subsequent periods. The amount of any future write-down is difficult to predict and will depend upon the oil and natural gas prices at the end of each period, the incremental proved reserves that might be added during each period and additional capital spent.

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 have generally been 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 2006 and 2007 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 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, and to pay royalties.

Prior to January 1, 2008, we expensed currently all costs associated with injecting CO_2 that we used 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 began 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. Had the new method of accounting for tertiary injection costs been used in periods prior to January 1, 2008, the effect on our financial statements would have been immaterial for all periods presented. During 2008, we capitalized $10.4 million of tertiary injection costs associated with our tertiary projects that we would have previously expensed.

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, 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, 2008, 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 more likely than not. A 1% increase in our effective tax rate would have increased our calculated income tax expense by approximately $6.2 million, $3.9 million and $3.3 million for the years ended December 31, 2008, 2007 and 2006, 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. We do not designate these derivative commodity contracts as hedge instruments for accounting purposes under SFAS No. 133. 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 were 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 2008, 2007 and 2006, we recognized expense (income) of ($257.6) million, $39.1 million and ($25.1) million, respectively, related to changes in the fair market value of our derivative contracts.

Stock Compensation Plans

SFAS No. 123(R), "Share-Based Payment" requires that we 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. 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, 2008, there was $12.5 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 2.6 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

Business Combinations. In December 2007, the FASB issued SFAS No. 141 (Revised 2008), "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 do not anticipate the adoption of SFAS 141(R) will have a material impact on our financial condition or results of operations, absent any material business combinations.

Noncontrolling Interests. 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. Since we currently do not have any noncontrolling interests, SFAS No. 160 does not presently have any impact on us.

Disclosures about Derivative Instruments and Hedging Activities. In March 2008, the FASB issued SFAS No. 161, "Disclosures about Derivative Instruments and Hedging Activities — an amendment of SFAS No. 133." SFAS No. 161 requires entities that utilize derivative instruments to provide qualitative disclosures about their objectives and strategies for using such instruments, as well as any details of credit-risk-related contingent features contained within derivatives. SFAS No. 161 also requires entities to disclose additional information about the amounts and location of derivatives located within the financial statements, how the provisions of SFAS No. 133 have been applied, and the impact that hedges have on an entity's financial position, financial performance, and cash flows. SFAS No. 161 is effective for us beginning January 1, 2009. As its only requirement is to enhance disclosures, SFAS No. 161 will not have a significant impact on us.

Modernization of Oil and Gas Reporting. On December 31, 2008, the Securities and Exchange Commission adopted major revisions to its rules governing oil and gas company reporting requirements. These include provisions that permit the use of new technologies to determine proved reserves, and that allow companies to disclose their probable and possible reserves to investors. The current rules limit disclosure to only proved reserves. The new disclosure requirements also require companies that have an audit performed of their reserves to report the independence and qualifications of the auditor of the reserve estimates, and to file reports when a third party reserve engineer is relied upon to prepare reserve estimates. The new rules also require that oil and gas reserves be reported and the full cost ceiling value calculated using an average price based upon the prior 12-month period. The new oil and gas reporting requirements are effective for annual reports on Forms 10-K for fiscal years ending on or after December 31, 2009, with early adoption not permitted. We are currently evaluating the impact the new rules may 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, capital budgets, production rates and volumes or forecasts thereof, hydrocarbon reserve quantities and values, CO_2 reserves, potential reserves from tertiary operations, hydrocarbon prices, pricing or cost assumptions based on current and projected oil and gas prices, liquidity, cash flows, availability of capital, borrowing capacity, regulatory matters, mark-to-market values, competition, long-term forecasts of production, finding costs, rates of return, estimated costs, or changes in costs, future capital expenditures and overall economics and other variables surrounding our 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; availability of and fluctuations in the prices of goods and services; the uncertainty of drilling results and reserve estimates; operating hazards; disruption of operations and damages from hurricanes or tropical storms; acquisition risks; requirements for capital or its availability; conditions in the financial and credit markets; 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 47 through 48.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

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, 2008 and 2007, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2008 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, 2008, 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 Management's Report on Internal Control over Financial Reporting under Item 9A. 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.

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, 2009

Consolidated Balance Sheets

(In thousands, except shares)	December 31, 2008	2007
ASSETS		
Current assets		
Cash and cash equivalents	$ 17,069	$ 60,107
Accrued production receivable	67,805	136,284
Trade and other receivables, net of allowance of $377 and $369	80,579	28,977
Derivative assets	249,746	2,283
Deferred tax assets	—	12,708
Total current assets	415,199	240,359
Property and equipment		
Oil and natural gas properties (using full cost accounting)		
Proved	3,386,606	2,682,932
Unevaluated	235,403	366,518
CO_2 properties, equipment and pipelines	899,542	436,591
Other	70,328	50,116
Less accumulated depletion, depreciation and impairment	(1,589,682)	(1,143,282)
Net property and equipment	3,002,197	2,392,875
Deposits on properties under option or contract	48,917	49,097
Other assets	43,357	32,338
Investment in Genesis	80,004	56,408
Total assets	$ 3,589,674	$ 2,771,077
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities		
Accounts payable and accrued liabilities	$ 202,633	$ 147,580
Oil and gas production payable	85,833	84,150
Derivative liabilities	—	28,096
Deferred revenue – Genesis	4,070	4,070
Deferred tax liability	89,024	—
Current maturities of long-term debt	4,507	737
Total current liabilities	386,067	264,633
Long-term liabilities		
Long-term debt – Genesis	251,047	4,544
Long-term debt	601,720	675,786
Asset retirement obligations	43,352	38,954
Deferred revenue – Genesis	19,957	24,424
Deferred tax liability	433,210	347,370
Other	14,253	10,988
Total long-term liabilities	1,363,539	1,102,066
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 248,005,874 and 245,386,951 shares issued at December 31, 2008 and 2007, respectively	248	245
Paid-in capital in excess of par	707,702	662,698
Retained earnings	1,139,575	751,179
Accumulated other comprehensive loss	(627)	(1,591)
Treasury stock, at cost, 446,287 and 637,795 shares at December 31, 2008 and 2007, respectively	(6,830)	(8,153)
Total stockholders' equity	1,840,068	1,404,378
Total liabilities and stockholders' equity	$ 3,589,674	$ 2,771,077

See accompanying Notes to Consolidated Financial Statements.

Consolidated Statements of Operations

(In thousands, except per share data)	Year Ended December 31, 2008	2007	2006
Revenues and other income			
Oil, natural gas and related product sales	$1,347,010	$952,788	$716,557
CO_2 sales and transportation fees	13,858	13,630	9,376
Interest income and other	4,834	6,642	5,603
Total revenues	1,365,702	973,060	731,536
Expenses			
Lease operating expenses	307,550	230,932	167,271
Production taxes and marketing expenses	55,770	43,130	31,993
Transportation expense – Genesis	7,982	5,961	4,358
CO_2 operating expenses	4,216	4,214	3,190
General and administrative	60,374	48,972	43,014
Interest, net of amounts capitalized of $29,161, $20,385 and $11,333 in 2008, 2007 and 2006, respectively	32,596	30,830	23,575
Depletion, depreciation and amortization	221,792	195,900	149,165
Commodity derivative expense (income)	(200,053)	18,597	(19,828)
Abandoned acquisition cost	30,601	—	—
Write-down of oil and natural gas properties	226,000	—	—
Total expenses	746,828	578,536	402,738
Equity in net income (loss) of Genesis	5,354	(1,110)	776
Income before income taxes	624,228	393,414	329,574
Income tax provision			
Current income taxes	40,812	30,074	19,865
Deferred income taxes	195,020	110,193	107,252
Net income	$ 388,396	$253,147	$202,457
Net income per share – basic	$ 1.59	$ 1.05	$ 0.87
Net income per share – diluted	$ 1.54	$ 1.00	$ 0.82
Weighted average common shares outstanding			
Basic	243,935	240,065	233,101
Diluted	252,530	252,101	247,547

See accompanying Notes to Consolidated Financial Statements.

Consolidated Statements of Cash Flows

(In thousands)	Year Ended December 31, 2008	2007	2006
Cash flow from operating activities:			
Net income	$ 388,396	$ 253,147	$ 202,457
Adjustments needed to reconcile to net cash flow provided by operations:			
Depreciation, depletion and amortization	221,792	195,900	149,165
Write-down of oil and natural gas properties	226,000	—	—
Deferred income taxes	195,020	110,193	107,252
Deferred revenue – Genesis	(4,466)	(4,419)	(4,180)
Stock based compensation	14,068	10,595	17,246
Non-cash fair value derivative adjustments	(257,502)	38,952	(25,129)
Other	(3,499)	4,149	1,603
Changes in assets and liabilities relating to operations:			
Accrued production receivable	68,479	(63,886)	(5,474)
Trade and other receivables	(58,236)	(10,409)	1,712
Derivative assets	(15,471)	—	—
Other assets	348	(819)	(672)
Accounts payable and accrued liabilities	254	1,576	7,038
Oil and gas production payable	1,683	31,906	10,422
Other liabilities	(2,347)	3,329	370
Net cash provided by operating activities	774,519	570,214	461,810
Cash flow used for investing activities:			
Oil and natural gas capital expenditures	(591,365)	(613,659)	(507,327)
Acquisitions of oil and gas properties	(31,367)	(49,077)	(319,000)
Change in accrual for capital expenditures	59,183	(421)	13,195
CO_2 capital expenditures, including pipelines	(462,889)	(171,182)	(63,586)
Investment in Genesis	(516)	(47,738)	—
Distributions from Genesis	7,139	—	—
Net purchases of other assets	(23,799)	(13,672)	(10,531)
Net proceeds from sales of oil and gas properties and equipment	51,684	142,667	42,762
Other	(2,729)	(9,431)	(12,140)
Net cash used for investing activities	(994,659)	(762,513)	(856,627)
Cash flow from financing activities:			
Bank repayments	(222,000)	(265,000)	(249,000)
Bank borrowings	147,000	281,000	383,000
Income tax benefit from equity awards	19,665	19,181	16,575
Issuance of subordinated debt	—	150,750	—
Pipeline financing – Genesis	225,252	—	—
Issuance of common stock	13,972	18,222	139,834
Other	(6,787)	(5,620)	(6,808)
Net cash provided by financing activities	177,102	198,533	283,601
Net increase (decrease) in cash and cash equivalents	(43,038)	6,234	(111,216)
Cash and cash equivalents at beginning of year	60,107	53,873	165,089
Cash and cash equivalents at end of year	$ 17,069	$ 60,107	$ 53,873

See accompanying Notes to Consolidated Financial Statements.

Consolidated Statements of Changes in Stockholders' Equity

(Dollar amounts in thousands)	Common Stock ($.001 Par Value) Shares	Common Stock Amount	Paid-In Capital in Excess of Par	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Treasury Stock (at cost) Shares	Treasury Stock Amount	Total Stockholders' Equity
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
Repurchase of common stock	—	—	—	—	—	155,297	(3,762)	(3,762)
Issued pursuant to employee stock purchase plan	—	—	1,176	—	—	(346,805)	5,085	6,261
Issued pursuant to employee stock option plan	2,578,563	3	7,708	—	—	—	—	7,711
Issued pursuant to directors' compensation plan	12,753	—	212	—	—	—	—	212
Restricted stock grants	278,973	—	—	—	—	—	—	—
Restricted stock grants – forfeited	(251,366)	—	—	—	—	—	—	—
Stock based compensation	—	—	16,243	—	—	—	—	16,243
Income tax benefit from equity awards	—	—	19,665	—	—	—	—	19,665
Derivative contracts, net	—	—	—	—	964	—	—	964
Net income	—	—	—	388,396	—	—	—	388,396
Balance – December 31, 2008	248,005,874	$248	$707,702	$1,139,575	$ (627)	446,287	$(6,830)	$1,840,068

See accompanying Notes to Consolidated Financial Statements.

Consolidated Statements of Comprehensive Income

(In thousands)	Year Ended December 31, 2008	2007	2006
Net income	$388,396	$253,147	$202,457
Other comprehensive income (loss), net of income tax:			
Change in fair value of interest rate lock contracts designated as a hedge, net of tax of $49, ($1,017) and $ —, respectively	12	(1,591)	—
Interest rate lock derivative contracts reclassified to income, net of taxes of $583	952	—	—
Comprehensive income	$389,360	$251,556	$202,457

See accompanying 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 Energy, L.P. ("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, Genesis Energy, LLC is the general partner of, and together with Denbury's other subsidiaries, owns an aggregate 12% interest in Genesis, a publicly traded master limited partnership. We account for our 12% 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 SPLIT

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.

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 split, 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.

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, capitalized interest on qualifying projects, 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 and future development costs, 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 per BOE associated with our oil and gas producing activities was $12.54 in 2008, $11.60 in 2007 and $10.54 in 2006.

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. We include that portion of net capitalized costs of CO_2 assets and CO_2 pipelines that are required for our current proved tertiary reserves in the net capitalized costs subject to the ceiling test. 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, "Supplemental Oil and Natural Gas Disclosures (Unaudited)" 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, and 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 began 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 status of some of our tertiary floods, during 2008 this change in accounting caused us to capitalize certain costs that we historically expensed. During 2008, we capitalized $10.4 million of tertiary injection costs associated with our tertiary projects that we would have previously expensed. Had the new method of accounting for tertiary injection 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, 2008 and 2007, 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. We do not apply hedge accounting to our oil and natural gas derivative contracts and accordingly 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 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 oil and natural gas derivative 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 61 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. To evaluate our CO_2 assets for impairment, we determine the CO_2 required for our proved tertiary reserves and include the estimated net capitalized costs of those CO_2 assets in the oil and natural gas ceiling test. The remaining net capitalized CO_2 asset cost is evaluated for impairment by comparing our expected future revenues from these assets to their net carrying value.

CO_2 PIPELINES

CO_2 pipelines are used for transportation of CO_2 to our tertiary floods from our CO_2 source field located near Jackson, Mississippi. We are continuing expansion of our CO_2 pipeline infrastructure with several pipelines currently under construction. At December 31, 2008 and 2007, we had $402.0 million and $106.2 million of costs, respectively, related to construction in progress, recorded under "CO_2 properties, equipment and pipelines" in our Consolidated Balance Sheets. These costs of CO_2 pipelines under construction were not being depreciated at December 31, 2008 or December 31, 2007. Depreciation will commence when the pipelines are placed into service. Each pipeline is depreciated on a straight-line basis over its estimated useful life. We include the net capitalized cost of the pipelines which provide CO_2 to the tertiary floods that have proved tertiary reserves, in the oil and natural gas ceiling test.

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, 2008 and 2007, we had approximately $7.4 million and $9.5 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, 2008 and 2007 was approximately 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, non-vested stock appreciation rights ("SARs"), non-vested restricted stock and any other convertible securities outstanding.

All shares have been adjusted for the 2-for-1 stock split effective December 5, 2007. For each of the three years in the period ended December 31, 2008, 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:

(In thousands)	Year Ended December 31, 2008	2007	2006
Weighted average common shares – basic	243,935	240,065	233,101
Potentially dilutive securities:			
Stock options and SARs	7,102	10,485	12,376
Restricted stock	1,493	1,551	2,070
Weighted average common shares – diluted	252,530	252,101	247,547

The weighted average common shares – basic amount in 2008, 2007 and 2006 excludes 2.2 million, 2.7 million and 2.8 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 1.1 million shares in 2008, 130,000 shares in 2007 and 256,000 shares in 2006 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 provisions of FASB Interpretation No. 48 ("FIN 48"), *Accounting for Uncertainties in Income Taxes* – an interpretation of SFAS 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.

RECENTLY ADOPTED ACCOUNTING PRONOUNCEMENT

Fair Value Measurements

During the first quarter of 2008, we adopted 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. On February 12, 2008, the FASB issued FASB Staff Position ("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. This deferral of SFAS No. 157 applies to our asset retirement obligation ("ARO"), which uses fair value measures at the date incurred to determine our liability. We do not expect the adoption of SFAS No. 157 to significantly change the methodology we use to estimate the initial fair value of our ARO.

In October 2008, the FASB issued FSP FAS 157-3, "Determining the Fair Value of a Financial Asset When the Market for That Asset Is Not Active." FSP FAS 157-3 clarifies the application of SFAS No. 157 in a market that is not active and provides an example to illustrate key considerations in determining the fair value of a financial asset when the market for that financial asset is not active. FSP FAS 157-3 was effective upon issuance, including prior periods for which financial statements had not been issued. Revisions resulting from a change in the valuation technique or its application should be accounted for as a change in accounting estimate following the guidance in FASB Statement No. 154, "Accounting Changes and Error Corrections." FSP FAS 157-3 was effective for the financial statements included in our quarterly report for the period ended September 30, 2008, but had no impact on our Consolidated Financial Statements.

As defined in SFAS No. 157, fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). We utilize market data or assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, market corroborated, or generally unobservable. We primarily apply the market approach for recurring fair value measurements and endeavor to utilize the best available information. Accordingly, we utilize valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs. We are able to classify fair value balances based on the observability of those inputs. SFAS No. 157 establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (level 1 measurement) and the lowest priority to unobservable inputs (level 3 measurement). The three levels of the fair value hierarchy defined by SFAS No. 157 are as follows:

Level 1 – Quoted prices in active markets for identical assets or liabilities as of the reporting date. During 2008 we had no level 1 recurring measurements.

Level 2 – Pricing inputs are other than quoted prices in active markets included in level 1, which are either directly or indirectly observable as of the reported date. Level 2 includes those financial instruments that are valued using models or other valuation methodologies. These models are primarily industry-standard models that consider various assumptions, including quoted forward prices for commodities, time value, volatility factors, and current market and contractual prices for the underlying instruments, as well as other relevant economic measures. Substantially all of these assumptions are observable in the marketplace throughout the full term of the instrument, can be derived from observable data or are supported by observable levels at which transactions are executed in the marketplace.

Instruments in this category include non-exchange-traded oil derivatives such as over-the-counter swaps. We have included an estimate of nonperformance risk in the fair value measurement of our oil derivative contracts as required by SFAS No. 157. At December 31, 2008, all of our oil derivative contracts are in an asset position. Therefore, in assessing the nonperformance risk of the counterparties to these contracts, we have measured the risk by using credit default swaps, as we believe this data is the most responsive to current market events. If a counter-party did not have credit default swaps associated with that specific entity, we utilized industry credit default swaps as an estimate of the fair value of this risk associated with that entity. At December 31, 2008, the fair value of our oil derivative contracts was reduced by $3.7 million for the estimated nonperformance risk of our counterparties.

Level 3 – Pricing inputs include significant inputs that are generally less observable from objective sources. These inputs may be used with internally developed methodologies that result in management's best estimate of fair value. During 2008 we had no level 3 recurring measurements.

The following table sets forth by level within the fair value hierarchy our financial assets that were accounted for at fair value on a recurring basis as of December 31, 2008.

	Fair Value Measurements at December 31, 2008 Using			
Amounts in thousands	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
Assets:				
Oil derivative contracts	$ —	$249,746	$ —	$249,746

See Note 10, "Derivative Instruments and Hedging Activities" for further information about these contracts.

RECENTLY ISSUED ACCOUNTING PRONOUNCEMENTS

Business Combinations. In December 2007, the FASB issued SFAS No. 141 (Revised 2008), "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 do not anticipate the adoption of SFAS 141(R) will have a material impact on our financial condition or results of operations, absent any material business combinations.

Noncontrolling Interests. 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. Since we currently do not have any noncontrolling interests, SFAS No. 160 does not presently have any impact on us.

Disclosures about Derivative Instruments and Hedging Activities. In March 2008, the FASB issued SFAS No. 161, "Disclosures about Derivative Instruments and Hedging Activities—an amendment of SFAS No. 133." SFAS No. 161 requires entities that utilize derivative instruments to provide qualitative disclosures about their objectives and strategies for using such instruments, as well as any details of credit-risk-related contingent features contained within derivatives. SFAS No. 161 also requires entities to disclose additional information about the amounts and location of derivatives located within the financial statements, how the provisions of SFAS No. 133 have been applied, and the impact that hedges have on an entity's financial position, financial performance, and cash flows. SFAS No. 161 is effective for us beginning January 1, 2009. As its only requirement is to enhance disclosures, SFAS No. 161 will not have a significant impact on us.

Modernization of Oil and Gas Reporting. On December 31, 2008, the Securities and Exchange Commission adopted major revisions to its rules governing oil and gas company reporting requirements. These include provisions that permit the use of new technologies to determine proved reserves, and that allow companies to disclose their probable and possible reserves to investors. The current rules limit disclosure to only proved reserves. The new disclosure requirements also require companies that have an audit performed of their reserves to report the independence and qualifications of the auditor of the reserve estimates, and to file reports when a third party reserve engineer is relied upon to prepare reserve estimates. The new rules also require that oil and gas reserves be reported and the full cost ceiling value calculated using an average price based upon the prior 12-month period. The new oil and gas reporting requirements are effective for annual reports on Forms 10-K for fiscal years ending on or after December 31, 2009, with early adoption not permitted. We are currently evaluating the impact the new rules may have on our financial condition or results of operations.

Note 2. Acquisitions and Divestitures

Cancellation of Conroe Field Acquisition

In August 2008, we entered into an agreement with a privately owned company to purchase a 91.4% interest in Conroe Field, a significant potential tertiary flood north of Houston, Texas, for $600 million, plus additional potential consideration if oil prices were to exceed $121 per barrel during the next three years. Closing was provided for in early October 2008. Based on capital market conditions in early October, and a desire to refrain from increasing our leverage in that environment, we cancelled the contract to purchase the Conroe Field, forfeiting a $30 million non-refundable deposit. The $30 million deposit plus miscellaneous acquisition costs of $0.6 million are included in "Abandoned acquisition costs" in our Consolidated Statement of Operations for the year ended December 31, 2008.

Hastings Acquisition

During November 2006, we entered into an agreement with a subsidiary of Venoco, Inc. that gave us an option to purchase their interest in Hastings Field, a strategically significant potential tertiary flood candidate located near Houston, Texas. We exercised the purchase option prior to September 2008, and closed the $201 million acquisition during February 2009. As consideration for the option agreement, we made total payments of $50 million. The deposit and final purchase price will be transferred to oil and natural gas properties in the first quarter of 2009 and will be 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.

The purchase price of $201 million included approximately $4.9 million for certain surface land, oilfield equipment and other related assets. Under the terms of the agreement, Venoco, Inc. the seller, retained a 2% override and reversionary interest of approximately 25% following payout, as defined in the option agreement. The Hastings proved reserves were not included in the Company's year-end proved reserves. We plan to commence flooding the field with CO_2 beginning in 2011, after completion of our Green CO_2 Pipeline currently under construction and construction of field recycling facilities.

As part of the agreement, we are required to spend an aggregate of approximately $179 million over a five year period to develop the field for tertiary operations (commencing in 2010), with an obligation to commence CO_2 injections in the field by late 2012.

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 we retained a net profits interest in one 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). We closed on the remaining portion of the sale in February 2008 and received net proceeds of approximately $48.9 million. 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. 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. The operating results of these sold properties are included in our financial statements through the applicable closing dates of the sold properties. We did not record any gain or loss on the sale in accordance with the full cost method of accounting.

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. Two of these fields are future potential CO_2 tertiary flood candidates. Tertiary flooding at these fields is not expected to begin until 2011, following completion of the Green Pipeline from Louisiana to Hastings Field, near Houston, Texas. The adjusted purchase price was approximately $39.4 million, of which $33.9 million was assigned to unevaluated properties.

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.

Note 3. Related Party Transactions – Genesis

Interest in and Transactions with Genesis

Denbury's subsidiary, Genesis Energy, LLC is the general partner of, and together with Denbury's other subsidiaries, owns an aggregate 12% interest in 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 12% 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. Denbury received cash distributions from Genesis of $7.1 million in 2008, $1.7 million in 2007, and $0.9 million in 2006. We also received $0.2 million in 2008, and $0.1 million in 2007 and 2006, 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, LLC.

On July 25, 2007, Genesis acquired several energy related businesses. Approximately one-half of the acquisition was funded by debt and approximately one-half through the issuance of Genesis common units to the seller. In conjunction with that acquisition, our subsidiary, Genesis Energy, LLC, 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, LLC, maintained its 2% general partner's interest and also acquired 734,732 common units in this offering for a total of $20 million, which maintained its same ownership interest of approximately 9.25%.

Our cumulative investments in Genesis of $85.5 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. At December 31, 2008, the balance of our equity investment in Genesis is $80.0 million. Based on quoted market values of Genesis' publicly traded limited partnership units at December 31, 2008, the estimated market value of our publicly traded common units of Genesis was approximately $35.2 million. Since the general partner units we hold are not publicly traded, there is not a readily available market value for these units. Due to the capital market conditions during the latter part of 2008, we have reviewed the value of our investment in Genesis as of December 31, 2008 for impairment. Based upon this review, and the current and future expected cash flows of Genesis, we do not believe the investment balance is impaired.

Incentive Compensation Agreement

In late December 2008, our subsidiary, Genesis Energy, LLC, entered into agreements with three members of Genesis' management for the purpose of providing them incentive compensation. On December 29, 2008, prior to entering these compensation agreements, we converted our subsidiary Genesis Energy, Inc. into Genesis Energy, LLC. The compensation agreements provide Genesis' management with the ability to earn up to an approximate 17% interest in the incentive distributions that Genesis Energy, LLC will receive from Genesis. These awards have a mandatory redemption feature upon termination of employment that requires a cash payment to be made by Genesis Energy, LLC (guaranteed by us) to the holder of the award. The awards have a graded vesting of 25% per year from the date of the award. The estimated fair value of the mandatory redemption feature of these awards will be recorded as a liability at each reporting date, adjusted for the graded vesting feature and estimated forfeitures, with the changes in this liability recorded as compensation expense in General and administrative expenses in our Consolidated Statement of Operations.

NEJD Pipeline and Free State Pipeline Transactions

On May 30, 2008, we closed on two transactions with Genesis involving our Northeast Jackson Dome ("NEJD") pipeline system and Free State CO_2 pipeline, which included a long-term transportation service agreement for the Free State pipeline and a 20-year financing lease for the NEJD system. We received from Genesis $225 million in cash and $25 million in Genesis common units. We used the proceeds to repay our outstanding borrowings on our bank credit facility and the balance was used for capital expenditures. We have recorded both of these transactions as financing leases. At December 31, 2008, we have recorded $173.6 million for the NEJD financing and $76.6 million for the Free State financing as debt on our Consolidated Balance Sheet (see Note 6, "Long-term Debt").

The NEJD pipeline system is a 183-mile, 20" pipeline extending from the Jackson Dome, near Jackson, Mississippi, to near Donaldsonville, Louisiana, and is currently being used by us to transport CO_2 for our tertiary operations in southwest Mississippi. We have the rights to exclusive use of the NEJD pipeline system, we will be responsible for all operations and maintenance on the system, and we will bear and assume all obligations and liabilities with respect to the pipeline. The NEJD financing lease requires us to make quarterly base rent payments beginning August 30, 2008. These quarterly rent payments are fixed at $5.2 million per quarter or approximately $20.7 million per year (prorated for 2008) during the 20-year term, at an interest rate of approximately 10.25% per annum. At the end of the term, Genesis will release its secured interest in the line to us for $1.00. We have the option or obligation upon the occurrence of certain events specified in the financing lease, and may have the obligation if we default, to prepay our financing lease obligations. In the event of significant downgrades of our corporate credit rating by the rating agencies, Genesis can require certain credit enhancements from us, and possibly other remedies under the lease.

The Free State pipeline is an 86-mile, 20" pipeline that extends from our CO_2 source fields at the Jackson Dome, near Jackson, Mississippi, to our oil fields in east Mississippi. Under the terms of the transportation agreement, Genesis is responsible for owning, operating, maintaining and making improvements to the pipeline. We have exclusive use of the pipeline and are required to use the pipeline to supply CO_2 to certain of our tertiary operations in east Mississippi. The Free State transportation agreement requires us to make monthly payments of $100,000 plus a through-put fee based on average daily volumes per month with no minimum volumes required. Based on our forecasted through-put, we currently project that we will initially pay Genesis approximately $9.3 million per annum (prorated for 2008). Approximately $1.5 million (increasing at 1% per year) of the annual payments will be expensed as operating costs, with the remainder recognized as principal and interest expense. The implicit rate on the financing is approximately 13.2% per annum.

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 $8.0 million in 2008, $6.0 million in 2007, and $4.4 million in 2006 for these transportation services.

Transportation Leases

We have 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, 2008 and 2007, we had $4.5 million and $5.2 million, respectively, of capital lease obligations with Genesis recorded as liabilities in our Consolidated Balance Sheets.

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, 2008 and 2007, $24.0 million and $28.5 million, respectively, was recorded as deferred revenue of which $4.1 million was included in current liabilities at both December 31, 2008 and 2007. We recognized deferred revenue of $4.5 million, $4.4 million and $4.2 million for the years ended December 31, 2008, 2007 and 2006, 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 $0.19 per Mcf of CO_2. For these services, we recognized revenues of $5.5 million, $5.2 million and $4.6 million for the years ended December 31, 2008, 2007 and 2006, respectively.

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, 2008 and 2007.

(In thousands)	Year Ended December 31, 2008	2007
Beginning asset retirement obligation	$41,258	$41,107
Liabilities incurred and assumed during period	1,382	6,530
Revisions in estimated retirement obligations	4,456	1,165
Liabilities settled during period	(4,711)	(1,302)
Accretion expense	3,048	2,976
Sales of properties	(369)	(9,218)
Ending asset retirement obligation	$45,064	$41,258

At December 31, 2008 and 2007, $1.7 million and $2.3 million, respectively, of our asset retirement obligations were classified in "Accounts payable and accrued liabilities" under current liabilities in our Consolidated Balance Sheets. Liabilities sold in 2008 and 2007 were primarily associated with the sale of our Louisiana natural gas properties in December 2007 and February 2008. The reversal of these asset retirement obligations, which were 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 2008 were primarily for new wells drilled. Liabilities incurred and assumed during 2007 were 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 $7.4 million at December 31, 2008, and $9.5 million at December 31, 2007, and are included in "Other assets" in our Consolidated Balance Sheets.

Note 5. Property and Equipment

(In thousands)	December 31, 2008	2007
Oil and natural gas properties		
Proved properties	$ 3,386,606	$ 2,682,932
Unevaluated properties	235,403	366,518
Total	3,622,009	3,049,450
Accumulated depletion and depreciation	(1,481,801)	(1,081,909)
Net oil and natural gas properties	2,140,208	1,967,541
CO_2 properties and equipment	377,711	269,335
Accumulated depletion and depreciation	(60,758)	(34,676)
Net CO_2 properties	316,953	234,659
CO_2 pipelines in service	119,819	61,025
CO_2 pipelines under construction	402,012	106,231
Accumulated depletion and depreciation	(16,392)	(3,340)
Net CO_2 pipelines	505,439	163,916
Capital leases	9,565	7,985
Accumulated depletion and depreciation	(3,333)	(2,482)
Net capital leases	6,232	5,503
Other	60,763	42,131
Accumulated depletion and depreciation	(27,398)	(20,875)
Net other	33,365	21,256
Net property and equipment	$ 3,002,197	$ 2,392,875

At December 31, 2008 and 2007, we had $402.0 million and $106.2 million of costs, respectively, related to pipelines under construction, and as such, were not being depreciated at December 31, 2008 or December 31, 2007, respectively. 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 $11.5 million in 2008 and $2.1 million in 2007.

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, 2008 and 2007, and the year in which they were incurred follows:

	December 31, 2008			
	Costs Incurred During:			
(In thousands)	2008	2007	2006	Total
Property acquisition costs	$ 3,520	$31,338	$72,020	$106,878
Exploration and development	74,127	30,439	2,877	107,443
Capitalized interest	12,538	5,963	2,581	21,082
Total	$90,185	$67,740	$77,478	$235,403

	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

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 three CO_2 tertiary oil field candidates: Citronelle Field, South Cypress Creek Field and Delhi Field. See Note 2, "Acquisitions and Divestitures." Exploration and development costs are primarily associated with our CO_2 tertiary oil fields that are under development and did not have proved reserves at December 31, 2008. During 2008, we established proved reserves at Tinsley Field, Lockhart Crossing Field and Heidelberg Field and as a result we transferred $284.6 million of costs incurred (as of December 31, 2007 these costs were $197.6 million) on these projects into the amortization base. 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.

Full Cost Ceiling Test

The Company recognized a write down of its oil and natural gas properties of $226 million under the full cost ceiling test at December 31, 2008. In accordance with the full cost ceiling rules, the ceiling limit is calculated utilizing the unescalated period-end prices, which were a NYMEX WTI oil price per Bbl of $44.60 and a Henry Hub cash price per MMBtu of $5.71. We include the portion of net capitalized cost of CO_2 assets and CO_2 pipelines that are required for our current proved tertiary reserves in the net capitalized costs subject to this ceiling test. The fair value of our oil derivative contracts at December 31, 2008 of $249.7 million, which contracts have a floor price of $75.00 per barrel on 30,000 barrels per day for calendar year 2009, was not included in the ceiling test as we did not designate these contracts as hedge instruments for accounting purposes under SFAS No. 133. Subsequent to December 31, 2008, oil and natural gas prices have continued to be volatile and are currently at levels lower than at year-end 2008. If oil and natural gas prices remain at these lower levels through March 31, 2009, or subsequent periods, we may be required to record additional write-downs under the full cost ceiling test in the first quarter of 2009, or in subsequent periods. The amount of any future write-down is difficult to predict and will depend upon the oil and natural gas prices at the end of each period, the incremental proved reserves that might be added during each period and additional capital spent.

Note 6. Notes Payable and Long-Term Indebtedness

(In thousands)	December 31, 2008	2007
7.5% Senior Subordinated Notes due 2015	$300,000	$300,000
Premium on Senior Subordinated Notes due 2015	599	685
7.5% Senior Subordinated Notes due 2013	225,000	225,000
Discount on Senior Subordinated Notes due 2013	(826)	(1,020)
NEJD financing – Genesis	173,618	—
Free State financing – Genesis	76,634	—
Senior bank loan	75,000	150,000
Capital lease obligations – Genesis	4,544	5,238
Capital lease obligations	2,705	1,164
Total	857,274	681,067
Less current obligations	4,507	737
Long-term debt and capital lease obligations	$852,767	$680,330

NEJD Financing and Free State Financing

On May 30, 2008, we closed on two transactions with Genesis involving two of our pipelines. The two transactions have been recorded as financing leases. See Note 3, "Related Party Transactions – Genesis – NEJD Pipeline and Free State Pipeline Transactions."

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 (collectively, the "2015 Notes") discussed below. These 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. 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.

Senior Bank Loan

Effective April 1, 2008, we amended our Sixth Amended and Restated Credit Agreement, the instrument governing our senior bank loan, which increased our borrowing base from $500 million to $1.0 billion. In early October 2008, we further amended our bank credit facility which increased the banks' commitment amount from $350 million to $750 million and maintained the borrowing base at $1.0 billion. This amendment also (i) allowed us to divest of our Barnett Shale properties, (ii) allowed us to do a tax free like-kind exchange of the Barnett Shale properties for Conroe, Hastings and other fields, (iii) allowed for additional permitted indebtedness of up to $600 million in the form of subordinated or convertible debt, and (iv) modified the commitment fees and pricing grid for the loan, raising the pricing grid by 25 basis points.

With regard to our bank credit facility, the borrowing base represents the amount that can be borrowed from a credit standpoint based on our mortgaged 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 ($750 million), up to the borrowing base limit ($1.0 billion), although the banks are not obligated to fund any amount in excess of the commitment amount.

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, 2008. 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, 2008, we had $75.0 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 2.95% at December 31, 2008. The next scheduled redetermination of the borrowing base will be as of April 1, 2009, based on December 31, 2008 assets and proved reserves. Our bank debt borrowing base is adjusted at the banks' discretion and is based in part upon external factors over which we have no control. Although we currently do not anticipate a reduction in our bank borrowing base or commitment amount as of April 1, 2009, if our borrowing base were to be less than our outstanding borrowings under the facility, we will be required to repay the deficit over a period of six months.

In February 2009, we amended our Sixth Amended and Restated Credit Agreement (see Note 14, "Subsequent Events").

Issuance of 9.75% Senior Subordinated Notes due 2016

On February 13, 2009, we issued $420 million of 9.75% Senior Subordinated Notes due 2016 (see Note 14, "Subsequent Events").

Indebtedness Repayment Schedule

At December 31, 2008, 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)	
2009	$ 4,507
2010	5,464
2011	82,634
2012	8,097
2013	233,578
Thereafter	523,221
Total indebtedness	$857,501

Note 7. Income Taxes

Our income tax provision is as follows:

(In thousands)	Year Ended December 31, 2008	2007	2006
Current income tax expense:			
Federal	$ 32,475	$ 21,948	$ 16,033
State	8,337	8,126	3,832
Total current income tax expense	40,812	30,074	19,865
Deferred income tax expense (benefit):			
Federal	184,630	113,868	97,902
State	10,390	(3,675)	9,350
Total deferred income tax expense	195,020	110,193	107,252
Total income tax expense	$235,832	$140,267	$127,117

During the third quarter of 2008, we obtained approval from the Internal Revenue Service ("IRS") to change our method of tax accounting for certain assets used in our tertiary oilfield recovery operations. Previously, we had capitalized and depreciated these costs, but now we can deduct these costs once the assets are placed into service. As a result, we expect to receive tax refunds of approximately $10.6 million for tax years through 2007, along with other tax benefits, and we have reduced our current income tax expense and increased our deferred income tax expense in 2008 to adjust for the impact of this change. This change is not expected to have a significant impact on our overall tax rate; however, it will allow for a quicker deduction of costs for tax purposes.

At December 31, 2008, we had state net operating loss carryforwards totaling $5.0 million and an estimated $44 million of enhanced oil recovery credits to carry forward related to our tertiary operations. Our enhanced oil recovery credits will begin to expire in 2022.

Deferred income taxes relate to temporary differences based on tax laws and statutory rates in effect at the December 31, 2008 and 2007, balance sheet dates. We believe that we will be able to realize all of our deferred tax assets at December 31, 2008, and therefore have provided no valuation allowance against our deferred tax assets.

At December 31, 2008 and 2007, our deferred tax assets and liabilities were as follows:

(In thousands)	December 31, 2008	2007
Deferred tax assets:		
Loss carryforwards – state	$ 152	$ —
Tax credit carryover	32,156	15,631
Enhanced oil recovery credit carryforwards	43,772	37,257
Other	13,221	19,950
Total deferred tax assets	89,301	72,838
Deferred tax liabilities:		
Property and equipment	(520,455)	(406,632)
Derivative contracts	(91,080)	(868)
Total deferred tax liabilities	(611,535)	(407,500)
Total net deferred tax liability	$(522,234)	$(334,662)

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:

(In thousands)	Year Ended December 31, 2008	2007	2006
Income tax provision calculated using the federal statutory income tax rate	$218,479	$137,695	$115,351
State income taxes	18,865	11,536	13,183
Estimated statutory rate change	—	(7,351)	—
Other	(1,512)	(1,613)	(1,417)
Total income tax expense	$235,832	$140,267	$127,117

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 December 31, 2008, the total amount of unrecognized tax benefits was $1.0 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. The Internal Revenue Service concluded its examination of our 2004 tax year during the third quarter of 2007 and concluded its examination of our 2005 tax year during the second quarter of 2008. 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. None of the concluded examinations by the Internal Revenue Service or the state of Mississippi resulted in any material assessments. As a result of the examinations concluded during 2007 and 2008, we decreased our total amount of unrecognized tax benefits from $4.5 million at January 1, 2007 to $3.5 million at December 31, 2007, and to $1.0 million at December 31, 2008. These adjustments all related to temporary timing differences and did not have any impact on our effective tax rate. 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 Split

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.

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.

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.

Stock Repurchases

In 2006, 2007 and 2008, 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, 2008, there were 432,288 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 $2.7 million, $2.2 million and $1.7 million for the years ended December 31, 2008, 2007 and 2006, 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. Effective January 1, 2008, Denbury increased its match to 100% of an employee's contribution, up to 6% of compensation, as defined by the plan. Previously, up to 3% of an employee's compensation, was matched by Denbury at 100%, and an employee's contribution between 3% and 6% of compensation was matched by Denbury at 50%. Denbury's match is vested immediately. During 2008, 2007 and 2006, Denbury's matching contributions were approximately $3.3 million, $2.2 million and $1.6 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, 2008, a total of 4,165,908 shares were available for future issuance of awards, of which only 1,386,318 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. On January 30, 2009 the Board of Directors modified the vesting provisions for the 35% of the awards that would vest upon retirement to now vest ratably each January 31 (beginning January 31, 2009) until the final vesting on the retirement eligibility date.

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 stock-based compensation expense was $14.1 million, $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, 2008, 2007 and 2006, respectively. Part of this expense, $1.4 million in 2008 and $1.5 million in both 2007 and 2006, 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 $5.3 million, $4.1 million and $4.6 million for the years ended December 31, 2008, 2007 and 2006, respectively. Share-based compensation capitalized as part of "Oil and natural gas properties" was $2.2 million, $1.6 million and $1.7 million for the years ended December 31, 2008, 2007 and 2006, respectively. 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 Sheets.

Stock Options and SARs

The fair value of each 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.

	2008	2007	2006
Weighted average fair value of SARs granted	**$11.91**	**$6.90**	**$6.32**
Risk free interest rate	**3.29%**	**4.54%**	**4.52%**
Expected life	**4.5 to 6.2 years**	**4.6 to 6.4 years**	**4.9 to 6.9 years**
Expected volatility	**38.1%**	**38.3%**	**41.1%**
Dividend yield	**—**	**—**	**—**

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

	Year Ended December 31,					
	2008		2007		2006	
	Number of Options	Weighted Average Price	Number of Options	Weighted Average Price	Number of Options	Weighted Average Price
Outstanding at beginning of year	**11,463,285**	**$ 6.28**	**14,964,920**	**$ 4.96**	**18,812,144**	**$ 4.04**
Granted	**1,042,810**	**29.45**	**873,649**	**16.34**	**1,034,310**	**13.58**
Exercised	**(2,612,134)**	**3.36**	**(4,054,844)**	**3.44**	**(4,032,652)**	**2.77**
Forfeited	**(378,962)**	**13.80**	**(320,440)**	**7.90**	**(848,882)**	**5.53**
Outstanding at end of year	**9,514,999**	**9.32**	**11,463,285**	**6.28**	**14,964,920**	**4.96**
Exercisable at end of year	**4,593,407**	**$ 4.55**	**3,969,466**	**$ 3.26**	**4,739,104**	**$ 2.66**

The total intrinsic value of stock options and SARs exercised during the years ended December 31, 2008, 2007 and 2006, was approximately $65.8 million, $60.3 million and $49.3 million, respectively. The total grant-date fair value of stock options and SARs vested during the years ended December 31, 2008, 2007 and 2006, was approximately $7.2 million, $6.8 million and $6.0 million, respectively. The aggregate intrinsic value of stock options and SARs outstanding at December 31, 2008, was approximately $39.8 million, and these options and SARs have a weighted-average remaining contractual life of 5.9 years. The aggregate intrinsic value of options exercisable at December 31, 2008, was approximately $30.6 million, and these stock options and SARs have a weighted-average remaining contractual life of 4.5 years.

A summary of the status of our non-vested stock options and SARs as of December 31, 2008, and the changes during the year ended December 31, 2008, is presented below:

Non-Vested Stock Options and SARs	Shares	Weighted Average Grant-Date Fair Value
Non-vested at January 1, 2008	7,493,819	$ 3.45
Granted	1,042,810	11.91
Vested	(3,236,075)	2.22
Forfeited	(378,962)	5.83
Non-vested at December 31, 2008	4,921,592	5.87

As of December 31, 2008, there was $12.5 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 2.6 years. Cash received from stock option exercises under share-based payment arrangements for the years ended December 31, 2008, 2007 and 2006, was $7.7 million, $13.1 million and $11.1 million, respectively. The tax benefit realized from the exercises of stock options and SARs totaled $18.9 million for 2008, $18.7 million for 2007, and $14.7 million for 2006.

Restricted Stock

As of December 31, 2008, we had issued 4,931,087 shares of restricted stock (net of forfeited shares) pursuant to the 2004 Plan and have recorded deferred compensation expense of $37.5 million, the fair market value of the shares on the grant dates, net of estimated forfeitures of $5.0 million. This expense is amortized over the applicable five-year, four-year, or retirement date vesting periods. As of December 31, 2008, there was $14.5 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 4.0 years.

A summary of the status of our non-vested restricted stock grants and the changes during the year ended December 31, 2008, is presented below:

Non-Vested Restricted Stock Grants	Shares	Weighted Average Grant-Date Fair Value
Non-vested at January 1, 2008	2,702,448	$ 7.46
Granted	278,973	31.36
Vested	(519,372)	7.32
Forfeited	(251,366)	7.43
Non-vested at December 31, 2008	2,210,683	10.52

The total vesting date fair value of restricted stock vested during the years ended December 31, 2008, 2007 and 2006 was $12.3 million, $10.7 million and $17.4 million, respectively.

Performance Equity Awards

On January 2, 2007 and January 7, 2008, the Board of Directors awarded performance equity awards to the officers of Denbury. These performance-based shares will vest on March 31, 2010 and 2011, respectively, when the Company's various financial and operational results for 2009 and 2010 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 aggregate number of performance-based equity awards (at the 100% targeted vesting level, net of forfeitures) granted to the Company's executive officers as of December 31, 2008, is 191,298 shares. The actual number of shares to be delivered pursuant to the performance-based awards could range from zero to 200% (382,596 shares) of the stated 100% targeted amount. These performance-based share awards have an average grant date fair value of $22.16 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 years ended December 31, 2008 and 2007, we recorded $1.2 million and $0.4 million, respectively, of expense in "General and administrative expenses" in our Consolidated Statements of Operations for these performance-based awards.

Note 10. Derivative Instruments and Hedging Activities

Oil and Natural Gas Derivative Contracts

We do not apply hedge accounting treatment to our oil and natural gas derivative contracts and therefore the changes in the fair values of these instruments are recognized in income in the period of change. These fair value changes, along with the cash settlements of expired contracts are shown under "Commodity derivative expense (income)" in our Consolidated Statements of Operations.

From time to time, we enter into various oil and natural gas 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 80% of our anticipated production 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. 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) at a weighted average price of $7.91 per Mcf. We cancelled the December 2008 natural gas swaps in the third quarter of 2008 because of our plans at that time to sell our Barnett Shale properties, receiving approximately $61,000 from the cancellation.

As a result of the current economic conditions and in order to protect our liquidity in the event that commodity prices continue to decline, during early October 2008, we purchased oil derivative contracts for 2009 with a floor price of $75 / Bbl and a ceiling price of $115 / Bbl for total consideration of $15.5 million. These 2009 contracts were entered into with the following counterparties: JPMorgan Chase Bank (10,000 Bbls/d), Wells Fargo Bank (7,500 Bbls/d), Keybank (5,000 Bbls/d), Fortis Energy Marketing and Trading GP (5,000 Bbls/d) and Comerica Bank (2,500 Bbls/d).

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. We have included an estimate of nonperformance risk in the fair value measurement of our oil derivative contracts as required by SFAS No. 157. At December 31, 2008, all of our oil derivative contracts are in an asset position. Therefore, in assessing the nonperformance risk of the counterparties to these contracts, we have measured the risk by using credit default swaps as we believe this data is the most responsive to current market events. If a counter-party did not have credit default swaps associated with that specific entity, we utilized industry credit default swaps as an estimate of the fair value of this risk associated with that entity. At December 31, 2008, the fair value of our oil derivative contracts was reduced by $3.7 million for the estimated nonperformance risk of our counterparties.

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

	Year Ended December 31,		
(In thousands)	2008	2007	2006
Receipt (payment) on settlements of derivative contracts – oil	$ (30,969)	$ (9,833)	$ (5,302)
Receipt (payment) on settlements of derivative contracts – gas	(26,584)	30,313	—
Fair value adjustments to derivative contracts – income (expense)	257,606	(39,077)	25,130
Commodity derivative income (expense)	$200,053	$(18,597)	$19,828

Oil Derivative Contracts at December 31, 2008:

Crude Oil Contracts:

	NYMEX Contract Prices Per Bbl			Estimated Fair Value
		Collar Prices		Asset at
Type of Contract and Period	Bbls/d	Floor	Ceiling	December 31, 2008 (In thousands)
Collar Contracts				
Jan. 2009 – Dec. 2009	**30,000**	**$75.00**	**$115.00**	**$249,746**

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 applied hedge accounting to these contracts as provided under SFAS No. 133. On June 30, 2008, we settled our remaining interest rate lock contracts for a payment due to the counterparty of approximately $1.6 million. During the second quarter of 2008, we determined that we would not complete the anticipated sale-leaseback transactions which were designated as the forecasted hedged transactions for several of the interest rate lock contracts. As a result, we reclassified the $1.4 million in fair market value changes for these contracts that was in "Accumulated other comprehensive loss" to expense during the second quarter of 2008. We have $0.6 million (net of taxes of $0.4 million) in "Accumulated other comprehensive loss" in our December 31, 2008 Consolidated Balance Sheet. We recognized ineffectiveness totaling $0.1 million as expense in our Consolidated Statement of Operations for the year ended December 31, 2008.

Note 11. Commitments and Contingencies

We have operating leases for the rental of equipment, office space and vehicles that totaled $128.6 million, $143.8 million and $101.4 million as of December 31, 2008, 2007 and 2006, respectively. During the last six 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 $6.1 million during 2008, $27.1 million during 2007, and $41.1 million during 2006 with associated required monthly payments of $56,000 for the 2008 leases, $257,000 for the 2007 leases, and $431,000 for the 2006 leases. Leases entered into prior to 2006 have seven-year terms, and the leases entered into in 2006, 2007 and 2008 have 10-year terms. Rental expense for operating leases totaled $27.2 million in 2008, $23.4 million in 2007, and $14.1 million in 2006. We have subleased part of the office space where we have operating leases. The cash payments we will receive under these contracts total approximately $1.3 million for 2009 through 2012.

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. In 2008, we entered into two transactions with Genesis involving our NEJD pipeline system and Free State CO_2 pipeline, which included a long-term transportation service agreement for the Free State pipeline and a 20-year financing lease for the NEJD pipeline system. These two transactions are accounted for as financing leases and are discussed in detail in Note 3.

At December 31, 2008, long-term commitments for these items require the following future minimum rental payments:

(In thousands)	Pipeline Financing Leases	Capital Leases	Operating Leases
2009	$ 29,358	$ 2,120	$ 17,938
2010	31,759	1,882	17,351
2011	33,205	1,882	16,571
2012	33,438	1,242	15,199
2013	33,518	700	12,510
Thereafter	427,136	1,393	49,037
Total minimum lease payments	588,414	9,219	$128,606
Less: Amount representing interest	(338,162)	(1,970)	
Present value of minimum lease payments	$ 250,252	$ 7,249	

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 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 512 Bcf of CO_2 to these customers over the next 19 years, with a maximum volume required in any given year of approximately 136 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, 2008 (approximately 5.6 Tcf before deducting approximately 153.8 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 four proposed gasification plants, two of which are in the Gulf Coast region and two in the Midwest region (Illinois / Kentucky area) of the United States. The Midwest plants are not only conditioned on those specific plants being constructed, but also upon Denbury contracting additional volumes of CO_2 for purchase in the general area of the proposed plants that would provide an acceptable economic return on the CO_2 pipeline that we would need to construct to transport these volumes to our existing CO_2 pipeline system. If all four plants are built, these CO_2 sources are currently anticipated to provide us with aggregate CO_2 volumes of around 1 Bcf/d. Due to the current economic conditions, the earliest we would expect any plant to be completed and provide CO_2 would be 2013, and there is some doubt as to whether they will be constructed at all. The base price of CO_2 per Mcf from these CO_2 sources varies by plant and location, but is generally higher than our most recent all-in cost of CO_2 from our natural sources (Jackson Dome) using current oil prices. Prices for CO_2 delivered from these projects are expected to be competitive with the cost of our natural CO_2 after adjusting for our share of potential carbon emissions reduction credits using estimated futures' prices of carbon emissions reduction credits. If all four plants are built, the aggregate purchase obligation for this CO_2 would be around $135 million per year, assuming a $50 per barrel oil price, before any potential savings from our share of carbon emissions reduction 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. While it is likely that not every plant currently under contract will be constructed, there are several other plants under consideration that could provide CO_2 to us that would either supplement or replace the CO_2 volumes from the four proposed plants that we currently have contracts with. We are having ongoing discussions and negotiations with several of these other potential sources. We have invested a total of $13.5 million during 2006, 2007 and 2008 in preferred stock of one of the proposed plants. All of our investment may later be redeemed, with a return, or converted to equity after construction financing for the project has been obtained. 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 a loss is probable and the amount can be reasonably estimated.

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, 2008, we had three significant purchasers that each accounted for 10% or more of our oil and natural gas revenues: Marathon Petroleum

Company LLC (49%), Hunt Crude Oil Supply Co. (20%) and Crosstex Energy Field Services Inc. (14%). For the year ended December 31, 2007, three purchasers each accounted for 10% or more of our oil and natural gas revenues: Marathon Petroleum Company 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 significant purchasers that each accounted for 10% or more of our oil and natural gas revenues: Marathon Petroleum Company LLC (28%) and Hunt Crude Oil Supply Co. (18%).

Accounts Payable and Accrued Liabilities

(In thousands)	December 31, 2008	December 31, 2007
Accounts payable	**$111,899**	**$ 59,076**
Accrued exploration and development costs	**50,571**	**36,409**
Accrued compensation	**10,746**	**10,872**
Accrued lease operating expense	**10,014**	**10,114**
Accrued interest	**6,780**	**5,716**
Taxes payable	**6,282**	**8,103**
Asset retirement obligations – current	**1,712**	**2,304**
Hastings purchase option – current	**—**	**4,709**
Other	**4,629**	**10,277**
Total	**$202,633**	**$147,580**

Supplemental Cash Flow Information

(In thousands)	Year Ended December 31, 2008	2007	2006
Interest paid, net of amounts capitalized	**$ 26,997**	**$ 27,892**	**$ 21,514**
Interest capitalized	**29,161**	**20,385**	**11,333**
Income taxes paid	**70,349**	**10,277**	**4,210**

During 2008, 2007, and 2006 we capitalized $17.6 million, $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 $11.5 million in 2008, $2.1 million in 2007, and $0.3 million in 2006 of interest relating to the construction of our CO_2 pipelines. In 2008 we received $225 million in cash, and recorded a $25 million non-cash increase to investments in subsidiaries for common limited partnership units received related to two financing leases entered into with Genesis (see Note 3, "Related Party Transactions – Genesis"). In 2008, we issued 278,973 shares of restricted stock with a market value of $8.7 million on the date of grant. 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. See Note 9, "Stock Compensation Plans – Restricted Stock."

In November 2006, we entered into an agreement for the option to purchase Hastings Field (see Note 2, "Acquisitions and Divestitures") 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, along with the additional payments of $7.5 million in 2007 and $5.0 million in 2008, are recorded on our Consolidated Statements of Cash Flow under "Investing Activities."

Fair Value of Financial Instruments

	December 31,			
	2008		2007	
(In thousands)	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
7.5% Senior Subordinated Notes due 2013	$224,174	$171,000	$223,980	$227,250
7.5% Senior Subordinated Notes due 2015	300,599	213,000	300,685	303,000
Senior Bank Loan	75,000	64,000	150,000	150,000

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 adjusted the estimated fair value measurement of our Senior Bank Loan at December 31, 2008 in accordance with SFAS No. 157 for estimated nonperformance risk. This estimated nonperformance risk totaled approximately $11.0 million and was determined utilizing industry credit default swaps. 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, 2008				
(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	$ 458,051	$ 408,940	$ 14,992	$ (466,784)	$ 415,199
Property and equipment	—	2,973,947	28,250	—	3,002,197
Investment in subsidiaries (equity method)	1,371,347	24,901	1,368,759	(2,685,003)	80,004
Other assets	312,239	89,471	899	(310,335)	92,274
Total assets	$2,141,637	$3,497,259	$1,412,900	$(3,462,122)	$3,589,674
Liabilities and Stockholders' Equity					
Current liabilities	$ 970	$ 810,476	$ 41,405	$ (466,784)	$ 386,067
Long-term liabilities	300,599	1,373,127	148	(310,335)	1,363,539
Stockholders' equity	1,840,068	1,313,656	1,371,347	(2,685,003)	1,840,068
Total liabilties and stockholders' equity	$2,141,637	$3,497,259	$1,412,900	$(3,462,122)	$3,589,674

(In thousands)	Denbury Resources Inc. (Parent and Co-Obligor)	Denbury Onshore, LLC (Issuer and Co-Obligor)	Guarantor Subsidiaries	Eliminations	Denbury Resources Inc. Consolidated
	December 31, 2007				
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)	961,990	—	962,204	(1,867,786)	56,408
Other assets	312,556	78,230	818	(310,169)	81,435
Total assets	$1,705,064	$2,708,368	$ 970,295	$(2,612,650)	$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	1,404,378	905,796	961,990	(1,867,786)	1,404,378
Total liabilties and stockholders' equity	$1,705,064	$2,708,368	$ 970,295	$(2,612,650)	$2,771,077

Condensed Consolidating Statements of Operations

(In thousands)	Denbury Resources Inc. (Parent and Co-Obligor)	Denbury Onshore, LLC (Issuer and Co-Obligor)	Guarantor Subsidiaries	Eliminations	Denbury Resources Inc. Consolidated
	Year Ended December 31, 2008				
Revenues	$ 22,500	$1,365,658	$ 44	$ (22,500)	$1,365,702
Expenses	22,982	743,033	3,313	(22,500)	746,828
Income (loss) before the following:	(482)	622,625	(3,269)	—	618,874
Equity in net earnings of subsidiaries	408,393	666	412,100	(815,805)	5,354
Income before income taxes	407,911	623,291	408,831	(815,805)	624,228
Income tax provision	19,515	215,879	438	—	235,832
Net income	$388,396	$ 407,412	$408,393	$(815,805)	$ 388,396

(In thousands)	Denbury Resources Inc. (Parent and Co-Obligor)	Denbury Onshore, LLC (Issuer and Co-Obligor)	Guarantor Subsidiaries	Eliminations	Denbury Resources Inc. Consolidated
	Year Ended December 31, 2007				
Revenues	$ 19,594	$972,992	$ 68	$ (19,594)	$ 973,060
Expenses	20,046	574,134	3,950	(19,594)	578,536
Income (loss) before the following:	(452)	398,858	(3,882)	—	394,524
Equity in net earnings of subsidiaries	253,970	—	256,443	(511,523)	(1,110)
Income before income taxes	253,518	398,858	252,561	(511,523)	393,414
Income tax provision (benefit)	371	141,305	(1,409)	—	140,267
Net income	$253,147	$257,553	$253,970	$(511,523)	$ 253,147

(In thousands)	Denbury Resources Inc. (Parent and Co-Obligor)	Denbury Onshore, LLC (Issuer and Co-Obligor)	Guarantor Subsidiaries	Eliminations	Denbury Resources Inc. Consolidated
	Year Ended December 31, 2006				
Revenues	$ 11,219	$731,516	$ 20	$ (11,219)	$ 731,536
Expenses	11,581	400,657	1,719	(11,219)	402,738
Income (loss) before the following:	(362)	330,859	(1,699)	—	328,798
Equity in net earnings of subsidiaries	202,749	—	204,446	(406,419)	776
Income before income taxes	202,387	330,859	202,747	(406,419)	329,574
Income tax provision (benefit)	(70)	127,189	(2)	—	127,117
Net income	$202,457	$203,670	$202,749	$(406,419)	$ 202,457

Condensed Consolidating Statements of Cash Flows

(In thousands)	Denbury Resources Inc. (Parent and Co-Obligor)	Denbury Onshore, LLC (Issuer and Co-Obligor)	Guarantor Subsidiaries	Eliminations	Denbury Resources Inc. Consolidated
	Year Ended December 31, 2008				
Cash flow from operations	**$ (10)**	**$776,112**	**$ (1,583)**	**$ —**	**$ 774,519**
Cash flow from investing activities	**(29,874)**	**(994,659)**	**—**	**29,874**	**(994,659)**
Cash flow from financing activities	**29,874**	**177,102**	**—**	**(29,874)**	**177,102**
Net (decrease) in cash	**(10)**	**(41,445)**	**(1,583)**	**—**	**(43,038)**
Cash, beginning of period	**34**	**58,343**	**1,730**	**—**	**60,107**
Cash, end of period	**$ 24**	**$ 16,898**	**$ 147**	**$ —**	**$ 17,069**

(In thousands)	Denbury Resources Inc. (Parent and Co-Obligor)	Denbury Onshore, LLC (Issuer and Co-Obligor)	Guarantor Subsidiaries	Eliminations	Denbury Resources Inc. Consolidated
	Year Ended December 31, 2007				
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)	Denbury Resources Inc. (Parent and Co-Obligor)	Denbury Onshore, LLC (Issuer and Co-Obligor)	Guarantor Subsidiaries	Eliminations	Denbury Resources Inc. Consolidated
	Year Ended December 31, 2006				
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**

Note 14. Subsequent Events

On February 2, 2009, we completed our purchase of Hastings Field from Venoco, Inc. for approximately $201 million (see Note 2, "Acquisition and Divestitures – Hastings Acquisition").

On February 13, 2009, we issued $420 million of 9.75% Senior Subordinated Notes due 2016. The notes, which carry a coupon rate of 9.75%, were sold at a discount (92.816% of par), which equates to an effective yield to maturity of approximately 11.25%. The net proceeds of $381.4 million were used to repay most of our outstanding borrowings under our bank credit facility, which increased from the December 31, 2008 balance, primarily associated with the funding of the Hastings acquisitions (see above). In conjunction with this debt offering we amended our bank credit facility in early February 2009, which among other things allowed us to issue these senior subordinated notes.

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 costs incurred below are capitalized interest of $17.6 million in 2008, $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 $5.8 million in 2008, $7.5 million in 2007 and $12.8 million in 2006 (see Note 4, "Asset Retirement Obligations").

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

	Year Ended December 31,		
(In thousands)	2008	2007	2006
Property acquisitions:			
Proved	$ 32,781	$ 15,531	$147,655
Unevaluated	16,129	60,079	205,506
Exploration	5,710	42,726	43,564
Development	575,947	553,315	443,866
Total costs incurred (1)	$630,567	$671,651	$840,591

(1) Capitalized general and administrative costs that directly relate to exploration and development activities were $12.5 million, $10.3 million and $7.6 million for the years ended December 31, 2008, 2007 and 2006, 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)	2008	2007	2006
Oil, natural gas and related product sales	$1,347,010	$952,788	$716,557
Lease operating costs	307,550	230,932	167,271
Production taxes and marketing expenses	63,752	49,091	36,351
Depletion, depreciation and amortization	195,839	177,333	135,269
CO_2 depletion, depreciation and amortization (1)	16,771	9,403	6,281
Write-down of oil and natural gas properties	226,000	—	—
Commodity derivative expense (income)	(200,053)	18,597	(19,828)
Net operating income	737,151	467,432	391,213
Income tax provision	278,643	177,624	151,008
Results of operations from oil and natural gas producing activities	$ 458,508	$289,808	$240,205
Depletion, depreciation and amortization per BOE	$ 12.54	$ 11.60	$ 10.54

(1) Represents an allocation of the depletion, depreciation and amortization of our CO_2 properties and pipelines 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,					
	2008		2007		2006	
	Oil (MBbl)	Gas (MMcf)	Oil (MBbl)	Gas (MMcf)	Oil (MBbl)	Gas (MMcf)
Balance at beginning of year	134,978	358,608	126,185	288,826	106,173	278,367
Revisions of previous estimates	1,348	10,291	(1,601)	1,478	4,351	(22,279)
Revisions due to price changes	(13,320)	(2,915)	1,538	(355)	(2)	(3,116)
Extensions and discoveries	5,037	107,020	6,887	131,451	4,587	65,582
Improved recovery [1]	59,317	—	12,376	—	5,044	—
Production	(11,505)	(32,736)	(10,193)	(35,456)	(8,372)	(30,322)
Acquisition of minerals in place	3,653	79	405	1,935	14,424	643
Sales of minerals in place	(382)	(12,392)	(619)	(29,271)	(20)	(49)
Balance at end of year	179,126	427,955	134,978	358,608	126,185	288,826
Proved Developed Reserves:						
Balance at beginning of year	97,005	226,271	83,703	176,648	59,640	151,681
Balance at end of year	96,746	298,114	97,005	226,271	83,703	176,648

(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,		
	2008	2007	2006
Oil (NYMEX)	$44.60	$95.98	$61.05
Natural Gas (Henry Hub)	5.71	6.80	5.63

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, 2008	2007	2006
Future cash inflows	$ 9,024,224	$14,082,865	$ 8,185,682
Future production costs	(4,039,898)	(3,687,197)	(2,697,206)
Future development costs	(944,716)	(605,638)	(565,488)
Future income taxes	(1,071,939)	(3,283,702)	(1,519,179)
Future net cash flows	2,967,671	6,506,328	3,403,809
10% annual discount for estimated timing of cash flows	(1,552,173)	(2,966,711)	(1,566,468)
Standardized measure of discounted future net cash flows	$ 1,415,498	$ 3,539,617	$ 1,837,341

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, 2008	2007	2006
Beginning of year	$ 3,539,617	$ 1,837,341	$ 2,084,449
Sales of oil and natural gas produced, net of production costs	(975,708)	(672,765)	(512,935)
Net changes in sales prices	(3,296,580)	2,346,008	(552,772)
Extensions and discoveries, less applicable future development and production costs	142,199	344,615	124,787
Improved recovery (1)	338,313	513,840	117,342
Previously estimated development costs incurred	157,321	192,696	124,207
Revisions of previous estimates, including revised estimates of development costs, reserves and rates of production	(321,733)	(214,994)	(324,608)
Accretion of discount	538,512	269,520	321,548
Acquisition of minerals in place	12,764	32,212	182,374
Sales of minerals in place	(53,356)	(121,209)	(222)
Net change in income taxes	1,334,149	(987,647)	273,171
End of year	$ 1,415,498	$ 3,539,617	$ 1,837,341

(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, 2008 (includes 153.8 Bcf of reserves dedicated to three volumetric production payments with Genesis), 5.6 Tcf at December 31, 2007 (includes 182.3 Bcf of reserves dedicated to three volumetric production payments with Genesis), and 5.5 Tcf at December 31, 2006 (includes 210.5 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
2008				
Revenues	$317,255	$417,049	$407,474	$223,924
Expenses (1)	201,446	234,310	156,537	154,535
Net income	73,002	114,053	157,548	43,793
Net income per share:				
Basic	0.30	0.47	0.64	0.18
Diluted	0.29	0.45	0.63	0.18
Cash flow from operations	206,257	164,072	262,442	141,748
Cash flow used for investing activities (2)	(163,688)	(218,384)	(235,605)	(376,982)
Cash flow provided by (used for) financing activities (3)	(28,637)	127,282	1,464	76,993
2007				
Revenues	$174,008	$222,637	$253,336	$323,079
Expenses	146,907	120,033	142,296	169,300
Net income	16,616	62,567	67,988	105,976
Net income per share (4):				
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 (5)	103,404	100,722	68,668	(74,261)

(1) Includes commodity derivative expense (income) of $46.8 million in the first quarter, $58.8 million in the second quarter, ($62.0) million in the third quarter and ($243.6) million in the fourth quarter. We had a full cost ceiling write-down of $226 million in the fourth quarter. In addition, during the third quarter we expensed approximately $30 million associated with a non-refundable deposit on a cancelled acquisition.

(2) In December 2007 and February 2008, we received cash proceeds of $108.6 million and $48.9 million, respectively, for the sale of our Louisiana natural gas assets. (See Note 2, "Acquisitions and Divestitures.")

(3) In the second quarter of 2008, we received $225 million in cash from two financing leases entered into with Genesis (See Note 3, "Related Party Transactions – Genesis.") Also during 2008, we had net borrowings of $75 million in the fourth quarter, and net payments of $39 million in the first quarter, and $111 million in the second quarter, all under our senior bank loan.

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

(5) 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.

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

As of the end of the period covered by this report, an evaluation of the effectiveness of the design and operation of the Company's disclosure controls and procedures (as defined in Rule 13a-15(e) under the Exchange Act) was performed under the supervision and with the participation of the Company's management, including our President and Chief Executive Officer and our Chief Financial Officer. Based on that evaluation, the Company's President and Chief Executive Officer and our Chief Financial Officer concluded that the Company's disclosure controls and procedures were effective as of December 31, 2008 to ensure: that information required to be disclosed in the reports it files and submits under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms; and that information that is required to be disclosed under the Exchange Act is accumulated and communicated to the Company's management, including our President and Chief Executive Officer and our Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

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 2008, 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 15d-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, 2008, 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 13, 2009, ("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 55. 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, 2006 (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 (incorporated by reference as Exhibit 3(c) of our Form 10-K filed February 29, 2008).
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 $420 million of 9.75% Senior Subordinated Notes due 2016 among Denbury Resources Inc., certain of its subsidiaries, and The Bank of New York Mellon Trust Company, N.A., as Trustee (incorporated by reference as Exhibit 4.1 of our Form 8-K filed February 17, 2009).
4(b)	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(c)	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) of our Registration Statement No. 333-105233-04 on Form S-4, filed May 14, 2003).
4(d)	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(e)	First Supplemental Indenture for $150 million of 7.5% Senior Subordinated Notes due 2015, dated April 3, 2008, 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, 2007 (incorporated by reference as Exhibit 10.1 of our Form 8-K filed September 19, 2006).
10(b)	First Amendment to Sixth 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, 2008 (incorporated by reference as Exhibit 10 of our Form 10-Q for the quarter ended March 31, 2007).
10(c)	Second Amendment to Sixth 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 dated as of October 7, 2008 (incorporated by reference as Exhibit 10(a) of our Form 10-Q for the quarter ended September 30, 2008).
10(d)*	Third Amendment to Sixth 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 dated as of February 6, 2009.

Exhibit No.	Exhibit
10(e)	Amendment for Increased Borrowing Base from $500 million to $1.0 billion 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 28, 2008 (incorporated by reference as Exhibit 10(a) of our Form 10-Q for the quarter ended March 31, 2008).
10(f)	Option Agreement to Purchase Hasting Field By and Between TexCal Energy South Texas, L.P. and Denbury Onshore, LLC dated November 1, 2006 (incorporated by reference as Exhibit 10(b) of our Form 10-Q for the quarter ended September 30, 2008).
10(g)	First Amendment to Option Agreement, dated as of August 29, 2008, by and between TexCal Energy South Texas, L.P. and Denbury Onshore, LLC (incorporated by reference as Exhibit 10(c) of our Form 10-Q for the quarter ended September 30, 2008).
10(h)	Pipeline Financing Lease Agreement by and between Genesis NEJD Pipeline, LLC as Lessor, and Denbury Onshore, LLC, as Lessee, dated May 30, 2008 (incorporated by reference as Exhibit 99.1 of our Form 8-K filed on June 5, 2008).
10(i)	Transportation Services Agreement by and between Genesis Free State Pipeline, LLC and Denbury Onshore, LLC, dated May 30, 2008 (incorporated by reference as Exhibit 99.2 of our Form 8-K filed on June 5, 2008).
10(j) **	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(k) **	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(l) **	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(m) **	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, 2006).
10(n)* **	Denbury Resources Severance Protection Plan, as amended and restated effective December 30, 2008.
10(o)* **	Denbury Resources Inc. 2004 Omnibus Stock and Incentive Plan, as amended and restated effective December 30, 2008.
10(p) **	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, 2006).
10(q) **	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, 2006).
10(r) **	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 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, 2006).
10(s) **	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, 2006).
10(t)**	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, 2008).
10(u)**	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(v)**	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).

Exhibit No.	Exhibit
10(w)**	2007 Form of restricted stock award to new directors that vest 20% per annum (incorporated by reference as Exhibit 10(z) of our Form 10-K for the year ended December 31, 2007).
10(x)**	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(y)**	2008 Form of restricted stock award to certain officers that cliff vests on March 31, 2011 (incorporated by reference as Exhibit 10(b) of our Form 10-Q for the first quarter ended March 31, 2008).
10(z)**	2008 Form of restricted stock award without change of control vesting to certain officers that cliff vests on March 31, 2011 (incorporated by reference as Exhibit 10(c) of our Form 10-Q for the first quarter ended March 31, 2008).
10(aa)**	2008 Form of performance share awards to certain officers with change of control vesting (incorporated by reference as Exhibit 10(d) of our Form 10-Q for the first quarter ended March 31, 2008).
10(bb)**	2008 Form of performance share awards to certain officers without change of control vesting (incorporated by reference as Exhibit 10(e) of our Form 10-Q for the first quarter ended March 31, 2008).
10(cc) **	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(dd)**	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(ee)**	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).
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, 2008, on oil and gas reserves (SEC Case) dated February 6, 2009.

* 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 27, 2009
Phil Rykhoek
Sr. Vice President and Chief Financial Officer

/s/ Mark C. Allen February 27, 2009
Mark C. Allen
Vice President and Chief Accounting 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 27, 2009
Gareth Roberts
Director, President and Chief Executive Officer
(Principal Executive Officer)

/s/ Phil Rykhoek February 27, 2009
Phil Rykhoek
Sr. Vice President and Chief Financial Officer
(Principal Financial Officer)

/s/ Mark C. Allen February 27, 2009
Mark C. Allen
Vice President and Chief Accounting Officer
(Principal Accounting Officer)

/s/ Ron Greene February 27, 2009
Ron Greene
Director

/s/ David I. Heather February 27, 2009
David I. Heather
Director

/s/ Randy Stein February 27, 2009
Randy Stein
Director

/s/ Wieland Wettstein February 27, 2009
Wieland Wettstein
Director

/s/ Greg McMichael February 27, 2009
Greg McMichael
Director

/s/ Michael Beatty February 27, 2009
Michael Beatty
Director

/s/ Michael Decker February 27, 2009
Michael Decker
Director

Exhibit 21

LIST OF SUBSIDIARIES

Name of Subsidiary	Jurisdiction of Organization
Denbury Gathering & Marketing, Inc.	Delaware
Genesis Energy, LLC	Delaware
Denbury Operating Company	Delaware
Denbury Onshore, L.L.C.	Delaware
Denbury Marine, L.L.C.	Louisiana
Tuscaloosa Royalty Fund L.L.C.	Delaware
Denbury New Frontiers, L.L.C.	Delaware
Denbury Green Pipeline – Texas, LLC	Delaware

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, 2009 relating to the consolidated financial statements and the effectiveness of internal control over financial reporting, which appears in this Form 10-K.

/s/ PricewaterhouseCoopers LLP

Dallas, Texas
February 28, 2009

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 March 2, 2009

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 March 2, 2009

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, 2008 (the Report) of Denbury Resources Inc. (Denbury) as filed with the Securities and Exchange Commission on March 2, 2009, 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 March 2, 2009

Gareth Roberts
President and Chief Executive Officer

/s/ Phil Rykhoek March 2, 2009

Phil Rykhoek
Sr. Vice President and Chief Financial Officer

Stock Exchange Listing
NYSE: DNR

Corporate Headquarters
Denbury Resources Inc.
5100 Tennyson Pkwy, Ste. 1200
Plano, Texas 75024
(972) 673-2000
www.denbury.com

Stock Transfer Agent & Registrar
For questions concerning stock certificates, transfer procedures or address changes, please contact:

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59 Maiden Lane
Plaza Level
New York, NY 10038
(800) 937-5449
Email: info@amstock.com
www.amstock.com

Investor Inquiries
Phil Rykhoek
Senior Vice President & Chief Financial Officer
(972) 673-2050

Laurie Burkes
Investor Relations Manager
(972) 673-2166
Email: ir@denbury.com

Financial Information Requests
To receive additional copies of the Annual Report on Form 10-K as filed with the SEC or to obtain other Denbury public documents, please contact:

Denbury Resources Inc.
Investor Relations
5100 Tennyson Pkwy, Ste. 1200
Plano, Texas 75024
(972) 673-2009
Email: ir@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.

Note that these documents are also available on our website at www.denbury.com.

Annual Certifications
In 2008, 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.

Annual Meeting
The Annual Meeting of Shareholders will be held on Wednesday, May 13, 2009, at 3:00 p.m. CDT at the Marriott at Legacy Town Center, located at 7120 Dallas Parkway, Plano, Texas 75024. A proxy statement and notice of the Annual Meeting have been sent to shareholders of record as of March 31, 2009.

Legal Counsel
Baker & Hostetler LLP

Bankers
JP Morgan (Agent)

Auditors
PricewaterhouseCoopers LLP

Evaluation Engineers
DeGolyer & MacNaughton

Design by Eisenberg And Associates Illustrations by Jack Unruh Printing by ColorDynamics

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