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

2010 FORM 10-K

(Mark One)

☑ **Annual report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934**

For the fiscal year ended December 31, 2010

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 *(State or other jurisdiction of incorporation or organization)*	**20-0467835** *(I.R.S. Employer Identification No.)*
5320 Legacy Drive, Plano, TX *(Address of principal executive offices)*	**75024** *(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 ☑ No ☐

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

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

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

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K 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 ☑	Accelerated filer ☐	Non-accelerated filer ☐ (Do not check if a smaller reporting company)	Smaller reporting company ☐

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

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 $5,097,619,350

The number of shares outstanding of the registrant's Common Stock as of January 31, 2011, was 401,021,995.

DOCUMENTS INCORPORATED BY REFERENCE

Document:	**Incorporated as to:**
1. Notice and Proxy Statement for the Annual Meeting of Shareholders to be held May 18, 2011.	1. Part III, Items 10, 11, 12, 13, 14

Denbury Resources Inc.
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Denbury Resources Inc.

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 at a temperature base of 60 degrees Fahrenheit (°F) and at the legal pressure base (14.65 to 15.025 pounds per square inch absolute) of the state or area in which the reserves are located.
Mcf/d	One thousand cubic feet of natural gas or CO_2 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.
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 future production, development and abandonment costs, and before income taxes, discounted to a present value using an annual discount rate of 10%. PV-10 Values calculated as of December 31, 2010 were prepared using average hydrocarbon prices equal to the unweighted arithmetic average of hydrocarbon prices on the first day of each month within a 12-month period ended December 31, 2010. PV-10 Values calculated prior to December 31, 2010 were prepared using prices and costs in effect at the determination date. PV-10 Value is a non-GAAP measure and its use is further discussed in footnote 4 to the reserves table included in Item 1. *Estimated Net Quantities of Proved Oil and Natural Gas Reserves and Present Value of Estimated Future Net Revenues*.
Probable Reserves*	Are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered.
Proved Developed Reserves*	Reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.
Proved Reserves*	The estimated quantities of crude oil, natural gas and natural gas liquids that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.
Proved Undeveloped Reserves*	Reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required.
Tcf	One trillion cubic feet of natural gas or CO_2.

* This definition is an abbreviated version of the complete definition as defined by the SEC in Rule 4-10(a) of Regulation S-X. For the complete definition see http://ecfr.gpoaccess.gov/cgi/t/text/text-idx?c=ecfr&rgn=div5&view=text&node=17:2.0.1.1.8&idno=17#17:2.0.1.1.8.0.21.42.

Item 1. Business

Denbury Resources Inc.

GENERAL

We are a domestic independent oil and natural gas company with 397.9 million BOE of proved reserves as of December 31, 2010, of which 85% is oil. We are the largest oil and natural gas producer in Mississippi and Montana, own the largest reserves of CO_2 used for tertiary oil recovery east of the Mississippi River, and hold significant operating acreage in the Rocky Mountain and Gulf Coast regions. Our goal is to increase the value of acquired properties through a combination of exploitation, drilling and proven engineering extraction practices, with our most significant emphasis relating to tertiary recovery operations.

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

- focus in specific regions where we either have, or believe we can create, a competitive advantage as a result of our ownership or use of CO_2 reserves, oil fields and CO_2 infrastructure;
- 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.

Denbury became a Canadian public company in 1992 through a reverse merger with a Canadian company which was originally incorporated in Canada in 1951. In 1999, we moved our corporate domicile from Canada to the United States as a Delaware corporation and have been publicly traded in the United States since 1995 and on the New York Stock Exchange since May 1997.

Our corporate headquarters is located at 5320 Legacy Drive, Plano, Texas 75024, and our phone number is 972-673-2000. At December 31, 2010, we had 1,195 employees, 660 of whom were employed in field operations or at the field offices. 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 SEC also maintains a website, www.sec.gov, which contains reports, proxy and information statements and other information filed by Denbury.

MERGER WITH ENCORE ACQUISITION COMPANY

On March 9, 2010, we acquired Encore Acquisition Company ("Encore") pursuant to an Agreement and Plan of Merger (the "Encore Merger Agreement") entered into with Encore on October 31, 2009. The Encore Merger Agreement provided for a stock and cash transaction valued at approximately $4.8 billion at the acquisition date, including the assumption of Encore debt and the value of the noncontrolling interest in Encore Energy Partners LP ("ENP"). Under the Encore Merger Agreement, Encore was merged with and into Denbury (the "Encore Merger"), with Denbury surviving the Encore Merger.

As part of the Encore Merger, we issued approximately 135.2 million shares of our common stock and paid approximately $833.9 million in cash to Encore stockholders. The Denbury shares issued to Encore stockholders represented approximately 34% of our common stock issued and outstanding immediately after the Encore Merger. The total fair value of the Denbury common stock issued to Encore stockholders pursuant to the Encore Merger was approximately $2.1 billion based upon Denbury's closing price of $15.43 per share on March 9, 2010. See Note 2, *Acquisitions and Divestitures*, to the Consolidated Financial Statements for additional information.

The Encore Merger was financed through a combination of issuing \$1.0 billion of 8¼% Senior Subordinated Notes due 2020 (the "2020 Notes"), which we issued on February 10, 2010; borrowings under a new \$1.6 billion revolving credit agreement (the "Credit Agreement"), entered into on March 9, 2010; and the assumption of Encore's remaining outstanding senior subordinated notes.

Pursuant to our stated intent, at the time of acquisition, of divesting certain non-strategic legacy Encore properties, certain oil and gas properties in the Permian Basin, Mid-continent area and East Texas Basin (collectively, the "Southern Assets") were sold in May 2010. We subsequently divested of our production and acreage in the Cleveland Sand Play and Haynesville Play during 2010 as well. In addition to the property sales, we sold our ownership interests in ENP on December 31, 2010. Collectively, we received approximately \$1.5 billion in total consideration from these divestitures in 2010, excluding the bank debt of ENP that was assumed by the purchaser in the sale. See Note 2, *Acquisitions and Divestitures*, to the Consolidated Financial Statements for further discussion of these transactions.

OIL AND NATURAL GAS OPERATIONS

Summary. Our oil and natural gas properties are concentrated in the Gulf Coast and Rocky Mountain regions in the United States. Currently our properties with proved and producing reserves in the Gulf Coast region are situated in Mississippi, Texas, Louisiana and Alabama, and in the Rocky Mountain region are primarily situated in Montana, North Dakota, Utah, and Wyoming. Our primary focus is using CO_2 in enhanced oil recovery ("EOR"), which we have been doing actively for over eleven years in our Gulf Coast region. EOR, which we also refer to as "improved oil recovery" or "tertiary recovery" (as opposed to primary and secondary recovery) is a term used to represent techniques for extracting incremental oil out of existing oilfields. We acquired Encore in 2010 with the intent to employ our tertiary recovery strategy using CO_2 throughout the Rocky Mountain region. As part of the Encore Merger, we obtained a significant acreage position in the Bakken play in North Dakota, one of the most significant oil plays in North America. We believe that our current properties provide us significant growth potential for the next ten years in both our tertiary operations in the Gulf Coast and Rocky Mountain regions and in our Bakken play.

Our Gulf Coast tertiary operations are driven by CO_2 produced from our natural source at Jackson Dome, Mississippi, which is transported to our Gulf Coast tertiary fields through pipelines that we control, the most significant of which are the NEJD and Green Pipelines. In the Rocky Mountain region, we are just beginning our tertiary operations, which include securing sufficient Rocky Mountain CO_2 supplies and constructing pipelines in order to transport that CO_2 to our oil fields. Each of our significant development areas and planned activities is discussed in more detail below.

The following table provides a summary by field and region of our proved oil and natural gas reserves and associated value of those reserves as of December 31, 2010, and sets forth the average daily production and net revenue interest ("NRI") for 2010:

	Proved Reserves as of December 31, 2010(1)					2010 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
Gulf Coast Region								
Tertiary Oil Fields								
Phase 1								
Brookhaven	14,833	—	14,833	3.7%	$ 470,969	3,429	—	81.2%
McComb Area	11,637		11,637	2.9%	263,846	1,764	—	79.6%
Mallalieu	8,823	—	8,823	2.2%	213,919	3,377	—	77.7%
Other	7,415	—	7,415	1.9%	185,459	3,780	—	70.1%
Phase 2								
Heidelberg	31,850	—	31,850	8.0%	897,942	2,454	—	85.2%
Eucutta	9,374	—	9,374	2.4%	259,541	3,495	—	83.6%
Soso	6,861	—	6,861	1.7%	153,781	3,065	—	77.2%
Martinville	1,129	—	1,129	0.3%	13,771	720	—	77.8%
Phase 3 (Tinsley)(3)	33,773	—	33,773	8.4%	972,532	5,584	—	79.9%
Phase 4 (Cranfield)	8,245	—	8,245	2.1%	169,392	911	—	78.1%
Phase 5 (Delhi)	29,372	—	29,372	7.4%	595,010	483	—	76.5%
Total Tertiary Oil Fields	163,312	—	163,312	41.0%	4,196,162	29,062	—	78.9%
Non-Tertiary Fields								
Conroe	16,480	15,080	18,993	4.8%	245,229	2,292	2,918	83.2%
Heidelberg	10,318	53,173	19,180	4.8%	283,988	2,839	11,221	77.0%
Citronelle	7,934	—	7,934	2.0%	99,236	1,036	—	63.6%
Hastings	8,297	—	8,297	2.1%	166,728	1,730	—	80.7%
Other	9,122	34,143	14,812	3.7%	248,270	2,442	12,095	19.6%
Total Non-Tertiary Fields	52,151	102,396	69,216	17.4%	1,043,451	10,339	26,234	44.1%
Total Gulf Coast Region	215,463	102,396	232,528	58.4%	5,239,613	39,401	26,234	64.8%
Rocky Mountain Region								
Non-Tertiary Fields								
Cedar Creek Anticline(4)	64,579	12,880	66,726	16.8%	1,076,816	7,893	218	84.6%
Bakken	39,712	42,031	46,718	11.7%	556,304	3,383	2,648	31.9%
Bell Creek	2,143	—	2,143	0.5%	57,002	802	—	91.8%
Paradox	4,931	913	5,083	1.3%	85,324	557	147	14.1%
Other Williston	11,448	199,673	44,727	11.3%	277,285	2,169	1,160	41.9%
Total Rocky Mountain Region	122,813	255,497	165,397	41.6%	2,052,731	14,804	4,173	49.3%
Total Properties Held at December 31, 2010	338,276	357,893	397,925	100.0%	7,292,344	54,205	30,407	60.8%
Disposed Properties								
Legacy Encore	—	—	—	—	—	759	34,782	
ENP	—	—	—	—	—	4,953	12,869	
Total Disposed Properties	—	—	—	—	—	5,712	47,651	
Company Total	338,276	357,893	397,925	100.0%	$ 7,292,344	59,917	78,058	

(1) The reserves were prepared in accordance with the guidelines of Financial Accounting Standards Board Codification ("FASC") Topic 932 *Extractive Industries — Oil and Gas* using the average first-day-of-the-month prices for each month during 2010 which for NYMEX oil was a price of $79.43 per barrel adjusted to prices received by field and for natural gas was a Henry Hub cash price of $4.40 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 the FASC Topic 932. The Standardized Measure was $4.9 billion at December 31, 2010. A comparison of PV-10 Value to the Standardized Measure is included in Note 16, *Supplemental Oil and Gas Disclosures*, to the Consolidated Financial Statements as well as further information regarding our use of this non-GAAP measure.

(3) Tinsley Field, which had initial tertiary oil production response from CO_2 injections during the first quarter of 2008, had an average sales price per unit of oil of $78.72 per barrel in 2010, $63.09 per barrel in 2009 and $96.36 per barrel in 2008. Tinsley Field's average production cost (excluding ad valorem and severance taxes) was $17.97 per barrel in 2010, $18.93 per barrel in 2009 and $33.01 per barrel in 2008.

(4) Cedar Creek Anticline, which we acquired through the Encore Merger in March 2010, had an average sales price per barrel of oil of $73.59 and an average sales price of $2.12 per Mcf of natural gas in 2010. Cedar Creek Anticline's average production cost (excluding ad valorem and severance taxes) was $13.78 per BOE in 2010.

Enhanced Oil Recovery Overview. CO_2 used in EOR is one of the most efficient tertiary recovery mechanisms for producing crude oil. The CO_2 acts somewhat like a solvent, mixing with the oil and ultimately freeing the oil from the formation as the CO_2 passes through the rock. CO_2 tertiary floods are unique because they require large volumes of CO_2. To our knowledge, the location of large quantities of natural CO_2 in the United States is limited to a few geological basins. Due to the current limited supplies of CO_2 and pipelines to deliver the CO_2, only 6% or approximately 280,000 Bbls/d of United States domestic oil production is derived from CO_2 EOR projects.

Since we acquired our first CO_2 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 the production of CO_2, transportation of CO_2 and tertiary recovery operations. Our tertiary operations have grown to the point that approximately 41% of our December 31, 2010, proved reserves are proved tertiary oil reserves; almost 49% of our forecasted 2011 production is expected to come from tertiary oil operations (on a BOE basis); and approximately 65% of our 2011 planned capital expenditures are related to our tertiary operations. We particularly like this play as (1) it has a lower risk, as we are working with oil fields that have significant historical production and data, (2) it provides a reasonable rate of return at relatively low oil prices (we estimate our economic break-even point on a per-barrel basis before corporate overhead and expenses on these projects at current oil prices is in the mid-to-upper $30 per barrel range, depending on the specific field and area), and (3) we have limited competition for this type of activity in our geographic regions. Our Gulf Coast region is more fully developed, as we have been conducting EOR operations in this area for over 11 years. We recently acquired assets in the Rocky Mountain region as part of the Encore Merger, and as such, we have significantly fewer oil fields, CO_2 sources and CO_2 pipeline infrastructure in this region, although we are pursuing the addition of all three. In the Gulf Coast region, we own the only known significant natural sources of CO_2 in the area, and these large volumes of CO_2 have driven the play in this area and have been a significant contributor to our overall positive results. We have more limited CO_2 volumes in the Rocky Mountain region, but now have two sources discussed in more detail below. 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 ultimately sequester CO_2.

While enhanced oil recovery projects utilizing CO_2 may not be considered a new technology, we apply several concepts we have learned over the years to fields to improve and increase sweep efficiency within the reservoirs, which include: (1) well evaluation methods, $_2$ new completion techniques, (3) varied operating equipment and operating conditions, and (4) application of intense reservoir management and production techniques. 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 and the ownership of the CO_2 reserves, we began to transition our capital spending and acquisition efforts to focus a greater percentage on CO_2 EOR and over time transformed our strategy to where we focus almost exclusively on CO_2 EOR projects, with the exception of the Bakken properties. Today, our asset base essentially consists of tertiary oil projects, future tertiary oil projects and the Bakken shale play.

At year-end 2010, the proved oil reserves in our tertiary recovery oil fields had an estimated PV-10 Value of approximately $4.2 billion, using 12-month first-day-of-the-month unweighted average NYMEX pricing of $79.43 per barrel. In addition, there are significant probable and possible reserves at several other fields for which tertiary operations are under way or planned, as well as in the Bakken shale area.

Gulf Coast Region

CO_2 Assets

Jackson Dome. Our CO_2 source, Jackson Dome, located near Jackson, Mississippi, was discovered during the 1970s while being explored for hydrocarbons. This significant and relatively pure source of CO_2 (98% CO_2) is the only known significant collection of CO_2 in the United States east of the Mississippi River.

We acquired this asset in February 2001 for $42 million, a purchase that gave us ownership and control of the NEJD 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 24 additional CO_2-producing wells, significantly increasing our estimated proved Gulf Coast CO_2 reserves from approximately 800 Bcf at the time of acquisition to approximately 7.1 Tcf as of December 31, 2010. These proved reserves are nearly sufficient to provide all of the CO_2 for our existing and currently planned phases of operations in the Gulf Coast, including several fields we own and plan to flood which do not have proven tertiary reserves. The CO_2 reserve estimates are based on 100% ownership of the CO_2 reserves, of which Denbury's net ownership (net revenue interest) is approximately 5.6 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 and probable 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

In addition to the proved reserves, we estimate that we have an additional 2.8 Tcf of probable CO_2 reserves at Jackson Dome. The majority of our probable reserves at Jackson Dome are located in structures that have been drilled and tested in the area but are not currently capable of producing due to the original well being plugged, located in fault blocks that are immediately adjacent to fault blocks with proved reserves, undrilled structures where we have sufficient subsurface data, seismic and geophysical attributes that provide a high degree of certainty that CO_2 is present, and reserves associated with increasing the ultimate recovery factor from our existing reservoirs with proved reserves. At the present time there have been 13 structures drilled within the Jackson Dome area and only one has not been productive of CO_2. This success rate, coupled with our seismic control across the undrilled structures, provides us with a high degree of certainty that CO_2 will be developed.

Although our current proved and potential CO_2 reserves are quite large, in order to continue our tertiary development of oil fields in the Gulf Coast region, incremental deliverability of CO_2 is required. In order to obtain additional CO_2 deliverability, we have continued our efforts by evaluating our 359 square miles of 3D seismic that we have recorded over the past several years. We anticipate drilling four wells during 2011, two of which are planned development wells and are intended to increase productive capacity, and two of which are pursuing additional reserves as well as increased flow rate. During 2010, we drilled and completed three additional CO_2 wells, two at Gluckstadt Field and one at our new field discovery, DRI Dock Field. The 2010 wells added approximately 1.0 Tcf of proved CO_2 reserves (311 Bcf at DRI Dock Field and 682 Bcf at Gluckstadt Field) and increased our estimated Jackson Dome total CO_2 production and transportation capacity to approximately 1.1 Bcf/d. In addition to our drilling at Jackson Dome, we continue to expand our processing and dehydration capacities, and we continue to install pipelines and/or pumping stations necessary to transport the CO_2 through our controlled pipeline network.

During 2010, we sold an average of 111 MMcf/d of CO_2 to commercial users, and we used an average of 742 MMcf/d for our tertiary activities. We are continuing to increase our CO_2 production, which averaged 974 MMcf/d during the fourth quarter of 2010, a 22% increase over the fourth quarter of 2009 CO_2 production levels. We estimate that our planned 2011 tertiary operations will not require any significant additional deliverability through 2011, although certain additional facilities and flow lines are needed to be able to deliver the CO_2 to the appropriate oil field.

Anthropogenic CO_2 Sources. In addition to our natural source of CO_2, we have entered into long-term contracts to purchase man-made CO_2 from nine proposed plants that will emit large volumes of CO_2, four of which are in the Gulf Coast region, four in the Midwest region (Illinois, Indiana, and Kentucky) and one in the Rocky Mountain region. The Midwest purchases are conditioned on both the specific plant being constructed and Denbury contracting enough volumes of CO_2 for purchase in the general area of our proposed Midwest pipeline system, such that an acceptable economic rate-of-return on the CO_2 pipeline will be achieved. At the present time, two of the Midwest facilities have been unable to meet a critical contractual obligation and thus Denbury is evaluating these two projects to determine if we should extend the time for the facility to meet the contractual obligation. If all nine of these plants were to be built, these CO_2 sources are currently anticipated to provide us with aggregate CO_2 volumes of 1.2 Bcf/d to 2.0 Bcf/d, although the earliest source of this man-made CO_2 is not expected to be available to us until 2014. Although these plants have all been delayed due to economic conditions, over the last six to nine months several of the projects appear to be making progress, but there is still some doubt as to whether they will be constructed at all. Several of these plants are in negotiations for federal support through grants and loan guarantees, which if secured, could increase the possibility that certain plants will be ultimately constructed.

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 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 nine plants are built, the aggregate purchase obligation for this CO_2 would be around $320 million per year, assuming an $85 per barrel NYMEX 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 other plants under consideration that could provide CO_2 to us that would either supplement or replace some of the CO_2 volumes from the nine proposed plants for which we currently have CO_2 output purchase contracts. We have ongoing discussions with several of these other potential sources.

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. Since 2001 we have constructed an additional 600 miles of CO_2 pipelines to deliver CO_2 to our fields throughout the Gulf Coast. As of December 31, we own or control approximately 846 miles of CO_2 pipelines. The major pipelines are the Free State Pipeline (90 miles), our Delta Pipeline (110 miles), and the Green Pipeline (325 miles) which was completed during 2010.

The Green Pipeline is the single largest capital project undertaken by the Company since we were formed. During December 2010 we completed the construction and loading of the remaining segment of the Green Pipeline and began injections at Hastings Field, located near Houston, Texas. We began the planning and development of the Green Pipeline in 2006. After four years and expenditure of approximately $884 million, excluding capitalized interest, we now have the ability to deliver CO_2 to oil fields along the Gulf Coast from Baton Rouge, Louisiana to Alvin, Texas. At the present time all CO_2 flowing in the Green Pipeline is delivered from Jackson Dome, but we expect to transport and deliver both natural and anthropogenic CO_2 volumes in the future as the anthropogenic CO_2 volumes are captured and delivered to the Green Pipeline.

Tertiary Properties

Phase 1. Phase 1 includes several fields along our 183-mile NEJD CO_2 pipeline, which runs through southwest Mississippi and into Louisiana. This phase includes our initial CO_2 field, Little Creek, as well as five other areas (Mallalieu, McComb, Smithdale, Brookhaven and Lockhart Crossing). Although the fields are developed, we continue to monitor and modify the floods to increase the sweep efficiency and ultimate recovery of oil from these fields. McComb, Brookhaven and Lockhart Crossing have additional areas and patterns to be developed, the timing of which is largely dictated by the current CO_2 recycle facility at each field. Several of the Phase 1 fields have been producing for some time, and they accounted for approximately 42% of our total 2010 CO_2 EOR production.

Phase 1 is our most mature phase, and most of the development work is complete in this area. As these fields have matured, we have experimented with a variety of techniques to maximize the recovery of oil from these reservoirs, gathering knowledge that will help us in all areas of our EOR business. All of the techniques we have employed are intended to improve the overall sweep efficiency in the formation. Due to the lower viscosity of CO_2 when compared to oil, CO_2 will tend to follow the path of least resistance. This may result in high producing gas-oil ratios ("GORs") sooner than anticipated. We have experimented with various techniques such as cement squeezes (injection and producing wells), chemical squeezes, perforation design and operating pressure controls. Each one of these processes has had some success and will be utilized in the future as appropriate. Our best results to date have been utilizing water-alternating gas ("WAG") injections, where water is substituted for the CO_2 for a given volume and then CO_2 is injected behind the water. We have seen multiple patterns respond to the WAG cycles, and we continue to institute the WAG cycles in new patterns as the need arises. The WAG process is currently being used to increase the recovery of oil at fields like Little Creek, our most mature field, where we have already recovered a majority of the forecasted oil, and in fields like Brookhaven, where we have seen certain areas produce high GORs sooner than anticipated. The techniques proven successful in Phase 1 will ultimately be transferrable to our other phases.

From inception through December 31, 2010, we have recovered all our costs in Phase 1, with excess net cash flow (revenue less operating expenses and capital expenditures, including the acquisition costs) from this Phase of $770.0 million. As of December 31, 2010, the estimated PV-10 Value of our Phase 1 properties was $1.1 billion.

Phase 2. Phase 2 includes Eucutta, Soso and Martinville Fields, where there has been tertiary oil production for several years, and Heidelberg Field, where we started injecting CO_2 in December 2008.

Unlike the majority of fields in our other Phases, fields in Phase 2 typically contain multiple reservoirs that are amenable to CO_2 EOR. At the present time Eucutta and Martinville Fields are essentially fully developed in the reservoir(s) under flood, but development of additional reservoirs will occur in future years. Soso Field has a number of reservoirs to be CO_2 flooded, and at the present time, two reservoirs are actively under flood due to no one reservoir containing the majority of the reserves expected to be recovered. Due to the limited number of wellbores in the field, the wells were divided between the two reservoirs during development. Therefore, development of the remaining portions of the each reservoir will occur when the other reservoir ceases utilizing the wellbore. All three fields were initiated in 2006 following completion of the Free State Pipeline.

Eucutta, Soso and Martinville fields are essentially fully developed in the reservoir(s) under flood at the present time. All three fields were initiated in 2006 following completion of the Free State Pipeline. Much like the initial Phase 1 fields, we continue to monitor and modify various patterns, operating conditions and CO_2 injections in an attempt to improve the oil recovery from these fields. Based on the performance to date, we expect to recover at least 17% of the original oil in place at these three fields with EOR.

During 2008, we began CO_2 injections at Heidelberg Field as our 12th producing CO_2 EOR field. Construction of the CO_2 facility, connecting pipeline and well work commenced during 2008, with our first CO_2 injections beginning in December 2008. Our first tertiary oil production response occurred during May 2009. During 2010, we added 19 new injection patterns and expanded the central processing facility. During the fourth quarter of 2010, EOR production at Heidelberg Field averaged 3,422 Bbls/d. We have completed the development of our West Heidelberg Unit and will begin development of our East Heidelberg Unit in 2011, which is larger and contains more oil-in-place than the west side. We have budgeted $49.4 million in 2011 to begin developing East Heidelberg CO_2 EOR operations in 2011.

In the Phase 2 area, we have also worked to determine the economic viability of CO_2 flooding of reservoirs that contain heavier oils than those contained in our current operations or that have extremely strong water drives.

The first "heavy oil" reservoir we have developed is the Martinville Field Wash Fred 8,500' reservoir. The Wash Fred formation contains a low oil gravity (thick oil), 15o 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 8,500' have had lower recoveries due to the low oil gravities and strong water drives, which do not sweep the oil efficiently. We had experimented with this reservoir since 2006 but did not have much success until late 2009, when an offset producing well began responding to CO_2 injections.

During 2010, production from the Wash Fred 8,500' increased from 182 Bbls/d in 2009 to 307 Bbls/d during the fourth quarter of 2010. We plan on reactivating one more well in 2011 and increasing CO_2 injections into this reservoir over time. The ability to produce and process this heavy crude has been difficult, but if we can economically and satisfactorily resolve these issues, this field could provide the impetus to look at other heavy oil reservoirs and fields that we have not previously considered.

Many of the fields in Phase 2 have multiple reservoirs. We plan to develop these additional reservoirs in the future when well bores become available (the well bores are currently in use by another reservoir) or when the recycle facilities have available capacity. From inception through December 31, 2010, we had not yet recovered our costs in Phase 2, with net negative cash flow (revenue less operating expenses and capital expenditures, including the acquisition cost) of $101.4 million. As of December 31, 2010, the estimated PV-10 Value of our Phase 2 properties was $1.3 billion.

Phase 3 (Tinsley). Phase 3, 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, although there is additional potential in the Perry sandstone and other smaller reservoirs as well. We initiated limited CO_2 injections in January 2007 through a previously existing 8-inch pipeline, but replaced the use of the 8-inch line in 2008 with the completion of the 24-inch Delta Pipeline to Tinsley. We had our first tertiary oil production from Tinsley Field in April 2008. Due to the excellent performance of Tinsley, we have continued to invest $35 to $60 million per year adding patterns in the field. To date we have completed the development of the West Fault Block, and by the end of 2011 we will have the vast majority of the East Fault Block developed. Following completion of the East Fault Block, the Northern Fault Block will be developed in 2012 and 2013, all in the Woodruff reservoir. The Perry sandstone and the other smaller reservoirs will be developed after the Woodruff. Additional proved reserves (2.0 MMBbls) were added at Tinsley Field in the West Fault Block during 2010 as the performance has been excellent. The additional reserves were added by increasing the recovery factor from 13% to 17% in the West Fault Block. During the fourth quarter of 2010, the average oil production was 6,614 Bbls/d. Tinsley Field produced an additional 291 Bbls/d from non-CO_2 operations during the fourth quarter of 2010.

From inception through December 31, 2010, 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 $139.9 million. As of December 31, 2010, the estimated PV-10 Value of our Phase 3 property was $972.5 million.

Phase 4 (Cranfield). Phase 4 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. Phase 4 also includes Lake St. John Field, a project currently scheduled to commence during 2012 or 2013 following a proposed crossing of the Mississippi River with our CO_2 pipeline. Both Phase 4 fields are located near the Mississippi/Louisiana border, near Natchez, Mississippi.

During 2008, we began development of Cranfield, with the drilling or re-entry of 11 CO_2 injectors and 11 producers and reconditioned the natural gas pipeline that we purchased, converting it to CO_2 service. We commenced injections into the Lower Tuscaloosa reservoir in the third quarter of 2008 and had our first tertiary oil production in the first quarter of 2009. Development of Cranfield will continue over the next several years with the addition of three to four patterns each year. During 2011, we plan to spend approximately $7.1 million for the drilling of an additional producer and CO_2 injection well, along with three re-entries of existing wells. We are participating with the Bureau of Economic Geology ("BEG") at the University of Texas as they study CO_2 injection and sequestration at Cranfield, to better define and understand the movement of CO_2 through the Lower Tuscaloosa reservoir.

From inception through December 31, 2010, we had not yet recovered our investment in this field, with net negative cash flow (revenue less operating expenses and capital expenditures, including the acquisition cost) from Cranfield of $109.1 million. As of December 31, 2010, the estimated PV-10 Value of our Phase 4 property was $169.4 million.

Phase 5 (Delhi). Phase 5 is Delhi Field, a Louisiana field located southwest of Tinsley Field and east of Monroe, Louisiana. During May 2006, we purchased Delhi for $50 million, plus a 25% reversionary interest to the seller after we achieve $200 million in net operating income. We began well work development in 2008 and drilled or recompleted additional wells in 2009 and constructed the initial phase of the CO_2 recycle and processing facility. We began delivering CO_2 to the field in the fourth quarter of 2009 via the Delta Pipeline (Tinsley to Delhi). First tertiary production occurred at Delhi field in March 2010. Based on this initial response we were able to book our initial proved reserves in the field, 29.4 MMbbls, which is an estimated 13% recovery factor, although we expect the ultimate recovery will increase over time to 17% of the original oil in place. Early performance data is indicating that Delhi field is acting as a miscible flood instead of a near-miscible flood as we originally modeled, which if true and if it continues, should positively affect our results. Our 2011 capital plans for the Delhi Field include the drilling of 33 wells and the workover or re-entry of an additional 7 wells. During the fourth quarter of 2010, the average oil production was 703 Bbls/d.

From inception through December 31, 2010, we had not yet recovered our investment in this field, with net negative cash flow (revenue less operating expenses and capital expenditures, including the acquisition cost) from Delhi of $212.7 million. As of December 31, 2010, the estimated PV-10 Value of our Phase 5 property was $595.0 million.

Future Tertiary Properties without Proved Tertiary Reserves or Tertiary Production at December 31, 2010

Phase 6 (Citronelle). Phase 6 is Citronelle Field in Southwest Alabama, another field acquired in 2006. Citronelle will require an extension to the Free State CO_2 Pipeline, or a man-made source of CO_2 in order to commence this project, the timing of which is uncertain at this time but currently anticipated to occur around 2015 or 2016.

Phase 7 (Hastings). Phase 7 is Hastings Field, a strategically significant property in southeast Texas, which we acquired during February 2009 for approximately $247 million. Under the terms of the option agreement, Venoco, Inc. ("Venoco"), the seller, retained a 2% override and reversionary interest of approximately 25% following payout, as defined in the option agreement. During 2010 we acquired the 2% override from Venoco for approximately $22.3 million. During the fourth quarter of 2010, non-tertiary production from Hastings Field averaged 1,474 BOE/d, with conventional proved reserves on December 31, 2010 of approximately 8.3 MMBOE. We initiated CO_2 injections in the West Hastings Unit during December 2010 upon completion of the construction of the Green Pipeline.

Based on preliminary engineering data, the West Hastings Unit has the second-largest CO_2 EOR reserve potential in our Gulf Coast inventory. During 2010, in anticipation of the completion of the Green Pipeline, we began the development in the West Hastings Unit. Due to the vertical oil column that exists in the field, we are developing the Frio reservoir in multiple vertically segregated CO_2 EOR projects. Each vertical interval will have dedicated CO_2 injection wells and dedicated producing wells. In addition to the injection and producing well work, we have initiated construction of the necessary CO_2 recycling facility to produce and operate the field once we see initial production, which is expected in late 2011 or early 2012. As with all large projects, we will construct the CO_2 recycle facility in stages as the field is developed. In 2011, we expect to invest $79.6 million to continue developing the West Hastings Unit, and additional capital expenditures will also be required over the next ten years to fully develop.

Gillock Field is a smaller field with CO_2 EOR potential located near the Green Pipeline and Hastings Field. Our acquisitions in Gillock Field included almost all of the South Gillock Unit, the Southeast Gillock Unit and the acquisition of key leases in the Gillock Field. At the present time we have not determined the timing of development for the Gillock Field properties, although we currently anticipate it will be around 2013 or 2014.

Phase 8 (Seabreeze Complex). Phase 8, the Seabreeze Complex, which we acquired in 2007, consists of two fields located in southeast Texas on the east side of Galveston Bay. The Oyster Bayou and Fig Ridge Fields are located in close proximity to each other. We acquired the majority interest in Oyster Bayou Field and a relatively small interest in Fig Ridge Field. Oyster Bayou Field was unitized in the spring of 2010 and we began CO_2 injections at Oyster Bayou Field in June 2010. Oyster Bayou Field is somewhat unique when compared to our other CO_2 EOR projects. The field covers a relatively small area, 3,912 acres, and the reservoir pressure was drawn down significantly. Due to these two conditions, the Oyster Bayou Field will be essentially fully developed before we experience our first response to CO_2 injections. Due to delays in receiving our permits to construct the CO_2 recycling facility and the low field pressure before we began CO_2 injections, we are less certain of when first response to CO_2 injections will be achieved. However, we do not anticipate any EOR oil production from Oyster Bayou during 2011.

The other field within the Seabreeze complex is the Fig Ridge Field. Due to our lack of majority interest in this field, it is uncertain if, or when, we will flood Fig Ridge Field.

Phase 9 (Conroe). Phase 9 is Conroe Field, potentially our largest tertiary flood in the Gulf Coast region, located north of Houston, Texas. We acquired this field in 2009 for $271 million in cash and 11,620,000 shares of Denbury common stock, or total aggregate value of $439 million. The acquired Conroe Field interests had estimated proved conventional reserves of approximately 19.0 MMBOE on December 31, 2010, nearly all of which are proved developed. During the fourth quarter of 2010, production at Conroe Field averaged 2,765 BOE/d net to our acquired interest. We will need to build a pipeline to transport CO_2 to this field, preliminarily estimated to cover 86 miles, as an extension of our Green Pipeline. Based on our preliminary estimates, Denbury will spend an additional $750 million to $1.0 billion, including the cost of the CO_2 pipeline, to develop Conroe Field as a tertiary flood. During 2011 we plan to determine the pipeline path, initiate the acquisition of rights-of-way, and engineer and design the Conroe pipeline. In addition, we also expect to refine and finalize our CO_2 EOR plan for Conroe. Given the size of Conroe Field, approximately 20,000 acres, the volumes of CO_2 that could be injected are quite sizable, much larger than any field we have developed to date. Therefore, the pace of development will likely be dictated by the amount of available CO_2.

Other Non-Tertiary Oil and Natural Gas Properties

We have been active in East Mississippi since Denbury was founded in 1990 and are by far the largest oil producer in the basin and the state. Conventional or non-tertiary production during the fourth quarter of 2010 averaged approximately 7,293 BOE/d from this area (10% of our Company total), and we had proved reserves of 32.6 MMBOE as of December 31, 2010 (8% 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 Heidelberg Fields). Production from our conventional and secondary recovery operations in our East Mississippi fields has been gradually declining, as expected, over the last three years, averaging 11,897 BOE/d during 2008, 9,937 BOE/d during 2009 and 8,012 BOE/d during 2010. During 2010, we invested very little capital in these non-tertiary assets.

The largest field in the region and one of our largest fields is Heidelberg Field, which for the fourth quarter of 2010 produced an average of 4,206 BOE/d of conventional or non-tertiary production. 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 feet to 5,000 feet.

The majority of the conventional oil production at Heidelberg is from waterflood units that produce from the Eutaw formation (at approximately 4,400 feet). We have converted all of the waterflood units in West Heidelberg to CO_2 EOR and will begin converting the East Heidelberg waterflood units to CO_2 EOR during 2011. Heidelberg also produces natural gas from the Selma Chalk, which was a fairly active area of development for us prior to 2009. The Selma Chalk is a natural gas reservoir at around 3,700 feet that is developed with horizontal wells and hydraulic fracturing. The Selma Chalk is estimated to contain 80.6 Bcf of proved natural gas reserves and produced 16.3 MMCf/d of gas during the fourth quarter of 2010, making it our largest gas field. Our current plans include drilling four additional wells in the Selma Chalk during 2011.

Rocky Mountain Region

CO_2 Assets

Riley Ridge. In October 2010, we acquired a 42.5% non-operated working interest in the Riley Ridge Federal Unit (“Riley Ridge”) located in southwestern Wyoming, together with approximately 33% of the CO_2 mineral rights in an additional 28,000 acres adjoining Riley Ridge in which we own a non-operating interest. Riley Ridge contains proved reserves of approximately 185 Bcf of natural gas, 6.6 Bcf of helium and approximately 0.9 Tcf of CO_2, net to our interest acquired. The additional 28,000 acres is estimated to contain an additional 1.0 Tcf of probable CO_2 reserves, net to our interest in the CO_2 mineral rights. The first production of natural gas and helium from Riley Ridge is expected to occur in late 2011 after the operator completes construction of the processing facilities to separate the natural gas and helium. The net development costs to our interest were approximately $9 million during 2010, and are expected to be approximately $42 million in 2011, and are primarily associated with constructing the processing facilities that will separate the natural gas and helium. Any potential tertiary oil production using the CO_2 from Riley Ridge is contingent on the development of facilities to separate the CO_2 from the hydrogen sulfide (“H_2S”), along with a pipeline framework and significant capital expenditures.

The full well stream at Riley Ridge is expected to contain approximately 68% CO_2, 19% natural gas, 12% H_2S and 1% helium and other gases. Currently, the operator plans to re-inject the CO_2 and H_2S; however, we have the right to separate and take the CO_2 and re-inject the H_2S. At this time, we are evaluating other potential CO_2 sources in the region, and therefore, we do not have a definitive development timetable for utilization of these CO_2 reserves. However, this CO_2 resource will likely be used at some point, as we plan to expand our operations in this region over time.

Anthropogenic CO_2 Sources. In addition to Riley Ridge, we have a contract to purchase 50 MMcf/d of CO_2 from ConocoPhillips’ Lost Cabin gas plant in central Wyoming. We are in the process of designing the processing and compression equipment for the Lost Cabin gas plant in order to capture the CO_2 and deliver it into our planned Greencore Pipeline. There are two other potential existing sources of CO_2 in the region for which we are negotiating purchase agreements, but to date we have not been able to reach agreement. One is a gas plant similar to Lost Cabin and the other is an operating gasification project.

Similar to our efforts in the Gulf Coast, we are also in discussions regarding proposed gasification plants in the Rocky Mountain region. These proposed facilities have the potential to produce approximately 200 MMcf/d of CO_2 per plant. These plants have all been delayed due to economic conditions and there is some doubt as to whether they will be constructed at all. Several of these plants are in negotiations for federal support through grants and loan guarantees, which if secured, could increase the possibility that certain plants will be ultimately constructed.

The base price of CO_2 per Mcf from these CO_2 sources varies by plant and location, but is expected to be generally similar to the price we have negotiated with potential Gulf Coast anthropogenic sources. Our existing Lost Cabin contract and all of the other contracts are expected to 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 other plants under consideration that could provide CO_2 as well.

Greencore Pipeline. We are finalizing our permitting and expect to begin construction of the 232-mile, 20-inch Greencore CO_2 pipeline in August 2011. This line will begin at the Lost Cabin gas plant and will initially terminate at the Bell Creek oil field in southeast Montana. The Greencore Pipeline will be constructed in two segments: construction of the first will commence in August 2011 and the second will commence in 2012. Pipeline completion is expected to coincide with the installation of capture equipment at the Lost Cabin gas plant. The Greencore Pipeline is the initial portion of our planned pipeline infrastructure in the Rocky Mountain region that will connect the various sources of CO_2 to our oil fields. The first segment of the pipeline will start at the Lost Cabin gas plant and run northeast through Wyoming. In 2012 we plan to complete the pipeline into southeast Montana, where it will initially terminate at the Bell Creek Field. We are estimating our 2011 capital costs for the Greencore Pipeline and Lost Cabin gas plant CO_2 capture equipment to be approximately $181 million.

Future Tertiary Properties without Proved Tertiary Reserves or Tertiary Production at December 31, 2010

Bell Creek Field. Bell Creek Field is located in Southeast Montana and was acquired as part of the Encore Merger in 2010. Development of the CO_2 EOR project at Bell Creek was started by Encore prior to our acquisition. The majority of the work to date has involved re-activating wells in the field and injecting additional water into the reservoir to raise reservoir pressure in anticipation of future CO_2 injections. The original operator of the field recognized the future CO_2 potential in the field and thus had temporarily abandoned wells in such a way as to preserve the mechanical integrity of the wellbore and to minimize the cost of re-entering the wells. We expect to have first CO_2 injections in Bell Creek Field in late 2012 or early 2013 following completion of the Greencore Pipeline. The producing reservoir in Bell Creek is a sandstone reservoir very similar to our Gulf Coast reservoirs, and therefore we expect the CO_2 EOR project to perform similarly. The original oil in place within the Muddy reservoir at Bell Creek is approximately 353 MMBbls of oil. Production net to our interest during the fourth quarter of 2010 averaged 957 Bbls/d, all conventional production. Our 2011 capital expenditures to reactivate additional wells and to continue installing the necessary field infrastructure for injection and production flow lines is estimated to be $26 million.

Cedar Creek Anticline. Cedar Creek Anticline (“CCA”) is primarily located in Montana but covers such a large area that it also extends into North Dakota. The CCA is actually a series of 10 producing oil units, each of which could be considered a field by itself. We acquired our interest in the CCA as part of the Encore Merger in 2010. Production net to our interest during the fourth quarter of 2010 from all of the units in the CCA averaged 9,328 BOE/d, and the conventional reserves associated with the CCA were 64.6 MMBbls of oil and 12.9 Bcf of gas as of December 31, 2010.

CCA is located approximately 110 miles north of Bell Creek Field, and we expect to ultimately connect this field to our proposed Greencore Pipeline. CCA produces from numerous reservoirs, although the primary reservoir is the Red River formation. The Red River formation is a series of dolomitic reservoirs that have produced significant amounts of oil. A CO_2 pilot project conducted in the South Pine Unit in the mid-1980s demonstrated the potential to produce an additional 18% of the original-oil-in-place from the Red River Zone U4 reservoir. The original-oil-in-place within the seven oil units that we expect to CO_2 flood at CCA is approximately 2.7 billion barrels of oil. At the present time we do not expect to begin CO_2 operations in CCA until late 2014 or early 2015. The majority of the capital spending at CCA over the next several years will be invested to modify and expand the existing waterflood operations, upgrade and improve our production handling equipment, and upgrade and improve artificial lift equipment.

Other Non-Tertiary Oil and Natural Gas Properties

Bakken. The Bakken play in North Dakota and Montana is one of the most active unconventional oil plays in North America. We acquired a significant acreage position in the Bakken play as part of the Encore Merger in 2010. At the present time we have approximately 275,000 net mineral acres under lease in the Bakken play. During 2010, we ramped up our operated activity in the play from a two-drilling-rig program at the time of the acquisition to a five-drilling-rig program at the present time. The typical Bakken well is horizontally drilled with a 10,000-foot horizontal section that traverses the majority of a two-section, 1,280-acre spacing unit. Where previous smaller spacing units exist, 640 acres or 320 acres, the horizontal section is reduced to approximately 5,000 feet. We are evaluating the performance of 10,000-foot laterals compared to 5,000-foot laterals to determine which is the most economical. In addition to the lateral length evaluation, we are also evaluating the number of wells per reservoir that can be economically drilled on each spacing unit. At the present time we are assuming six wells, three per reservoir per unit, but other operators are testing the possibility of adding a fourth well in each reservoir per unit.

Completion of the Bakken has been evolving and will continue to evolve as operators test ideas. At the present time, after the well is drilled, the horizontal section is typically hydraulically fractured utilizing 20 to 30 frac stages to complete the well, although others have experimented with up to 40 stages. Once all of the stages are pumped, the well is turned to production. The Bakken shale includes two producing intervals over a large portion of the play. The Middle Bakken is the shallower productive interval and is present throughout the entire play. The Sanish or Three Forks is the lower productive interval of the Bakken, but does not cover the entire Bakken play. Given the reservoir characteristics of the Bakken, which is a tight shale, production rates may initially exceed 2,000 BOE/d but thereafter decline rapidly for the first year or two, producing for many years thereafter at a more conventional or slow rate of decline. During 2010, we drilled and completed 15 operated Bakken wells at a total net cost of $76.0 million. Fourth quarter 2010 production averaged 5,193 BOE/d. In addition to the operated wells we drilled, we also participated in an additional 68 non-operated wells during 2010 at a total net cost of $48.6 million bringing our total investment during 2010 to $152.2 million in the Bakken play.

Denbury is continually refining the completion and hydraulic fracturing designs on wells, as are all operators in the Bakken. Early in the life of the play, many wells were stimulated with a relatively small number of stages, typically fewer than six or eight. We have had success in re-fracturing these early wells and will continue to re-frac additional wells during 2011.

Our 2011 capital program will utilize a five-drilling-rig program that we operate and in which we expect to drill an estimated 40 to 50 operated Bakken wells. Typically we own a 40% to 100% working interest in our operated wells. Due to our large acreage position, we also participate in numerous non-operated wells within the Bakken play. We are estimating that, on average, we will be participating in wells drilled by 10 to 12 non-operated drilling rigs throughout 2011 with working interests ranging from under 1% to a more typical range of 10% to 25%. Our total estimated capital for our Bakken drilling program in 2011 is approximately $300 million, net of capitalized interest.

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 our 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 our acreage position at December 31, 2010:

	Developed		Undeveloped		Total	
	Gross	Net	Gross	Net	Gross	Net
Gulf Coast	305,026	242,936	383,591	83,597	688,617	326,533
Rocky Mountain	268,249	198,228	753,336	472,740	1,021,585	670,968
Total	573,275	441,164	1,136,927	556,337	1,710,202	997,501

Our net undeveloped acreage that is subject to expiration over the next three years, if not renewed, is approximately 31% in 2011, 20% in 2012 and 13% in 2013.

Productive Wells

The following table sets forth our gross and net productive oil and natural gas wells as of December 31, 2010:

	Producing Oil Wells		Producing Natural Gas Wells		Total	
	Gross	Net	Gross	Net	Gross	Net
Operated Wells:						
Gulf Coast	1,183	1,101.1	245	224.2	1,428	1,325.3
Rocky Mountain	823	683.4	—	—	823	683.4
Total	2,006	1,784.5	245	224.2	2,251	2,008.7
Non-Operated Wells:						
Gulf Coast	70	2.8	234	3.8	304	6.6
Rocky Mountain	430	52.4	2	0.1	432	52.5
Total	500	55.2	236	3.9	736	59.1
Total Wells:						
Gulf Coast	1,253	1,103.9	479	228.0	1,732	1,331.9
Rocky Mountain	1,253	735.8	2	0.1	1,255	735.9
Total	2,506	1,839.7	481	228.1	2,987	2,067.8

Drilling Activity

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

	Year Ended December 31,					
	2010		2009		2008	
	Gross	Net	Gross	Net	Gross	Net
Exploratory Wells:(1)						
Productive(2)	—	—	1	1.0	—	—
Non-productive(3)	—	—	—	—	1	1.0
Development Wells:(1)						
Productive(2)	127	62.8	23	16.6	102	98.3
Non-productive(3)(4)	—	—	—	—	1	0.7
Total	127	62.8	24	17.6	104	100.0

(1) An exploratory well is a well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir. Generally, an exploratory well is any well that is not a development well, an extension well, a service well, or a stratigraphic test well.

(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 non-productive well is an exploratory or development well that is not a producing well.

(4) During 2010, 2009 and 2008, an additional 41, 20 and 33, 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 Results* included herein.

TITLE TO PROPERTIES

Customarily in the oil and natural 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.

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, 2010, two purchasers accounted for 10% or more of our oil and natural gas revenues: Marathon Petroleum Company LLC (46%) and Plains Marketing LP (14%). For the year ended December 31, 2009, we had two significant purchasers that each accounted for 10% or more of our oil and natural gas revenues: Marathon Petroleum Company LLC (52%) and Hunt Crude Oil Supply Co. (21%). For the year ended December 31, 2008, three purchasers 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%).

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 in Gulf Coast region is primarily from developed fields close to major pipelines or refineries and established infrastructure. Our production in the Rocky Mountain region is dependent on limited transportation options caused by oversubscribed pipelines and market centers that are distant from producing properties. We have not experienced significant 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. As an example, in Heidelberg Field, one of our larger fields, and our other Eastern Mississippi non-tertiary 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 1 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, 2010, the discount for our non-tertiary oil production from Heidelberg Field averaged $8.22 per Bbl, and for our eastern Mississippi non-tertiary properties as a whole the discount averaged $8.03 per Bbl relative to NYMEX oil prices. For our Phase 1 tertiary fields in southwest Mississippi, we averaged a premium of $2.84 per Bbl over NYMEX oil prices during 2010.

The marketing of our Rocky Mountain region oil production is dependent on transportation through local pipelines to market centers in Guernsey, Wyoming; Clearbrook, Minnesota; and Wood River, Illinois. Shipments on some of the pipelines are oversubscribed and subject to apportionment. We have currently been allocated sufficient pipeline capacity to move our oil production; however, there can be no assurance that we will be allocated sufficient pipeline capacity to move all of our oil production in the future. Expansion of the pipeline infrastructure in the Rockies is ongoing and, we believe, is providing greater stability to oil differentials in the area. For the year ended December 31, 2010 the discount for our oil production in the Rocky Mountain region averaged $8.31 per Bbl.

Overall, during 2010, approximately 43% of our production was sold on a NYMEX or West Texas Intermediate (“WTI”) Posting plus Argus P+ basis, 40% on a Light Louisiana Sweet (“LLS”)/Heavy Louisiana Sweet (“HLS”) basis, 15% on a Eugene Island Crude (“EIC”)/Mars/Poseidon/Maya basis and 2% on a Posted Prices basis.

Natural Gas Marketing

Virtually all of our natural gas production in the Gulf Coast region is close to existing pipelines and consequently we generally have a variety of options to market our natural gas. Our gas production in the Rocky Mountain region, like our oil production, is dependent on limited transportation options that can affect our ability to find markets for it. 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, 2010, we averaged $0.07 per Mcf above NYMEX prices for our Mississippi natural gas production. In the Texas Gulf Coast region, due primarily to its location, the price we received averaged $0.13 per Mcf above NYMEX prices. The Rocky Mountain region natural gas production is sold at the wellhead on a percent of proceeds basis. We receive a percent of proceeds on both the residue natural gas volumes and the natural gas liquids volumes. There are a limited number of gas markets in this region. The natural gas has a significant component of propane, butanes, and other higher density hydrocarbons resulting in a measurable natural gas liquids stream. For the year ended December 31, 2010, we averaged $1.49 per Mcf over NYMEX prices for our Rocky Mountain region natural gas production.

COMPETITION AND MARKETS

We face competition from other oil and natural gas companies in all aspects of our business, including acquisition of producing properties, oil and gas leases, and carbon dioxide properties; 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 liquidity, available information about prospective properties and our expectations for earning minimum projected return on our investments. 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 to a lesser extent 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 relatively uncommon significant natural sources of carbon dioxide in the Gulf Coast region, 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 and for 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 cost 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 natural 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 and Regulation

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. Certain pipeline transportation safety and environmental legislation was proposed in the United States Senate in February 2011 which could affect our operations, effectiveness, and the costs thereof, as they relate to unspecified safety regulations for CO_2 pipelines. In future periods Congress may create new incentives for alternative energy sources, and may also consider legislation to reduce emissions of CO_2 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. The Environmental Protection Agency ("EPA") has promulgated new regulations requiring permitting for release of certain greenhouse gases, along with requirements for wells used for geologic sequestration. At the same time, legislation to reduce the emissions of CO_2 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 includes 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, the Bureau of Ocean Energy Management, Regulation and Enforcement, the Bureau of Indian Affairs, and other federal and state stakeholder agencies.

Environmental Regulations

Public interest in the protection of the environment has increased dramatically in recent years. Our oil and natural gas production, saltwater disposal operations, and our processing, handling and disposal of 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 product, 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 our 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 our operations 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. 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

Internal Controls Over Reserve Estimates

We engage DeGolyer and MacNaughton, an independent petroleum engineering consulting firm located in Dallas, Texas, to prepare our reserve estimates and rely on their expertise to ensure that our reserve estimates are prepared in compliance with SEC rules and regulations and that appropriate geologic, petroleum engineering, and evaluation principles and techniques applied are in accordance with practices generally recognized by the petroleum industry as presented in the publication of the Society of Petroleum Engineers entitled "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information (Revision as of February 19, 2007)". The person responsible for the preparation of the reserve report is a Senior Vice President at this consulting firm; he is a Registered Professional Engineer in the State of Texas; he received a Bachelor of Science degree in Petroleum Engineering at Texas A&M University in 1974; and he has in excess of 35 years of experience in oil and gas reservoir studies and evaluations. Denbury's Vice President — Business Development is primarily responsible for overseeing the independent petroleum engineering firm during the process. Our Vice President — Business Development has a Bachelor of Science degree in Petroleum Engineering and over 20 years of industry experience working with petroleum reserve estimates. The Company's internal reserve engineering team consists of qualified petroleum engineers who both provide data to the independent petroleum engineer and prepare interim reserve estimates. The internal reserve team reports directly to our Vice President — Business Development. In addition, the Company's Board of Directors' Reserves Committee, on behalf of the Board of Directors, oversees the qualifications, independence, performance and hiring of the Company's independent petroleum engineering firm and reviews the final report and subsequent reporting of the Company's oil and natural gas reserves. The Chairman of the Reserves Committee is a Chartered Engineer of Great Britain and received his Bachelor of Science degree in Chemical Engineering from the University of London in 1963.

Oil and Natural Gas Reserves Estimates

DeGolyer and MacNaughton prepared estimates of our net proved oil and natural gas reserves as of December 31, 2010, 2009 and 2008. See the summary of DeGolyer and MacNaughton's report as of December 31, 2010 included as an exhibit to this Form 10-K. Estimates of reserves as of year-end 2010 and 2009 were prepared using an average price equal to the un-weighted arithmetic average of hydrocarbon prices on the first day of each month within the 12-month period in accordance with revised rules and regulations of the SEC. Estimates of reserves as of year-end 2008 were prepared using constant prices and costs in accordance with previous rules and regulations of the SEC, based on hydrocarbon prices received on a field-by-field basis as of December 31. Our oil and natural gas 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 interest in our properties. During 2010, we provided oil and gas reserve estimates for 2009 to the United States Energy Information Agency, which was substantially the same as the reserve estimates included in our Form 10-K for the year ended December 31, 2009.

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 account for a significant portion 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 they are waiting for a production response to the water or CO_2 injections. During 2010, our proved undeveloped oil reserves increased due to tertiary reserve additions at Delhi Field and the acquisition of our Bakken properties as part of the Encore Merger. During 2011, we expect to drill an estimated 40 to 50 operated Bakken wells, in addition to our participation in numerous non-operated Bakken drilling programs.

Our proved undeveloped natural gas reserves are located in our Riley Ridge Field and in our Selma Chalk Play at Heidelberg and Sharon Fields. The increase in our proved undeveloped natural gas reserves from December 31, 2009 to December 31, 2010 is primarily due to the acquisition of Riley Ridge Field. The gas separation facilities at the Riley Ridge Field are currently under construction and are expected to start-up in late 2011.

	December 31,		
	2010	2009	2008
Estimated Proved Reserves:			
Oil (MBbls)	338,276	192,879	179,126
Natural gas (MMcf)	357,893	87,975	427,955
Oil equivalent (MBOE)	397,925	207,542	250,452
Reserve Volumes Categories:			
Proved developed producing:			
Oil (MBbls)	186,705	93,833	73,347
Natural gas (MMcf)	104,050	67,952	270,824
Oil equivalent (MBOE)	204,047	105,158	118,484
Proved developed non-producing:			
Oil (MBbls)	32,372	22,359	23,399
Natural gas (MMcf)	6,466	1,561	27,290
Oil equivalent (MBOE)	33,450	22,619	27,947
Proved undeveloped: (1)			
Oil (MBbls)	119,199	76,687	82,380
Natural gas (MMcf)	247,377	18,462	129,841
Oil equivalent (MBOE)	160,428	79,764	104,020
Percentage of Total MBOE:			
Proved producing	51%	51%	47%
Proved non-producing	9%	11%	11%
Proved undeveloped	40%	38%	42%
Representative Oil and Natural Gas Prices:(2)			
Oil — NYMEX	$ 79.43	$ 61.18	$ 44.60
Natural gas — Henry Hub	4.40	3.87	5.71
Present Values (thousands):(3)			
Discounted estimated future net cash flow before income taxes (PV-10 Value)(4)	$ 7,292,344	$ 3,075,459	$ 1,926,855
Standardized measure of discounted estimated future net cash flow after income taxes (Standardized Measure)	$ 4,917,927	$ 2,457,385	$ 1,415,498

(1) As of December 31, 2010, approximately 2% of our proved undeveloped reserves have been held as proved undeveloped for a period greater than five years, and 94% of these are tertiary reserves. It is expected that the tertiary reserves will become proved developed reserves during the next several years as the remaining tertiary development at these fields is completed. The remaining undeveloped reserves will either be developed in 2011 or will be developed in the next several years as part of a tertiary flood.

(2) The reference prices for 2010 and 2009 were based on the average first day of the month prices for each month during the respective year. The reference prices for 2008 were based on year-end prices. For all the periods presented, these representative prices were adjusted for differentials by field to arrive at the appropriate net price Denbury receives.

(3) Determined based on the average first day of the month prices for each month during 2010 and 2009 and year-end unescalated prices for 2008, in all cases adjusted to prices received by field in accordance with standards set forth in the FASC.

(4) 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 FASC Topic 932. The difference between these two amounts, the discounted estimated future income tax (in thousands) was $2,374,417 at December 31, 2010, $618,074 at December 31, 2009 and $511,357 at December 31, 2008. 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 16, *Supplemental Oil and Natural Gas Disclosures*, to the 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 Item 1A. *Risk Factors — Estimating our reserves, production and future net cash flow is difficult to do with any certainty*. See also Note 16, *Supplemental Oil and Natural Gas Disclosures*, to the Consolidated Financial Statements.

Item 1A. Risk Factors

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

Our future financial condition, results of operations and the carrying value of our oil and natural gas properties depend primarily upon the prices we receive for our oil and natural gas production. Oil and natural gas prices historically have been volatile, and may 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 year-end 2008, we recorded a $226.0 million full cost ceiling test write-down. Oil and natural gas prices have continued their volatility, with NYMEX oil prices per barrel increasing 15% between year-end 2009 and year-end 2010, and NYMEX natural gas prices per MMBtu decreasing by 21% during the year. Future decreases in commodity prices could require us to record additional full cost ceiling test write-downs. 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. Oil prices are likely to affect us more than natural gas prices because approximately 85% of our December 31, 2010 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;
- 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 that can damage oil and natural gas facilities and delivery systems and disrupt operations;
- 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 around $12.00 per Bbl to record highs of approximately $145 per Bbl in July 2008. During the last half of 2008, oil prices declined substantially, ending the year at a NYMEX price of $44.60 per Bbl. Oil prices again increased through 2009 and 2010, ending 2009 at a NYMEX price of $79.36 per barrel and ending 2010 at a NYMEX price of $91.38 per barrel. As of February 28, 2011, we have oil commodity derivative contracts in place covering approximately 51,000 Bbls/d during 2011 and 53,750 Bbls/d during the first half of 2012. As a result, 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 operating costs do not decrease 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 our economic break-even (before corporate overhead and expenses on these projects at current oil prices) occurs at per barrel dollar costs in the range of the mid-to-upper 30s, depending on the specific field and area.

The prices we receive for our crude oil do not always correlate with NYMEX prices. The prices we receive for our crude oil production can vary from NYMEX oil prices depending on the quality of the crude oil we sell, the location of our crude oil production and the related markets we sell to, and the pricing contracts and indices we sell at. Our NYMEX differentials on a field-by-field basis over the last few years have ranged from a positive $10 per Bbl to a negative $35 per Bbl. On a corporate-wide basis, our NYMEX differentials over the last few years have ranged from a low of approximately $1.50 per Bbl below NYMEX oil prices to a high of almost $10.00 per Bbl below NYMEX prices. 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 prices, have generally trended upward since that time, although with significant fluctuations along the way. NYMEX natural gas prices averaged $8.89 per MMBtu during 2008, $4.16 per MMBtu during 2009, $4.40 per MMBtu during 2010, and ended 2010 at $4.41 per MMBtu. We have natural gas commodity derivative contracts in place covering approximately 33,500 Mcf/d during 2011 and 20,000 Mcf/d during 2012 (please refer to Note 9, *Derivative Instruments and Hedging Activities*, to the Consolidated Financial Statements for further details regarding our commodity derivative contracts).

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

Our long-term growth strategy is focused on our CO_2 tertiary recovery operations. The crude oil production from our tertiary recovery projects depends on having access to sufficient amounts of CO_2. Our ability to produce this oil would be hindered if our supply of CO_2 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.

Our planned tertiary operations and the related construction of necessary CO_2 pipelines could be delayed by difficulties in obtaining pipeline rights-of-way or other permits.

The production of crude oil from our planned tertiary operations is dependent upon having access to sufficient amounts of CO_2 and pipelines to transport this CO_2 to our oil fields at a cost that is economically viable. Our ongoing construction of CO_2 pipelines will require us to obtain rights-of-way from private landowners and, in certain areas, from the federal government if the proposed pipelines cross federal lands. As a result, obtaining these rights-of-way may require additional regulatory and environmental compliance and additional expenditures, which could delay our CO_2 pipeline construction schedule and increase the costs of constructing those pipelines.

Certain of our operations may be limited during certain periods due to severe weather conditions and other regulations.

Certain of our operations in North Dakota, Montana and Wyoming are conducted in areas subject to extreme weather conditions and often in difficult terrain. As a result, our operations may be delayed because of cold, snow and wet conditions. Due to the harsh winter, certain operations may only be practical during non-winter months. Unusually severe weather could delay certain of these operations, including the construction of CO_2 pipelines, the drilling of new wells and production from existing wells, and depending on the severity of the weather, could have a negative effect on our results of operations in this region. Further, certain of our operations are limited to certain time periods due to environmental regulations. These time restrictions could also slow down our operations, cause delays, and have a negative effect on our results of operations.

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

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 senior secured credit facilities, we would be in default under our debt instruments. This default would permit the holders of such indebtedness to accelerate the maturity of such indebtedness and could cause defaults under other indebtedness 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, commodity prices, and to financial, business and other factors, including factors beyond our control.

As of February 17, 2011, we had outstanding $2.2 billion (principal amount) of subordinated notes at interest rates ranging from 6.375% to 9.75% at a weighted average interest rate of 8.28% and $130 million of bank debt. At that time, we had approximately $1.47 billion available on our bank credit line. We currently have a bank borrowing base of $1.6 billion. The next semi-annual redetermination of the borrowing base for our bank credit facility will be on May 1, 2011. 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 four months.

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

- a substantial portion of our cash flows from operations may be dedicated to servicing our indebtedness and would not be available for other purposes;
- our 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, and increases in interest rates thereon, 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.

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 *Market Risk Management* in Management's Discussion and Analysis of Financial Condition and Results of Operations, and in Note 9, *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 acquisitions and internal organic growth activities. 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, up to four or five 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.

During the last few years, we have acquired several fields at a significant cost 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, we plan to continue acquiring other 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.

The occurrence of a financial crisis, such as the financial crisis in recent years, may have lasting 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 obtain capital in the long-term or short-term debt capital markets or equity capital markets or an inability to access bank financing. A prolonged credit crisis and related turmoil in the global financial system would likely materially affect our liquidity, business and our financial condition. 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 condition could lead to reduced demand for oil and gas, or lower prices for oil and gas, which could have a negative impact on our revenues.

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.

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. During periods of 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.

We depend on our key personnel.

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

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

For the year ended December 31, 2010, two purchasers each accounted for more than 10% of our oil and natural gas revenues and in the aggregate, for 60% of these revenues. 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.

The reserve data included in documents incorporated by reference represent only estimates. 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. 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, 2010, approximately 40% 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.

Enactment of legislative or regulatory proposals under consideration could negatively affect our business.

Numerous legislative and regulatory proposals affecting the oil and gas industry have been proposed or are under consideration by the current federal administration, Congress and various federal agencies. Among these proposals are: (1) climate change legislation introduced in Congress, Environmental Protection Agency regulations, carbon emission "cap-and-trade" regimens, and related proposals, none of which have been adopted in final form; (2) proposals contained in the President's budget, along with legislation introduced in Congress, none of which have been enacted by both houses of Congress, to impose new taxes on or repeal various tax deductions available to oil and gas producers, such as the current tax deduction for intangible drilling and development costs and the current deduction for qualified tertiary injectant expenses, which if eliminated could raise the cost of energy production, reduce energy investment and affect the economics of oil and gas exploration and production activities; (3) legislation being considered by Congress that would subject the process of hydraulic fracturing to federal regulation under the Safe Drinking Water Act; and (4) pipeline safety legislation proposed in the United States Senate in February 2011, including CO_2 pipeline safety provisions, any of which could affect Company operations, their effectiveness, and the costs thereof. Generally, any such future laws and regulations could result in increased costs or additional operating restrictions, and could have an effect on demand for oil and gas or prices at which it can be sold. Until any such legislation or regulations are enacted or adopted, it is not possible to gauge their impact on our future operations or our results of operations and financial condition.

We may experience an impairment of our goodwill.

We test goodwill for impairment annually during the fourth quarter, or between annual tests if an event occurs or circumstances change that may indicate the fair value of a reporting unit is less than the carrying amount. The need to test for impairment can be based on several indicators, including but not limited to a significant reduction in the price of oil or natural gas, a full cost ceiling write-down of oil and natural gas properties, unfavorable revisions to oil and natural gas reserves and significant changes in the expected timing of production, or changes in the regulatory environment.

Fair value calculated for the purpose of testing for impairment of our goodwill is estimated using the expected present value of future cash flows method and comparative market prices when appropriate. A significant amount of judgment is involved in performing these fair value estimates for goodwill since the results are based on estimated future cash flows and assumptions related thereto. Significant assumptions include estimates of future oil and natural gas prices, projections of estimated quantities of oil and natural gas reserves, estimates of future rates of production, timing and amount of future development and operating costs, estimated availability and cost of CO_2, projected recovery factors of reserves and risk-adjusted discount rates. We base our fair value estimates on projected financial information which we believe to be reasonable. However, actual results may differ from those projections.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

See Item 1. *Business — Oil and Natural 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

The class action cases brought in Texas state courts and in the Delaware Court of Chancery related to the Encore Merger have all been settled and the cases dismissed. The shareholder derivative action brought in the District Court of Dallas County, Texas, regarding a compensation matter has been settled, and application to the Court by all parties to dismiss the case is pending. The amounts paid in settlements were immaterial to the Company's financial condition and results of operations.

We are involved in various other 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. Reserved

PART II

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. As of February 9, 2011, 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 1,359. On February 25, 2011, the last reported sale price of Denbury's common stock, as reported on the NYSE, was $24.32 per share.

	2010		2009	
	High	Low	High	Low
First Quarter	$ 16.870	$ 13.550	$ 17.520	$ 9.610
Second Quarter	19.150	14.640	18.840	13.390
Third Quarter	17.020	14.180	17.780	12.450
Fourth Quarter	19.790	16.240	17.390	12.510

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 2010.

Purchases of Equity Securities by the Issuer and Affiliated Purchasers

Month	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number of Shares that May Yet Be Purchased Under the Plans or Programs
October 2010	5,558	$ 16.77	—	—
November 2010	7,131	18.18	—	—
December 2010	18,942	19.15	—	—
Total	31,631	18.51	—	—

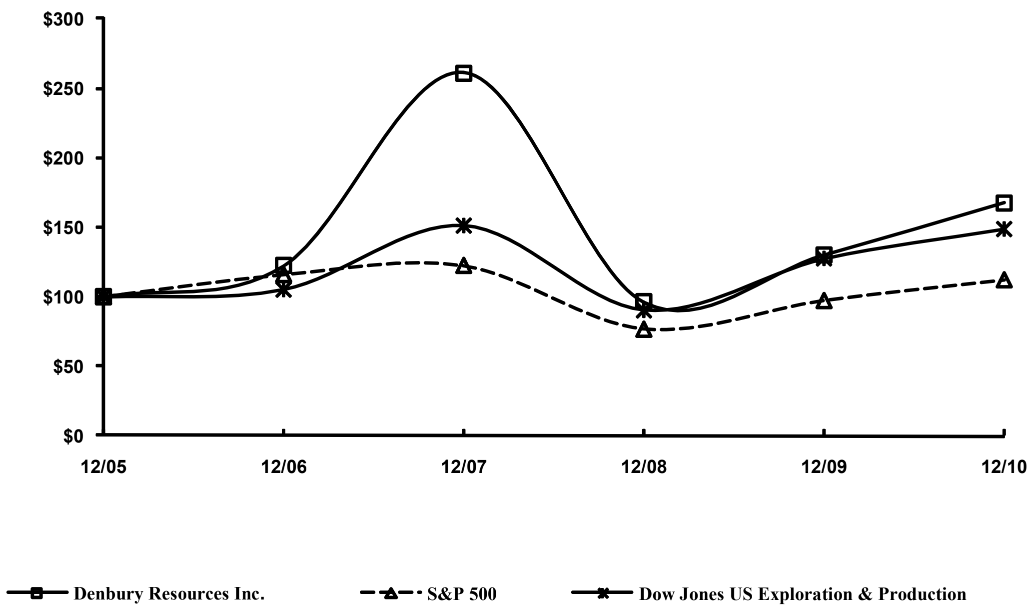
These shares were purchased from employees of Denbury who delivered shares to the Company to satisfy their minimum tax withholding requirements related to the vesting of restricted shares and the exercise of stock appreciation rights.

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 filings.

The following graph illustrates changes over the five-year period ended December 31, 2010, 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 graph tracks the performance of a $100 investment in our common stock and in each index (with the reinvestment of all dividends) from December 31, 2005 to December 31, 2010.

COMPARISON OF 5 YEAR CUMULATIVE TOTAL RETURN



	December 31,					
	2005	2006	2007	2008	2009	2010
Denbury Resources Inc.	$ 100.00	$ 121.99	$ 261.19	$ 95.87	$ 129.94	$ 167.60
S&P 500	100.00	115.80	122.16	76.96	97.33	111.99
Dow Jones US Exploration & Production	100.00	105.37	151.39	90.65	127.42	148.74

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Item 6. Selected Financial Data

In thousands, except per share data or otherwise noted	Year Ended December 31, 2010 (1)	2009	2008	2007	2006
Consolidated Statements of Operations Data:					
Revenues and other income:					
Oil, natural gas, and related product sales	$ 1,793,292	$ 886,709	$ 1,347,010	$ 952,788	$ 716,557
Other	128,499	22,441	24,046	20,272	14,979
Total revenues and other income	$ 1,921,791	$ 889,150	$ 1,371,056	$ 973,060	$ 731,536
Net income (loss) attributable to Denbury stockholders(2)	271,723	(75,156)	388,396	253,147	202,457
Net income (loss) per common share:(3)					
Basic	0.73	(0.30)	1.59	1.05	0.87
Diluted	0.72	(0.30)	1.54	1.00	0.82
Weighted average number of common shares outstanding:(3)					
Basic	370,876	246,917	243,935	240,065	233,101
Diluted	376,255	246,917	252,530	252,101	247,547
Consolidated Statements of Cash Flow Data:					
Cash provided by (used by):					
Operating activities	$ 855,811	$ 530,599	$ 774,519	$ 570,214	$ 461,810
Investing activities(4)	(354,780)	(969,714)	(994,659)	(762,513)	(856,627)
Financing activities(5)	(139,753)	442,637	177,102	198,533	283,601
Production (average daily):					
Oil (Bbls)	59,918	36,951	31,436	27,925	22,936
Natural gas (Mcf)	78,057	68,086	89,442	97,141	83,075
BOE (6:1)	72,927	48,299	46,343	44,115	36,782
Unit Sales Price (excluding impact of derivative settlements):					
Oil (per Bbl)	$ 75.97	$ 57.75	$ 92.73	$ 69.80	$ 59.87
Natural gas (per Mcf)	4.63	3.54	8.56	6.81	7.10
Unit Sales Price (including impact of derivative settlements):					
Oil (per Bbl)	$ 71.69	$ 68.63	$ 90.04	$ 68.84	$ 59.23
Natural gas (per Mcf)	6.45	3.54	7.74	7.66	7.10
Costs per BOE:					
Lease operating expenses	$ 18.29	$ 18.50	$ 18.13	$ 14.34	$ 12.46
Production taxes and marketing expenses	4.85	2.41	3.76	3.05	2.71
General and administrative(6)	5.25	6.59	3.56	3.04	3.20
Depletion, depreciation and amortization	16.32	13.52	13.08	12.17	11.11
Proved Reserves:					
Oil (MBbls)	338,276	192,879	179,126	134,978	126,185
Natural gas (MMcf)(7)	357,893	87,975	427,955	358,608	288,826
MBOE (6:1)	397,925	207,542	250,452	194,746	174,322
Proved Carbon Dioxide Reserves:					
Gulf Coast region (MMcf)(8)	7,085,131	6,202,836	5,612,167	5,641,054	5,525,948
Rocky Mountain region (MMcf)(9)	920,266	—	—	—	—
Consolidated Balance Sheet Data:					
Total assets	$ 9,065,063	$ 4,269,978	$ 3,589,674	$ 2,771,077	$ 2,139,837
Total long-term liabilities	4,105,011	1,903,951	1,363,539	1,102,066	833,380
Stockholders' equity(10)	4,380,707	1,972,237	1,840,068	1,404,378	1,106,059

(1) On March 9, 2010, we acquired Encore Acquisition Company ("Encore"). We consolidated Encore's results of operations beginning March 9, 2010.

(2) During 2010, we consolidated Encore's results of operations beginning March 9, 2010. In 2009, we had a pretax charge of $236.2 million associated with our commodity derivative contracts. 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.

(3) On December 5, 2007, 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 split.

(4) During 2010, we closed our purchase of Encore, a cash and stock transaction which included cash outlay of \$815.0 million, net of cash acquired, during 2010. We also closed the purchase of Riley Ridge, and sold non-strategic Encore assets for aggregate cash proceeds aggregating \$1.5 billion. During February 2009, we closed our \$201 million purchase of Hastings Field, and in December 2009, we closed our \$430.7 million purchase of Conroe Field (for \$269.8 million in cash and the issuance of 11,620,000 shares of common stock). We sold our Barnett Shale natural gas assets in 2009 for aggregate proceeds of \$469.7 million.

(5) In February 2010, we issued \$1.0 billion of 8¼% Senior Subordinated Notes due 2020 and in March and April 2010, we repurchased approximately \$500.5 million and \$95.7 million, respectively, in principal amount of senior subordinated notes previously issued by Encore (see Note 5, *Long-term Debt*, to the Consolidated Financial Statements). In February 2009, we issued \$420 million of 9¾% Senior Subordinated Notes due 2016.

(6) General and administrative expenses were higher in 2010 primarily due to additional expenses related to the Encore Merger. General and administrative expenses were higher in 2009 than in prior years primarily due to higher employee costs, \$14.2 million of non-recurring expense related to a compensation agreement with certain members of Genesis Energy, L.P. management and a \$10.0 million compensation charge related to the retirement of Denbury's then-CEO and President and his retention in a non-officer role as Chief Strategist.

(7) During 2009, we sold our Barnett Shale assets and in December 2007 and February 2008, we sold our Louisiana natural gas assets.

(8) Proved CO_2 reserves in the Gulf Coast region consist of reserves from our reservoirs at Jackson Dome and are presented on a gross working interest basis and include reserves dedicated to volumetric production payments of 100.2 Bcf at December 31, 2010, 127.1 Bcf at December 31, 2009, 153.8 Bcf at December 31, 2008, 182.3 Bcf at December 31, 2007, and 210.5 Bcf at December 31, 2006. (See Note 16, *Supplemental Oil and Gas Disclosures,* to the Consolidated Financial Statements).

(9) Proved CO_2 reserves in the Rocky Mountain region consist of our reserves at Riley Ridge and are net to our interest.

(10) 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 Information* 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 natural gas company. We are the largest oil and natural gas producer in both Mississippi and Montana, own the largest CO_2 reserves used for tertiary oil recovery east of the Mississippi River, and hold significant operating acreage in the Rocky Mountain and Gulf Coast regions. Our goal is to increase the value of acquired properties through a combination of exploitation, drilling and proven engineering extraction practices, with the most significant emphasis on our CO_2 tertiary recovery operations.

During 2010, we completed several strategic initiatives and achieved several milestones:

- Acquired Encore Acquisition Company ("Encore"), which established a new core area in the Rocky Mountain region;
- Sold non-strategic legacy Encore properties and our interests in Encore Energy Partners LP ("ENP") to reduce debt, which increased in conjunction with the Encore acquisition;
- Completed construction of our 325-mile Green Pipeline and commenced injecting CO_2 transported by that pipeline into our Oyster Bayou and Hastings Fields in southeast Texas;
- Acquired an interest in the Riley Ridge Federal Unit ("Riley Ridge") in Wyoming, a property that contains natural gas, helium and significant volumes of CO_2 potentially available for use in our proposed future tertiary operations in the Rocky Mountain region;
- Commenced tertiary production at Delhi Field and recognized proved reserves of 29.5 MMBbls at that field;
- Increased our proved reserves in our Bakken play by 33.4 MMBOE to 46.7 MMBOE;
- Increased our proved CO_2 reserves by 27% to 8.0 Tcf; and
- Sold our interests in Genesis Energy, L.P. ("Genesis") and recognized a gain on the sale of $101.5 million.

2010 Operating Highlights. The acquisition of Encore in March 2010 ("Encore Merger") has had a significant impact on nearly every aspect of our business, including oil and natural gas production, revenues and operating expenses, which is more fully discussed throughout the analysis below. Encore's results were included in Denbury's results beginning from the March 9, 2010, acquisition date. We recognized net income of $271.7 million during 2010, or $0.73 per common share, compared to a net loss of $75.2 million, or $0.30 per common share during 2009. Although the Encore Merger had a significant impact on our 2010 revenues and operating expenses, when evaluating the change in net income between the two years a couple of items stand out: (1) a $436.0 million pre-tax ($270.3 million after tax) increase in our income due to non-cash fair value changes in our commodity derivative contracts, and $_2$ a $101.5 million pre-tax ($62.9 million after tax) gain on sale of our interests in Genesis in 2010.

In 2010, NYMEX oil and natural gas prices averaged $79.51 per Bbl and $4.40 per MMbtu, respectively, higher than average prices of $61.96 per Bbl and $4.17 per MMBtu during 2009. However, as oil comprises a majority of our production volumes, our average revenue per BOE, excluding the impact of oil and natural gas derivative contracts, was $67.37 per BOE in 2010, as compared to $49.16 per BOE in 2009, a 37% increase between the two periods.

During 2010, our oil and natural gas production averaged 72,927 BOE/d, a 51% increase over average production for 2009. Our continuing production, which in 2009 excludes the production from our Barnett Shale properties, which were sold in 2009, and which in 2010 excludes our non-strategic legacy Encore and ENP properties, which were sold in 2010, increased 20,513 BOE/d (53%), from 38,760 BOE/d in 2009 to 59,273 BOE/d in 2010. This increase was due primarily to production from the properties acquired in the Encore Merger (15,500 BOE/d) and an increase in our tertiary production (4,719 BOE/d). On a pro forma basis, our continuing production adjusted to include continuing production from the Encore properties for the whole year beginning January 1, 2010, instead of the March 9, 2010, acquisition date, Denbury's continuing pro forma production (62,558 BOE/d) would have increased 61% rather than 53% over continuing production in 2009. See *Results of Operations — Operating Results — Production* for more information.

Tertiary oil production averaged 29,062 BOE/d during 2010, representing a 19% increase over our tertiary oil production during 2009. We had strong production increases during 2010 from several of our existing tertiary oil fields, and had initial production response from CO_2 injections at Delhi Field during the second quarter of 2010. See *Results of Operations — CO_2 Operations* for more information.

Cash payments on our commodity derivative contracts during 2010 were $31.6 million, compared to $146.7 million received during 2009. During 2010, we had a non-cash fair value gain on our derivative contracts of $53.0 million, compared to a non-cash fair value loss of $383.0 million in 2009. Coupled together, our total adjustments on our commodity derivative contracts reflected a net swing between 2009 and 2010 of $257.6 million of additional pretax income in 2010 ($159.7 million after tax).

Our lease operating expenses increased 49% ($160.8 million) between 2009 and 2010 on an absolute basis, but decreased 1% on a per BOE basis. The increase on an absolute basis is primarily attributable to the properties acquired in the Encore Merger and further expansion of our tertiary operations, partially offset by the 2009 sale of our Barnett Shale properties. The decrease on a per BOE basis is primarily due to the Encore Merger, as the assets acquired have a lower production cost per BOE than Denbury's legacy assets, of which the majority are CO_2 enhanced oil recovery ("EOR").

General and administrative expenses totaled $139.7 million during 2010, a 30% increase from 2009 levels, due primarily to incremental administrative expense incurred as a result of the Encore Merger. In addition, during 2010 we incurred $92.3 million of transaction costs associated with the Encore Merger, primarily associated with employee severance and third-party fees. Encore Merger related fees are included in our income statement under the caption "Transaction costs and other related to the Encore Merger." Interest expense also increased during 2010, primarily due to our issuance of $1.0 billion of senior subordinated notes due 2020 in February 2010, debt assumed in the Encore Merger, and slightly less interest capitalization.

Merger with Encore Acquisition Company. On March 9, 2010, we acquired Encore pursuant to the Encore Merger Agreement entered into with Encore on October 31, 2009. The Encore Merger Agreement provided for a stock and cash transaction valued at approximately $4.8 billion at the acquisition date, including the assumption of Encore debt and the value of the noncontrolling interest in ENP. Under the Encore Merger Agreement, Encore was merged with and into Denbury, with Denbury surviving the Encore Merger. The Encore Merger was consummated on March 9, 2010.

In the Encore Merger, we issued approximately 135.2 million shares of our common stock and paid approximately $833.9 million in cash to Encore stockholders. The Denbury shares issued to Encore stockholders represented approximately 34% of our common stock issued and outstanding immediately after the Encore Merger. The total fair value of the Denbury common stock issued to Encore stockholders pursuant to the Encore Merger was approximately $2.1 billion based upon our closing price of $15.43 per share on March 9, 2010. See Note 2, *Acquisitions and Divestitures*, to the Consolidated Financial Statements for additional information.

The Encore Merger was financed through a combination of $1.0 billion of 8¼% Senior Subordinated Notes due 2020, (the "2020 Notes"), which we issued on February 10, 2010, a new $1.6 billion revolving credit agreement (the "Credit Agreement") entered into on March 9, 2010, and the assumption of Encore's remaining outstanding senior subordinated notes. We structured the financing of the Encore Merger to provide $600 million to $700 million of availability under the new bank facility upon closing the transaction in order to provide a level of liquidity similar to our liquidity prior to the Encore Merger.

Pursuant to our intent to divest non-strategic legacy Encore properties, properties in the Permian Basin, Mid-continent area and East Texas Basin (collectively, the "Southern Assets") and in the Cleveland Sand Play were sold during the second and third quarters of 2010. During the fourth quarter of 2010, we sold our legacy Encore Haynesville and East Texas natural gas properties and sold our ownership interests in ENP. Aggregate proceeds from these 2010 transactions included approximately $1.5 billion in cash and 3,137,255 common units of Vanguard Natural Resources LLP ("Vanguard") (NYSE:VNR) as part of the ENP sale. At December 31, 2010, the Vanguard common units had a value of approximately $93 million. In addition, Vanguard assumed $234 million of ENP bank debt. Proceeds were used to reduce our bank debt during 2010, which increased as a result of the Encore Merger, and provide additional liquidity which we plan to use to fund a portion of our capital spending in 2011 and repay up to $125 million of our senior subordinated notes in early 2011 (see *Capital Resources and Liquidity* below). For all Encore legacy properties disposed of during 2010, we reduced our full cost pool by the amount of the net proceeds and did not record a gain or loss on the sale in accordance with the full cost method of accounting. See Note 2, *Acquisitions and Divestitures*, to the Consolidated Financial Statements for further discussion of these transactions.

Completion of Green Pipeline. The Green Pipeline is a 325-mile CO_2 pipeline that runs from Southern Louisiana to near Houston, Texas. In June 2010, we placed the first 267 miles of the Green Pipeline from Southern Louisiana to our Oyster Bayou Field in Southeast Texas in service, and we began CO_2 injections at Oyster Bayou Field. During December 2010, we placed the remaining portion of the Green Pipeline from Oyster Bayou Field to Hastings Field in service, and we began CO_2 injections at Hastings Field. The Green Pipeline is also expected to service other tertiary operations along the Gulf Coast.

Acquisition of reserves in Rocky Mountain region at Riley Ridge. In October 2010, we acquired a 42.5% non-operated working interest in the Riley Ridge Federal Unit ("Riley Ridge"), located in southwestern Wyoming, together with approximately 33% of the CO_2 mineral rights in an additional 28,000 acres adjoining Riley Ridge in which we own a non-operating interest, for consideration of $132.3 million after preliminary closing adjustments.

Riley Ridge has proved and probable natural gas, helium and CO_2 reserves. The first production of natural gas and helium from Riley Ridge is expected to occur in late 2011 after the operator completes construction of the processing facilities to separate the natural gas and helium. The net development costs to our interest were approximately $9 million during 2010, are expected to be approximately $42 million in 2011, and are primarily associated with constructing the processing facilities that will separate the natural gas and helium. Any potential tertiary oil production using the CO_2 from Riley Ridge is contingent on the development of facilities to separate the CO_2 from the hydrogen sulfide ("H_2S") along with a pipeline framework and significant capital expenditures.

The full well stream at Riley Ridge is expected to contain approximately 68% CO_2, 19% natural gas, 12% H_2S and 1% helium and other gases. Currently, the operator plans to re-inject the CO_2 and H_2S; however, we have the right to separate and take the CO_2 and re-inject the H_2S. At this time, we are evaluating other potential CO_2 sources in the region, and therefore, we have not committed to a definitive timetable for utilization of the Riley Ridge CO_2 reserves in our tertiary oil fields in the Rocky Mountain region.

Sale of Interests in Genesis. In February 2010, we sold our interest in Genesis Energy, LLC, the general partner of Genesis Energy, L.P., for net proceeds of approximately $84 million, after giving effect to the change of control provision of the incentive compensation agreement with Genesis' management, which was triggered and under which we paid a total of $14.9 million comprised of deferred compensation of $1.9 million and a change of control redemption of $13.0 million. In February 2010, we recognized general and administrative expense of $1.1 million associated with the $14.9 million payment. The remainder of the payment had been previously accrued in our Consolidated Financial Statements as of December 31, 2009. In March 2010, we sold all of our Genesis common units in a secondary public offering for net proceeds of approximately $79 million. As a result, we no longer hold any interest in Genesis. We recognized a pre-tax gain of approximately $101.5 million ($63.0 million after tax) on these dispositions.

February 2011 Debt Issuance and Tender Offer

On February 3, 2011, we commenced cash tender offers to purchase any and all of our outstanding $225 million in principal amount of our 7½% Senior Subordinated Notes due 2013 ("2013 Notes") and $300 million in principal amount of our 7½% Senior Subordinated Notes due 2015 ("2015 Notes"). On February 16, 2011, the early consent date, we accepted for purchase $169.5 million in principal of the 2013 Notes at 100.625% of par and $220.9 million in principal of the 2015 Notes at 104.125% of par. The tender offers will expire on March 3, 2011. The tenders accepted for repurchase on February 16, 2011 were primarily funded with $393 million in net proceeds from our February 17, 2011 issuance of $400 million of 6⅜% Senior Subordinated Notes due 2021 ("2021 Notes"). The 2021 Notes, which carry a coupon rate of 6.375%, were sold at par. On February 17, 2011, we called for redemption all of the remaining outstanding 2013 and 2015 Notes and will fund the remaining repurchases with cash on hand. The net impact of these refinancing transactions is expected to result in the utilization of approximately $147 million of cash on hand including $125 million for the repurchase of the principal amount of the 2013 Notes and 2015 Notes, $14 million in premiums on the notes and $8 million of fees and expenses.

Capital Resources and Liquidity

In order to facilitate the financing of the Encore Merger and to retire approximately $600 million of Encore's subordinated debt, in early 2010 we entered into a new $1.6 billion, four-year bank facility and issued $1.0 billion in 8¼% Senior Subordinated Notes due 2020. During 2010, in order to reduce the bank debt incurred to acquire Encore, we sold non-strategic properties that were included in the Encore Merger as well as our ownership interests in ENP. In the aggregate, these transactions generated approximately $1.5 billion of cash and $93 million of Vanguard common units, which provided adequate cash to repay all of our credit facility as of December 31, 2010, fund our acquisition of Riley Ridge, and leave us with $381.9 million of cash and $93 million of Vanguard common units at December 31, 2010, more than ample liquidity to cover our 2011 planned capital expenditures in excess of anticipated cash flow (see further discussion below).

In early February 2011, in conjunction with refinancing a portion of our senior subordinated notes, we made tender offers to purchase our $225 million of 7½% Senior Subordinated Notes due 2013, at 100.625% of par, and our $300 million of 7½% Senior Subordinated Notes due 2015, at 104.125% of par. To partially fund these repurchases, we issued $400 million of 6½% Senior Subordinated Notes due August 2021. We estimate that we will utilize approximately $147 million of cash on hand including $125 million for the repurchase of the principal amount of the 2013 Notes and 2015 Notes, $14 million of premiums on these notes and $8 million of fees and expenses. See *February 2011 Debt Issuance and Tender Offer* above.

We estimate our 2011 capital spending will be approximately $1.2 billion, net of equipment leases and including approximately $100 million for capitalized interest and startup costs associated with new tertiary floods. Our current 2011 capital budget includes the following:

- $420 million allocated for tertiary oil field expenditures,
- $300 million for development of our Bakken properties,
- $219 million for pipeline construction and maintenance,
- $71 million to be spent in the Jackson Dome area,
- $100 million of capitalized interest and startup costs, and
- $90 million in all other areas.

This estimate of our 2011 capital spending assumes that we fund approximately $60 million of budgeted equipment purchases with operating leases, which is dependent upon securing acceptable financing. If we do not enter into a total of $60 million of operating leases during 2011, our net capital expenditures would increase accordingly, and we would anticipate funding those additional capital expenditures with our available cash or borrowings under our bank credit facility.

Based on oil and natural gas commodity futures prices as of late February 2011 and our current 2011 production forecasts, our 2011 capital budget is expected to be $100 million to $200 million greater than our anticipated cash flow from operations. We plan to fund this shortfall with cash on hand at December 31, 2010 and, if necessary, borrowings under our bank facility. Also, we could potentially monetize the Vanguard common units we hold; however, registration rights regarding those units do not become available to us until August 2011. As of February 25, 2011, we had $130 million of bank debt outstanding on our $1.6 billion bank facility and estimated cash of $422 million, leaving us significant liquidity to fund any shortfall. To help protect our cash flows in case commodity prices were to decrease significantly from the levels of futures strip prices near the end of February 2011, we currently have oil and natural gas derivative commodity contracts in-place through mid-2012 covering approximately 80-85% of our anticipated 2011 oil and natural gas production and 75-80% of our anticipated first half 2012 oil and natural gas production. We are primarily dependent on oil prices, as approximately 90% of our continuing production (excluding production from properties sold) is oil, and most of our oil contracts are costless collars with a NYMEX floor price of $70 per barrel. See Note 9, *Derivative Instruments and Hedging Activities,* to the Consolidated Financial Statements for further details regarding pricing and volumes of our commodity derivative contracts.

We continually monitor our capital spending and anticipated cash flows and believe that we can adjust our capital spending up or down depending on cash flows; however, any such reduction in capital spending could reduce our anticipated production levels in future years. For 2011, we have contracted for certain capital expenditures and therefore we cannot eliminate all of our capital commitments without penalties (refer to *Off-Balance Sheet Arrangements — Commitments and Obligations* for further information regarding these commitments).

As part of our semi-annual bank review, on November 1, 2010, our borrowing base for our bank credit facility was reaffirmed at $1.6 billion. Our next borrowing base re-determination is scheduled for May 1, 2011 and we currently do not anticipate any reduction in our borrowing base as part of our next re-determination.

Capital Expenditure Summary for 2010. The following table of capital expenditures includes accrued capital for each period.

	Year Ended December 31,		
In thousands	**2010**	**2009**	**2008**
Oil and natural gas exploration and development:			
Drilling	$ 291,516	$ 45,403	$ 244,841
Geological, geophysical and acreage	26,594	15,004	18,183
Facilities	144,337	154,772	170,263
Recompletions	170,897	73,968	140,451
Capitalized interest	32,593	14,350	17,627
Total oil and natural gas exploration and development expenditures	665,937	303,497	591,365
CO_2 and other products — capital expenditures:			
CO_2 pipelines and facilities	209,198	542,654	343,043
CO_2 acreage, geological and drilling	29,071	33,302	108,312
Other products capital expenditures	8,927	—	—
Capitalized interest	34,222	54,246	11,534
Total CO_2 capital expenditures	281,418	630,202	462,889
Total capital expenditures excluding acquisitions	947,355	933,699	1,054,254
Oil and natural gas property acquisitions	25,672	621,517	31,367
Consideration for Encore Merger(1)	2,952,515	—	—
Consideration for Riley Ridge acquisition	132,257	—	—
Total	$ 4,057,799	$ 1,555,216	$ 1,085,621

(1) Consideration given in Encore Merger includes $2.09 billion for the fair value of Denbury common stock issued.

Our 2010 capital expenditures, excluding the Encore acquisition, were funded with $855.8 million of cash flow from operations and incremental cash generated from the sale of non-strategic assets discussed above.

Net cash used to acquire Encore was approximately $815 million, which was funded with incremental debt as discussed above in *Overview — Merger with Encore Acquisition Company.*

Our 2009 capital expenditures were funded with $530.6 million of cash flow from operations, $516.8 million in net proceeds from the sale of oil and natural gas properties, $381.4 million in net proceeds from the February issuance of senior subordinated debt, $168.7 million from the issuance of 11,620,000 shares of our common stock in the acquisition of Conroe Field and $50.0 million in net bank borrowings.

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 the sale of oil and natural gas properties.

Off-Balance Sheet Arrangements — Commitments and Obligations. At December 31, 2010, our largest contractual payment obligation that is not on our balance sheet relates to our operating leases, which at year-end 2010 totaled $237.2 million, 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, 2010, we had a total of $10.9 million of letters of credit outstanding under our bank credit agreement. Additionally, we have 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 and asset retirement obligations. For a further discussion of our future development costs and proved reserves, see the contractual obligations table below.

Included in our obligations for development and exploratory expenditures are those related to our February 2009 purchase of Hastings Field. Under the agreement, we are required to make aggregate cumulative capital expenditures in this field of approximately $179 million cumulating as follows: $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 inject an average of at least 50 MMcf/d 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 rate in the Hastings Field equals or exceeds the minimum required injection rate. As of December 31, 2010, we are, and believe we will continue to be, compliant with both of these commitments.

We have entered into long-term contracts to purchase man-made CO_2 from nine proposed plants that will emit large volumes of CO_2, four of which are in the Gulf Coast region, four in the Midwest region (Illinois, Indiana, and Kentucky) and one in the Rocky Mountain region. The Midwest purchases are conditioned on both the specific plant being constructed and Denbury contracting enough volumes of CO_2 for purchase in the general area of our proposed Midwest pipeline system, such that an acceptable economic rate-of-return on the CO_2 pipeline will be achieved. At the present time, two of the Midwest facilities have been unable to meet a critical contractual obligation and thus Denbury is evaluating these two projects to determine if we should extend the time for the facility to meet the contractual obligation. If all nine of these plants were to be built, these CO_2 sources are currently anticipated to provide us with aggregate CO_2 volumes of 1.2 Bcf/d to 2.0 Bcf/d, although the earliest source of this man-made CO_2 is not expected to be available to us until 2014. Although these plants have all been delayed due to economic conditions, over the last six to nine months several of the projects appear to be making progress, but there is still some doubt as to whether they will be constructed at all. Several of these plants are in negotiations for federal support through grants and loan guarantees, which if secured, could increase the possibility that certain plants will be ultimately constructed. 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 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 nine plants are built, the aggregate purchase obligation for this CO_2 would be around $320 million per year, assuming an $85 per barrel NYMEX 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 other plants under consideration that could provide CO_2 to us that would either supplement or replace some of the CO_2 volumes from the nine proposed plants for which we currently have CO_2 output purchase contracts. We have ongoing discussions with several of these other potential sources.

We are subject to audits for sales and use taxes and severance taxes in the various states in which we operate, and from time to time receive assessments for potential taxes that we may owe. We have received a $14.9 million assessment from the Mississippi taxing authority for use tax, penalties and interest covering the 2004-2007 period, which has been appealed. We do not believe the outcome of this matter will have a material adverse impact on the Company.

A summary of our obligations at December 31, 2010, is presented in the following table:

	Payments Due by Period						
In thousands	Total	2011	2012	2013	2014	2015	Thereafter
Contractual Obligations:							
Subordinated debt(a)	$ 2,176,350	$ —	$ —	$ 225,000	$ 1,072	$ 300,485	$ 1,649,793
Estimated interest payments on subordinated debt(a)	1,229,459	184,763	184,763	172,049	167,841	166,760	353,283
Pipeline lease obligations(b)	538,194	30,882	31,926	34,280	34,114	31,847	375,145
Operating lease obligations	237,156	34,027	32,930	31,733	27,519	26,759	84,188
Capital lease obligations(c)	8,040	2,987	2,213	1,446	673	106	615
Capital expenditure obligations(d)	581,092	326,930	168,455	49,673	35,873	138	23
Derivative contracts payment(e)	36,408	27,558	8,850	—	—	—	—
Other Cash Commitments:							
Future development costs on proved oil and gas reserves, net of capital obligations(f)	1,527,949	486,271	575,838	257,594	100,320	55,623	52,303
Future development cost on proved CO_2 reserves, net of capital obligations(g)	114,076	5,076	—	—	22,000	—	87,000
Asset retirement obligations(h)	262,236	4,883	1,302	1,604	755	4,723	248,969
Total	$ 6,710,960	$ 1,103,377	$ 1,006,277	$ 773,379	$ 390,167	$ 586,441	$ 2,851,319

(a) These long-term borrowings and related interest payments are further discussed in Note 5, *Notes Payable and Long-Term Indebtedness*, to the Consolidated Financial Statements. This table assumes that our long-term debt is held until maturity. During February 2011, we repurchased a portion of our 2013 Notes and 2015 Notes and issued $400 million in additional senior subordinated notes. See Note 15, *Subsequent Events,* 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 financing lease are computed based upon our internal forecasts. Approximately $290 million of these payments represent interest. See Note 5, *Notes Payable and Long-Term Indebtedness,* to the Consolidated Financial Statements.

(c) Represents future minimum cash commitments of $3.5 million to Genesis under capital leases in place at December 31, 2010, primarily for transportation of crude oil and CO_2, and $4.5 million for office space and rental equipment. Approximately $1.2 million of these payments represents interest.

(d) Represents future cash commitments under contracts in place as of December 31, 2010, primarily for pipe, pipeline construction contracts, drilling rig services and well-related costs. As is common in our industry, we commit to make certain expenditures on a regular basis as part of our ongoing development and exploration program. These commitments generally relate to projects that occur during the subsequent several months and are usually part of our normal operating expenses or part of our capital budget, which for 2011 is currently set at $1.2 billion, exclusive of acquisitions. In certain cases we have the ability to terminate contracts for equipment in which case we would be liable only 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 the estimated future payments under our oil and natural gas derivative contracts based on the futures market prices as of December 31, 2010. These amounts will change as oil and natural gas commodity prices change. The estimated fair market value of our oil and natural gas commodity derivatives at December 31, 2010, was a $44 million net liability. See further discussion of our derivative contracts and their market price sensitivities in *Market Risk Management* below in this *Management's Discussion and Analysis of Financial Condition and Results of Operations,* and in Note 9, *Derivative Instruments and Hedging Activities,* to the Consolidated Financial Statements.

(f) Represents projected capital costs as scheduled in our December 31, 2010 proved reserve report that are necessary in order to recover our proved 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.

(g) Represents projected capital costs as scheduled in our December 31, 2010 proved reserve report that are necessary in order to recover our proved 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.

(h) Represents the estimated future asset retirement obligations on an undiscounted basis. The present discounted asset retirement obligation is $85.7 million, as determined under the *Asset Retirement and Environmental Obligations* topic of the FASC, and is further discussed in Note 3, *Asset Retirement Obligations,* to the Consolidated Financial Statements.

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 ("VPPs"). 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 382 Bcf of CO_2 to these customers over the next 17 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 194 Bcf. The maximum volume required in any given year is approximately 136 MMcf/d. Given the size of our Jackson Dome proved CO_2 reserves at December 31, 2010 (approximately 7.1 Tcf before deducting approximately 100.2 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.

Concurrent with our purchase of an interest in the Riley Ridge Field, we became party to a long-term helium supply agreement whereby the participants in the Riley Ridge Field will supply helium to a purchaser for a period of 20 years beginning at the earlier of the start-up of the Riley Ridge plant or December 31, 2011. The agreement provides for annual delivery of 200 MMcf for the first two years and 400 MMcf for the remaining term of the contract. If the guaranteed quantity of helium is not supplied, the suppliers will compensate the purchaser for the amount of the shortfall in an amount not to exceed $8.0 million per year, of which the Company's share would be $3.4 million. The start-up of the Riley Ridge plant is expected to occur in late 2011.

Results of Operations

CO_2 Operations

Overview. Since we acquired our first CO_2 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 CO_2 and we have continued to expand our CO_2 resources and acquire oil fields throughout the Gulf Coast region that have the potential to produce significant amounts of oil from CO_2 injection. In March 2010 we acquired Encore for the primary purpose of expanding our tertiary operations to a new core area in the Rocky Mountain region, and our acquisition of an interest in Riley Ridge later in 2010 further supports this strategy as it potentially provides us a large source of CO_2. Although our development of tertiary operations in this new area is just beginning, we believe there are sufficient potential sources of CO_2 in this area to provide us the opportunity to utilize CO_2 injection and to potentially recover significant amounts of incremental oil from old oil fields in this area.

Our tertiary operations have grown to the point that approximately 41% of our December 31, 2010 proved oil and natural gas reserves are proved tertiary oil reserves and almost 49% of our forecasted 2011 oil and natural gas production is expected to come from tertiary oil operations (on a BOE basis). We particularly like this play as (1) it has a lower risk as we are working with oil fields that have significant historical production and data, (2) it provides a reasonable rate of return at relatively low oil prices (we estimate that our economic break-even point on a per barrel basis before corporate overhead and expenses on these projects at current oil prices is in the mid-to-upper $30 per barrel range, depending on the specific field and area), and (3) we have limited competition for this type of activity in our geographic regions. Our Gulf Coast region is more fully developed, as we have been conducting tertiary recovery in this area for over 11 years. Since we are just beginning our tertiary operations in the Rocky Mountain region, we have significantly fewer oil fields, CO_2 sources and CO_2 pipelines in this region, although we are pursuing the addition of all three. In the Gulf Coast region, we own the only known significant natural resource of CO_2 in the area, and these large volumes of CO_2 drive the play. In addition to the sources of CO_2 we currently have, 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. We are continuing to expand our CO_2 pipeline infrastructure to transport CO_2.

We refer to our Gulf Coast tertiary operations by labeling our operating areas or groups of fields as Phases:

- Phase 1 is in southwest Mississippi and includes several fields along our 183-mile NEJD CO_2 Pipeline that we acquired in 2001. The current tertiary fields in this area are Little Creek, Mallalieu, McComb, Brookhaven and Lockhart Crossing;

- Phase 2, which began with the early 2006 completion of the Free State CO_2 Pipeline to east Mississippi, currently includes Eucutta, Soso, Martinville and Heidelberg Fields;

- Phase 3, which includes Tinsley Field, is located northwest of Jackson, Mississippi, was acquired in January 2006, and is serviced by that portion of the Delta CO_2 Pipeline completed in January 2008;

- Phase 4 includes Cranfield and Lake St. John Fields, two fields near the Mississippi/Louisiana border located west of the Phase 1 fields;

- Phase 5 is Delhi Field, a Louisiana field we acquired in 2006, located southwest of Tinsley Field. Our first tertiary oil response from Delhi Field occurred during early 2010;

- Phase 6 is Citronelle Field in southwest Alabama, another field acquired in 2006, which will require an extension to the Free State CO_2 Pipeline or another pipeline depending on the ultimate CO_2 source for this field, the timing of which is uncertain at this time;

- Phase 7 is Hastings Field in southeast Texas, a field we purchased in February 2009, where we commenced CO_2 injections during December 2010 in conjunction with placing the final leg of the Green Pipeline into service;

- Phase 8 is Seabreeze Complex in southeast Texas, acquired in 2007, where we initiated CO_2 injections at Oyster Bayou Field in June 2010; and

- Phase 9 is Conroe Field, a field we purchased in December 2009, which will require construction of an additional CO_2 pipeline to connect the field to the Green Pipeline in southeast Texas.

In the Rocky Mountain region, we have two fields that we acquired in the Encore Merger that we plan to flood with CO_2, Bell Creek Field and Cedar Creek Anticline. We must first build a pipeline to these fields; we plan to begin construction in 2011. We plan to begin injection of CO_2 at Bell Creek Field in late 2012 or early 2013. See further discussion regarding our tertiary operations in Item 1, Business — *Oil and Natural Gas Operations — Rocky Mountain Region — Future Tertiary Properties without Proved Tertiary Reserves or Tertiary Production at December 31, 2010*.

CO_2 Resources. Since we acquired the Jackson Dome CO_2 source located near Jackson, Mississippi, in 2001, we have continued to develop the area and have increased the proven CO_2 reserves from approximately 800 Bcf at the time of the acquisition to approximately 7.1 Tcf as of December 31, 2010. During 2010, we drilled three additional CO_2 source wells, and we increased our CO_2 reserves by approximately 1.0 Tcf, more than offsetting the 311.1 Bcf of CO_2 produced during the year. The estimate of 7.1 Tcf of proved Gulf Coast CO_2 reserves is based on 100% ownership of the CO_2 reserves, of which our net revenue interest ownership is approximately 5.6 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 our tertiary recovery programs, industrial users, and volumetric production payments with Genesis, as we are responsible for distributing the entire CO_2 production stream for all of these uses. We currently estimate that it will take approximately 2.5 Tcf of CO_2 to develop and produce the proved tertiary oil recovery reserves we have recorded at December 31, 2010, in Phases 1-5.

Today, we own every known producing CO_2 well in the Gulf Coast 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 28, 2011, we estimate that we are capable of producing and transporting approximately 1.1 Bcf/d of CO_2, approximately 10 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 four more wells planned for 2011 in order to further increase our proved CO_2 reserves and production capacity. Our drilling activity at Jackson Dome will continue beyond 2011, as our current forecasts for the existing nine phases suggest that we will need approximately 1.5 Bcf/d of CO_2 production by 2017.

In addition to using CO_2 for our Gulf Coast 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 2010, 2009 and 2008 was approximately 852 MMcf/d, 683 MMcf/d and 637 MMcf/d, respectively, of which approximately 87% in 2010, 87% in 2009 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.

Our cost to produce, transport and pay royalties for the CO_2 we utilize in our tertiary floods was approximately $0.22 per Mcf in 2010, as compared to our 2009 average cost of $0.17 per Mcf, and 2008 average cost of $0.22 per Mcf. The changes in our cost of CO_2 are primarily directly attributable to changes in oil prices, as the royalty we pay is directly tied to oil prices. Our CO_2 costs gradually increased throughout 2010 from $0.20 per Mcf in the first quarter to $0.24 per Mcf in the fourth quarter of 2010, corresponding to the increase in oil prices. Our estimated total cost per thousand cubic feet of CO_2 during 2010 was approximately $0.30 per Mcf, after inclusion of depreciation and amortization expense related to the CO_2 production, as compared to approximately $0.25 per Mcf during 2009 and $0.30 per Mcf during 2008.

In addition to our natural source of CO_2 and the proposed gasification plants discussed above (see *Off-Balance Sheet Arrangements — Commitments and Obligations*), we continue to have ongoing discussions with owners of existing plants of various types that emit CO_2 that we may be able to purchase. In order to capture such volumes, we (or the plant owner) would need to install additional equipment, which includes 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 Pipeline or planned Greencore Pipeline. The capture of CO_2 could also be influenced by potential 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 areas of operation because of the scale of our tertiary operations, our CO_2 pipeline infrastructure, and our large natural sources of CO_2, which can act as a swing CO_2 source to balance CO_2 supply and demand.

Overview of Tertiary Economics. When we began our Gulf Coast 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 and higher oil prices, and we estimate that our current break-even for our Gulf Coast operations, before corporate overhead and interest, is in the mid-to-upper $30 per barrel range if oil prices remain at their current level (approximately $85-$90 per barrel). Our inception-to-date finding and development costs (including future development and abandonment costs but excluding expenditures on fields without proven reserves) for our Gulf Coast tertiary oil fields through December 31, 2010, are approximately $13.05 per BOE. Currently, we forecast that finding and development costs will average less than $10 per BOE over the life of each field, excluding pipeline infrastructure, and less than $12 per BOE over the life of each field, including pipeline infrasructure, 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. Our finding and development costs to date do not include additional probable reserves in fields with current proved reserves. Our operating costs for our Gulf Coast tertiary operations are highly dependent on commodity prices and could range from $20 per BOE to $25 per BOE over the life of each field, again depending on the field itself.

Although we have yet to commence tertiary operations in our Rocky Mountain region, it is our expectation that our tertiary operating costs, including the cost of CO_2 resources, will be higher than our tertiary operating costs in the Gulf Coast region. The primary factor contributing to this increase is that while our current source for CO_2 in the Gulf Coast region is a natural source completely operated and controlled by us, potential sources of CO_2 in the Rocky Mountain region will require some degree of processing and may involve joint operations or purchase agreements with third parties, all of which will contribute to higher costs. However, pipeline construction costs in the Rocky Mountain region are anticipated to be lower than those incurred in the Gulf Coast region due to differing geographic and regulatory factors.

While these economic factors have wide ranges, our rate of return from these operations has generally been higher than our rate of return on traditional oil and gas operations, and thus our tertiary operations have become our single most important area of focus. While it is difficult to accurately forecast future production, we do believe 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 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. We must build facilities, and often a CO_2 pipeline to the field, before CO_2 flooding can commence, and it usually takes six to twelve 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. However, on an overall basis, future development costs of our tertiary operations tend to be lower than those in conventional oil operations.

Second, tertiary projects may be more expensive to operate than 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). The costs of our CO_2 and the electricity required to recycle and inject this CO_2 comprise almost half of our typical tertiary operating expenses, and since these costs vary along with commodity and electrical prices, they 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 2010 the cost of our CO_2 varied from \$0.20 per Mcf to \$0.24 per Mcf. Most of our CO_2 operating costs are allocated to our tertiary oil fields and recorded as lease operating expenses (following the commencement of tertiary oil production) at the time the CO_2 is injected, and these costs have historically represented over 25% of the total operating costs for our tertiary operations. 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**.* In our Gulf Coast region, we currently have tertiary operations ongoing at all planned Phase 1 fields; at Soso, Martinville, Eucutta and Heidelberg Fields in Phase 2; Tinsley Field in Phase 3; Cranfield Field in Phase 4; Delhi Field in Phase 5; Hastings Field in Phase 7; and Oyster Bayou Field in Phase 8. 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 projects and phases. As of December 31, 2010, we had approximately 163.3 MMBbls of proved oil reserves related to tertiary operations (42.7 MMBbls in Phase 1, 49.2 MMBbls in Phase 2, 33.8 MMBbls in Phase 3, 8.2 MMBbls in Phase 4, and 29.4 MMBbles in Phase 5), representing about 41% 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 39.4 MMBbls of tertiary-related proved oil reserves during 2010, primarily initial proven tertiary oil reserves at Delhi Field in Phase 5. 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 from new floods and the performance of our existing floods.

Our average annual oil production from our CO_2 tertiary recovery activities has increased over time, from 3,970 Bbls/d in 2002 to 29,062 Bbls/d during 2010 (31,139 Bbls/d during the fourth quarter of 2010). Tertiary oil production represented approximately 54% of our continuing oil production during 2010 and approximately 49% of our continuing 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 fluctuations 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. A detailed discussion of each of our tertiary oil fields and the development of each is included in Item 1. *Business.* The following chart shows our tertiary oil production by field by quarter for 2010 and for the years ending December 31, 2010, 2009 and 2008:

Tertiary Oil Field	Average Daily Production (BOE/d)						
	First Quarter 2010	Second Quarter 2010	Third Quarter 2010	Fourth Quarter 2010	Year Ended December 31, 2010	2009	2008
Phase 1:							
Brookhaven	3,416	3,277	3,323	3,699	3,429	3,416	2,826
McComb area	2,289	2,160	2,484	2,433	2,342	2,391	1,901
Mallalieu area	3,443	3,628	3,279	3,164	3,377	4,107	5,686
Other	2,817	3,282	3,343	3,361	3,202	2,306	1,869
Phase 2:							
Heidelberg	1,708	1,857	2,806	3,422	2,454	651	—
Eucutta	3,792	3,625	3,284	3,286	3,495	3,985	3,109
Soso	3,213	3,207	3,016	2,828	3,065	2,834	2,111
Martinville	927	764	606	586	720	877	865
Phase 3:							
Tinsley	4,419	5,248	6,024	6,614	5,584	3,328	1,010
Phase 4:							
Cranfield	936	811	855	1,043	911	448	—
Phase 5:							
Delhi	63	648	511	703	483	—	—
Total tertiary oil production (BOE/d)	27,023	28,507	29,531	31,139	29,062	24,343	19,377
Tertiary operating expense per Bbl	$ 22.67	$ 21.37	$ 22.54	$ 22.26	$ 22.21	$ 21.67	$ 23.57

Oil production from our tertiary operations increased to an average of 29,062 Bbls/d during 2010, a 19% increase over our 2009 tertiary production level of 24,343 Bbls/d. Tertiary oil production during the fourth quarter of 2010 averaged 31,139 Bbls/d, an 18% increase over the fourth quarter 2009 levels, and a 5% sequential increase from third quarter 2010 levels. These year-over-year increases are the result of production growth in response to continued expansion of the tertiary floods in our Tinsley, Heidelberg, Cranfield, and Lockhart Crossing Fields, and to initial production response from Delhi Field during 2010. Offsetting these production gains were declines in our Mallalieu and Eucutta Fields, production from which has most likely peaked and will most likely continue to decline. With the Green Pipeline complete, we initiated CO_2 injections at Oyster Bayou Field (Phase 8) and Hastings Fields (Phase 7) during June 2010 and December 2010, respectively. We currently anticipate tertiary production responses at both Hastings and Oyster Bayou Fields in late 2011 or early 2012, depending on the date of completion of our CO_2 recycle facilities at those fields. We recently received the regulatory approvals required to commence construction of the CO_2 recycling facilities at Hastings and Oyster Bayou Fields, which we had been waiting on for several months, and we expect to begin construction of these facilities in the first quarter of 2011.

During 2010, operating costs for our tertiary properties averaged $22.21 per Bbl, higher than the prior year's average of $21.67 per Bbl. During the fourth quarter of 2010, the operating costs on our tertiary properties averaged $22.26 per Bbl as compared to $22.03 per Bbl in the fourth quarter of 2009 and $22.54 per Bbl during the third quarter of 2010. Our per barrel costs in 2010 are higher than in 2009 due primarily to the higher cost of CO_2 during this period. On a per barrel basis, our cost of CO_2 increased by $1.09 per Bbl, from $3.96 per Bbl in 2009 to $5.05 per Bbl in 2010, primarily due to the increase in oil prices to which our CO_2 costs are partially tied. Our single highest cost for our tertiary operations is our cost for fuel and utilities, which averaged $5.93 per Bbl in 2010, $5.76 per Bbl in 2009 and $5.39 per Bbl in 2008, which has increased on a per barrel basis due to continued expansion of our tertiary floods. For any specific field, we expect our tertiary lease operating expense per BOE to be high initially and then decrease as production increases, ultimately leveling off until production begins to decline in the later life of the field, when lease operating expense per BOE will again increase.

Through December 31, 2010, we have invested a total of $2.2 billion in tertiary fields in our Gulf Coast region (including allocated acquisition costs and amounts assigned to goodwill) and have only $5.7 million in unrecovered net cash flow (revenue less operating expenses and capital expenditures). Of this total invested amount, approximately $416.0 million (19%) was spent on fields that have yet to have appreciable proved reserves at December 31, 2010 (i.e., fields for which significant incremental proved reserves are anticipated during 2011 and beyond). The proved oil reserves in our tertiary oil fields have a PV-10 Value of $4.2 billion, using the calendar 2010 first-day-of-the-month 12-month unweighted average NYMEX pricing of $79.43 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. Excluding the Green Pipeline, which currently does not have any proved tertiary revenue associated with it, we have invested a total of $821.6 million in CO_2 assets in the Gulf Coast region.

CO_2 Source Field and Tertiary Oil Field Related Capital Budget for 2011. Our current capital spending plans for 2011, net of capitalized interest, include approximately $71 million to be spent in the Jackson Dome area, with the intent to add CO_2 reserves and deliverability for future operations, approximately $420 million to be spent in development of our tertiary floods, and approximately $219 million to be spent for our CO_2 pipelines, making our combined CO_2 related expenditures approximately 65% of our $1.2 billion 2011 capital budget.

Operating Results

As summarized in the *Overview* section above, and discussed in further detail below, our operating results decreased from 2008 to 2009, but increased from 2009 to 2010. The operating results for Encore and ENP from March 9, 2010 through December 31, 2010 are included in these results. As we controlled the general partner of ENP until we sold our ownership interests in ENP on December 31, 2010, the operating results of ENP are consolidated with our results of operations, even though we only owned approximately 46% of ENP's common units. The primary factors impacting our operating results were the Encore Merger in 2010, fluctuating commodity prices, changes in the fair value of our oil and natural gas derivative contracts, increases and decreases in production, and the gain on our sale of our interests in Genesis in 2010, which are all explained in more detail below.

Certain of our operating results and statistics for each of the last three years are included in the following table:

In thousands, except per share and unit data	Year Ended December 31, 2010 (1)	2009	2008
Operating results			
Net income (loss) attributable to Denbury stockholders	$ 271,723	$ (75,156)	$ 388,396
Net income (loss) per common share — basic	0.73	(0.30)	1.59
Net income (loss) per common share — diluted	0.72	(0.30)	1.54
Cash flow from operations	855,811	530,599	774,519
Average daily production volumes			
Bbls/d	59,918	36,951	31,436
Mcf/d	78,057	68,086	89,442
BOE/d(2)	72,927	48,299	46,343
Operating revenues			
Oil sales	$ 1,661,380	$ 778,836	$ 1,066,917
Natural gas sales	131,912	87,873	280,093
Total oil and natural gas sales	$ 1,793,292	$ 866,709	$ 1,347,010
Commodity derivative contracts(3)			
Cash receipt (payment) on settlement of commodity derivative contracts	$ (31,612)	$ 146,734	$ (57,553)
Non-cash fair value adjustment income (expense)	53,026	(382,960)	257,606
Total income (expense) from commodity derivative contracts	$ 21,414	$ (236,226)	$ 200,053
Operating expenses			
Lease operating expenses	$ 486,923	$ 326,132	$ 307,550
Production taxes and marketing expenses	129,046	42,484	63,752
Total production expenses	$ 615,969	$ 368,616	$ 371,302
Non-tertiary CO_2 operating margin			
CO_2 sales and transportation fees	$ 19,204	$ 13,422	$ 13,858
CO_2 discovery and operating expenses	(8,212)	(4,649)	(4,216)
Non-tertiary CO_2 operating margin	$ 10,992	$ 8,773	$ 9,642
Unit prices — including impact of derivative settlements(3)			
Oil price per Bbl	$ 71.69	$ 68.63	$ 90.04
Natural gas price per Mcf	6.45	3.54	7.74
Unit prices — excluding impact of derivative settlements			
Oil price per Bbl	$ 75.97	$ 57.75	$ 92.73
Natural gas price per Mcf	4.63	3.54	8.56
Oil and natural gas operating revenues and expenses per BOE(2)			
Oil and natural gas revenues	$ 67.37	$ 49.16	$ 79.42
Oil and natural gas lease operating expenses	$ 18.29	$ 18.50	$ 18.13
Oil and natural gas production taxes and marketing expense	4.85	2.41	3.76
Total oil and natural gas production expenses	$ 23.14	$ 20.91	$ 21.89

(1) Includes the results of operations of Encore and ENP from March 9, 2010, through December 31, 2010.

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

(3) See also *Market Risk Management* below for information concerning the Company's derivative transactions.

Production

Average daily production by area for 2010, 2009 and 2008, and for each of the quarters of 2010 is shown below, as is our estimated pro forma production for the first quarter of 2010 had the production from the properties acquired in the Encore Merger been included with our production for the entire first quarter of 2010:

	Average Daily Production (BOE/d)								
						Year Ended December 31,			
Operating Area	First Quarter 2010 (1)	Pro Forma First Quarter 2010 (2)	Second Quarter 2010	Third Quarter 2010	Fourth Quarter 2010	2010 (3)	Pro Forma 2010 (2)	2009	2008
Gulf Coast Region:									
Tertiary oil fields	27,023	27,023	28,507	29,531	31,139	29,062	29,062	24,343	19,377
Non-tertiary fields:									
Mississippi	7,829	7,829	8,967	7,965	7,293	8,012	8,012	9,937	11,897
Texas	5,235	5,235	5,148	4,824	4,564	4,941	4,941	2,615	514
Louisiana	662	662	775	714	687	709	709	743	624
Alabama and other	997	997	1,078	1,091	1,026	1,049	1,049	1,122	1,231
Total Gulf Coast Region	41,746	41,746	44,475	44,125	44,709	43,773	43,773	38,760	33,643
Rocky Mountain Region:									
Cedar Creek Anticline	2,537	9,830	9,967	9,791	9,328	7,930	9,728	—	—
Bakken	890	3,549	4,500	4,657	5,193	3,824	4,480	—	—
Bell Creek	252	966	997	994	957	802	979	—	—
Paradox	173	675	702	738	716	582	707	—	—
Other	777	2,925	2,944	2,889	2,809	2,362	2,891	—	—
Total Rocky Mountain Region	4,629	17,945	19,110	19,069	19,003	15,500	18,785	—	—
Total Continuing Production	46,375	59,691	63,585	63,194	63,712	59,273	62,558	38,760	33,643
Disposed properties:									
Barnett Shale	—	—	—	—	—	—	—	9,539	12,700
Legacy Encore properties	4,479	17,853	11,684	5,906	4,156	6,556	9,852	—	—
ENP	2,271	9,034	8,842	8,630	8,567	7,098	8,767	—	—
Total Production	53,125	86,578	84,111	77,730	76,435	72,927	81,177	48,299	46,343

(1) Includes production of Encore and ENP from the March 9, 2010 acquisition date.

(2) Represents pro forma production assuming we had reported the production from the Encore Merger between January 1, 2010, and March 8, 2010.

(3) Includes production of Encore and ENP from the March 9, 2010 acquisition date through December 31, 2010, or in the case of non-strategic assets disposed, through the date the asset was sold.

As outlined in the above table, total production increased 24,628 BOE/d (51%) between 2009 and 2010, and 1,956 BOE/d (4%) between 2008 and 2009. The increase from 2009 to 2010 is due primarily to the additional production from the properties acquired in the Encore Merger, a 19% increase in tertiary oil production, and a full year of production from the Conroe Field acquisition, which closed in December 2009. Offsetting these increases are the Barnett Shale dispositions in 2009. Excluding production from the Barnett Shale properties sold during 2009 and production attributable to the non-strategic legacy Encore and ENP properties sold during 2010, production would have averaged 59,273 BOE/d during 2010 and 38,760 BOE/d during 2009, a 53% increase year-to-year. Assuming a full year of production for the acquired Encore properties, our continuing pro forma production (62,558 BOE/d) would have increased 61% rather than 53% over continuing production in 2009. Our production increase between 2008 and 2009 was primarily due to a 26% increase in tertiary oil production and to the February 2009 acquisition of Hastings Field, partially offset by the sale of our Barnett Shale properties and decreases in our Mississippi non-CO_2 floods. The increase in our tertiary oil production is discussed above under *Results of Operations — CO_2 Operations*.

The acquisition of Encore in March 2010 added 29,154 BOE/d to our 2010 production. Excluding the non-strategic legacy Encore and ENP properties sold during 2010, continuing production attributable to Encore averaged 15,500 BOE/d during 2010.

Non-tertiary production in the Heidelberg Field decreased in each of the last three years. Production in this area decreased 19% from 2008 to 2009, and further decreased 22% from 2009 to 2010. Most of this decrease is due to depletion and the development of the Heidelberg CO_2 flood, which resulted in production being shut-in while portions of the field were converted to tertiary operations. When production commences from these CO_2 floods, these volumes produced from the CO_2 floods will be reported as tertiary oil production for Heidelberg Field.

Our production at CCA averaged 9,328 BOE/d during the fourth quarter of 2010, a decrease of 5% as compared to third quarter 2010 levels due in part to natural production declines. Production from our Bakken properties averaged 5,193 BOE/d during the fourth quarter of 2010, an increase of 12% as compared to third quarter 2010 production levels. The production increases in the Bakken during 2010 are due to the on-going drilling and hydraulic fracturing in this area.

Overall production for the fourth quarter of 2010 decreased from third quarter 2010 levels due to the sale of the Haynesville and East Texas natural gas properties in early December 2010. The sale of our ownership interests in ENP during December 2010 will further reduce our overall production for the first quarter of 2011.

Our production during 2010 was 82% oil as compared to 77% during 2009 and 68% during 2008. These increases are due to the sale of our natural gas-rich Barnett Shale properties in the second half of 2009, the acquisition of interests in the oil-rich Hastings Field in February 2009, the acquisition of interests in the oil-rich Conroe Field in December 2009, and the increase in our tertiary operations, partially offset by the non-strategic natural gas properties that we acquired in the Encore Merger and subsequently sold during 2010. Pro forma for the sales of Haynesville and East Texas properties and our interests in ENP, fourth quarter 2010 production would have been 92% oil.

Oil and Natural Gas Revenues

Fluctuating commodity prices resulted in a decline in our oil and natural gas revenue between 2008 and 2009, but resulted in a sharp increase between 2009 and 2010. Our increasing production partially offset the revenue decrease from commodity prices between 2008 and 2009 and added to the revenue increase between 2009 and 2010. These changes in revenues, excluding any impact of our derivative contracts, are reflected in the following table:

	Year Ended December 31, 2010 vs. 2009		Year Ended December 31, 2009 vs. 2008	
In thousands	Increase in Revenues	Percentage Increase in Revenues	Increase (Decrease) in Revenues	Percentage Increase (Decrease) in Revenues
Change in revenues due to:				
Increase in production	$ 441,959	51%	$ 53,051	4%
Increase (decrease) in commodity prices	484,624	56%	(533,352)	(40%)
Total increase (decrease) in revenues	$ 926,583	107%	$ (480,301)	(36%)

Excluding any impact of our derivative contracts, our net realized commodity prices and NYMEX differentials were as follows during 2010, 2009 and 2008:

	Year ended December 31,		
	2010	2009	2008
Net Realized Prices:			
Oil price per Bbl	$ 75.97	$ 57.75	$ 92.73
Natural gas price per Mcf	4.63	3.54	8.56
Price per BOE	67.37	49.16	79.42
NYMEX Differentials:			
Oil per Bbl	$ (3.54)	$ (4.21)	$ (7.02)
Natural gas per Mcf	0.23	(0.63)	(0.33)

Our Company-wide oil NYMEX differential improved during 2010 over our differential in 2009 primarily due to the 2009 sale of our Barnett Shale properties, where the NGL price was significantly below NYMEX oil prices, partially offset by the Rocky Mountain properties we acquired in the Encore Merger which tend to have higher oil differentials than our historical corporate average. Our oil NYMEX differential improved during 2009 over our differential in 2008 primarily due to the overall decrease in oil prices during 2009 and to a lesser extent due to the Barnett Shale properties sold during the year.

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

Oil and Natural Gas Derivative Contracts

The following table summarizes the impact our oil and natural gas derivative contracts had on our operating results for 2010, 2009 and 2008:

	Non-Cash Fair Value Gain/(Loss)			Cash Settlements Receipt/(Payment)		
In thousands	**2010**	**2009**	**2008**	**2010**	**2009**	**2008**
Crude oil derivative contracts:						
First quarter	$ 61,821	$ (95,861)	$ 2,638	$ (63,550)	$ 85,836	$ (7,392)
Second quarter	145,099	(189,318)	(7,557)	(13,829)	42,002	(12,131)
Third quarter	(62,450)	(20,850)	22,652	(3,590)	18,527	(11,186)
Fourth quarter	(100,029)	(69,721)	242,156	(12,448)	369	(260)
Full Year	$ 44,441	$ (375,750)	$ 259,889	$ (93,417)	$ 146,734	$ (30,969)
Natural gas derivative contracts:						
First quarter	$ 39,018	$ (10,490)	$ (41,371)	$ 3,749	$ —	$ (656)
Second quarter	(19,909)	(5,473)	(22,666)	16,630	—	(16,463)
Third quarter	19,933	(1,434)	63,427	13,626	—	(12,886)
Fourth quarter(1)	(30,457)	10,187	(1,673)	27,800	—	3,421
Full Year	$ 8,585	$ (7,210)	$ (2,283)	$ 61,805	$ —	$ (26,584)
Total commodity derivative contracts:						
First quarter	$ 100,839	$ (106,351)	$ (38,733)	$ (59,801)	$ 85,836	$ (8,048)
Second quarter	125,190	(194,791)	(30,223)	2,801	42,002	(28,594)
Third quarter	(42,517)	(22,284)	86,079	10,036	18,527	(24,072)
Fourth quarter	(130,486)	(59,534)	240,483	15,352	369	3,161
Full Year	$ 53,026	$ (382,960)	$ 257,606	$ (31,612)	$ 146,734	$ (57,553)

(1) Natural gas derivative settlements for the fourth quarter 2010 include receipts of $10.0 million related to the monetization of natural gas swaps that were unwound due to the sale of our Haynesville and East Texas assets.

Changes in commodity prices and the expiration of contracts cause fluctuations in the estimated fair value of our oil and natural gas derivative contracts. Because we do not utilize hedge accounting for our commodity derivative contracts, the changes in fair value of these contracts, as outlined above, are recognized currently in our statements of operations.

Production Expenses

Lease operating expenses increased by 49% between 2010 and 2009, and by 6% between 2009 and 2008. The increases between 2010 and 2009 were primarily a result of the properties added from the Encore Merger on March 9, 2010, our increasing emphasis on tertiary operations and incremental expense from the acquisition of Conroe Field in December 2009.

Although our lease operating expenses increased in absolute dollars between 2009 and 2010, our lease operating expenses on a per BOE basis actually decreased from $18.50 in 2009 to $18.29 in 2010, due primarily to the fact that the properties acquired in the Encore Merger generally had a lower cost per BOE than Denbury's legacy properties, offset in part by the sale of our Barnett Shale natural gas assets in 2009, which had a very low cost per BOE. Our lease operating expense per BOE increased from $18.13 in 2008 to $18.50 in 2009 due primarily to the sale of our Barnett Shale assets in 2009, and the acquisition of Hastings Field in February 2009, which had a higher cost per BOE than most of Denbury's properties. On a pro forma basis, after adjusting our operating results to remove the production and operating expenses related to ENP and the legacy Encore and Barnett Shale properties sold, Company-wide lease operating expenses would have been higher, or $20.32 per BOE during 2010, $21.94 per BOE during 2009 and $23.02 per BOE during 2008. The higher BOE costs are due to those properties sold being natural gas properties, which carry a lower per BOE operating cost. Our tertiary operating costs, which have historically been higher than our Company-wide operating costs, averaged $22.21 per BOE during 2010, $21.67 per BOE during 2009 and $23.57 per BOE during 2008 (see *Results of Operations — CO_2 Operations* for a more detailed discussion). As our tertiary operations become a larger percentage of our total operations, we expect that our operating costs on a per BOE basis will become closer to our tertiary operating costs. Costs of electricity and utilities to operate our properties have increased due primarily to the expansion of our tertiary operations. We expect our tertiary operating costs to partially correlate with oil prices, as the price we pay for CO_2 is partially tied to oil prices.

Production taxes and marketing expenses generally change in proportion to commodity prices and production volumes, assuming the areas of production are consistent. In 2010, with the acquisition of Encore, our production expanded into several new states in which we had not previously operated. Also, many of those states have higher production tax rates than our historical areas of operation. As such, our production taxes increased 204% between 2009 and 2010, despite our production and revenues increasing less than that percentage. In addition, a portion of Denbury's legacy production was taxed at reduced rates (primarily tertiary oil production in Mississippi and Barnett Shale properties), which also contributed to the large increase in production taxes between the two years. The decrease in production taxes between 2008 and 2009 was primarily due to the decrease in commodity prices in 2009 compared to 2008. Marketing, transportation and plant processing fees in 2010 were approximately $26.8 million, 59% higher than 2009 levels due to the addition of properties in other operating areas acquired in the Encore Merger, and were $3.6 million lower in 2009 than 2008 primarily due to the sale of Barnett Shale properties in mid 2009.

General and Administrative Expenses

During the last three years, general and administrative ("G&A") expenses have increased on a gross basis but have fluctuated on a per BOE basis as outlined in the following table:

	Year Ended December 31,		
In thousands, except per BOE data and employees	**2010**	**2009**	**2008**
Gross cash G&A expense	$ 232,163	$ 143,886	$ 121,209
Gross stock-based compensation	33,926	24,322	16,243
Founder's retirement compensation	—	10,000	—
Incentive compensation for Genesis management	1,149	14,212	—
Acquisition expenses, excluding Encore	823	454	527
State franchise taxes	3,855	4,703	3,415
Operator labor and overhead recovery charges	(112,160)	(76,044)	(68,556)
Capitalized exploration and development costs	(20,074)	(13,905)	(12,464)
Net G&A expense	$ 139,682	$ 107,628	$ 60,374
G&A per BOE:			
Net cash G&A expense	$ 3.98	$ 3.27	$ 2.58
Net stock-based compensation	1.06	1.16	0.75
Founder's retirement compensation	—	0.57	—
Incentive compensation for Genesis management	0.04	0.81	—
Acquisition expenses, excluding Encore	0.03	0.03	0.03
State franchise taxes	0.14	0.27	0.20
Net G&A expense	$ 5.25	$ 6.11	$ 3.56
Employees as of December 31	1,195	830	797

Gross cash G&A expenses increased $88.3 million, or 61%, between 2009 and 2010, and $22.7 million, or 19%, between 2008 and 2009. The increase in 2010 compared to 2009 is primarily due to the Encore Merger, including higher compensation and personnel-related costs associated with a 44% increase in the number of employees between the respective year-ends, although the employee count during the year was even higher as certain Encore legacy employees were performing transition work. In addition, we continued to increase wages as we consider this necessary in order to remain competitive in our industry. Additional third-party fees plus office operating expenses attributable to the legacy Encore and new Denbury headquarters office leases, both required due to the Encore Merger, contributed to higher cash G&A expense during 2010. During 2009 we increased our employee count by 4% over 2008 levels, although our employee count was higher for part of 2009 before the sale of a portion of our Barnett Shale properties in mid 2009. Stock compensation expense reflected in gross G&A expense was $33.9 million during 2010, $24.3 million during 2009 and $16.2 million during 2008, due primarily to the increase in employees and changes in the mix of compensation awarded to employees.

The increase in personnel-related costs in 2010 was partially offset by the absence during 2010 of the nonrecurring charge associated with the Founder's Retirement Agreement for Gareth Roberts, as he retired as CEO and President of the Company on June 30, 2009 and a $13.1 million decrease in charges relating to incentive compensation awards for the management of Genesis. The change-of-control provision of the Genesis management compensation agreement was triggered concurrent with our sale of Genesis in the first quarter of 2010 with $1.1 million of this being recognized as expense during February 2010 and $14.2 million in 2009. The increase in gross G&A expense in each of the last three years was offset in part by an increase in operator overhead recovery charges. 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 additional operated wells from the Encore Merger and other acquisitions, additional tertiary operations, increased drilling activity, and increased compensation expense, the amount we recovered as operator labor and overhead charges increased by 47% between 2009 and 2010, and 11% between 2008 and 2009. Capitalized exploration and development costs also 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 30% increase in net G&A expense between 2009 and 2010, and a 78% increase in net G&A expense between 2008 and 2009. On a per BOE basis, net G&A expense decreased 14% in 2010 compared to 2009 due to increased production and the lack of non-recurring charges in 2009 related to Mr. Roberts and Genesis as discussed above, and increased 72% in 2009 compared to 2008 primarily due to higher personnel-related costs discussed above.

Interest and Financing Expenses

In thousands, except per BOE data and interest rates	Year Ended December 31, 2010	2009	2008
Cash interest expense	$ 221,759	$ 108,629	$ 59,955
Non-cash interest expense	21,169	7,397	1,802
Less: Capitalized interest	(66,815)	(68,596)	(29,161)
Interest expense	$ 176,113	$ 47,430	$ 32,596
Interest income and other	$ (7,758)	$ (9,019)	$ (10,188)
Net cash interest expense and other income per BOE(1)	$ 5.67	$ 2.14	$ 1.59
Average debt outstanding	$ 2,736,634	$ 1,265,142	$ 735,288
Average interest rate(2)	8.1%	8.6%	8.2%

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

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

Interest expense increased $128.7 million, or 271%, between 2010 and 2009 and $14.8 million, or 46%, between 2008 and 2009. The increase in interest expense between 2009 and 2010 is due to the increase in our average debt outstanding to finance the Encore Merger which closed in March 2010, a portion of which was repaid during 2010 with proceeds from the asset sales discussed above in *Overview — Merger with Encore Acquisition Company.* Interest capitalized during 2010 was comparable to the 2009 amount due to the continued construction of the Green Pipeline through most of the year. The increase in interest expense between 2008 and 2009 is due primarily to the increase in average debt outstanding, which increased primarily due to the February 2009 issuance of $420 million of 9¾% Senior Subordinated Notes due 2016 used to repay bank borrowings drawn for, among other things, the Hastings acquisition. The increase is also due to a full year of interest expense recognized during 2009 on the pipeline dropdown transactions with Genesis, compared to only seven months of interest recognized on the dropdowns during 2008. This increase in interest expense between 2008 and 2009 was largely offset by a $39.4 million increase in capitalized interest, primarily relating to interest capitalized on our Green Pipeline. Since the Green Pipeline was placed in service during 2010, interest capitalized should decrease in future periods. See Note 5, *Notes Payable and Long-Term Indebtedness,* to our Consolidated Financial Statements for more information regarding our debt increases resulting from the Encore Merger.

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

In thousands, except per BOE data	Year Ended December 31, 2010	2009	2008
Depletion and depreciation of oil and natural gas properties	$ 394,957	$ 203,719	$ 192,791
Depletion and depreciation of CO_2 assets	20,665	18,052	15,644
Asset retirement obligations	6,443	3,280	3,048
Depreciation of other fixed assets	21,860	13,272	10,309
Cumulative change due to revision in policy for CO_2 properties	(9,618)	—	—
Total DD&A	$ 434,307	$ 238,323	$ 221,792
DD&A per BOE:			
Oil and natural gas properties	$ 15.08	$ 11.74	$ 11.55
CO_2 assets and other fixed assets	1.60	1.78	1.53
Cumulative change due to revision in policy for CO_2 properties	(0.36)	—	—
Total DD&A cost per BOE	$ 16.32	$ 13.52	$ 13.08
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. Depletion of oil and natural gas properties increased on both a per BOE basis and in absolute dollars during 2010 compared to 2009, primarily due to the fact that the properties acquired in the Encore Merger were recorded at fair market value as required by the FASC *Business Combinations* topic, resulting in a higher rate than our historical DD&A rate. In addition, the sale of our Barnett Shale assets in 2009 and acquisition of Conroe Field in late 2009 also increased our DD&A rate. Depletion of oil and natural gas properties increased in 2009 compared to 2008 due primarily to capital spending and increasing costs. Our proved reserves increased to 398 MMBOE at December 31, 2010, from 207.5 MMBOE at December 31, 2009 and 250.5 MMBOE at December 31, 2008.

During 2010, we added approximately 344.5 MMBOE of proved reserves (before netting out 2010 production and property sales), and net of property sales we added 217.0 MMBOE of proved reserves. The most significant additions were approximately 217.4 MMBOE from the acquisition of Encore (including 43.0 MMBOE associated with ENP), 39.4 MMBbls added in our tertiary oil operations, 33.4 MMBOE from the development of the Bakken properties, 32.3 MMBOE of natural gas reserves added through the acquisition of Riley Ridge, and 2.9 MMBOE related to commodity price revisions. Our tertiary oil reserves added during 2010 were primarily at Delhi Field (29.5 MMBbls). Correspondingly, we moved approximately $196.1 million from unevaluated properties to the full cost pool relating to Delhi Field, representing the acquisition costs and development expenditures incurred on the field prior to recognizing proved reserves. The decrease in our proved reserves from December 31, 2008 to December 31, 2009 was primarily due to the sale of our Barnett Shale properties in 2009.

Our DD&A expense for our CO_2 and other fixed assets increased in 2010 and 2009 due primarily to other fixed assets added in the Encore Merger. However, our DD&A rate on a per BOE basis decreased approximately 10% between 2009 and 2010, as a result of increased oil and natural gas production volumes as a result of the Encore Merger and a result of the proved CO_2 reserves added at Jackson Dome and Riley Ridge in 2010. Our DD&A rate for our CO_2 and other fixed assets increased approximately 16% between 2008 and 2009, as a result of the Heidelberg CO_2 pipeline being placed into service during 2008, expansion of our corporate offices during 2008, and field office expansion during 2009.

During the third quarter of 2010, we changed our method of accounting for CO_2 properties and recorded a one-time, non-cash net reduction of $9.6 million ($6.0 million after tax) to DD&A expense for the period, which reflects the cumulative impact of the revised accounting policy on our historical financials. See Note 1, *Significant Accounting Policies,* to the Consolidated Financial Statements for additional information regarding this change.

Under full cost accounting rules, we are required each quarter to perform a ceiling test calculation. As a result of depressed oil and natural gas prices at December 31, 2008, we recorded our first full cost ceiling test write-down in a decade, resulting in expense of $226.0 million or $13.32 per BOE at December 31, 2008. The SEC adopted major revisions to its rules governing oil and gas company reporting requirements which were effective beginning on December 31, 2009. Under these new rules, the full cost ceiling value is calculated using a 12-month average price based on the first day price of every month price during the period. We did not have a ceiling test write-down during either 2009 or 2010. However, if oil prices were to decrease significantly in subsequent periods, we may be required to record additional write-downs under the full cost pool ceiling test in the future. The possibility and amount of any future write-down is difficult to predict, and will depend upon oil and natural gas prices, the incremental proved reserves that may be added each period, revisions to previous estimates of reserves and future capital expenditures, and additional capital spent.

Encore Transaction and Other Costs

The FASC *Business Combinations* topic requires that all transaction costs (advisory, legal, accounting, due diligence, integration, third-party fees, etc.) be expensed as incurred. We recognized a total of $92.3 million of transaction and other costs during 2010 associated with the Encore Merger, including $43.8 million related to severance costs.

Income Taxes

	Year Ended December 31,		
Amounts in thousands, except per BOE amounts and tax rates	**2010**	**2009**	**2008**
Current income tax expense	$ 33,194	$ 4,611	$ 40,812
Deferred income tax expense (benefit)	160,349	(51,644)	195,020
Total income tax expense (benefit)	$ 193,543	$ (47,033)	$ 235,832
Average income tax expense (benefit) per BOE	$ 7.27	$ (2.67)	$ 13.90
Effective tax rate	40.4%	38.5%	37.8%
Total net deferred tax liability	$ (1,520,538)	$ (469,195)	$ (522,234)

Our income tax provision for each of the last three years has been based on an estimated statutory rate of approximately 38%. Our effective tax rate has generally been slightly lower than our estimated statutory rate due to the impact of certain items such as our domestic production activities deduction, offset in part by compensation arising from certain equity compensation that cannot be deducted for tax purposes in the same manner as book expense. Our 2010 effective tax rate was higher, however, compared to our statutory rate due to the recognition of additional net tax expense on the revaluation of our deferred taxes at the date of the Encore Merger and as a result of our legal entity restructuring at December 31, 2010. During 2010, 2009 and 2008, the current income tax expense represents our anticipated alternative minimum cash taxes that we cannot offset with enhanced oil recovery credits, as well as state income taxes. The significant increase in our total net deferred tax liability in 2010 compared to 2009 is primarily due to the Encore Merger, in which Encore's net deferred tax liability and tax attributes carried over to us. During 2010, we were able to deduct approximately $1.0 billion of Section 193 (tertiary injectant) deductions (see following paragraph), primarily related to the Green Pipeline going into service, but these deductions were almost completely offset by gains related to the 2010 property sales. As of December 31, 2010, we had an estimated $39.8 million of enhanced oil recovery credits, including those of Encore, to carry forward that can be utilized to reduce our current income taxes during 2011 or future years. These enhanced oil recovery credits do not begin to expire until 2024. Since the ability to earn additional enhanced oil recovery credits is based upon the level of oil prices, we would not currently expect to earn additional enhanced oil recovery credits unless oil prices were to decrease significantly from current levels.

In the third quarter of 2008, we obtained approval from the National Office of the Internal Revenue Service ("IRS") to change our method of tax accounting for certain assets used in our tertiary oilfield recovery operations. As a result of the approved change in method of tax accounting, beginning with the 2007 tax year we began to deduct, rather than capitalize, such costs for tax purposes, and applied for tax refunds associated with such change for our 2004 and 2006 tax years. Notwithstanding its consent to our change in tax accounting in 2008, the IRS recently exercised its prerogative to challenge the tax accounting method we used. In late January 2011, we received a Technical Advice Memorandum ("TAM") issued by the IRS National Office disapproving our method of accounting and revoking its consent to our change, on a prospective basis only, commencing January 1, 2011. Henceforth, beginning with the 2011 tax year, we will return to capitalizing and depreciating the costs of these assets for tax purposes. As a result of the prospective nature of the IRS's determination, there should be no change in our position with respect to the deductibility of these costs for 2007, 2008, 2009 and 2010. However, refund claims of $10.6 million for tax years through 2006 are pending and are subject to review by the Joint Committee on Taxation of the U.S. Congress. We are unable to assess the outcome of any such review, nor how that outcome may affect the other years covered by the TAM.

The current administration in Washington D.C. is attempting to remove many tax incentives for the oil and gas industry. Those items that would have the most significant impact on us would include the loss of the domestic manufacturing deduction as well as the repeal of the immediate expensing of intangible drilling costs and tertiary injectant costs. It is uncertain whether or not the current administration will be successful in changing the laws, but if they were successful, it would likely increase the amount of cash taxes that we pay. Should cash taxes increase significantly, it could impact our forecasted 2011 capital expenditure budget.

Per BOE Data

The following table summarizes our 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.

Per BOE data	Year Ended December 31, 2010	2009	2008
Oil and natural gas revenues	$ 67.37	$ 49.16	$ 79.42
Gain (loss) on settlements of derivative contracts	(1.19)	8.32	(3.40)
Lease operating expenses	(18.29)	(18.50)	(18.13)
Production taxes and marketing expenses	(4.85)	(2.41)	(3.76)
Production netback	43.04	36.57	54.13
Non-tertiary CO_2 operating margin	0.41	0.50	0.57
General and administrative expenses	(5.25)	(6.11)	(3.56)
Transaction costs and other related to the Encore Merger	(3.47)	(0.48)	—
Net cash interest expense and other income	(5.67)	(2.14)	(1.59)
Abandoned acquisition costs	—	—	(1.80)
Current income taxes and other	0.03	2.30	(1.78)
Changes in assets and liabilities relating to operations	3.06	(0.54)	(0.31)
Cash flow from operations	32.15	30.10	45.66
DD&A	(16.32)	(13.52)	(13.08)
Write-down of oil and natural gas properties	—	—	(13.32)
Deferred income taxes	(6.02)	2.93	(11.50)
Gain on sale of interests in Genesis	3.81	—	—
Non-cash commodity derivative adjustments	1.99	(21.72)	15.19
Net income attributable to noncontrolling interest	(0.52)	—	—
Changes in assets and liabilities and other non-cash items	(4.88)	(2.05)	(0.05)
Net income (loss)	$ 10.21	$ (4.26)	$ 22.90

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. At December 31, 2010, we did not have any outstanding borrowings on our bank credit facility. 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, 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 our senior subordinated debt is based on quoted market prices. The following table presents the carrying and fair values of our outstanding debt, along with average interest rates at December 31, 2010.

In thousands	2013	2014	2015	2016	2017	2020	Carrying Value	Fair Value
Fixed rate debt:								
7 ½% Senior Subordinated Notes due 2013	$ 225,000	$ —	$ —	$ —	$ —	$ —	$ 224,563	$ 228,375
7 ½% Senior Subordinated Notes due 2015	—	—	300,000	—	—	—	300,427	310,500
9 ½% Senior Subordinated Notes due 2016	—	—	—	224,920	—	—	239,509	249,661
9 ¾% Senior Subordinated Notes due 2016	—	—	—	426,350	—	—	404,211	475,380
8 ¼% Senior Subordinated Notes due 2020	—	—	—	—	—	996,273	996,273	1,080,956
Other Subordinated Notes	—	1,072	485	—	2,250	—	3,848	3,807

See Note 5, *Notes Payable and Long-Term Indebtedness,* to the Consolidated Financial Statements for details regarding our long-term debt.

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. We currently employ a strategy to hedge a portion of our forecasted production 12 to 15 months in advance, as we believe it is important to protect our future cash flow for a short period of time in order to give us time to adjust to commodity price fluctuations, particularly since many of our expenditures have long lead times. See Note 9, *Derivative Instruments and Hedging Activities,* to the Consolidated Financial Statements for additional information regarding our commodity derivative contracts.

All of the mark-to-market valuations used for our oil and natural gas derivatives are provided by external sources. 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. All of our commodity derivative contracts are with parties that are lenders under our revolving credit agreement. We have included an estimate of nonperformance risk in the fair value measurement of our oil and natural gas derivative contracts, which we have measured for nonperformance risk based upon credit default swaps or credit spreads.

For accounting purposes, we do not apply hedge accounting to 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.

At December 31, 2010, our derivative contracts were recorded at their fair value, which was a net liability of approximately $44.0 million (excluding $26.7 million of deferred premiums that Denbury is obligated to pay for its derivative contracts, which payments are not subject to changes in commodity prices), a significant change from the $128.7 million net liability recorded at December 31, 2009. This change is primarily related to the expiration of oil derivative contracts during 2010, and to the oil and natural gas futures prices as of December 31, 2010, in relation to the new commodity derivative contracts we entered into during 2010 for future periods.

Commodity Derivative Sensitivity Analysis

Based on NYMEX crude oil and natural gas futures prices as of December 31, 2010, and assuming both a 10% increase and decrease thereon, we would expect to make or receive payments on our crude oil and natural gas derivative contracts as shown in the following table:

In thousands	**Crude Oil Derivative Contracts Receipt/ (Payment)**	**Natural Gas Derivative Contracts Receipt/ (Payment)**
Based on:		
NYMEX futures prices as of December 31, 2010	$ (7,304)	$ 43,713
10% increase in prices	(61,792)	32,395
10% decrease in prices	(1,877)	55,047

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, *Significant Accounting Policies,* 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 Properties

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 FASB guidance under the *Accounting for the Impairment or Disposal of Long-Lived Assets* topic of the FASC, under which the net book value of assets is 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 the average first-day-of-the-month oil and natural gas price for each month during the 12-month period ended as of each quarterly 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 the *Derivatives and Hedging* topic of the FASC (see below), and as a result, these contracts are not considered in the full cost ceiling test.

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 reported estimates, 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 1.4% of the previous year's estimates and have been both positive and negative.

Changes in commodity prices also affect our reserve quantities. Between 2008 and 2009, commodity prices increased, resulting in an increase in our proved reserves of 4.2 MMBOE. This trend continued between 2009 and 2010, resulting in an additional increase in our proved reserves of 2.9 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 2010 DD&A rate from $15.87 per BOE to approximately $15.20 per BOE, and a 5% decrease in our proved reserve quantities would have increased our DD&A rate to approximately $16.61 per BOE. Also, reserve quantities and their ultimate values, determined solely by our banks, are the primary factors in determining the borrowing base under our bank credit facility and in measuring certain covenants of our senior debt.

Under full cost accounting rules, we are required each quarter to perform a ceiling test calculation. 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 (1) 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 during 2008 and for the first three quarters of 2009; and beginning in the fourth quarter of 2009, the average first-day-of-the-month oil and natural gas price for each month during the 12-month periods ended December 31, 2009 and 2010; (2) plus the cost of properties not being amortized; (3) plus the lower of cost or estimated fair value of unproved properties included in the costs being amortized, if any; (4) less related income tax effects. Our future net revenues from proved reserves are not reduced for development costs related to the cost of drilling for and developing CO_2 reserves nor for those related to the cost of constructing CO_2 pipelines, as those costs have already been incurred by the Company. Therefore, we include in the ceiling test, as a reduction of future net revenues, that portion of the Company's capitalized CO_2 costs related to CO_2 reserves and CO_2 pipelines that we estimate will be consumed in the process of producing our proved oil and natural gas reserves. The fair value of our oil and natural gas derivative contracts is not included in the ceiling test, as we do not designate these contracts as hedge instruments for accounting purposes. The cost center ceiling test is prepared quarterly.

We did not have a full cost pool ceiling test write-down in 2009 or 2010. 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 increased throughout 2009 and 2010, with NYMEX oil prices at $91.38 per barrel, and NYMEX natural gas prices at $4.41 per Mcf, at December 31, 2010. Commodity prices have historically been volatile and are expected to be in the future. If oil and natural gas should again decrease, we may be required to record additional write-downs due to the full cost ceiling test. The amount of any future write-down is difficult to predict and will depend upon the oil and natural gas prices utilized in the ceiling test, the incremental proved reserves that might be added during each period and additional capital spent.

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.

We capitalize, 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 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. During 2010, 2009, and 2008, we capitalized $20.5 million, $8.0 million and $10.4 million, respectively, of tertiary injection costs associated with our tertiary projects.

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 and state loss carryforwards). 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, 2010, 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 likely. A 1% increase in our effective tax rate would have increased our calculated income tax expense (benefit) by approximately \$4.8 million, \$(1.2) million and \$6.2 million for the years ended December 31, 2010, 2009 and 2008, respectively. See Note 6, *Income Taxes,* to the Consolidated Financial Statements and see *Income Taxes* above for further information concerning our income taxes.

Fair Value Estimates

The FASC defines fair value, establishes a framework for measuring fair value and expands disclosures about fair value measurements. It does not require us to make any new fair value measurements, but rather establishes a fair value hierarchy that prioritizes the inputs to the valuation techniques used to measure fair value. Level 1 inputs are given the highest priority in the fair value hierarchy, as they represent observable inputs that reflect unadjusted quoted prices for identical assets or liabilities in active markets as of the reporting date, while Level 3 inputs are given the lowest priority, as they represent unobservable inputs that are not corroborated by market data. Valuation techniques that maximize the use of observable inputs are favored. See Note 10, *Fair Value Measurements,* to the Consolidated Financial Statements for disclosures regarding our recurring fair value measurements.

Significant uses of fair value measurements include:

- allocation of the purchase price paid to acquire businesses to the assets acquired and liabilities assumed in those acquisitions,
- assessment of impairment of long-lived assets,
- assessment of impairment of goodwill, and
- recorded value of derivative instruments.

Acquisitions

Under the acquisition method of accounting for business combinations, the purchase price paid to acquire a business is allocated to its assets and liabilities based on the estimated fair values of the assets acquired and liabilities assumed as of the date of acquisition. The FASC *Fair Value Measurements and Disclosures* topic defines fair value as 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 (often referred to as the “exit price”). A fair value measurement is based on the assumptions of market participants and not those of the reporting entity. Therefore, entity-specific intentions do not impact the measurement of fair value unless those assumptions are consistent with market participant views.

The excess of the purchase price over the fair value of the net tangible and identifiable intangible assets acquired is recorded as goodwill. A significant amount of judgment is involved in estimating the individual fair values involving long-term tangible assets, identifiable intangible assets and long-term asset retirement obligations. The valuation of oil and natural gas properties is even more difficult due to the nature of our core business, enhanced oil recovery operations. In order to appropriately apply the FASC standard, we must estimate what value a third-party market participant would place on the acquired property. It is very subjective as to what value another entity would place on the potential barrels recoverable with CO_2, which impacts our allocation of the purchase price to goodwill, unevaluated properties and proved properties. Although we find that this standard is difficult to apply in our circumstance, we use all available information to make these fair value determinations and, for certain acquisitions, engage third-party consultants for assistance.

The fair values used to allocate the purchase price of an acquisition are often estimated using the expected present value of future cash flows method, which requires us to project related future cash inflows and outflows and apply an appropriate discount rate. The estimates used in determining fair values are based on assumptions believed to be reasonable but which are inherently uncertain. Accordingly, actual results may differ from the projected results used to determine fair value.

Impairment Assessment of Goodwill

We test goodwill for impairment annually during the fourth quarter, or between annual tests if an event occurs or circumstances change that would more likely than not reduce the fair value of a reporting unit below its carrying amount. The need to test for impairment can be based on several indicators, including a significant reduction in prices of oil or natural gas, a full-cost ceiling write-down of oil and natural gas properties, unfavorable adjustments to reserves, significant changes in the expected timing of production, other changes to contracts or changes in the regulatory environment.

Goodwill is tested for impairment at the reporting unit level. Denbury applies SEC full cost accounting rules, under which the acquisition cost of oil and gas properties is recognized on a cost center basis (country), of which Denbury has only one cost center (United States). Goodwill is assigned to this single reporting unit.

Fair value calculated for the purpose of testing for impairment of our goodwill is estimated using the expected present value of future cash flows method and comparative market prices when appropriate. A significant amount of judgment is involved in performing these fair value estimates for goodwill since the results are based on forecasted assumptions. Significant assumptions include projections of future oil and natural gas prices, projections of estimated quantities of oil and natural gas reserves, projections of future rates of production, timing and amount of future development and operating costs, projected availability and cost of CO_2, projected recovery factors of tertiary reserves, and risk-adjusted discount rates. We base our fair value estimates on projected financial information that we believe to be reasonable. However, actual results may differ from those projections.

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 the FASC *Derivatives and Hedging* topic. 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 the FASC *Derivatives and Hedging* topic, 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 2010, 2009 and 2008, we recognized expense (income) of $(53.0) million, $383.0 million and $(257.6) million, respectively, related to non-cash changes in the fair market value of our derivative contracts.

Use of Estimates

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

Recent Accounting Pronouncements

In December 2010, the FASB issued Accounting Standards Update ("ASU") 2010-29, *Business Combinations: Disclosure of Supplementary Pro Forma Information for Business Combinations* ("ASU 2010-29"), which amends the FASC *Business Combinations* topic. The update addresses diversity in the interpretation of the pro forma revenue and earnings disclosure requirements for business combinations. If a public entity presents comparative financial statements, the entity should disclose revenue and earnings of the combined entity as though the business combination that occurred during the current year had occurred as of the beginning of the comparable prior annual reporting period only. We adopted ASU 2010-29 on January 1, 2011 and will apply the new standard to pro forma disclosures for acquisitions occurring after January 2, 2011.

We have reviewed recently issued accounting standards that are not yet effective and have determined that none would have a material impact to our Consolidated Financial Statements.

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 the sections entitled *Business* and *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 including the timing and location thereof, 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, percentages of recoverable original oil in place, 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, prospective legislation affecting the oil and gas industry, 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; effects of our indebtedness; success of our risk management techniques; 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.

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 59 through 60.

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, 2010 and 2009, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2010 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, 2010, 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.

As discussed in Note 1 to the Consolidated Financial Statements, the Company changed the manner in which it estimates the quantities of oil and natural gas reserves in 2009.

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.

/s/ PricewaterhouseCoopers LLP
PricewaterhouseCoopers LLP
Dallas, Texas
March 1, 2011

Consolidated Balance Sheets
(In thousands, except shares)

	December 31, 2010	December 31, 2009
Assets		
Current assets		
Cash and cash equivalents	$ 381,869	$ 20,591
Accrued production receivable	223,584	120,667
Trade and other receivables, net of allowance of $456 and $414	114,149	67,874
Short-term investments	93,020	—
Derivative assets	24,242	309
Deferred tax assets	27,454	46,321
Total current assets	864,318	255,762
Property and equipment		
Oil and natural gas properties (using full cost accounting)		
Proved	6,042,442	3,595,726
Unevaluated	870,130	320,356
CO_2 and other products — properties and pipelines	1,901,662	1,529,781
Other property and equipment	120,641	82,537
Less accumulated depletion, depreciation, amortization and impairment	(2,197,517)	(1,825,528)
Net property and equipment	6,737,358	3,702,872
Derivative assets	12,919	506
Goodwill	1,232,418	169,517
Other assets	218,050	141,321
Total assets	$ 9,065,063	$ 4,269,978
Liabilities and Stockholders' Equity		
Current liabilities		
Accounts payable and accrued liabilities	$ 345,998	$ 169,874
Oil and gas production payable	143,145	90,218
Derivative liabilities	78,184	124,320
Current maturities of long-term debt	7,948	5,308
Other liabilities	4,070	4,070
Total current liabilities	579,345	393,790
Long-term liabilities		
Long-term debt, net of current portion	2,416,208	1,301,068
Asset retirement obligations	81,290	53,251
Deferred taxes	1,547,992	515,516
Derivative liabilities	29,687	5,239
Other liabilities	29,834	28,877
Total long-term liabilities	4,105,011	1,903,951
Commitments and contingencies (Note 11)		
Stockholders' equity		
Common stock, $.001 par value, 600,000,000 shares authorized; 400,291,033 and 261,929,292 shares issued at December 31, 2010 and 2009, respectively	400	262
Paid-in capital in excess of par	3,045,937	910,540
Retained earnings	1,336,142	1,064,419
Accumulated other comprehensive loss	(488)	(557)
Treasury stock, at cost, 78,524 and 156,284 shares at December 31, 2010 and 2009, respectively	(1,284)	(2,427)
Total stockholders' equity	4,380,707	1,972,237
Total liabilities and stockholders' equity	$ 9,065,063	$ 4,269,978

See accompanying Notes to Consolidated Financial Statements.

Consolidated Statements of Operations

(In thousands, except per shares data)

	Year ended December 31, 2010	2009	2008
Revenues and other income			
Oil, natural gas, and related product sales	$ 1,793,292	$ 866,709	$ 1,347,010
CO_2 sales and transportation fees	19,204	13,422	13,858
Gain on sale of interests in Genesis	101,537	—	—
Interest income and other income	7,758	9,019	10,188
Total revenues and other income	1,921,791	889,150	1,371,056
Expenses			
Lease operating expenses	486,923	326,132	307,550
Production taxes and marketing expenses	129,046	42,484	63,752
CO_2 discovery and operating expenses	8,212	4,649	4,216
General and administrative	139,682	107,628	60,374
Interest, net of amounts capitalized of $66,815, $68,596, and $29,161, respectively	176,113	47,430	32,596
Depletion, depreciation and amortization	434,307	238,323	221,792
Derivatives expense (income)	(23,833)	236,226	(200,053)
Transaction costs and other related to the Encore Merger	92,271	8,467	—
Abandoned acquisition costs	—	—	30,601
Write-down of oil and natural gas properties	—	—	226,000
Total expenses	1,442,721	1,011,339	746,828
Income (loss) before income taxes	479,070	(122,189)	624,228
Income tax provision (benefit)			
Current income taxes	33,194	4,611	40,812
Deferred income taxes	160,349	(51,644)	195,020
Consolidated net income (loss)	285,527	(75,156)	388,396
Less: net income attributable to noncontrolling interest	(13,804)	—	—
Net income (loss) attributable to Denbury stockholders	$ 271,723	$ (75,156)	$ 388,396
Net income (loss) per common share — basic	$ 0.73	$ (0.30)	$ 1.59
Net income (loss) per common share — diluted	$ 0.72	$ (0.30)	$ 1.54
Weighted average common shares outstanding			
Basic	370,876	246,917	243,935
Diluted	376,255	246,917	252,530

See accompanying Notes to Consolidated Financial Statements.

Consolidated Statements of Cash Flows
(In thousands)

	Year Ended December 31,		
	2010	2009	2008
Cash flow from operating activities:			
Consolidated net income (loss)	$ 285,527	$ (75,156)	$ 388,396
Adjustments needed to reconcile to net cash flow provided by operations:			
Depletion, depreciation and amortization	434,307	238,323	221,792
Write-down of oil and natural gas properties	—	—	226,000
Deferred income taxes	160,349	(51,644)	195,020
Gain on sale of interests in Genesis	(101,537)	—	—
Stock-based compensation	35,366	35,581	14,068
Non-cash fair value derivative adjustments	(55,445)	383,072	(257,502)
Founder's retirement compensation	—	6,350	—
Debt issuance costs and discount amortization	17,876	7,215	1,435
Other, net	(2,144)	(3,704)	(9,400)
Changes in assets and liabilities, net of effects from acquisitions:			
Accrued production receivable	2,426	(52,863)	68,479
Trade and other receivables	23,133	12,548	(58,236)
Derivative assets	—	—	(15,471)
Other assets	(2,275)	(426)	348
Accounts payable and accrued liabilities	48,549	25,673	254
Oil and natural gas production payable	15,565	4,385	1,683
Other liabilities	(5,886)	1,245	(2,347)
Net cash provided by operating activities	855,811	530,599	774,519
Cash flow used for investing activities:			
Oil and natural gas capital expenditures	(671,574)	(343,351)	(587,968)
Acquisitions of oil and natural gas properties	(25,672)	(452,795)	(31,367)
Cash paid in Encore Merger, net of cash acquired	(814,984)	—	—
Cash paid in Riley Ridge acquisition	(132,257)	—	—
CO_2 and other products — capital expenditures, including pipelines	(301,092)	(666,372)	(407,103)
Purchases of other assets	(28,684)	(13,591)	(23,799)
Net proceeds from sale of interests in Genesis	162,619	—	—
Net proceeds from sales of oil and natural gas properties and equipment	1,458,029	516,814	51,684
Other	(1,165)	(10,419)	3,894
Net cash used for investing activities	(354,780)	(969,714)	(994,659)
Cash flow from financing activities:			
Bank repayments	(1,530,000)	(856,000)	(222,000)
Bank borrowings	1,114,000	906,000	147,000
Senior subordinated notes tendered post Encore Merger	(616,637)	—	—
Net proceeds from issuance of senior subordinated debt	1,000,000	389,827	—
Net proceeds from issuance of common stock	13,065	12,991	13,972
Costs of debt financing	(76,251)	(10,080)	(2,288)
ENP distributions to noncontrolling interest	(36,738)	—	—
Pipeline financing	(2,101)	369	225,252
Other	(5,091)	(470)	15,166
Net cash provided by (used for) financing activities	(139,753)	442,637	177,102
Net increase in cash and cash equivalents	361,278	3,522	(43,038)
Cash and cash equivalents at beginning of year	20,591	17,069	60,107
Cash and cash equivalents at end of year	$ 381,869	$ 20,591	$ 17,069

See accompanying Notes to Consolidated Financial Statements.

Consolidated Statements of Changes in Stockholders' Equity
(Dollar amounts in thousands)

	Common Stock ($.001 Par Value)		Paid—In Capital in Excess of Par	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Treasury Stock (at cost)		Denbury Stockholders' Equity	Noncontrolling Interest	Total Equity
	Shares	Amount				Shares	Amount			
Balance — December 31, 2007	245,386,951	$ 245	$ 662,698	$ 751,179	$ (1,591)	637,795	$ (8,153)	$ 1,404,378	$	$ 1,404,378
Repurchase of common stock	—	—	—	—	—	155,297	(3,762)	(3,762)		(3,762)
Issued pursuant to employee stock purchase plan	—	—	1,176	—	—	(346,805)	5,085	6,261		6,261
Issued pursuant to employee stock option plan	2,578,563	3	7,708	—	—	—	—	7,711		7,711
Issued pursuant to directors' compensation plan	12,753	—	212	—	—	—	—	212		212
Restricted stock grants	278,973	—	—	—	—	—	—	—		—
Restricted stock grants — forfeited	(251,366)	—	—	—	—	—	—	—		—
Stock based compensation	—	—	16,243	—	—	—	—	16,243		16,243
Income tax benefit from equity awards	—	—	19,665	—	—	—	—	19,665		19,665
Derivative contracts, net	—	—	—	—	964	—	—	964		964
Net income	—	—	—	388,396	—	—	—	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	—	1,840,068
Repurchase of common stock	—	$ —	$ —	$ —	$ —	194,943	(3,014)	$ (3,014)	$	$ (3,014)
Issued pursuant to employee stock purchase plan	—	—	(81)	—	—	(484,946)	7,417	7,336		7,336
Issued pursuant to employee stock option plan	1,312,714	2	5,651	—	—	—	—	5,653		5,653
Issued pursuant to directors' compensation plan	21,658	—	322	—	—	—	—	322		322
Issued pursuant to Conroe Field acquisition	11,620,000	12	168,711	—	—	—	—	168,723		168,723
Restricted stock grants	1,032,895	—	—	—	—	—	—	—		—
Restricted stock grants — forfeited	(63,849)	—	—	—	—	—	—	—		—
Stock based compensation	—	—	24,322	—	—	—	—	24,322		24,322
Income tax benefit from equity awards	—	—	3,913	—	—	—	—	3,913		3,913
Derivative contracts, net	—	—	—	—	70	—	—	70		70
Net loss	—	—	—	(75,156)	—	—	—	(75,156)		(75,156)
Balance — December 31, 2009	261,929,292	262	910,540	$ 1,064,419	(557)	156,284	(2,427)	1,972,237	—	1,972,237
Repurchase of common stock	—	$ —	$ —	$ —	$ —	413,869	(6,729)	$ (6,729)	$	$ (6,729)
Issued pursuant to employee stock purchase plan	—	—	325	—	—	(491,629)	7,872	8,197		8,197
Issued pursuant to employee stock option plan	999,077	1	4,867	—	—	—	—	4,868		4,868
Issued pursuant to directors' compensation plan	16,118	—	266	—	—	—	—	266		266
Issued pursuant to Encore Merger	135,170,505	135	2,085,546	—	—	—	—	2,085,681		2,085,681
Encore restricted stock grants	1,070,686	1	(1)	—	—	—	—	—		—
Restricted stock grants	960,597	1	—	—	—	—	—	1		1
Restricted stock grants — forfeited	(301,735)	—	—	—	—	—	—	—		—
Performance—based shares issued	446,493	—	—	—	—	—	—	—		—
Stock based compensation	—	—	39,791	—	—	—	—	39,791		39,791
Income tax benefit from equity awards	—	—	4,603	—	—	—		4,603		
ENP revaluation at Encore Merger	—	—	—	—	—	—		—		4,603
ENP cash distributions to noncontrolling interest	—	—	—	—	—	—		—	515,210	515,210
Sale of ENP	—	—	—	—	—	—		—	(36,738)	(36,738)
Derivative contracts, net	—	—	—	—	69	—		69	(492,193)	(492,193)
Consolidated net income	—	—	—	271,723	—	—		271,723	(83)	(14)
Balance — December 31, 2010	400,291,033	$ 400	$ 3,045,937	$ 1,336,142	$ (488)	78,524	$ (1,2	$ 4,380,707	$ 13,804	$ 285,527

See accompanying Notes to Consolidated Financial Statements.

Consolidated Statements of Comprehensive Operations
(In thousands)

	Year Ended December 31,		
	2010	2009	2008
Consolidated net income (loss)	$ 285,527	$ (75,156)	$ 388,396
Other comprehensive income (loss), net of income tax:			
Interest rate lock derivative contracts reclassified to income, net of taxes of $43, $43 and $583, respectively	69	70	952
Change in deferred hedge loss on interest rate swaps, net of taxes of $62, $- and $49, respectively	(83)	—	12
Comprehensive income (loss)	285,513	(75,086)	389,360
Less: comprehensive income attributable to noncontrolling interest	(13,727)	—	—
Comprehensive income (loss) attributable to Denbury stockholders	$ 271,786	$ (75,086)	$ 389,360

See accompanying Notes to Consolidated Financial Statements.

Notes to Consolidated Financial Statements

Note 1. Significant Accounting Policies

Organization and Nature of Operations

Denbury Resources Inc., a Delaware corporation, is a growing independent oil and natural gas company. We are the largest oil and natural gas producer in both Mississippi and Montana, own the largest reserves of CO_2 used for tertiary oil recovery east of the Mississippi River, and hold significant operating acreage in the Rocky Mountain and Gulf Coast regions. Our goal is to increase the value of our acquired properties through a combination of exploitation, drilling, and proven engineering extraction practices, with our most significant emphasis relating to tertiary recovery operations.

Encore Merger. On March 9, 2010, we acquired Encore Acquisition Company ("Encore"), pursuant to an Agreement and Plan of Merger (the "Encore Merger Agreement"), under which Encore was merged with and into Denbury (the "Encore Merger") with Denbury surviving the Encore Merger following approval by the stockholders of both Denbury and Encore, closing of a new revolving credit facility as part of the financing for the Encore Merger, and satisfaction of conditions precedent. The Encore Merger provided Encore stockholders stock and/or cash and included the assumption of Encore's debt by Denbury. Denbury has consolidated Encore's results of operations beginning March 9, 2010, the acquisition date. See Note 2, *Acquisitions and Divestitures,* for more information.

Principles of Reporting and Consolidation

The consolidated financial statements herein have been prepared in accordance with accounting principles generally accepted in the United States ("GAAP") and include the accounts of Denbury and entities in which we hold a controlling financial interest. Undivided interests in oil and gas joint ventures are consolidated on a proportionate basis. Investments in non-controlled entities over which we exercise significant influence are accounted for under the equity method. Other investments are carried at cost. All intercompany balances and transactions have been eliminated.

From March 9, 2010 through December 31, 2010, we owned approximately 46% of Encore Energy Partners LP ("ENP") outstanding common units and 100% of Encore Energy Partners GP LLC ("GP LLC"), which was ENP's general partner. Considering the presumption of control of GP LLC in accordance with the *Consolidation* topic of the Financial Accounting Standards Board Codification ("FASC"), the results of operations and cash flows of ENP were consolidated with those of Denbury for this period. On December 31, 2010 we sold all of our ownership interests in ENP and therefore we do not consolidate ENP on our Consolidated Balance Sheet as of December 31, 2010. As presented in the accompanying Consolidated Statement of Operations for the year ended December 31, 2010, "Net income attributable to noncontrolling interest" of $13.8 million represents ENP's results of operations attributable to third-party owners other than Denbury for the portion of the year for which we consolidated ENP.

At December 31, 2009, we owned the general partner of Genesis Energy, L.P. ("Genesis"), a publicly traded master limited partnership, and approximately 10% of Genesis' outstanding common units. In aggregate, our ownership interests represented approximately a 12% ownership interest in Genesis, which we accounted for under the equity method of accounting. On February 5, 2010, we sold our general partner interest in Genesis and in March 2010 we sold our Genesis common units. See Note 2, *Acquisitions and Divestitures* for more information.

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 (1) the fair value of financial derivative instruments, (2) 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 the ceiling test, (3) accruals related to oil and natural gas sales volumes and revenues, capital expenditures and lease operating expenses, (4) the estimated costs and timing of future asset retirement obligations, (5) estimates made in the calculation of income taxes and, (6) estimates made in determining the fair values for purchase price allocations, including goodwill. 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 natural 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 natural gas industry, many of which require retroactive application. These types of adjustments cannot be currently estimated and will be recorded in the period in 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.

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.

Short-term Investments

Short-term investments are available-for-sale securities recorded at fair value with any unrealized gains or losses included in accumulated other comprehensive income. At December 31, 2010, short-term investments consisted entirely of our investment in Vanguard Natural Resources LLC ("Vanguard") common units obtained as partial consideration for the sale of our interests in ENP to a subsidiary of Vanguard on December 31, 2010. See Note 2, *Acquisitions and Divestitures*.

Oil and Natural Gas Properties

*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. We assign the purchase price of oil and natural gas properties we acquire to proved and unevaluated properties based on the estimated fair values as defined in the FASC *Fair Value Measurements and Disclosures* topic. 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 would be recognized.

*Depletion and Depreciation***.** The costs capitalized, including production equipment and future development costs, are depleted or depreciated using 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 on a basis of 6,000 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 $15.82 in 2010, $13.39 in 2009 and $12.54 in 2008.

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. The costs classified as unevaluated are transferred to the full cost amortization base as the properties are developed, tested and evaluated.

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 (1) 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 during 2008 and for the first three quarters of 2009; and beginning in the fourth quarter of 2009, the average first-day-of-the-month oil and natural gas price for each month during the 12-month period prior to the end of the current reporting period; (2) plus the cost of properties not being amortized; (3) plus the lower of cost or estimated fair value of unproved properties included in the costs being amortized, if any; (4) less related income tax effects. Our future net revenues from proved reserves are not reduced for development costs related to the cost of drilling for and developing CO_2 reserves nor those related to the cost of constructing CO_2 pipelines, as those costs have previously been incurred by the Company. Therefore, we include in the ceiling test, as a reduction of future net revenues, that portion of the Company's capitalized CO_2 costs related to CO_2 reserves and CO_2 pipelines that we estimate will be consumed in the process of producing our proved oil and natural gas reserves. The fair value of our oil and natural gas derivative contracts is not included in the ceiling test as we do not designate these contracts as hedge instruments for accounting purposes. The cost center ceiling test is prepared quarterly.

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.

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.

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 SEC rules and regulations 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 and inject are principally our costs of production, transportation and acquisition, and to pay royalties.

We capitalize, 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 are included in our unevaluated property costs 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 are expensed as incurred and any previously deferred unevaluated development costs will become subject to depletion upon recognition of proved tertiary reserves.

CO_2 and Other Products - Properties and Pipelines

We own and produce CO_2 reserves that are used for our own tertiary oil recovery operations, and in addition, we sell a portion of our CO_2 production to third-party industrial users. We record revenue from our sales of CO_2 to third parties when it is produced and sold. Expenses related to the production of CO_2 are allocated between volumes sold to third parties and volumes consumed internally which are directly related to our tertiary production. The expenses related to third-party sales are recorded in "CO_2 discovery and operating expenses," and the expenses related to internal use are recorded in "Lease operating expenses" in the Consolidated Statements of Operations or 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* above for further discussion).

During 2010, we acquired an interest in the Riley Ridge Field, which contains helium, a non-hydrocarbon resource, as well as natural gas, a hydrocarbon. Capitalized costs related to the development of the natural gas and helium reserves are allocated between "Oil and natural gas properties" and "CO_2 and other products - properties and pipelines" on the Consolidated Balance Sheets based on the relative future revenue value of each product line.

During the third quarter of 2010, we revised our capitalization policies for CO_2 properties. Previously, we accounted for our CO_2 source properties in a manner similar to our method of accounting for oil and natural gas properties, as the process and activities to identify, develop and produce CO_2 reserves are virtually identical to those used to identify, develop and produce oil and natural gas reserves. However, because CO_2 is not a hydrocarbon, it is excluded from the scope of FASC Topic 932, *Extractive Industries – Oil and Gas*, and, therefore, we are precluded from accounting for our CO_2 operations in accordance with FASC Topic 932.

Accordingly, commencing in July 2010, costs incurred to search for CO_2 and other non-hydrocarbon resources are expensed as incurred until proved or probable reserves are established. Once proved or probable reserves are established, costs incurred to obtain those reserves are capitalized and classified as "CO_2 and other products — properties and pipelines" on our Consolidated Balance Sheets. Capitalized CO_2 and other products properties are aggregated by geologic formation and depleted on a unit-of-production basis over proved and probable reserves. The impact of the revised accounting policy on our financial statements is not material to any individual year. The Company has recognized the cumulative impact of the revised accounting policy as a non-cash net reduction to depletion, depreciation and amortization during the year ended December 31, 2010, resulting in a pretax credit of $9.6 million ($6.0 million after tax), which reflects a reduction to "CO_2 properties, equipment and pipelines" of $26.1 million offset by a decrease in "Accumulated depletion, depreciation and amortization" of $35.7 million. The cumulative adjustment did not have an impact on our net cash flows.

CO_2 pipelines are used for transportation of CO_2 to our tertiary floods from our CO_2 source fields located near Jackson, Mississippi. Costs of CO_2 pipelines under construction are not depreciated until the pipelines are placed into service. Pipelines are depreciated on a straight-line basis over their estimated useful lives, which range from 20 to 50 years.

The portion of the Company's capitalized CO_2 costs related to CO_2 reserves and CO_2 pipelines that we estimate will be consumed in the process of producing our proved oil reserves is included in the ceiling test as a reduction to future net revenues. The remaining net capitalized CO_2 properties, equipment and pipelines balance is evaluated for impairment by comparing the net carrying costs to the expected future net revenues from (1) the production of our probable and possible tertiary oil reserves and $_2$ the sale of CO_2 to third-party industrial users.

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. Vehicles and furniture and fixtures are generally depreciated over a useful life of five to ten years, and computer equipment and software are generally depreciated over a useful life of three to five years. Leasehold improvements are amortized over the shorter of the estimated useful life or the remaining lease term.

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.

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, removing equipment and facilities from leased acreage, and returning 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.

Asset retirement obligations are estimated at the present value of expected future net cash flows and are discounted using the Company's credit adjusted risk free rate. We utilize unobservable inputs in the estimation of asset retirement obligations that include, but are not limited to, costs of labor, costs of materials, profits on costs of labor and materials, the effect of inflation on estimated costs, and the discount rate. Accordingly, asset retirement obligations are considered a Level 3 measurement under the FASC's *Fair Value Measurements and Disclosures* topic.

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 the consolidated statements of operations in the period of change.

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. All of our derivative contracts are with banks, which are part of the syndicate of banks in our revolving credit agreement, or with their affiliates. There are no margin requirements with the counterparties of our derivative contracts.

Goodwill

Goodwill represents the excess of the purchase price over the estimated fair value of the net assets acquired in the acquisition of a business. Goodwill is not amortized, but rather it is tested for impairment annually during the fourth quarter and also when events or changes in circumstances indicate that the fair value of a reporting unit with goodwill has been reduced below carrying value. The impairment test requires allocating goodwill and other assets and liabilities to reporting units. However, we have only one reporting unit. If it is determined that the fair value of the reporting unit is less than the book value, including goodwill, the recorded goodwill is impaired to its implied fair value with a charge to operating expense. We completed our annual goodwill impairment test during the fourth quarter of 2010 and did not record any goodwill impairment during 2010 or historically.

The following table summarizes the changes in goodwill for the year ended December 31, 2010:

In thousands	
Balance as of December 31, 2009	$ 169,517
Adjustment to goodwill related to the acquisition of interests in the Conroe Field	318
Goodwill related to the Encore Merger	1,061,123
Goodwill related to the Riley Ridge acquisition	1,460
Balance as of December 31, 2010	$ 1,232,418

Restricted Cash and Investments

At December 31, 2010 and 2009, we had approximately $33.1 million and $22.8 million, respectively, of restricted cash and investments held in escrow accounts for future site reclamation costs, including asset retirement obligations. These balances are recorded at amortized cost and are included in “Other assets” in the Consolidated Balance Sheets. The estimated fair market value of these investments at December 31, 2010 and 2009 approximate cost.

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, 2010 and 2009, 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.

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.

We recognize the tax benefit from an uncertain tax position only if it is more likely than not that the tax position will be sustained upon 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 are measured based on the largest benefit that has a greater than 50% likelihood of being realized upon ultimate settlement.

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") and non-vested restricted stock.

For each of the three years in the period ended December 31, 2010, there were no adjustments to net income for purposes of calculating basic and diluted net income per common share.

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

	Year Ended December 31,		
In thousands	2010	2009	2008
Weighted average common shares — basic	370,876	246,917	243,935
Potentially dilutive securities:			
Stock options and SARs	3,844	—	7,102
Performance equity awards	319	—	—
Restricted stock	1,216	—	1,493
Weighted average common shares — diluted	376,255	246,917	252,530

The weighted average common shares – basic amount in 2010, 2009 and 2008 excludes 3.2 million, 2.5 million and 2.2 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 following securities could potentially dilute earnings per share in the future, but were not included in the computation of diluted net earnings per share as their effect would have been anti-dilutive:

	Year Ended December 31,		
In thousands	2010	2009	2008
Stock options and SARs	3,671	10,764	1,098
Performance equity awards	—	523	—
Restricted stock	17	2,507	—
Total	3,688	13,794	1,098

Recently Adopted Accounting Pronouncements

Pro Forma Disclosures. In December 2010, the FASB issued Accounting Standards Update ("ASU") 2010-29, *Business Combinations: Disclosure of Supplementary Pro Forma Information for Business Combinations* ("ASU 2010-29"), which amends FASC *Business Combinations* topic. The update addresses diversity in the interpretation of the pro forma revenue and earnings disclosure requirements for business combinations. If a public entity presents comparative financial statements, the entity should disclose revenue and earnings of the combined entity as though the business combination that occurred during the current year had occurred as of the beginning of the comparable prior annual reporting period only. The Company adopted ASU 2010-29 on January 1, 2011. The Company will apply the new standard to pro forma disclosures for acquisitions occurring after January 2, 2011.

Subsequent Events. In February 2010, the FASB issued guidance in the *Subsequent Events* topic of the FASC to provide updates including: (1) requiring the company to evaluate subsequent events through the date on which the financial statements are issued; (2) amending the glossary of the *Subsequent Events* topic to include the definition of "SEC filer" and exclude the definition of "Public entity"; and (3) eliminating the requirement to disclose the date through which subsequent events have been evaluated. This guidance was prospectively effective upon issuance. The adoption of this guidance did not impact our results of operations or financial condition.

Recently Issued Accounting Pronouncements

We have reviewed recently issued accounting standards that are not yet effective and have determined that none would have a material impact to our Consolidated Financial Statements.

Note 2. Acquisitions and Divestitures

Acquisitions

Fair Value. The FASC *Fair Value Measurements and Disclosures* topic defines fair value as 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 (often referred to as the "exit price"). The fair value measurement is based on the assumptions of market participants and not those of the reporting entity. Therefore, entity-specific intentions do not impact the measurement of fair value unless those assumptions are consistent with market participant views.

The fair value of oil and natural gas properties is based on significant inputs not observable in the market, which the FASC *Fair Value Measurements and Disclosures* topic defines as Level 3 inputs. Key assumptions include (1) NYMEX oil and natural gas futures (this input is observable), (2) projections of the estimated quantities of oil and natural gas reserves, including those classified as proved, probable, and possible, (3) projections of future rates of production, (4) timing and amount of future development and operating costs, (5) projected cost of CO_2 (to a market participant), (6) projected recovery factors, and (7) risk-adjusted discount rates. Fair value is determined using a risk-adjusted after-tax discounted cash flow analysis.

2010 Merger with Encore Acquisition Company. On March 9, 2010, we acquired Encore pursuant to the Encore Merger Agreement entered into with Encore on October 31, 2009. The Encore Merger Agreement provided for a stock and cash transaction valued at approximately $4.8 billion at the acquisition date, including the assumption of debt and the value of the noncontrolling interest in ENP. Under the Encore Merger Agreement, Encore was merged with and into Denbury, with Denbury surviving the Encore Merger.

In the Encore Merger, we issued approximately 135.2 million shares of common stock and paid approximately $833.9 million in cash to Encore stockholders. The Denbury shares issued to Encore stockholders represented approximately 34% of Denbury's common stock issued and outstanding immediately after the Encore Merger. The total fair value of our common stock issued to Encore stockholders in the Encore Merger was approximately $2.1 billion based upon our closing price of $15.43 per share on March 9, 2010.

The Encore Merger was financed through a combination of issuing $1.0 billion of 8¼% Senior Subordinated Notes due 2020, (the "2020 Notes"), which we issued on February 10, 2010, borrowings under a new $1.6 billion revolving credit agreement (the "Credit Agreement") entered into on March 9, 2010, and the assumption of Encore's remaining outstanding senior subordinated notes.

Encore shareholders received the following consideration for each share of Encore common stock they owned, depending upon the elections, if any, which they made, and the collar, proration and allocation features of the Encore Merger Agreement so that, in the aggregate, 30% of the consideration for the outstanding shares of Encore common stock would consist of cash, and the remaining 70% of the consideration would consist of shares of our common stock:

- Mixed cash/stock electing (or non-electing) Encore stockholders received $15.00 in cash and 2.4048 shares of Denbury common stock;
- All-cash electing Encore stockholders received $46.48 in cash and 0.2417 shares of Denbury common stock; and
- All-stock electing Encore stockholders (including those whose Encore restricted stock bonuses were converted into Denbury restricted stock) received 3.4354 shares of Denbury common stock.

All Encore stock options fully vested and their intrinsic value was paid in cash. All Encore restricted stock vested and each holder had the opportunity to make the same elections as other holders of Encore common stock as described above, except for shares of Encore restricted stock granted during 2010 as a bonus pursuant to the 2009 Encore annual incentive program, which were converted into restricted shares of our common stock.

The Encore Merger met the definition of a business combination under the FASC *Business Combinations* topic. As such, we estimated the fair value of Encore as of the acquisition date, which is the date on which we obtained control of Encore. The acquisition date for the Encore Merger was March 9, 2010.

In applying these accounting principles, we estimated the fair value of the Encore assets acquired less liabilities assumed on the acquisition date to be approximately $2.4 billion. This measurement resulted in the recognition of goodwill totaling approximately $1.1 billion. Goodwill was calculated as the excess of the consideration transferred to acquire Encore plus the fair value of the noncontrolling interest in ENP, over the acquisition date estimated fair value of the net assets acquired. Goodwill recorded in the Encore Merger primarily represents the value of the opportunity to expand Encore's CO_2 EOR operations in the Rocky Mountain region, the experience and technical expertise of former Encore employees who have joined Denbury, and the addition of strategic areas of operations in which we did not previously have a significant presence. None of the goodwill is deductible for income tax purposes.

The following table is a preliminary summary of the consideration issued in the Encore Merger and the fair value of the assets acquired and liabilities assumed at the acquisition date, as well as the fair value at the acquisition date of the noncontrolling interest in ENP. The purchase price allocation is preliminary pending finalization during the first quarter of 2011 of the pre-acquisition tax review.

In thousands	
Consideration and noncontrolling interest:	
Fair value of Denbury common stock issued(1)	$ 2,085,681
Cash payment to Encore stockholders(2)	833,909
Severance payments	32,925
Consideration issued	2,952,515
Fair value of noncontrolling interest of ENP(3)	515,210
Consideration and noncontrolling interest of ENP(4)	3,467,725
Add: fair value of liabilities assumed:	
Accounts payable and accrued liabilities	116,236
Oil and natural gas production payable	54,201
Current derivatives	65,954
Other current liabilities	38,407
Long-term debt	1,375,149
Asset retirement obligations	42,360
Long-term derivatives	35,631
Long-term deferred taxes	871,912
Other long-term liabilities	2,717
Amount attributable to liabilities assumed	2,602,567
Less: fair value of assets acquired:	
Cash and cash equivalents	51,850
Accrued production receivable	124,494
Trade and other receivables	46,383
Current derivatives	29,737
Oil and natural gas properties — proved	3,340,141
Oil and natural gas properties — unevaluated	1,279,000
CO_2 and other products — properties and pipelines	7,254
Other property, plant, and equipment	11,475
Long-term derivatives	35,207
Other long-term assets	83,628
Amount attributable to assets acquired	5,009,169
Goodwill	$ 1,061,123

(1) 135.2 million Denbury common shares at $15.43 per share.

(2) Based on holders of 55.3 million Encore common shares being paid $15.00 per share plus cash payment to stock option holders of $4.5 million.

(3) Represents fair value of the noncontrolling interest of ENP. As of March 9, 2010, there were 45.3 million ENP common units outstanding and the closing price was $21.10 per common unit. As of March 9, 2010, Encore owned approximately 46% of ENP's outstanding units.

(4) The sum of the consideration issued, the noncontrolling interest of ENP and the fair value of Encore's long-term debt assumed totals approximately $4.8 billion, representing the aggregate purchase price.

For the period from March 9, 2010 to December 31, 2010, we recognized $623.4 million of oil, natural gas and related product sales related to properties acquired in the Encore Merger. For the period from March 9, 2010, to December 31, 2010, we recognized $426.0 million net field operating income (oil, natural gas and related product sales less lease operating expenses and production taxes and marketing expenses) related to properties acquired in the Encore Merger. Transaction and other costs related to the Encore Merger included in the Consolidated Statement of Operations for the year ended December 31, 2010, include $48.5 million of third-party, legal and accounting fees, which have been expensed as incurred, and $43.8 million of employee-related severance and termination costs, which are accrued over the employees' service period. Accrued employee-related severance costs totaled $19.8 million at December 31, 2010, of which $16.5 million is classified as Accounts payable and accrued liabilities and $3.3 million is classified as long-term other liabilities on our balance sheet.

2010 Acquisition of Reserves in Rocky Mountain Region at Riley Ridge. In October 2010, we acquired a 42.5% non-operated working interest in the Riley Ridge Federal Unit ("Riley Ridge"), located in the LaBarge Field of southwestern Wyoming for $132.3 million after preliminary closing adjustments. Riley Ridge contains natural gas resources, as well as helium and CO_2 resources. The purchase includes a working interest in a gas plant, which is currently under construction, that will separate the helium and natural gas from the comingled gas stream. The acquisition also includes approximately 33% of the CO_2 mineral rights in an additional 28,000 acres adjoining the Riley Ridge Unit in which we own a non-operating interest.

The acquisition of Riley Ridge meets the definition of a business under the FASC *Business Combinations* topic. The purchase price allocation for the acquisition of interests in Riley Ridge Field is preliminary and subject to revision pending finalization of closing adjustments. The following table presents a summary of the preliminary fair value of assets acquired:

In thousands	
Oil and natural gas properties	$ 19,646
CO_2 and other products — properties and pipelines (CO_2 properties)	10,907
CO_2 and other products — properties and pipelines (Riley Ridge plant)	72,070
Prepaid construction and drilling costs	9,346
Other assets	19,300
Asset retirement obligations	(472)
Goodwill	1,460
Total	$ 132,257

2009 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 ensuing three years. Based on capital market conditions in early October 2008, 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.

In December 2009, we purchased Conroe Field for consideration consisting of approximately $270.6 million in cash (after closing adjustments) and 11,620,000 shares of our common stock. The common stock was valued at $168.7 million based on the closing date price of our stock on December 18, 2009, of $14.52. We believe the acquisition includes significant opportunities for enhanced oil recovery using our available sources of CO_2. We have recorded the acquisition as unevaluated oil and gas properties as determined under the FASC *Fair Value Measurement* topic. During the year ended December 31, 2009, we recognized $2.3 million and $1.4 million of revenues and net field operating income (revenues less production taxes and lease operating expenses), respectively, related to our acquisition of Conroe Field.

The acquisition of Conroe Field meets the definition of a business under the FASC *Business Combinations* topic. The following table presents a summary of the fair value of assets acquired:

In thousands	
Proved oil and natural gas properties	$ 305,009
Unevaluated oil and natural gas properties	93,585
Other assets	15,385
Asset retirement obligations	(5,705)
Goodwill	31,005
Total	$ 439,279

Goodwill is the excess of the consideration paid to acquire Conroe Field over the acquisition date estimated fair value. Goodwill is due to the estimated fair value assigned to the estimated oil reserves recoverable through a CO_2 EOR project. Denbury has one of the few known significant natural sources of CO_2 in the United States, and the largest known source east of the Mississippi River. This source of CO_2 that we own will allow Denbury to carry out CO_2 EOR activities in this field at a much lower cost than other market participants. However, the FASC *Fair Value Measurements and Disclosures* topic does not allow entity-specific assumptions in the measurement of fair value. Therefore, we estimated the fair value of the oil reserves recoverable through CO_2 EOR using the estimated cost of CO_2 to other market participants. This assumption of a higher cost of CO_2 resulted in lower fair value assigned to undeveloped property in the Conroe Field acquisition. Goodwill recorded in the Conroe acquisition is deductible for federal income tax purposes.

2009 Hastings Field 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 acquisition during February 2009. As consideration for the option agreement, from 2006 through 2008, we made cash payments totaling $50 million, which we recorded as a deposit. The remaining purchase price of $196 million (after final closing adjustments) was paid in cash. During the year ended December 31, 2009, we recognized $43.5 million and $18.8 million of revenues and net field operating income (revenues less production taxes and lease operating expenses), respectively, related to our acquisition of Hastings Field.

Under the terms of the agreement, Venoco, Inc., the seller, retained a 2% override and a reversionary interest of approximately 25% following payout, as defined in the option agreement. We began CO_2 injections at Hastings Field during the fourth quarter of 2010. Under the agreement, we are required to make aggregate net cumulative capital expenditures in this field of approximately $179 million prior to December 31, 2014 as follows: $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 inject 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 rate in the Hastings Field equals or exceeds the minimum required injection rate. At December 31, 2010, we are, and believe that we will continue to be compliant with both of these commitments.

The acquisition of Hastings Field meets the definition of a business under the FASC *Business Combinations* topic. The following table presents a summary of the fair value of assets acquired:

In thousands	
Proved oil and natural gas properties	$ 107,582
Other assets	2,425
Asset retirement obligations	(2,067)
Goodwill	138,830
Total	$ 246,770

Goodwill is the excess of the consideration paid to acquire Hastings Field over the acquisition date estimated fair value. Goodwill recorded in the Hastings Field acquisition is due to the estimated fair value assigned to the estimated oil reserves recoverable through a CO_2 enhanced oil recovery project. As discussed in the *2009 Conroe Field Acquisition* above, we own a CO_2 source that allows us to carry out CO_2 EOR activities at a much lower cost than other market participants. However, FASC *Fair Value Measurements and Disclosures* topic does not allow entity-specific assumptions in the measurement of fair value. Therefore, we estimated the fair value of the oil reserves recoverable through CO_2 EOR using an estimated cost of CO_2 to other market participants.

This assumption of a higher cost of CO_2 resulted in an estimated fair value of the projected CO_2 EOR reserves that would not have been economically viable at Hastings Field on the acquisition date. In addition, goodwill recorded is also due to the decrease in the NYMEX oil and natural gas futures prices between the effective date of January 1, 2009, which is the date at which the acquisition price was determined, and the acquisition date of February 2, 2009, which is the date at which the assets were valued for accounting purposes. The purchase agreement provided that the Hastings Field reserves be valued using the NYMEX oil and gas futures prices on the effective date of January 1, 2009. Goodwill recorded in the Hastings Field acquisition is deductible for federal income tax purposes.

2010 Unaudited Pro Forma Acquisition Information. Had our acquisition of Encore occurred on January 1, 2010 and had our acquisitions of Encore, Hastings Field and Conroe Field occurred on January 1, 2009, our combined pro forma revenue and net income (loss) would have been as follows:

	Year Ended December 31,	
In thousands	**2010**	**2009**
Pro forma total revenues and other income	$ 2,098,241	$ 1,622,685
Pro forma net income (loss) attributable to Denbury stockholders	286,891	(134,101)
Pro forma net income (loss) per common share:		
Basic	0.73	(0.34)
Diluted	0.72	(0.34)

2009 Unaudited Pro Forma Acquisition Information. Had our acquisitions of Hastings Field and Conroe Field occurred on January 1 of each respective year, our combined pro forma revenue and net income (loss) would have been as follows:

	Year Ended December 31,	
In thousands	**2009**	**2008**
Pro forma total revenues and other income	$ 937,986	$ 1,547,776
Pro forma net income (loss) attributable to Denbury stockholders	(71,774)	422,707
Pro forma net income (loss) per common share:		
Basic	(0.28)	1.65
Diluted	(0.28)	1.60

Dispositions

2010 Sale of Interests in Genesis. In February 2010, we sold our interest in Genesis Energy, LLC, the general partner of Genesis Energy, L.P. ("Genesis"), for net proceeds of approximately $84 million, after giving effect to the change of control provision of the incentive compensation agreement with Genesis' management, which was triggered and under which we paid a total of $14.9 million comprised of deferred compensation of $1.9 million and change of control redemption amounts of $13.0 million. In February 2010, we recognized general and administrative expense of $1.1 million associated with the $14.9 million payment. The remainder of the payment had been previously accrued in our financial statements as of December 31, 2009. In March 2010, we sold all of our Genesis common units in a secondary public offering for net proceeds of approximately $79 million. We recognized a pre-tax gain of approximately $101.5 million ($63.0 million after tax) on these dispositions.

2010 Sales of Non-strategic Encore Legacy Properties. Pursuant to our plan of divesting non-strategic legacy Encore properties, certain oil and gas properties in the Permian Basin, Mid-continent area and East Texas Basin (collectively, the "Southern Assets") were sold in May 2010 to Quantum Resources Management, LLC for consideration of $892.1 million after final closing adjustments. We subsequently divested our production and acreage in the Cleveland Sand Play of western Oklahoma for consideration of $32.1 million after closing adjustments, and the Haynesville and East Texas natural gas properties for consideration of $213.8 million after closing adjustments. In addition to the property sales, we sold our ownership interests in ENP on December 31, 2010. Collectively, we received $1.5 billion in total consideration from these divestitures in 2010. For all Encore legacy property dispositions during 2010, we reduced our full cost pool by the amount of the net proceeds and did not record a gain or loss on the sale in accordance with the full cost method of accounting.

2010 Sale of Ownership Interests in ENP. In December 2010, we sold our ownership interests in ENP, which consisted of our 100% ownership in ENP's general partner and 20.9 million ENP common units, to a subsidiary of Vanguard Natural Resources, LLC ("Vanguard") for consideration consisting of $300.0 million cash and 3,137,255 Vanguard common units valued at $93.0 million at the time of closing. In addition, Vanguard assumed all of ENP's long-term bank debt of $234.0 million. Under the terms of the sale we are restricted from divesting these Vanguard common units until July 31, 2011, and have classified the units as available-for-sale securities in "Short-term investments" on the Consolidated Balance Sheet for the year ended December 31, 2010. We did not record a gain or loss on the sale of oil and gas properties in accordance with the full cost method of accounting nor did we record a gain or loss on the remainder of the net assets sold as the book value approximated fair value.

2009 Sale of Barnett Shale Natural Gas Assets. In May 2009, we entered into an agreement to sell 60% of our Barnett Shale natural gas assets to Talon Oil and Gas LLC ("Talon"), a privately held company, for $259.8 million after closing adjustments. We closed on approximately three-quarters of the sale in June 2009 and closed on the remainder of the sale in July 2009. In December 2009, we closed the sale of our remaining 40% interest in the Barnett Shale natural gas assets to Talon for $209.9 million after closing adjustments. We did not record a gain or loss on the sales in accordance with the full cost method of accounting.

Note 3. Asset Retirement Obligations

The following table summarizes the changes in our asset retirement obligations for the years ended December 31, 2010 and 2009:

	Year Ended December 31,	
In thousands	**2010**	**2009**
Beginning asset retirement obligation	$ 54,338	$ 45,064
Liabilities incurred and assumed during period	4,291	8,911
Liabilities assumed in the Encore Merger	43,783	—
Revisions in estimated retirement obligations	5,505	2,357
Liabilities settled during period	(6,622)	(3,478)
Accretion expense	6,443	3,280
Sales of properties	(21,994)	(1,796)
Ending asset retirement obligation	$ 85,744	$ 54,338

At December 31, 2010 and 2009, $4.5 million and $1.1 million, respectively, of our asset retirement obligation was classified in "Accounts payable and accrued liabilities" in our Consolidated Balance Sheets. Liabilities incurred and assumed during 2010 are primarily related to the Encore Merger and the drilling of incremental wells, and during 2009 to the acquisition of Hastings and Conroe Fields. Sales of properties during the periods primarily related to the disposition of our non-strategic legacy Encore properties and ENP during 2010 and our Barnett Shale natural gas properties in 2009. The reversal of these asset retirement obligations, which were assumed by the purchasers, 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.

We have escrow accounts that are legally restricted for certain of our asset retirement obligations. The balances of these escrow accounts were $33.1 million and $22.8 million at December 31, 2010 and 2009, respectively, and are included in "Other assets" in our Consolidated Balance Sheets. The increase in the escrow balance during 2010 is related to escrow accounts acquired in the Encore Merger.

Note 4. Property and Equipment

The following table presents a summary of our net property and equipment balances as of December 31, 2010 and 2009:

In thousands	December 31, 2010	December 31, 2009
Oil and natural gas properties		
Proved properties	$ 6,042,442	$ 3,595,726
Unevaluated properties	870,130	320,356
Total	6,912,572	3,916,082
Accumulated depletion and depreciation	(2,045,091)	(1,685,171)
Net oil and natural gas properties	4,867,481	2,230,911
CO_2 and other products — properties and pipelines		
CO_2 properties	564,408	438,045
CO_2 pipelines in service	1,240,710	312,656
CO_2 pipelines under construction	11,890	779,080
Other products — properties under construction	84,654	—
Total	1,901,662	1,529,781
Accumulated depletion and depreciation	(100,345)	(101,622)
Net CO_2 and other products — properties and pipelines	1,801,317	1,428,159
Other property and equipment		
Capital leases	12,395	9,857
Other	108,246	72,680
Total	120,641	82,537
Accumulated depletion and depreciation	(52,081)	(38,735)
Net Other property and equipment	68,560	43,802
Net property and equipment	$ 6,737,358	$ 3,702,872

In the table above, amounts included in "CO_2 pipelines under construction" and "Other products plant, property, and equipment under construction" are excluded from DD&A expense until placed into service and reclassified to the appropriate accounts.

A summary of the unevaluated properties excluded from oil and natural gas properties being amortized at December 31, 2010, and the year in which they were incurred follows:

	December 31, 2010				
	Costs Incurred During:				
In thousands	2010	2009	2008	2007 and prior	Total
Property acquisition costs	$ 598,445	$ 95,484	$ 1,592	$ 48,992	$ 744,513
Exploration and development	86,916	3,858	5,100	1,633	97,507
Capitalized interest	20,959	3,228	2,009	1,914	28,110
Total	$ 706,320	$ 102,570	$ 8,701	$ 52,539	$ 870,130

Our 2010 property acquisition costs were primarily related to the fair value allocated to CO_2 tertiary potential at our Bell Creek and Cedar Creek Anticline properties and Bakken properties acquired as part of the Encore Merger. Our 2009 property acquisition costs were primarily related to CO_2 tertiary potential at our Conroe Field. Property acquisition costs for 2007 and prior were primarily for CO_2 tertiary potential at our Oyster Bayou, Hastings and Citronelle Fields. We commenced CO_2 injection at Oyster Bayou and Hastings Fields during 2010, representing the majority of the costs related to this period. Exploration and development costs are primarily associated with our tertiary oil fields that are under development but did not have proved reserves at December 31, 2010. During 2010, we established proved reserves at Delhi Field, and as a result we transferred $196.1 million of costs incurred on this project into the amortization base. Costs are transferred into the amortization base on an ongoing basis as 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 of the full cost pool.

Note 5. Long-Term Debt

The following long-term debt and capital lease obligations were outstanding as of December 31, 2010 and 2009:

In thousands	December 31, 2010	December 31, 2009
Credit Agreement	$ —	$ —
Senior bank loan (replaced with Credit Agreement)	—	125,000
7½% Senior Subordinated Notes due 2013, including discount of $437 and $631, respectively	224,563	224,369
7½% Senior Subordinated Notes due 2015, including premium of $427 and $513, respectively	300,427	300,513
9½% Senior Subordinated Notes due 2016, including premium of $14,589	239,509	—
9¾% Senior Subordinated Notes due 2016, net of discount of $22,139 and $26,424, respectively	404,211	399,926
8¼% Senior Subordinated Notes due 2020	996,273	—
Other Subordinated Notes, including premium of $41	3,848	—
NEJD financing	167,331	170,633
Free State financing	81,188	79,987
Capital lease obligations	6,806	5,948
Total	2,424,156	1,306,376
Less current obligations	7,948	5,308
Long-term debt and capital lease obligations	$ 2,416,208	$ 1,301,068

$1.6 Billion Revolving Credit Agreement

On March 9, 2010, we entered into a $1.6 billion revolving credit agreement with JPMorgan Chase Bank, N.A. (“JPMorgan”), as administrative agent, and 23 other lenders as party thereto (the “Credit Agreement”). This new Credit Agreement was entered into in conjunction with the Encore Merger to:

- fund a portion of the consideration issued in the Encore Merger (inclusive of payments made to stock option holders);
- repay amounts outstanding under our then-existing $750 million revolving credit agreement, which had $125 million outstanding as of March 9, 2010;
- repay amounts outstanding under Encore’s then-existing revolving credit agreement, which had $265 million outstanding as of March 9, 2010;
- pay Encore’s severance costs;
- pay transaction fees and expenses; and
- provide additional liquidity.

Availability under the Credit Agreement is subject to a borrowing base, which is re-determined semi-annually on or prior to May 1 and November 1 and upon requested special redeterminations. The Credit Agreement provides for a borrowing base of $1.6 billion, which was reaffirmed on November 1, 2010. The borrowing base is adjusted at the banks’ discretion and is based in part upon external factors over which we have no control. If the borrowing base were to be less than outstanding borrowings under the Credit Agreement, we would be required to repay the deficit over a period of four months. We incur a commitment fee of 0.5% on the unused portion of the credit facility or if less, the borrowing base. Loans under the Credit Agreement mature in March 2014.

The Credit Agreement is secured by substantially all of the proved oil and natural gas properties of our restricted subsidiaries and by the equity interests of our restricted subsidiaries. In addition, our obligations under the Credit Agreement are guaranteed by our restricted subsidiaries. Our restricted subsidiaries include most of the subsidiaries of the combined company after the Encore Merger.

The Credit Agreement contains several restrictive covenants including, among others:

- a prohibition on the payment of dividends to parties other than us and our restricted subsidiaries;
- a requirement to maintain a current ratio, as determined under the Credit Agreement, of not less than 1.0 to 1.0;
- a maximum permitted ratio of debt to adjusted EBITDA (as defined in the Credit Agreement) of us and our restricted subsidiaries of not more than 4.5 to 1.0 through December 31, 2010 and 4.0 thereafter; and
- a prohibition against incurring debt, subject to permitted exceptions.

Additionally, there is a limitation on the aggregate amount of forecasted oil and natural gas production that can be economically hedged with oil or natural gas derivative contracts.

Loans under the Credit Agreement are subject to varying rates of interest based on (1) the total outstanding borrowings in relation to the borrowing base and $_2$ whether the loan is a Eurodollar loan or a base rate loan. Eurodollar loans bear interest at the Eurodollar rate plus the applicable margin of 2.0% to 3.0% based on the ratio of outstanding borrowings to the borrowing base, and base rate loans bear interest at the base rate plus the applicable margin of 1.0% to 2.0% based on the ratio of outstanding borrowings to the borrowing base. The "Eurodollar rate" for any interest period (either one, two, three, six, nine or twelve months, as selected by us) is the rate per year equal to LIBOR, as published by Reuters or another source designated by JPMorgan, for deposits in dollars for a similar interest period. The "base rate" is calculated as the highest of (1) the annual rate of interest announced by JPMorgan as its "prime rate," $_2$ the federal funds effective rate plus 0.5%, and (3) the Adjusted Eurodollar Rate (as defined in the Credit Agreement) for a one-month interest period plus 1.0%.

8¼% Senior Subordinated Notes due 2020

On February 10, 2010, we issued $1.0 billion of 8¼% Senior Subordinated Notes due 2020 (the "2020 Notes"), for net proceeds after underwriting discounts and commissions of $980 million. The 2020 Notes were sold at par. Upon the closing of the Encore Merger, $400 million of the net proceeds were used to finance a portion of the Encore Merger consideration. Under the indenture governing the 2020 Notes, we redeemed $3.7 million principal amount of the 2020 Notes, the amount by which the $596.3 million aggregate principal amount of Encore's outstanding senior subordinated notes actually tendered by holders was less than the $600 million principal amount of these notes for which we made tender offers. See *Tender Offers and Consent Solicitations for Encore's Senior Subordinated Notes; Supplements to Indentures Governing Encore's Senior Subordinated Notes* below.

The 2020 Notes mature on February 15, 2020, and interest is payable on February 15 and August 15 of each year. We may redeem the 2020 Notes in whole or in part at our option beginning February 15, 2015, at the following redemption prices: 104.125% after February 15, 2015, 102.75% after February 15, 2016, 101.375% after February 15, 2017, and 100% after February 15, 2018. Prior to February 15, 2013, we may at our option redeem up to an aggregate of 35% of the principal amount of the 2020 Notes at a price of 108.25% with the proceeds of certain equity offerings. In addition, at any time prior to February 15, 2015, we may redeem 100% of the principal amount of the 2020 Notes at a price equal to 100% of the principal amount plus a "make-whole" premium and accrued and unpaid interest. 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 2020 Notes are not subject to any sinking fund requirements. Certain of our subsidiaries fully and unconditionally guarantee this debt.

Supplements to Indentures Governing Denbury's Senior Subordinated Notes

On March 9, 2010, upon closing of the Encore Merger, we became an obligor, as successor in interest to Encore, with respect to Encore's senior subordinated notes, which are governed by four indentures covering an aggregate original principal amount of $825 million. In conjunction with the closing of the Encore Merger, we and our subsidiaries entered into supplemental indentures to become subsidiary guarantors under Encore's senior subordinated notes, as required under the Encore indentures, as well as the indentures governing our senior subordinated notes. The Encore legacy subsidiaries, with permitted exceptions, became guarantors under the indentures that were in effect prior to the Encore Merger.

Tender Offers and Consent Solicitations for Encore's Senior Subordinated Notes; Supplements to Indentures Governing Encore's Senior Subordinated Notes

On February 8, 2010, we commenced a cash tender offer to repurchase $600 million principal amount of Encore's senior subordinated notes that were governed by three of Encore's four indentures and solicited consents to amend each of those three indentures to eliminate most of the indenture covenants. Those indentures to which Encore was a party prior to the Encore Merger govern their 6¼% Senior Subordinated Notes due 2014 (the "6¼% Notes"), their 6% Senior Subordinated Notes due 2015 (the "6% Notes") and their 7¼% Senior Subordinated Notes due 2017 (the "7¼% Notes" and collectively, the "Other Subordinated Notes").

On March 10, 2010, upon expiration of the tender offers and consent solicitations, we accepted for purchase all notes tendered in the tender offer. The total amount of notes that we purchased was approximately $500.5 million in principal amount of the $600 million in original principal amount for which tenders were made, leaving outstanding approximately $99.5 million of the $600 million of notes for which we made tender offers.

The tender of the notes also constituted the delivery of consents of holders of the notes to eliminate or modify certain provisions contained in each of the three indentures governing the Other Subordinated Notes, which was sufficient to amend these three Encore indentures effective upon the date of the Encore Merger. The amendments of the three indentures governing the $600 million of Other Subordinated Notes eliminated most of the restrictive covenants and certain events of default in the indentures. The amendments do not apply to the 9½% Senior Subordinated Notes due 2016 (the "9½% Notes").

On March 12, 2010, we commenced a second tender offer to repurchase, for 101% of the face amount, the $99.5 million of notes that remained outstanding after completion of the February 8, 2010, tender, plus an initial offer to purchase, for 101% of the face amount, the $225 million of outstanding 9½% Notes. These change-of-control tenders were required by each of the Encore indentures. In April 2010, we purchased approximately $95.7 million of these senior subordinated notes, leaving approximately $228.7 million of former Encore notes outstanding.

Encore Indentures

In addition to the three indentures that govern the Other Subordinated Notes, as a result of the Encore Merger, we also became successor in interest to Encore under the Encore indenture with respect to the 9½% Notes in the original principal amount of $225 million (the "9½% Notes"). Interest on the 9½% Notes is due semi-annually, on May 1 and November 1. The 9½% Notes mature on May 1, 2016. We may redeem the 9½% Notes, in whole or in part at our option beginning May 1, 2013, at the following redemption prices: 104.75% after May 1, 2013, 102.375% after May 1, 2014 and 100% after May 1, 2015. Prior to May 1, 2012, we may at our option redeem up to an aggregate of 35% of the principal amount of the 9.5% Notes at a price of 109.5% with the proceeds of certain equity offerings. In addition, at any time prior to May 1, 2013, we may redeem 100% of the principal amount of the 9½% Notes at a price equal to 100% of the principal amount plus a "make-whole" premium and accrued and unpaid interest. The material terms of the 9½% Notes include covenants requiring the filing of SEC reports, restricting certain payments, limiting indebtedness, restricting distributions from certain restricted subsidiaries, affiliate transactions, and liens, requiring certain subsidiaries to deliver guarantees of the notes, requiring the delivery of certificates concerning compliance with the indenture, and covenants relating to mergers and consolidations.

All of the Encore indentures, including the 9½% Notes, also have covenants limiting the sale of assets and providing a put right by holders upon change of control, as well as other certain affirmative and negative covenants.

9¾% Senior Subordinated Notes due 2016

In February 2009, we issued $420 million of 9¾% Senior Subordinated Notes due 2016 ("2016 Notes"). The 2016 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 then-outstanding borrowings under our bank credit facility. 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.

In June 2009, we issued an additional $6.35 million of 2016 Notes to our founder, Gareth Roberts, as part of a Founder's Retirement Agreement. In connection with this issuance, we recorded compensation expense of $6.35 million in "General and administrative" expense in our Consolidated Statement of Operations during the year ended December 31, 2009.

The 2016 Notes mature on March 1, 2016, and interest on the 2016 Notes is payable March 1 and September 1 of each year. We may redeem the 2016 Notes in whole or in part at our option beginning March 1, 2013, at the following redemption prices: 104.875% after March 1, 2013, 102.4375% after March 1, 2014, and 100% after March 1, 2015. In addition, we may at our option, redeem up to an aggregate of 35% of the 2016 Notes before March 1, 2012, at a price of 109.75%. 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 2016 Notes are not subject to any sinking fund requirements. All of our significant subsidiaries fully and unconditionally guarantee this debt.

7½% Senior Subordinated Notes due 2015

In April 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 7½% 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 $150 million of 2015 Notes issued on December 21, 2005 were priced at par, and we used the net proceeds from the offering to fund a portion of the $250 million oil and natural gas property acquisition, which closed in January 2006. 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 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. On February 3, 2011, we launched a tender offer to repurchase all $300 million of our 2015 Notes outstanding and on February 17, 2011 called for redemption all of the notes which remain outstanding after the early consent date repurchases in the tender offer. See Note 15, *Subsequent Events*, for more information.

7½% Senior Subordinated Notes due 2013

In March 2003, we issued $225 million of 7½% Senior Subordinated Notes due 2013 ("2013 Notes"). The 2013 Notes were priced at 99.135% of par. 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 at the following remaining redemption prices: 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. On February 3, 2011, we launched a tender offer to repurchase all $225 million of our 2013 Notes outstanding and on February 17, 2011 called for redemption all of the notes which remain outstanding after the early consent date repurchases in the tender offer. See Note 15, *Subsequent Events*, for more information.

Issuance of 6⅜% Senior Subordinated Notes due 2021

On February 17, 2011, we issued $400 million of 6⅜% Senior Subordinated Notes due 2021 ("2021 Notes"). The 2021 Notes, which carry a coupon rate of 6.375%, were sold at par. The net proceeds of $393 million were used to repurchase a portion of our 2013 Notes and 2015 Notes, to the extent tendered. See Note 15, *Subsequent Events*, for more information.

NEJD Financing and Free State Financing

In May 2008, we closed two transactions with Genesis involving two of our pipelines. The NEJD pipeline system included a 20-year financing lease, and the Free State Pipeline included a long-term transportation service agreement. We recorded both of these transactions as financing leases.

Indebtedness Repayment Schedule

At December 31, 2010, our indebtedness, including our capital and financing lease obligations but excluding the discount and premium on our senior subordinated debt, is repayable over the next five years and thereafter as follows:

In thousands	
2011	$ 7,948
2012	9,081
2013	236,599
2014	12,779
2015	310,354
Thereafter	1,854,913
Total indebtedness	$ 2,431,674

Note 6. Income Taxes

Our income tax provision (benefit) is as follows:

	Year Ended December 31,		
In thousands	**2010**	**2009**	**2008**
Current income tax expense (benefit)			
Federal	$ 15,683	$ 7,090	$ 32,475
State	17,511	(2,479)	8,337
Total current income tax expense	33,194	4,611	40,812
Deferred income tax expense (benefit)			
Federal	143,381	(50,457)	184,630
State	16,968	(1,187)	10,390
Total deferred income tax expense (benefit)	160,349	(51,644)	195,020
Total income tax expense (benefit)	$ 193,543	$ (47,033)	$ 235,832

At December 31, 2010, we had tax-effected state net operating loss carryforwards ("NOLs") totaling $44.6 million, an estimated $39.8 million of enhanced oil recovery credits to carry forward related to our tertiary operations, and $34.5 million of alternative minimum tax credits. These carryforwards include Encore's tax attributes, which, as a result of the Encore Merger, carried over to us, with the tax attributes being subject to certain limitations. Upon testing these limitations, it has been determined that the limitations are not likely to affect our use of Encore's tax attributes. Our state NOLs expire in various years, starting in 2013; however, the significant portion of our state NOLs expires in 2025. Our enhanced oil recovery credits will begin to expire in 2024.

Deferred income taxes reflect the available tax carryforwards and the temporary differences based on tax laws and statutory rates in effect at the December 31, 2010 and 2009 balance sheet dates. We believe that we will be able to realize all of our deferred tax assets at December 31, 2010, and therefore have provided no valuation allowance against our deferred tax assets.

Significant components of our deferred tax assets and liabilities as of December 31, 2010 and 2009 are as follows:

	December 31,	
In thousands	**2010**	**2009**
Deferred tax assets:		
Loss carryforwards — state	$ 44,595	$ 4,394
Tax credit carryover	34,476	32,156
Derivative contracts	24,918	47,056
Enhanced oil recovery credit carryforwards	39,810	38,929
Stock based compensation	38,947	23,840
Other	49,928	6,150
Total deferred tax assets	232,674	152,525
Deferred tax liabilities:		
Property and equipment	(1,725,430)	(619,621)
Other	(27,782)	(2,099)
Total deferred tax liabilities	(1,753,212)	(621,720)
Total net deferred tax liability	$ (1,520,538)	$ (469,195)

Our reconciliation of income tax expense (benefit) computed by applying the U.S. federal statutory rate and the reported effective tax rate on income (loss) from continuing operations is as follows:

In thousands	Year Ended December 31, 2010	2009	2008
Income tax provision (benefit) calculated using the federal statutory income tax rate	$ 167,674	$ (42,765)	$ 218,479
State income taxes, net of federal income tax benefit	13,087	(3,666)	18,865
Revaluation of deferred tax liabilities, net	11,502	—	—
Other	1,280	(602)	(1,512)
Total income tax expense (benefit)	$ 193,543	$ (47,033)	$ 235,832

During 2010, we revalued our deferred tax liabilities due to a change in our statutory rate resulting from the Encore Merger, asset sales, and a corporate legal entity restructuring.

In the third quarter of 2008, we obtained approval from the National Office of the Internal Revenue Service ("IRS") to change our method of tax accounting for certain assets used in our tertiary oilfield recovery operations. As a result of the approved change in method of tax accounting, beginning with the 2007 tax year we began to deduct, rather than capitalize, such costs for tax purposes, and applied for tax refunds associated with such change for our 2004 and 2006 tax years. Notwithstanding its consent to our change in tax accounting in 2008, the IRS recently exercised its prerogative to challenge the tax accounting method we used. In late January 2011, we received a Technical Advice Memorandum ("TAM") issued by the IRS National Office disapproving our method of accounting and revoking its consent to our change, on a prospective basis only, commencing January 1, 2011. Henceforth, beginning with the 2011 tax year, we will return to capitalizing and depreciating the costs of these assets for tax purposes. As a result of the prospective nature of the IRS's determination, there should be no change in our position with respect to the deductibility of these costs for 2007, 2008, 2009, or 2010. However, refund claims of $10.6 million for tax years through 2006 are pending and are subject to review by the Joint Committee on Taxation of the U.S. Congress. We are unable to assess the outcome of any such review, nor how that outcome may affect the other years covered by the TAM.

Uncertain Tax Positions

Total unrecognized tax benefits were $0.2 million, $1.0 million and $1.0 million as of December 31, 2010, 2009 and 2008, respectively. During 2010, after analyzing the evidence and facts, we reduced our liability for unrecognized tax benefits by $0.8 million as we believe our position is more likely than not of being sustained upon potential audit or examination. 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 is expected to change over the next 12 months; however, such change is not expected to have a material impact on our results of operations or financial position.

We file consolidated and separate income tax returns in the U.S. federal jurisdiction and in many state jurisdictions. We are currently under examination by the IRS for the 2006, 2007 and 2008 tax years. The IRS concluded its examination of our 2005 tax year during the second quarter of 2008. The state of Mississippi concluded its examination of our 2001–2003 tax years during the fourth quarter of 2010 with no significant adjustments. We are currently under examination by the state of Mississippi for the 2004, 2005, 2006 and 2007 tax years. As a result of the examinations concluded during 2008, we decreased our total amount of unrecognized tax benefits from $3.5 million at December 31, 2007, to $1.0 million at December 31, 2008. These adjustments are 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 7. Stockholders' Equity

Stock Repurchases

In 2008, 2009 and 2010, all of our share repurchases were from our employees that surrendered shares to the Company to satisfy their minimum tax withholding requirements as provided for under our 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 8,900,000 shares of common stock. As of December 31, 2010, there were 955,713 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 we match 75% of their contribution. The combined funds are used to purchase previously unissued Denbury common stock or treasury stock that we purchased in the open market for that purpose, in either case, based on the market value of our common stock at the end of each quarter. We recognize compensation expense for the 75% Company match portion, which totaled $3.5 million, $3.1 million and $2.7 million for the years ended December 31, 2010, 2009 and 2008, respectively. This plan is administered by the Compensation Committee of our Board of Directors.

401(k) Plan

We offer a 401(k) plan to which employees may contribute tax-deferred earnings subject to Internal Revenue Service limitations. We match 100% of an employee's contribution, up to 6% of compensation, as defined by the plan, which is vested immediately. During 2010, 2009 and 2008, our matching contributions were approximately $5.7 million, $4.0 million and $3.3 million, respectively, to the 401(k) Plan.

Note 8. Stock Compensation Plans

Stock Incentive Plans

We have 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 provided only 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 2010, shareholders approved the latest increase to the number of shares that may be used under our 2004 Plan, from 21.5 million to 29.5 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 29.5 million shares of common stock are authorized for issuance pursuant to the 2004 Plan, of which awards covering no more than 22.2 million shares may be issued in the form of restricted stock or performance vesting awards. At December 31, 2010, a total of 11,857,316 shares were available for future issuance of awards, all of which may be in the form of restricted stock or performance vesting awards. Our incentive compensation program is administered by the Compensation Committee of our Board of Directors.

We have historically granted incentive and non-qualified stock options to our 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, 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.

In 2004, we began the use of restricted stock awards. 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. Restricted stock awards vest over three to four year vesting periods, with the specific terms of vesting determined at the time of grant.

Total stock-based compensation expense was $36.1 million, $21.9 million and $14.1 million for the years ended December 31, 2010, 2009 and 2008, respectively. Part of this expense, $2.1 million in 2010, $1.4 million in 2009 and $1.4 million in 2008, 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 $14.4 million, $8.7 million and $5.3 million for the years ended December 31, 2010, 2009 and 2008, respectively. Share-based compensation associated with our employees involved in exploration and drilling activities of $3.6 million, $2.5 million and $2.2 million for the years ended December 31, 2010, 2009 and 2008, respectively, has been capitalized as part of "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 (cliff vesting and 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 we do not pay a dividend.

Beginning in 2009, SARs granted have a term of 7 years as compared to 10 years for grants in prior periods. Additionally, these SARs were issued with a graded vesting as compared to a combination of cliff and graded vesting in prior periods. Both of these changes resulted in a reduced expected term as compared to awards previously issued.

	2010	2009	2008
Weighted average fair value of SARs granted	$ 8.45	$ 6.40	$ 11.91
Risk-free interest rate	2.19%	1.58%	3.29%
Expected life	4.0 to 4.3 years	3.9 to 4.7 years	4.5 to 6.2 years
Expected volatility	65.0%	60.1%	38.1%
Dividend yield	—	—	—

The following is a summary of our stock option and SAR activity:

	Year Ended December 31,					
	2010		2009		2008	
	Number of Options	Weighted Average Exercise Price	Number of Options	Weighted Average Exercise Price	Number of Options	Weighted Average Exercise Price
Outstanding at beginning of period	10,763,955	$ 10.77	9,514,999	$ 9.32	11,463,285	$ 6.28
Granted	3,444,494	16.30	2,883,311	13.23	1,042,810	29.45
Exercised	(1,119,853)	6.21	(1,315,535)	4.33	(2,612,134)	3.36
Forfeited or expired	(819,256)	17.57	(318,820)	16.36	(378,962)	13.80
Outstanding at end of period	12,269,340	12.28	10,763,955	10.77	9,514,999	9.32
Exercisable at end of period	6,214,546	$ 8.07	6,087,019	$ 6.48	4,593,407	$ 4.55

The total intrinsic value of stock options and SARs exercised during the years ended December 31, 2010, 2009 and 2008, was approximately $12.7 million, $14.8 million and $65.8 million, respectively. The total grant-date fair value of stock options and SARs vested during the years ended December 31, 2010, 2009 and 2008, was approximately $8.7 million, $10.1 million and $7.2 million, respectively. The aggregate intrinsic value of stock options and SARs outstanding at December 31, 2010, was approximately $93.7 million, and these options and SARs have a weighted-average remaining contractual life of 4.8 years. The aggregate intrinsic value of options and SARs exercisable at December 31, 2010, was approximately $70.5 million, and these stock options and SARs have a weighted-average remaining contractual life of 3.8 years.

A summary of the status of our non-vested stock options and SARs as of December 31, 2010, and the changes during the year ended December 31, 2010, is presented below:

	Shares	Weighted Average Grant-Date Fair Value
Non-vested at December 31, 2009	4,676,936	$ 7.45
Granted	3,444,494	8.45
Vested	(1,292,228)	6.72
Forfeited	(774,408)	8.69
Non-vested at December 31, 2010	6,054,794	8.02

As of December 31, 2010, there was $22.4 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 2.4 years. Cash received from stock option exercises under share-based payment arrangements for the years ended December 31, 2010, 2009 and 2008, was $4.9 million, $5.7 million and $7.7 million, respectively. The tax benefit realized from the exercises of stock options and SARs totaled $4.6 million for 2010, $3.1 million for 2009, and $18.9 million for 2008.

Restricted Stock-2004 Plan

As of December 31, 2010, we had issued 7,961,418 shares of restricted stock (net of forfeited shares) pursuant to the 2004 Plan, and there was $18.7 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 3.2 years. The total vesting date fair value of restricted stock vested during the years ended December 31, 2010, 2009 and 2008 under the 2004 Plan was $12.7 million, $10.0 million and $12.3 million, respectively.

A summary of the status of our non-vested restricted stock grants and the changes during the year ended December 31, 2010, is presented below:

	Shares	Weighted Average Grant-Date Fair Value
Non-vested at December 31, 2009	2,506,998	$ 12.29
Granted	1,382,467	16.29
Vested	(666,870)	12.34
Forfeited	(273,761)	17.20
Non-vested at December 31, 2010	2,948,834	13.70

Restricted Stock – Encore Plan

In February 2010, prior to the consummation of the Encore Merger, Encore issued a restricted stock grant to its employees under the Encore Acquisition Company 2008 Incentive Stock Plan (“Encore Plan”). At the time of the Encore Merger, the shares were converted to shares of Denbury restricted stock. The shares vest ratably over a four-year graded vesting period; however, legacy Encore employees who terminate their employment for Good Reason, as defined by Encore’s legacy Employee Severance Protection Plan, will automatically vest in their awards upon termination. Encore employees who did not accept permanent positions with Denbury but who continued their employment through a predefined transition period were considered to have terminated for Good Reason and, accordingly, vested in their awards upon termination. The total vesting date fair value of restricted stock vested during the year ended December 31, 2010, under the Encore Plan was $6.6 million.

A summary of the status of the non-vested restricted stock grants under the Encore Plan and the changes during the year ended December 31, 2010, is presented below:

	Shares	Weighted Average Grant-Date Fair Value
Non-vested at December 31,2009	—	$ —
Granted	652,503	14.33
Vested	(344,223)	13.35
Forfeited	(31,660)	15.43
Non-vested at December 31, 2010	276,620	15.42

Performance Equity Awards

Beginning in 2007, the Board of Directors has awarded an annual grant of performance equity awards to officers of Denbury. These performance-based shares originally vested over 3.25 years, but beginning with awards granted in 2009, the vesting period was 1.25 years. The number of performance-based shares 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 that could be earned 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 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.

During 2010, we granted performance-based equity awards (204,525 shares reflecting the 100% targeted vesting level) to the Company's officers, with an average grant date fair value of $15.63 per share. The aggregate number of performance-based equity awards outstanding at December 31, 2010, was 300,405 at the 100% targeted vesting level, less actual forfeitures. The actual number of shares to be delivered pursuant to the performance-based awards could range from zero to 200% (600,810 shares) of the stated 100% targeted amount. During 2010, the performance-based equity awards originally granted in 2007 vested at 110% of their original targeted amount, resulting in the issuance of 104,959 shares of Denbury stock with a weighted average grant date fair value of $13.90 per share. Also during 2010, the performance-based equity awards originally granted in 2009 vested at 120% of their originally targeted amount, resulting in the issuance of 341,534 shares of Denbury stock with a weighted average grant date fair value of $12.97 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 a targeted vesting level of 162% and 130% for the 2010 and 2008 performance grants, respectively. During the years ended December 31, 2010, 2009 and 2008, we recorded $6.9 million, $4.7 million and $1.2 million, respectively, of expense in "General and administrative expenses" in our Consolidated Statements of Operations for these performance-based awards.

Note 9. 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 "Derivatives 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. 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. We currently employ a strategy to hedge a portion of our forecasted production approximately 12 to 15 months in advance, as we believe it is important to protect our future cash flow to provide a level of assurance for our capital spending in those future periods in light of current worldwide economic uncertainties.

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

	Year Ended December 31,		
In thousands	**2010**	**2009**	**2008**
Oil			
Receipt (payment) on settlements of derivative contracts	$ (93,417)	$ 146,734	$ (30,969)
Fair value adjustments to derivative contracts — income (expense)	44,441	(375,750)	259,889
Total derivative income (expense) — oil	(48,976)	(229,016)	228,920
Natural gas			
Receipt (payment) on settlements of derivative contracts	61,805	—	(26,584)
Fair value adjustments to derivative contracts — income (expense)	8,585	(7,210)	(2,283)
Total derivative income (expense) — natural gas	70,390	(7,210)	(28,867)
Ineffectiveness on interest rate swaps	2,419	—	—
Derivative income (expense)	$ 23,833	$ (236,226)	$ 200,053

Fair Value of Commodity Derivative Contracts Not Classified as Hedging Instruments

				NYMEX Contract Prices Per Bbl			Estimated Fair Value Asset (Liability)	
				Weighted Average Price				
Year	Months	Type of Contract	Bbls/d	Swap	Floor	Ceiling	December 31, 2010	December 31, 2009
							In thousands	
Oil Contracts:								
2010	Jan - Mar	Swap	30,625	$ 55.40	$ -	$ -	$ -	$ (63,525)
		Collar	10,000	-	67.45	86.38	-	95
	Total Jan - Mar 2010		40,625				$ -	$ (63,430)
		Collar	35,000	-	62.13	89.08	-	(24,741)
	Total Apr - June 2010		35,000				$ -	$ (24,741)
		Collar	35,000	-	62.13	89.08	-	(20,761)
	Total July - Sept 2010		35,000				$ -	$ (20,761)
	Oct - Dec	Collar	35,000	$ -	$ 62.13	$ 89.08	$ -	$ (13,320)
	Total Oct - Dec 2010		35,000				$ -	$ (13,320)
2011	Jan - Mar	Swap	625	$ 79.18	$ -	$ -	$ (737)	$ -
		Collar	43,500	-	67.25	95.80	(3,656)	177
		Put	6,625	-	69.53	-	79	-
	Total Jan - Mar 2011		50,750				$ (4,314)	$ 177
	Apr - June	Swap	625	$ 79.18	$ -	$ -	$ (827)	$ -
		Collar	43,500	-	70.34	100.20	(12,113)	(318)
		Put	6,625	-	69.53	-	499	-
	Total Apr - June 2011		50,750				$ (12,441)	$ (318)
	July - Sept	Swap	625	$ 79.18	$ -	$ -	$ (865)	$ -
		Collar	42,500	-	70.35	100.09	(17,308)	(1,078)
		Put	6,625	-	69.53	-	1,026	-
	Total July - Sept 2011		49,750				$ (17,147)	$ (1,078)
	Oct - Dec	Swap	625	$ 79.18	$ -	$ -	$ (871)	$ -
		Collar	45,500	-	70.33	101.74	(18,878)	(2,533)
		Put	6,625	-	69.53	-	1,445	-
	Total Oct - Dec 2011		52,750				$ (18,304)	$ (2,533)
2012	Jan - Mar	Swap	625	$ 81.04	$ -	$ -	$ (741)	$ -
		Collar	44,000	-	70.00	101.93	(19,065)	-
		Put	625	-	65.00	-	123	-
	Total Jan - Mar 2012		45,250				$ (19,683)	$ -
	Apr-June	Swap	625	$ 81.04	$ -	$ -	$ (726)	$ -
		Collar	26,000	-	70.00	113.26	(3,288)	
		Put	625	-	65.00	-	151	-
	Total Apr - June 2012		27,250				$ (3,863)	$ -
	July-Sept	Swap	625	$ 81.04	$ -	$ -	$ (719)	$ -
		Put	625	-	65.00	-	178	-
	Total July - Sept 2012		1,250				$ (541)	$ -
	Oct - Dec	Swap	625	$ 81.04	$ -	$ -	$ (709)	$ -
		Put	625	-	65.00	-	191	-
	Total Oct - Dec 2012		1,250				$ (518)	$ -
						Total Oil Contracts	$ (76,811)	$ (126,004)

Year	Months	Type of Contract	Mcf/d	Contract Prices Per Mcf/d Weighted Average Price Swap	Floor	Ceiling	Estimated Fair Value Asset (Liability) December 31, 2010	December 31, 2009
							In thousands	
Natural Gas Contracts:								
2010	Jan - Mar	Swap	79,000	$ 5.77	$ -	$ -	$ -	$ 92
	Total Jan - Mar 2010		79,000				$ -	$ 92
	Apr - June	Swap	79,000	$ 5.77	$ -	$ -	$ -	$ 397
	Total Apr - June 2010		79,000				$ -	$ 397
	July - Sept	Swap	59,000	$ 5.96	$ -	$ -	$ -	$ (294)
	Total July - Sept 2010		59,000				$ -	$ (294)
	Oct - Dec	Swap	59,000	$ 5.96	$ -	$ -	$ -	$ (1,954)
	Total Oct - Dec 2010		59,000				$ -	$ (1,954)
2011	Jan - Dec	Swap	33,500	$ 6.27	$ -	$ -	$ 21,192	$ (981)
	Total Jan - Dec 2011		33,500				$ 21,192	$ (981)
2012	Jan - Dec	Swap	20,000	$ 6.53	$ -	$ -	$ 11,618	$ -
	Total Jan - Dec 2012		20,000				$ 11,618	$ -
				Total Natural Gas Contracts			$ 32,810	$ (2,740)
				Total Commodity Derivative Contracts			$ (44,001)	$ (128,744)

As of December 31, 2010, Denbury had $26.7 million of deferred premiums payable, which relate to various oil and natural gas floor contracts and are payable on a monthly basis from January 2011 to December 2012. These premiums are excluded from the above tables.

Additional Disclosures about Derivative Instruments:

At December 31, 2010 and 2009, we had derivative financial instruments recorded in our Consolidated Balance Sheets as follows:

Type of Contract	Balance Sheet Location	Estimated Fair Value Asset (Liability) December 31, 2010	2009
		In thousands	
Derivatives not designated as hedging instruments:			
Derivative Assets			
Crude Oil contracts	Derivative assets - current	$ 3,050	$ 309
Natural Gas contracts	Derivative assets - current	21,192	—
Crude Oil contracts	Derivative assets - long-term	1,301	506
Natural Gas contracts	Derivative assets - long-term	11,618	—
Derivative Liabilities			
Crude Oil contracts	Derivative liabilities - current	(55,256)	(122,561)
Natural Gas contracts	Derivative liabilities - current	—	(1,759)
Deferred premiums	Derivative liabilities - current	(22,928)	—
Crude Oil contracts	Derivative liabilities - long-term	(25,906)	(4,258)
Natural Gas contracts	Derivative liabilities - long-term	—	(981)
Deferred premiums	Derivative liabilities - long-term	(3,781)	—
Total derivatives not designated as hedging instruments		$ (70,710)	$ (128,744)

Note 10. Fair Value Measurements

Fair value is the price that would be received to sell an asset or would be 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. The FASC 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 are as follows:

- Level 1 - Quoted prices in active markets for identical assets or liabilities as of the reporting date.

- 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 and natural gas derivatives that are based on NYMEX pricing.

- 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. Instruments in this category include non-exchange-traded natural gas derivatives swaps that are based on regional pricing other than NYMEX (i.e. Houston ship channel).

We adjust the valuations from the valuation model for nonperformance risk, using our estimate of the counterparty's credit quality for asset positions and Denbury's credit quality for liability positions. Denbury uses multiple sources of third-party credit data in determining counterparty nonperformance risk, including credit default swaps.

The following table sets forth by level within the fair value hierarchy our financial assets and liabilities that were accounted for at fair value on a recurring basis as of December 31, 2010 and 2009:

In thousands	Fair Value Measurements Using: Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
December 31, 2010				
Assets:				
Short-term investments	$ 93,020	$	$	$ 93,020
Oil and natural gas derivative contracts	—	20,683	16,478	37,161
Liabilities:				
Oil and natural gas derivative contracts	—	(81,162)	—	(81,162)
Total	$ 93,020	$ (60,479)	$ 16,478	$ 49,019
December 31, 2009				
Assets:				
Oil derivative contracts	$ —	$ 815	$ —	$ 815
Liabilities:				
Oil and natural gas derivative contracts	—	(129,559)	—	(129,559)
Total	$ —	$ (128,744)	$ —	$ (128,744)

The following table summarizes the changes in the fair value of our Level 3 assets and liabilities for the year ended December 31, 2010:

In thousands	Fair Value Measurements Using Significant Unobservable Inputs (Level 3)
Balance at December 31, 2009	$ —
Commodity derivative contracts acquired in Encore Merger	38,093
Included in earnings	21,240
Receipts on settlement of commodity derivative contracts	(42,855)
Balance at December 31, 2010	$ 16,478
The amount of total gains for the period included in earnings attributable to the change in unrealized gains relating to assets still held at the reporting date	$ 21,240

The following table sets forth the fair value of financial instruments that are not recorded at fair value in our Consolidated Financial Statements:

In thousands	December 31, 2010 Carrying Amount	December 31, 2010 Estimated Fair Value	December 31, 2009 Carrying Amount	December 31, 2009 Estimated Fair Value
Liabilities:				
Credit Agreement	$ —	$ —	$ —	$ —
Senior Bank Loan (replaced with Credit Agreement)	—	—	125,000	122,500
7 ½% Senior Subordinated Notes due 2013	224,563	228,375	224,369	226,125
7 ½% Senior Subordinated Notes due 2015	300,427	310,500	300,513	299,250
9 ½% Senior Subordinated Notes due 2016	239,509	249,661	—	—
9 ¾% Senior Subordinated Notes due 2016	404,211	475,380	399,926	455,129
8 ¼% Senior Subordinated Notes due 2020	996,273	1,080,956	—	—
Other subordinated notes	3,848	3,807	—	—

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 as 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 for estimated nonperformance risk. 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 11. Commitments and Contingencies

We lease office space, equipment and vehicles that have non-cancelable lease terms. Leases entered into during 2010 have terms up to eleven years. Lease payments associated with these operating leases were $42.4 million, $37.6 million and $32.3 million in 2010, 2009 and 2008, respectively. We have subleased part of the office space included in our operating leases for which we will receive approximately $4.0 million for 2011 through 2013 under these sublease agreements.

The following table summarizes by the remaining non-cancelable future payments under these operating leases as of December 31, 2010:

In thousands	Pipeline Financing Leases	Capital Leases	Operating Leases
2011	$ 30,882	$ 2,987	$ 34,027
2012	31,926	2,213	32,930
2013	34,280	1,446	31,733
2014	34,114	673	27,519
2015	31,847	106	26,759
Thereafter	375,145	615	84,188
Total minimum lease payments	538,194	8,040	$ 237,156
Less: Amount representing interest	(289,675)	(1,234)	
Present value of minimum lease payments	$ 248,519	$ 6,806	

We are party to long-term contracts that 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 14, *Related Party Transactions - Genesis*. 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 382 Bcf of CO_2 to these customers over the next 17 years; 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 would likely be reduced to 194 Bcf. The maximum volume required in any given year is approximately 136 MMcf/d. Given the size of our Jackson Dome proven CO_2 reserves at December 31, 2010 (approximately 7.1 Tcf before deducting approximately 100.2 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 can meet these contractual delivery obligations.

We have entered into long-term contracts to purchase man-made CO_2 from nine proposed plants that will emit large volumes of CO_2, four of which are in the Gulf Coast region, four in the Midwest region (Illinois, Indiana, and Kentucky) and one in the Rocky Mountain region. The Midwest purchases are conditioned on both the specific plant being constructed and Denbury contracting enough volumes of CO_2 for purchase in the general area of our proposed Midwest pipeline system, such that an acceptable economic rate-of-return on the CO_2 pipeline will be achieved. At the present time, two of the Midwest facilities have been unable to meet a critical contractual obligation and thus Denbury is evaluating these two projects to determine if we should extend the time for the facility to meet the contractual obligation. If all nine of these plants were to be built, these CO_2 sources are currently anticipated to provide us with aggregate CO_2 volumes of 1.2 Bcf/d to 2.0 Bcf/d, although the earliest source of this man-made CO_2 is not expected to be available to us until 2014. Although these plants have all been delayed due to economic conditions, over the last six to nine months several of the projects appear to be making progress but there is still some doubt as to whether they will be constructed at all. Several of these plants are in negotiations for federal support through grants and loan guarantees, which if secured, could increase the possibility that certain plants will be ultimately constructed. 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 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 nine plants are built, the aggregate purchase obligation for this CO_2 would be around $320 million per year, assuming an $85 per barrel NYMEX 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 other plants under consideration that could provide CO_2 to us that would either supplement or replace some of the CO_2 volumes from the nine proposed plants for which we currently have CO_2 output purchase contracts. We have ongoing discussions with several of these other potential sources. We have invested a total of $13.8 million 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 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.

Concurrent with our purchase of an interest in the Riley Ridge Field, we became party to a long-term helium supply agreement whereby the participants in the Riley Ridge Field will supply helium to a purchaser for a period of 20 years beginning at the earlier of the start-up of the Riley Ridge plant or December 31, 2011. The agreement provides for annual delivery of 200 MMcf for the first two years and 400 MMcf for the remaining term of the contract. If the guaranteed quantity of helium is not supplied, the suppliers will compensate the purchaser for the amount of the shortfall in an amount not to exceed $8.0 million per year, of which the Company's share would be $3.4 million.

We are subject to audits in the various states in which we operate for sales and use taxes and severance taxes, and from time to time receive assessments for potential taxes that we may owe. We have received a $14.9 million assessment from the Mississippi taxing authority for use tax, penalties and interest covering the 2004-2007 period, which has been appealed. We do not believe the outcome of this matter will have a material adverse impact on the Company.

We are 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 we believe that we have 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

The class action cases brought in Texas state courts and in Delaware Court of Chancery related to the Encore Merger have all been settled and the cases dismissed. The shareholder derivative action brought in the District Court of Dallas County, Texas, regarding a compensation matter has been settled, and application to the Court by all parties to dismiss the case is pending. The amounts paid in settlement were immaterial to our balance sheet, results of operations and cash flows.

We are involved in other 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. We do not expect that the loss of any purchaser would have a material adverse effect upon our operations. For the year ended December 31, 2010, two purchasers accounted for 10% or more of our oil and natural gas revenues: Marathon Petroleum Company LLC (46%) and Plains Marketing LP (14%). For the year ended December 31, 2009, two purchasers accounted for 10% or more of our oil and natural gas revenues: Marathon Petroleum Company LLC (52%) and Hunt Crude Oil Supply Co. (21%). For the year ended December 31, 2008, three purchasers 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%).

Accounts Payable and Accrued Liabilities

	December 31,	
In thousands	**2010**	**2009**
Accounts payable	$ 47,660	$ 40,140
Accrued exploration and development costs	101,758	40,375
Accrued compensation	39,757	35,292
Accrued interest	57,077	24,214
Accrued taxes payable	34,371	5,358
Other	65,375	24,495
Total	$ 345,998	$ 169,874

Supplemental Cash Flow Information

In thousands, except shares	Year Ended December 31, 2010	2009	2008
Cash paid for interest, net of amounts capitalized	$ 151,831	$ 20,924	$ 26,997
Interest capitalized	66,815	68,596	29,161
Cash paid for income taxes	2,853	241	70,349
Increase (decrease) in liabilities for capital expenditures	(237)	(76,605)	59,183
Issuance of Denbury common stock in connection with the Encore Merger	2,085,681	—	—
Vanguard common units received as consideration for sale of ENP	93,020	—	—
Common stock issued pursuant to Conroe Field Acquisition	—	168,723	—
Genesis common units received in lease financing	—	—	25,000

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 (“Onshore”) 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. Each subsidiary guarantor and the subsidiary co-obligor are 100% owned, directly or indirectly, by Denbury Resources Inc.

As of December 31, 2010, Denbury effected an internal reorganization whereby, among other things, Encore Operating L.P., a wholly-owned subsidiary of Denbury Resources Inc., liquidated into Onshore. As a result, the Condensed Consolidated Balance Sheet as of December 31, 2010 reflects the impact of this reorganization.

The following is condensed consolidating financial information for Denbury Resources Inc., Onshore and subsidiary guarantors:

Condensed Consolidating Balance Sheets

	December 31, 2010					
In thousands	Denbury Resources Inc. (Parent and Co-Obligor)	Denbury Onshore, LLC (Issuer, Co-Obligor, and Guarantor)	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Denbury Resources Inc. Consolidated
ASSETS						
Current assets:						
Cash and cash equivalents	$ 457	$ 370,383	$ 11,029	$ —	$ —	$ 381,869
Other current assets	144,247	226,804	792,452	—	(681,054)	482,449
Total current assets	144,704	597,187	803,481	—	(681,054)	864,318
Property and equipment:						
Proved	—	3,965,436	2,077,006	—	—	6,042,442
Unevaluated	—	268,566	601,564	—	—	870,130
CO_2 and other products - properties and pipelines	—	578,849	1,319,955	2,858	—	1,901,662
Other	—	109,631	11,010	—	—	120,641
Less accumulated depletion, depreciation, amortization, and impairment	—	(2,049,545)	(147,972)	—	—	(2,197,517)
Net property and equipment	—	2,872,937	3,861,563	2,858	—	6,737,358
Other assets, net	1,891,576	221,486	109,578	—	(759,253)	1,463,387
Investment in subsidiaries (equity method)	4,332,350	—	1,565,204	—	(5,897,554)	—
Total assets	$ 6,368,630	$ 3,691,610	$ 6,339,826	$ 2,858	$ (7,337,861)	$ 9,065,063
LIABILITIES AND EQUITY						
Current liabilities	43,654	810,533	402,984	3,228	(681,054)	579,345
Long-term debt	1,944,269	1,198,289	—	—	(726,350)	2,416,208
Deferred taxes	—	825,676	755,197	22	(32,903)	1,547,992
Other liabilities	—	106,338	34,473	—	—	140,811
Total liabilities	1,987,923	2,940,836	1,192,654	3,250	(1,440,307)	4,684,356
Total equity	4,380,707	750,774	5,147,172	(392)	(5,897,554)	4,380,707
Total liabilities and equity	$ 6,368,630	$ 3,691,610	$ 6,339,826	$ 2,858	$ (7,337,861)	$ 9,065,063

In thousands	Denbury Resources Inc. (Parent and Co-Obligor)	Denbury Onshore, LLC (Issuer, Co-Obligor, and Guarantor)	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Denbury Resources Inc. Consolidated
	December 31, 2009					
ASSETS						
Current assets:						
Cash and cash equivalents	$ 24	$ 20,281	$ 286	$—	$ —	$ 20,591
Other current assets	637,310	233,320	20,432	—	(655,891)	235,171
Total current assets	637,334	253,601	20,718	—	(655,891)	255,762
Property and equipment:						
Proved	—	3,595,726	—	—	—	3,595,726
Unevaluated	—	320,356	—	—	—	320,356
CO_2 and other products - properties and pipelines	—	1,309,325	220,456	—	—	1,529,781
Other	—	82,185	352	—	—	82,537
Less accumulated depletion, depreciation, amortization, and impairment	—	(1,825,282)	(246)	—	—	(1,825,528)
Net property and equipment	—	3,482,310	220,562	—	—	3,702,872
Other assets, net	746,442	225,938	6,078	—	(742,131)	236,327
Investment in subsidiaries (equity method)	1,303,728	23,792	1,299,186	—	(2,551,689)	75,017
Total assets	$ 2,687,504	$ 3,985,641	$ 1,546,544	$—	$ (3,949,711)	$ 4,269,978
LIABILITIES AND EQUITY						
Current liabilities	14,827	795,486	239,368	—	(655,891)	393,790
Long-term debt	700,440	1,326,978	—	—	(726,350)	1,301,068
Deferred taxes	—	527,849	3,448	—	(15,781)	515,516
Other liabilities	—	87,367	—	—	—	87,367
Total liabilities	715,267	2,737,680	242,816	—	(1,398,022)	2,297,741
Total equity	1,972,237	1,247,961	1,303,728	—	(2,551,689)	1,972,237
Total liabilities and equity	$ 2,687,504	$ 3,985,641	$ 1,546,544	$—	$ (3,949,711)	$ 4,269,978

Condensed Consolidating Statements of Operations

In thousands	Year Ended December 31, 2010 Denbury Resources Inc. (Parent and Co-Obligor)	Denbury Onshore, LLC (Issuer, Co-Obligor, and Guarantor)	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Denbury Resources Inc. Consolidated
Revenues and other income:						
Oil, natural gas, and related product sales	$ —	1,169,894	475,864	147,534	—	1,793,292
CO_2 sales and transportation fees	—	35,317	3,406	—	(19,519)	19,204
Gain on sale of interests in Genesis	—	(227)	101,764	—	—	101,537
Interest income and other	64,304	3,728	3,761	34	(64,069)	7,758
Total revenues and other income	64,304	1,208,712	584,795	147,568	(83,588)	1,921,791
Expenses:						
Lease operating expenses	—	383,303	85,806	34,187	(16,373)	486,923
Production taxes and marketing expenses	—	51,652	62,852	14,542	—	129,046
CO_2 discovery and operating expenses	—	10,732	626	—	(3,146)	8,212
General and administrative	705	113,466	16,116	9,395	—	139,682
Interest, net of amounts capitalized	184,278	80,449	(34,293)	9,748	(64,069)	176,113
Depletion, depreciation, and amortization	—	264,531	130,833	38,943	—	434,307
Derivative expense (income)	—	(30,951)	(6,493)	13,611	—	(23,833)
Transaction costs and other related to the Encore Merger	—	47,150	43,597	1,524	—	92,271
Total expenses	184,983	920,332	299,044	121,950	(83,588)	1,442,721
Equity in net earnings of subsidiaries	226,821	—	154,481	—	(381,302)	—
Income (loss) before income taxes	106,142	288,380	440,232	25,618	(381,302)	479,070
Income tax provision (benefit)	(43,035)	133,899	102,587	92	—	193,543
Consolidated net income (loss)	149,177	154,481	337,645	25,526	(381,302)	285,527
Less: Net income attributable to noncontrolling interest	—	—	—	(13,804)	—	(13,804)
Net income (loss) attributable to Denbury stockholders	$ 149,177	154,481	337,645	11,722	(381,302)	271,723

In thousands	Denbury Resources Inc. (Parent and Co-Obligor)	Denbury Onshore, LLC (Issuer, Co-Obligor, and Guarantor)	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Denbury Resources Inc. Consolidated
	Year Ended December 31, 2009					
Revenues and other income:						
Oil, natural gas, and related product sales	$ —	866,709	—	—	—	866,709
CO_2 sales and transportation fees	—	13,422	—	—	—	13,422
Interest income and other	58,984	2,889	6,130	—	(58,984)	9,019
Total revenues and other income	58,984	883,020	6,130	—	(58,984)	889,150
Expenses						
Lease operating expenses	—	326,132	—	—	—	326,132
Production taxes and marketing expenses	—	42,484	—	—	—	42,484
CO_2 discovery and operating expenses	—	4,649	—	—	—	4,649
General and administrative	165	88,857	18,606	—	—	107,628
Interest, net of amounts capitalized	64,183	51,000	(8,769)	—	(58,984)	47,430
Depletion, depreciation, and amortization	—	238,323	—	—	—	238,323
Derivative expense	—	236,226	—	—	—	236,226
Transaction costs and other related to the Encore Merger	—	8,467	—	—	—	8,467
Total expenses	64,348	996,138	9,837	—	(58,984)	1,011,339
Equity in net earnings of subsidiaries	(67,689)	—	(65,764)	—	133,453	—
Income before income taxes	(73,053)	(113,118)	(69,471)	—	133,453	(122,189)
Income tax provision (benefit)	2,103	(47,354)	(1,782)	—	—	(47,033)
Consolidated net income	(75,156)	(65,764)	(67,689)	—	133,453	(75,156)
Less: Net income attributable to noncontrolling interest	—	—	—	—	—	—
Net income (loss) attributable to Denbury stockholders	$ (75,156)	(65,764)	(67,689)	—	133,453	(75,156)

In thousands	Year Ended December 31, 2008 Denbury Resources Inc. (Parent and Co-Obligor)	Denbury Onshore, LLC (Issuer, Co-Obligor, and Guarantor)	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Denbury Resources Inc. Consolidated
Revenues and other income:						
Oil, natural gas, and related product sales	$ —	1,347,010	—	—	—	1,347,010
CO_2 sales and transportation fees	—	13,858	—	—	—	13,858
Interest income and other	22,500	5,456	4,732	—	(22,500)	10,188
Total revenues and other income	22,500	1,366,324	4,732	—	(22,500)	1,371,056
Expenses						
Lease operating expenses	—	307,542	8	—	—	307,550
Production taxes and marketing expenses	—	63,752	—	—	—	63,752
CO_2 discovery and operating expenses	—	4,216	—	—	—	4,216
General and administrative	165	56,906	3,303	—	—	60,374
Interest, net of amounts capitalized	22,817	32,279	—	—	(22,500)	32,596
Depletion, depreciation, and amortization	—	221,790	2	—	—	221,792
Derivative income	—	(200,053)	—	—	—	(200,053)
Abandoned acquisition costs	—	30,601	—	—	—	30,601
Write-down of oil and natural gas properties	—	226,000	—	—	—	226,000
Total expenses	22,982	743,033	3,313	—	(22,500)	746,828
Equity in net earnings of subsidiaries	408,393	—	407,412	—	(815,805)	—
Income before income taxes	407,911	623,291	408,831	—	(815,805)	624,228
Income tax provision (benefit)	19,515	215,879	438	—	—	235,832
Consolidated net income	388,396	407,412	408,393	—	(815,805)	388,396
Less: Net income attributable to noncontrolling interest	—	—	—	—	—	—
Net income (loss) attributable to Denbury stockholders	$ 388,396	407,412	408,393	—	(815,805)	388,396

Condensed Consolidating Statements of Cash Flows

Denbury Resources Inc. (Parent) has no independent assets or operations. Denbury Onshore, LLC is one of our operating subsidiaries. Cash flow activity of Denbury Resources Inc. consists of intercompany loans between Denbury Resources Inc. and our subsidiaries to service the parent company-issued debt. This intercompany cash flow activity is eliminated in consolidation. Cash flow activity of Denbury Onshore, LLC, combined with the other guarantor subsidiaries, is presented in our Consolidated Statements of Cash Flows.

	Year Ended December 31, 2010					
In thousands	Denbury Resources Inc. (Parent and Co-Obligor)	Denbury Onshore, LLC (Issuer, Co-Obligor, and Guarantor)	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Denbury Resources Inc. Consolidated
Cash flow from operating activities:						
Net cash provided by (used for) operating activities	$ 714,643	$ 722,209	$ (466,556)	$ 76,547	$ (191,032)	$ 855,811
Cash flow used for investing activities:						
Oil and natural gas capital expenditures	—	(406,168)	(259,696)	(5,710)	—	(671,574)
Acquisitions of oil and natural gas properties	—	(25,358)	(132,291)	(280)	—	(157,929)
Cash paid in the Encore Merger, net of cash acquired	(830,309)	—	2,209	13,116	—	(814,984)
CO_2 and other products - capital expenditures, including pipelines	—	(150,453)	(147,780)	(2,859)	—	(301,092)
Net proceeds from sale of interests in Genesis	—	23,537	139,082	—	—	162,619
Net proceeds from sale of oil and natural gas properties and equipment	—	33,923	1,424,106	—	—	1,458,029
Investments in subsidiaries (equity method)	(216,730)	—	—	—	216,730	—
Other	—	(28,531)	(854)	(464)	—	(29,849)
Net cash provided by (used for) investing activities	(1,047,039)	(553,050)	1,024,776	3,803	216,730	(354,780)
Cash flow from financing activities:						
Bank repayments	(879,000)	(350,000)	(265,000)	(36,000)	—	(1,530,000)
Bank borrowings	879,000	225,000	—	10,000	—	1,114,000
Senior subordinated notes tendered per Encore Merger	(616,637)	—	—	—	—	(616,637)
Net proceeds from issuance of senior subordinated debt	1,000,000	—	—	—	—	1,000,000
Net proceeds from issuance of common stock	13,065	13,065	—	—	(13,065)	13,065
Contributed capital from sale of interests in ENP	—	300,000	(300,000)	—	—	—
Costs of debt financing	(76,232)	—	—	—	—	(76,232)
ENP distributions to noncontrolling interest	15,750	—	16,232	(52,970)	(15,750)	(36,738)
Pipeline financing	—	(2,101)	—	—	—	(2,101)
Other	(3,117)	(5,021)	(89)	—	3,117	(5.110)
Net cash provided by (used for) financing activities	332,829	180,943	(548,857)	(78,970)	(25,698)	(139,753)
Net increase (decrease) in cash and cash equivalents	433	350,102	9,363	1,380	—	361,278
Cash and cash equivalents at beginning of period	24	20,281	286	—	—	20,591
Cash and cash equivalents at end of period	$ 457	$ 370,383	$ 9,649	$ 1,380	$ —	$ 381,869

In thousands	Year Ended December 31, 2009 Denbury Resources Inc. (Parent and Co-Obligor)	Denbury Onshore, LLC (Issuer, Co-Obligor, and Guarantor)	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Denbury Resources Inc. Consolidated
Cash flow from operating activities:						
Net cash provided by (used for) operating activities	$ —	$ 530,460	$ 139	$—	$ —	$ 530,599
Cash flow used for investing activities:						
Oil and natural gas capital expenditures	—	(343,351)	—	—	—	(343,351)
Acquisitions of oil and natural gas properties	—	(452,795)	—	—	—	(452,795)
CO_2 and other products - capital expenditures, including pipelines	—	(666,372)	—	—	—	(666,372)
Net proceeds from sale of oil and natural gas properties and equipment	—	516,814	—	—	—	516,814
Investments in subsidiaries (equity method)	(412,837)	—	—	—	412,837	—
Other	—	(24,010)	—	—	—	(24,010)
Net cash provided by (used for) investing activities	(412,837)	(969,714)	—	—	412,837	(969,714)
Cash flow from financing activities:						
Bank repayments	—	(856,000)	—	—	—	(856,000)
Bank borrowings	—	906,000	—	—	—	906,000
Net proceeds from issuance of senior subordinated debt	389,827	389,827	—	—	(389,827)	389,827
Net proceeds from issuance of common stock	12,991	12,991	—	—	(12,991)	12,991
Costs of debt financing	9,120	(10,080)	—	—	(9,120)	(10,080)
Pipeline financing	—	369	—	—	—	369
Other	899	(470)	—	—	(899)	(470)
Net cash provided by (used for) financing activities	412,837	442,637	—	—	(412,837)	442,637
Net increase (decrease) in cash and cash equivalents	—	3,383	139	—	—	3,522
Cash and cash equivalents at beginning of period	24	16,898	147	—	—	17,069
Cash and cash equivalents at end of period	$ 24	$ 20,281	$ 286	$—	$ —	$ 20,591

In thousands	Year Ended December 31, 2008 Denbury Resources Inc. (Parent and Co-Obligor)	Denbury Onshore, LLC (Issuer, Co-Obligor, and Guarantor)	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Denbury Resources Inc. Consolidated
Cash flow from operating activities:						
Net cash provided by (used for) operating activities	(10)	776,112	(1,583)	—	—	774,519
Cash flow used for investing activities:						
Oil and natural gas capital expenditures	—	(587,968)	—	—	—	(587,968)
Acquisitions of oil and natural gas properties	—	(31,367)	—	—	—	(31,367)
CO_2 and other products - capital expenditures, including pipelines	—	(407,103)	—	—	—	(407,103)
Net proceeds from sale of oil and natural gas properties and equipment	—	51,684	—	—	—	51,684
Investments in subsidiaries (equity method)	(29,874)	—	—	—	29,874	—
Other	—	(19,905)	—	—	—	(19,905)
Net cash provided by (used for) investing activities	(29,874)	(994,659)	—	—	29,874	(994,659)
Cash flow from financing activities:						
Bank repayments	—	(222,000)	—	—	—	(222,000)
Bank borrowings	—	147,000	—	—	—	147,000
Net proceeds from issuance of common stock	13,972	13,972	—	—	(13,972)	13,972
Costs of debt financing	—	(2,288)	—	—	—	(2,288)
Pipeline financing	—	225,252	—	—	—	225,252
Other	15,902	15,166	—	—	(15,902)	15,166
Net cash provided by (used for) financing activities	29,874	177,102	—	—	(29,874)	177,102
Net increase (decrease) in cash and cash equivalents	(10)	(41,445)	(1,583)	—	—	(43,038)
Cash and cash equivalents at beginning of period	34	58,343	1,730	—	—	60,107
Cash and cash equivalents at end of period	$ 24	$ 16,898	$ 147	$—	$ —	$ 17,069

Note 14. Related Party Transactions - Genesis

Interest in and Transactions with Genesis

During February 2010, we sold our interest in Genesis Energy, LLC, the general partner of Genesis, which is a publicly traded master limited partnership. In March 2010, we sold all of our Genesis common units in a secondary public offering. As a result, we no longer hold any interests in Genesis and Genesis is no longer considered a related party.

Prior to these sales we accounted for our 12% ownership in Genesis under the equity method of accounting, as we had significant influence over the limited partnership; however, our control was limited under the limited partnership agreement and, therefore, we did not consolidate Genesis. We received cash distributions from Genesis of $11.6 million in 2009 and $7.1 million in 2008. We also received $0.2 million in both 2009 and 2008 in directors' fees for certain officers of Denbury who were board members of Genesis prior to the February 5, 2010, sale of our General Partner ownership.

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, which agreements make them Class B Members in Genesis Energy, LLC, and each an owner of a Class B ownership interest. The awards are mandatorily redeemable upon a change in control and require the membership interests of the holders of the awards to be redeemed for cash (or in certain circumstances Genesis limited partnership units) by Genesis Energy, LLC. Upon the sale of our interest in Genesis Energy, LLC in February 2010, the change in control provision of each member's compensation agreement was triggered. As such, the awards were settled for cash in February 2010 for $14.9 million. We recorded approximately $14.2 million for the year ended December 31, 2009, in “General and administrative” expenses on our Consolidated Statement of Operations, of which $0.4 million relates to cash payments made under these awards prior to the trigger of the change in control provision, and $13.8 million is associated with the fair value of the award.

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 $7.9 million in 2009 and $8.0 million in 2008 for these transportation services.

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, 2009 and 2008, $19.8 million and $24.0 million, respectively, was recorded as deferred revenue of which $4.1 million was included in current liabilities at both December 31, 2009 and 2008 and the remaining portion was classified as long-term other liabilities. We recognized deferred revenue of $4.2 million and $4.5 million for the years ended December 31, 2009 and 2008 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 $0.20 per Mcf of CO_2. For these services, we recognized revenues of $5.5 million and $5.5 million for the years ended December 31, 2009 and 2008, respectively.

Note 15. Subsequent Events

New Senior Subordinated Notes

In February 2011, we issued $400 million of 6 ⅜% Senior Subordinated Notes due 2021 (“2021 Notes”). The 2021 Notes, which carry a coupon rate of 6.375%, were sold at par. The net proceeds of $393 million were used to repurchase a portion of our outstanding 2013 Notes and 2015 Notes, tendered in tender offers (see *Tender Offers* below).

The 2021 Notes mature on August 15, 2021, and interest is payable on February 15 and August 15 of each year, beginning August 15, 2011. We may redeem the 2021 Notes in whole or in part at our option beginning August 15, 2016, at the following redemption prices: 103.188% after August 15, 2016; 102.125% after August 15, 2017; 101.062% after August 15, 2018; and 100% after August 15, 2019. Prior to August 15, 2014, we may at our option redeem up to an aggregate of 35% of the principal amount of the 2021 Notes at a price of 106.375% with the proceeds of certain equity offerings. In addition, at any time prior to August 15, 2016, we may redeem 100% of the principal amount of the 2021 Notes at a price equal to 100% of the principal amounts plus a “make whole” premium and accrued and unpaid interest. 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 merger, or sell substantially all of our assets. The 2021 Notes are not subject to any sinking fund requirements. All of our significant subsidiaries fully and unconditionally guaranteed this debt.

Tender Offers

On February 3, 2011, we commenced cash tender offers to purchase $225 million principal amount of our 2013 Notes and $300 million principal amount of our 2015 Notes. On February 16, 2011, we accepted for purchase $169.5 million in principal of the 2013 Notes at 100.625% of par and $220.9 million in principal of the 2015 Notes for 104.125% of par, and adopted amendments to eliminate most of the restrictive covenants in both indentures governing these notes. The purchases made on February 16, 2011 under these tender offers were funded by the proceeds from sale of our 2021 Notes. The tender offers will expire on March 3, 2011. On February 17, 2011, we called for redemption all of the remaining outstanding 2013 and 2015 Notes.

Equity Award Grant

In January 2011, we granted equity incentive awards to our employees under the 2004 Plan. The grant included 786,213 shares of restricted stock valued at $18.71 per share (the closing price of Denbury's common stock on January 7, 2011) and 1,180,163 SARs with an exercise price of $18.71 and a weighted average grant date fair value of $9.66 per unit. The awards generally vest 25% per year over a four-year period.

Note 16. 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 ongoing development activities. Included in the costs incurred below is capitalized interest of $32.6 million in 2010, $14.3 million in 2009 and $17.6 million in 2008. Costs incurred also includes 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 $45.1 million in 2010, $11.2 million in 2009 and $5.8 million in 2008. See Note 3, *Asset Retirement Obligations*, for additional information.

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

	Year Ended December 31,		
In thousands	**2010**	**2009**	**2008**
Property acquisitions:			
Proved	$ 3,373,450	$ 585,637	$ 32,781
Unevaluated	1,297,695	104,772	16,129
Exploration	8,728	4,635	5,710
Development	658,758	292,545	575,947
Total costs incurred(1)	$ 5,338,631	$ 987,589	$ 630,567

(1) Capitalized general and administrative costs that directly relate to exploration and development activities were $20.1 million, $14.0 million and $12.5 million for the years ended December 31, 2010, 2009 and 2008, 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:

In thousands, except per BOE data	Year Ended December 31, 2010	2009	2008
Oil, natural gas and related product sales	$ 1,793,292	$ 866,709	$ 1,347,010
Lease operating costs	486,923	326,132	307,550
Production taxes and marketing expenses	129,046	42,484	63,752
Depletion, depreciation and amortization	391,782	206,999	195,839
CO_2 depletion, depreciation and amortization (1)	29,206	29,076	16,771
Write-down of oil and natural gas properties	—	—	226,000
Commodity derivative expense (income)	(21,414)	236,226	(200,053)
Net operating income	777,749	25,792	737,151
Income tax provision	295,545	9,927	278,643
Results of operations from oil and natural gas producing activities	$ 482,204	$ 15,865	$ 458,508
Depletion, depreciation and amortization per BOE	$ 15.82	$ 13.39	$ 12.54

(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

Effective December 31, 2009, the Company adopted new guidance issued by the SEC related to the quantification of oil and natural gas reserves. Estimates of reserves as of year-end 2010 and 2009 were prepared using an average price equal to the unweighted arithmetic average of hydrocarbon prices received on a field-by-field basis on the first day of each month within the applicable fiscal 12-month period. Estimates of reserves as of year-end 2008 were prepared using constant prices and costs in accordance with previous rules and regulations of the SEC based on hydrocarbon prices received on a field-by-field basis as of December 31, 2008.

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. Oil and natural gas 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 interest in our properties. (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.

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,					
	2010		2009		2008	
	Oil (MBbl)	Gas (MMcf)	Oil (MBbl)	Gas (MMcf)	Oil (MBbl)	Gas (MMcf)
Balance at beginning of year	192,879	87,975	179,126	427,955	134,978	358,608
Revisions of previous estimates	3,538	16,171	(69)	(1,298)	1,348	10,291
Revisions due to price changes	2,780	811	4,557	(2,079)	(13,320)	(2,915)
Extensions and discoveries	26,313	130,245	334	11,785	5,037	107,020
Improved recovery(1)	30,173	—	13,875	—	59,317	—
Production	(21,870)	(28,491)	(13,495)	(24,764)	(11,505)	(32,736)
Acquisition of minerals in place	155,021	622,984	28,379	2,317	3,653	79
Sales of minerals in place	(50,558)	(471,802)	(19,828)	(325,941)	(382)	(12,392)
Balance at end of year	338,276	357,893	192,879	87,975	179,126	427,955
Proved Developed Reserves:						
Balance at beginning of year	116,192	69,513	96,746	298,114	97,005	226,271
Balance at end of year	219,077	110,516	116,192	69,513	96,746	298,114

(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.

Acquisitions of minerals in place during 2010 were primarily from the Encore Merger and Riley Ridge acquisition. The sales of minerals in place during 2010 were primarily due to the sale of the non-strategic Encore properties and our ownership interests in ENP. Extensions and discoveries primarily include reserves added at our Bakken and Haynesville Fields. We added 39.4 MMBbls of tertiary proved oil reserves during 2010, primarily initial proved tertiary oil reserves at Delhi Field in Phase 5, plus upward revisions to reserves in other tertiary floods. In order to recognize proved tertiary oil reserves, we must either have an oil production response to 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 production response.

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, 2010 and 2009 future cash inflows were estimated by applying a first-day-of-the-month 12-month average price to the estimated future production of year-end proved reserves. Prior to 2009, 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 proved reserves, as reductions in oil and natural 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 prices were used in the Standardized Measure. These prices were adjusted by field to arrive at the appropriate corporate net price.

	December 31,		
	2010	2009	2008
Oil (NYMEX)	$ 79.43	$ 61.18	$ 44.60
Natural Gas (Henry Hub)	4.40	3.87	5.71

Future cash inflows were reduced by estimated future production, development and abandonment costs based on current cost, with no escalation to determine pre-tax cash inflows. Our future net inflows do not include a reduction for cash previously expended on our capitalized CO_2 assets that will be consumed in the production of proved tertiary reserves. Future income taxes were computed by applying the statutory tax rate to the excess of net 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, 2010	2009	2008
Future cash inflows	$ 26,698,819	$ 11,579,159	$ 9,024,224
Future production costs	(9,702,896)	(5,034,393)	(4,039,898)
Future development costs	(1,912,457)	(836,455)	(944,716)
Future income taxes	(4,700,023)	(1,257,844)	(1,071,939)
Future net cash flows	10,383,443	4,450,467	2,967,671
10% annual discount for estimated timing of cash flows	(5,465,516)	(1,993,082)	(1,552,173)
Standardized measure of discounted future net cash flows	$ 4,917,927	$ 2,457,385	$ 1,415,498

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, 2010	2009	2008
Beginning of year	$ 2,457,385	$ 1,415,498	$ 3,539,617
Sales of oil and natural gas produced, net of production costs	(1,177,322)	(498,093)	(975,708)
Net changes in sales prices	2,062,181	1,263,346	(3,296,580)
Extensions and discoveries, less applicable future development and production costs	295,074	6,735	142,199
Improved recovery(1)	623,622	202,145	338,313
Previously estimated development costs incurred	193,947	98,659	157,321
Revisions of previous estimates, including revised estimates of development costs, reserves and rates of production	(285,158)	(63,044)	(321,733)
Accretion of discount	307,546	192,686	538,512
Acquisition of minerals in place	3,671,439	365,771	12,764
Sales of minerals in place	(1,474,443)	(419,601)	(53,356)
Net change in income taxes	(1,756,344)	(106,717)	1,334,149
End of year	$ 4,917,927	$ 2,457,385	$ 1,415,498

(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 proved CO_2 reserves were estimated as follows (in MMcf):

	Year Ended December 31, 2010	2009	2008
Gulf Coast region(1)	7,085,131	6,302,836	5,612,167
Rocky Mountain region(2)	920,266	—	—

(1) Proved CO_2 reserves in the Gulf Coast region consist of reserves from our reservoirs at Jackson Dome, are presented on a gross working interest basis and include reserves dedicated to volumetric production payments of 100.2 Bcf, 127.1 Bcf and 153.8 Bcf, at December 31, 2010, 2009 and 2008, respectively.

(2) Proved CO_2 reserves in the Rocky Mountain region consist of our reserves at Riley Ridge and are net to our interest.

Note 17. Unaudited Quarterly Information

In thousands, except per share amounts	March 31	June 30	September 30	December 31
2010				
Revenues	$ 438,821	$ 497,210	$ 466,703	$ 519,057
Expenses	261,676	265,518	415,170	500,357
Net income	96,888	135,367	29,104	10,364
Net income per share:				
Basic	0.33	0.34	0.07	0.03
Diluted	0.32	0.34	0.07	0.03
Cash flow from operations	113,168	271,123	208,484	263,036
Cash flow provided by (used for) investing activities	(764,327)	505,713	(261,539)	165,373
Cash flow provided by (used for) financing activities	739,753	(818,547)	71,926	(132,885)
2009				
Revenues	$ 171,821	$ 215,362	$ 225,415	$ 269,895
Expenses	202,734	358,060	185,987	264,558
Net income (loss):	(18,297)	(87,240)	26,885	3,496
Net income (loss) per share:				
Basic	(0.07)	(0.35)	0.11	0.01
Diluted	(0.07)	(0.35)	0.11	0.01
Cash flow from operations	112,619	148,170	145,645	124,165
Cash flow used for investing activities	(509,539)	(65,301)	(161,550)	(233,324)
Cash flow provided by (used for) financing activities	398,058	(41,117)	(22,365)	108,061

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 Chief Executive Officer and our Chief Financial Officer. Based on that evaluation, the Company's Chief Executive Officer and our Chief Financial Officer concluded that the Company's disclosure controls and procedures were effective as of December 31, 2010 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 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 Chief Executive Officer and our Chief Financial Officer, we have determined that, during the fourth quarter of fiscal 2010, 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 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 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.

Pricewaterhouse Coopers LLP, an independent registered public accounting firm, has issued an attestation report on the Company's internal controls over financial reporting as of December 31, 2010 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 18, 2011, ("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.

PART IV

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 71. 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
2	Agreement and Plan of Merger by and between Encore Acquisition Company and Denbury Resources Inc. Executed on October 31, 2009 (incorporated by reference as Exhibit 2.1 of our Form 8-K filed November 5, 2009).
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 $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(b)	First Supplemental Indenture to 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(c)	Second Supplemental Indenture to Indenture for $225 million of 7.5% Senior Subordinated Notes due 2013 dated as of July 24, 2009, 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(c) of our form 10-K filed March 1, 2010).
4(d)	Third Supplemental Indenture to Indenture for $225 million of 7.5% Senior Subordinated Notes due 2013 dated as of March 9, 2010, among Denbury Resources, Inc., certain of its subsidiaries, and The Bank of New York Mellon Trust Company, N.A., as trustee (incorporated by reference from Exhibit 4.4 of our Form 8-K filed on March 12, 2010).
4(e)*	Fourth Supplemental Indenture to Indenture for $225 million of 7.5% Senior Subordinated Notes due 2013 dated as of February 3, 2011, among Denbury Resources Inc., certain of its subsidiaries, and The Bank of New York Mellon Trust Company, N.A., as trustee.
4(f)	Fifth Supplemental Indenture, dated as of February 17, 2011, among Denbury Resources Inc., Denbury Onshore, LLC and certain other subsidiaries of Denbury Resources Inc. and The Bank of New York Mellon Trust Company, N.A., with respect to $225 million of 7 ½% Senior Subordinated Notes due 2013. (incorporated by reference as Exhibit 4.2 of our Form 8-K filed February 22, 2011).
4(g)	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(h)	First Supplemental Indenture for $150 million of 7.5% Senior Subordinated Notes due 2015, dated as of April 3, 2007, between Denbury Resources Inc., as issuer, and The Bank of New York Trust Company, N.A., as Trustee (incorporated by reference as Exhibit 4.1 of our Form 8-K filed April 3, 2007).
4(i)	Second Supplemental Indenture to Indenture for $150 million of 7.5% Senior Subordinated Notes due 2015, dated as of July 24, 2009, between Denbury Resources Inc., as issuer, and The Bank of New York Mellon Trust Company, N.A., as Trustee (incorporated by reference as Exhibit 4(f) of our form 10-K for the year ended 2009, filed March 1, 2010).

4(j)	Third Supplemental Indenture to Indenture for $150 million of 7.5% Senior Subordinated Notes due 2015, dated as of March 9, 2010, between Denbury Resources Inc., as issuer, and The Bank of New York Mellon Trust Company, N.A., as Trustee (incorporated by reference from Exhibit 4.5 of our Form 8-K filed on March 12, 2010).
4(k)*	Fourth Supplemental Indenture to Indenture for $150 million of 7.5% Senior Subordinated Notes due 2015, dated as of February 3, 2011, between Denbury Resources Inc., as issuer, and The Bank of New York Mellon Trust Company, N.A., as Trustee.
4(l)	Fifth Supplemental Indenture, dated as of February 17, 2011, among Denbury Resources Inc. and certain other subsidiaries of Denbury Resources Inc. and The Bank of New York Mellon Trust Company, N.A., with respect to $300 million of 7½% Senior Subordinated Notes due 2015 (incorporated by reference as Exhibit 4.3 to our Form 8-K filed February 22, 2011).
4(m)	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(n)	First Supplemental Indenture to Indenture for $420 million of 9.75% Senior Subordinated Notes due 2016, dated as of June 30, 2009, between Denbury Resources Inc., as issuer, and The Bank of New York Mellon Trust Company, N.A., as Trustee (incorporated by reference as Exhibit 4(h) of our form 10-K for the year ended 2009, filed March 1, 2010).
4(o)	Second Supplemental Indenture to Indenture for $420 million of 9.75% Senior Subordinated Notes due 2016, dated as of March 9, 2010, between Denbury Resources Inc., as issuer, and The Bank of New York Mellon Trust Company, N.A., as Trustee (incorporated by reference as Exhibit 4.6 of our Form 8-K filed on March 12, 2010).
4(p)*	Third Supplemental Indenture to Indenture for $420 million of 9.75% Senior Subordinated Notes due 2016, dated as of February 3, 2011, between Denbury Resources Inc., as issuer, and The Bank of New York Mellon Trust Company, N.A., as Trustee.
4(q)	Indenture for $1 billion of 8¼% Senior Subordinated Notes due 2020 among Denbury Resources Inc., certain of its subsidiaries, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference as Exhibit 4.1 of our Form 8-K filed February 12, 2010).
4(r)	First Supplemental Indenture to Indenture for $1billion of 8¼% Senior Subordinated Notes due 2020, dated as of March 9, 2010, among Denbury Resources Inc., certain of its subsidiaries, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference as Exhibit 4.7 of our Form 8-K filed on March 12, 2010).
4(s)*	Second Supplemental Indenture to Indenture for $1 billion of 8¼% Senior Subordinated Notes due 2020, dated as of February 3, 2011, among Denbury Resources Inc., certain of its subsidiaries, and Wells Fargo Bank, National Association, as Trustee.
4(t)	Indenture, dated as of April 2, 2004, among Encore Acquisition Company, the subsidiary guarantors party thereto and Wells Fargo Bank, National Association, with respect to the 6.25% Senior Subordinated Notes due 2014 (incorporated by reference as Exhibit 4.1.1 of our Form 8-K filed on March 12, 2010).
4(u)	First Supplemental Indenture, dated as of January 2, 2008, among Encore Acquisition Company, the subsidiary guarantors party thereto and Wells Fargo Bank, National Association, with respect to the 6.25% Senior Subordinated Notes due 2014 (incorporated by reference as Exhibit 4.1.2 of our Form 8-K filed on March 12, 2010).
4(v)	Second Supplemental Indenture, dated as of January 27, 2010, among Encore Acquisition Company, the subsidiary guarantors party thereto and Wells Fargo Bank, National Association, with respect to the 6.25% Senior Subordinated Notes due 2014 (incorporated by reference as Exhibit 4.1.3 of our Form 8-K filed on March 12, 2010).
4(w)	Third Supplemental Indenture, dated as of March 10, 2010, among Denbury Resources Inc. as successor in interest by merger to Encore Acquisition Company, the subsidiary guarantors party thereto and Wells Fargo Bank, National Association, with respect to the 6.25% Senior Subordinated Notes due 2014 (incorporated by reference as Exhibit 4.1.4 of our Form 8-K filed on March 12, 2010).
4(x)*	Fourth Supplemental Indenture, dated as of February 3, 2011, among Denbury Resources Inc., the subsidiary guarantors party thereto and Wells Fargo Bank, National Association, with respect to the 6.25% Senior Subordinated Notes due 2014.
4(y)	Indenture, dated as of July 13, 2005, among Encore Acquisition Company, the subsidiary guarantors party thereto and Wells Fargo Bank, National Association, with respect to the 6.0% Senior Subordinated Notes due 2015 (incorporated by reference as Exhibit 4.2.1 of our Form 8-K filed on March 12, 2010).
4(z)	First Supplemental Indenture, dated as of January 2, 2008, among Encore Acquisition Company, the subsidiary guarantors party thereto and Wells Fargo Bank, National Association, with respect to the 6.0% Senior Subordinated Notes due 2015 (incorporated by reference as Exhibit 4.2.2 of our Form 8-K filed on March 12, 2010).

4(aa)	Second Supplemental Indenture, dated as of January 27, 2010, among Encore Acquisition Company, the subsidiary guarantors party thereto and Wells Fargo Bank, National Association, with respect to the 6.0% Senior Subordinated Notes due 2015 (incorporated by reference as Exhibit 4.2.3 of our Form 8-K filed on March 12, 2010).
4(bb)	Third Supplemental Indenture, dated as of March 10, 2010, among Denbury Resources Inc., as successor in interest by merger to Encore Acquisition Company, the subsidiary guarantors party thereto and Wells Fargo Bank, National Association, with respect to the 6.0% Senior Subordinated Notes due 2015 (incorporated by reference as Exhibit 4.2.4 of our Form 8-K filed on March 12, 2010).
4(cc)*	Fourth Supplemental Indenture, dated as of February 3, 2011, among Denbury Resources Inc., the subsidiary guarantors party thereto and Wells Fargo Bank, National Association, with respect to the 6.0% Senior Subordinated Notes due 2015.
4(dd)	Indenture, dated as of November 16, 2005, among Encore Acquisition Company, the subsidiary guarantors party thereto and Wells Fargo Bank, National Association, with respect to Subordinated Debt Securities (incorporated by reference as Exhibit 4.3.1 of our Form 8-K filed on March 12, 2010).
4(ee)	First Supplemental Indenture, dated as of November 16, 2005, among Encore Acquisition Company, the subsidiary guarantors party thereto and Wells Fargo Bank, National Association, with respect to the 7.25% Senior Subordinated Notes due 2017 (incorporated by reference as Exhibit 4.3.2 of our Form 8-K filed on March 12, 2010).
4(ff)	Second Supplemental Indenture, dated as of January 2, 2008, among Encore Acquisition Company, the subsidiary guarantors party thereto and Wells Fargo Bank, National Association, with respect to the 7.25% Senior Subordinated Notes due (incorporated by reference as Exhibit 4.3.3 of our Form 8-K filed on March 12, 2010).
4(gg)	Third Supplemental Indenture, dated as of April 27, 2009, among Encore Acquisition Company, the subsidiary guarantors party thereto, and Wells Fargo Bank, National Association, with respect to the 9.50% Senior Subordinated Notes due 2016 (incorporated by reference as Exhibit 4.3.4 of our Form 8-K filed on March 12, 2010).
4(hh)	Fourth Supplemental Indenture, dated as of January 27, 2010, among Encore Acquisition Company, the subsidiary guarantors party thereto and Wells Fargo Bank, National Association, with respect to the 7.25% Senior Subordinated Notes due 2017 and the 9.50% Senior Subordinated Notes due 2016 (incorporated by reference as Exhibit 4.3.5 of our Form 8-K filed on March 12, 2010).
4(ii)	Fifth Supplemental Indenture, dated as of March 10, 2010, among Denbury Resources Inc., as successor in interest by merger to Encore Acquisition Company, the subsidiary guarantors party thereto and Wells Fargo Bank, National Association, with respect to the 7.25% Senior Subordinated Notes due 2017 and the 9.50% Senior Subordinated Notes due 2016 (incorporated by reference as Exhibit 4.3.6 of our Form 8-K filed on March 12, 2010).
4(jj)*	Sixth Supplemental Indenture, dated as of February 3, 2011, among Denbury Resources Inc., the subsidiary guarantors party thereto and Wells Fargo Bank, National Association, with respect to the 7.25% Senior Subordinated Notes due 2017 and the 9.50% Senior Subordinated Notes due 2016.
4(kk)	Indenture dated as of February 17, 2011 among the Company, certain of the Company's subsidiaries as guarantors and Wells Fargo, National Association, as trustee, with respect to $400 million of 6⅜% Senior Subordinated Notes due 2021 (incorporated by reference as Exhibit 4.1 to our Form 8-K filed February 22, 2011).
10(a)	Credit Agreement, dated as March 9, 2010, among Denbury Resources Inc., as Borrower, the financial institutions listed on Schedule 1.1 thereto, as Banks, JPMorgan Chase Bank, N.A., as Administrative Agent, Banc of America Securities LLC, as Syndication Agent, and BNP Paribas, The Bank of Nova Scotia, and Credit Suisse Securities (USA) LLC, as Co-Documentation Agents (incorporated by reference as Exhibit 10.1 of our Form 8-K filed on March 12, 2010).
10(b)	First Amendment to Credit Agreement dated as of March 9, 2010, dated as of May 13, 2010, among Denbury Resources Inc., as Borrower, the financial institutions listed on Schedule 1.1 thereto, as Banks, JPMorgan Chase Bank, N.A., as Administrative Agent, Banc of America Securities LLC, as Syndication Agent, and BNP Paribas, The Bank of Nova Scotia, and Credit Suisse Securities (USA) LLC, as Co-Documentation Agents (incorporated by reference as 10.1 of our Form 8-K filed on May 19, 2010).
10(c)	Second Amendment to Credit Agreement dated as of March 9, 2010, dated as of September 30, 2010, among Denbury Resources Inc., as Borrower, the financial institutions listed on Schedule 1.1 thereto, as Banks, JPMorgan Chase Bank, ,N.A., as Administrative Agent, Banc of America Securities LLC, as Syndication Agent, and BNP Paribas, The Bank of Nova Scotia, as Credit Suisse Securities (USA) LLC, as Co-Documentation Agents (incorporated by reference as Exhibit 10.1 to our Form 10-Q filed on November 9, 2010).
10(d)*	Third Amendment to Credit Agreement dated as of March 9, 2010, dated as of December 17, 2010, among Denbury Resources Inc., as Borrower, JPMorgan Chase Bank, ,N.A., as Administrative Agent, and the financial institutions party thereto.

10(e)*	Fourth Amendment to Credit Agreement dated as of March 9, 2010, dated as of February 1, 2011, among Denbury Resources Inc., as Borrower, JPMorgan Chase Bank, N.A., as Administrative Agent, and the financial institutions party thereto.
10(f)	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(g)	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(h)	Purchase and Sale Agreement, dated March 31, 2010, effective May 1, 2010, by and between Encore Operating, L.P., as Seller, and Quantum Resources Management, LLC, as Buyer (incorporated by reference as Exhibit 2.2 of our Form 10-Q, filed on May 10, 2010).
10(i)**	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(j)**	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(k)**	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(l)**	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(m)* **	Denbury Resources Severance Protection Plan, as amended and restated effective December 31, 2010.
10(n)**	Denbury Resources Inc. 2004 Omnibus Stock and Incentive Plan, as amended and restated effective December 30, 2008 (incorporated by reference as Exhibit 10(o) of our Form 10-K for the year ended December 31, 2008).
10(o)* **	Denbury Resources Inc. Amendment to 2004 Omnibus Stock and Incentive Plan, dated effective as of December 31, 2010.
10(p)**	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(q)**	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(r)**	2004 Form of restricted stock award that vests 20% per annum, for grants to directors pursuant to 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc. (incorporated by reference as Exhibit 10(m) of our Form 10-K for the year ended December 31, 2004).
10(s)**	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(t)**	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(u)**	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(v)**	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(w)**	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(x)**	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(q)**	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(z)**	2007 Form of restricted stock award to directors that cliff vests after three years pursuant to 2004 Omnibus Stock and Incentive Plan (incorporated by reference as Exhibit 10(cc) of our Form 10-K for the year ended December 31, 2007).
10(aa)**	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(bb)**	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(cc)**	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(dd)**	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(ee)**	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(ff)**	2009 Form of restricted stock award to certain officers that cliff vests on March 31, 2012 pursuant to 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc. (incorporated by reference as Exhibit 10(b) of our Form 10-Q for the quarter ended March 31, 2009).
10(gg)**	2009 Form of restricted stock award without change of control vesting to certain officers that cliff vests on March 31, 2012 pursuant to 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc. (incorporated by reference as Exhibit 10(c) of our Form 10-Q for the quarter ended March 31, 2009).
10(hh)**	2009 Form of performance share awards to certain officers pursuant to 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc. (incorporated by reference as Exhibit 10(d) of our Form 10-Q for the quarter ended March 31, 2009).
10(ii)**	2009 Form of performance share awards without change of control vesting to certain officers pursuant to 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc. (incorporated by reference as Exhibit 10(e) of our Form 10-Q for the quarter ended March 31, 2009).
10(jj)**	2009 Form stock appreciation rights to certain officers that cliff vests on March 31, 2012 pursuant to 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc. (incorporated by reference as Exhibit 10(f) of our Form 10-Q for the quarter ended March 31, 2009).
10(kk)**	2009 Form of stock appreciation rights without change of control vesting pursuant to 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc. (incorporated by reference as Exhibit 10(g) of our Form 10-Q for the quarter ended March 31, 2009).
10(ll)**	2010 Form of performance stock award pursuant to the 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc. (incorporated by reference as Exhibit 99.2 of our Form 8-K filed on May 25, 2010).
10(mm)**	2010 Form of performance cash award pursuant to the 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc. (incorporated by reference as Exhibit 99.3 or our Form 8-K filed on May25, 2010).
10(nn)**	Founder's Retirement Agreement by and between Denbury Resources Inc. and Gareth Roberts effective June 30, 2009 (incorporated by reference as Exhibit 10.1 of our Form 8-K filed July 7, 2009).
10(oo)**	Amendment to Founder's Retirement Agreement by and between Denbury Resources Inc. and Gareth Roberts effective as of October 6, 2010 (incorporated by reference in Form 8-K filed October 12, 2010).
10(pp)**	$6.350 million 9.75% Senior Subordinated Note due 2016 issued on June 30, 2009 to Gareth Roberts (incorporated by reference as Exhibit 10.2 of our Form 8-K filed July 7, 2009).
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, 2010, on oil and gas reserves (SEC Case) dated February 8, 2011.

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* Filed herewith.

** Compensation arrangements.

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.
March 1, 2011	/s/ Mark C. Allen Mark C. Allen Sr. Vice President and Chief Financial Officer
March 1, 2011	/s/ Alan Rhoades Alan Rhoades Vice President, Accounting

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.

March 1, 2011	/s/ Phil Rykhoek Phil Rykhoek Director and Chief Executive Officer (Principal Executive Officer)
March 1, 2011	/s/ Mark C. Allen Mark C. Allen Sr. Vice President and Chief Financial Officer (Principal Financial Officer)
March 1, 2011	/s/ Alan Rhoades Alan Rhoades Vice President, Accounting (Principal Accounting Officer)
March 1, 2011	/s/ Gareth Roberts Gareth Roberts Director
March 1, 2011	/s/ Wieland Wettstein Wieland Wettstein Director
March 1, 2011	/s/ Michael Beatty Michael Beatty Director
March 1, 2011	/s/ Michael Decker Michael Decker Director
March 1, 2011	/s/ Ron Greene Ron Greene Director
March 1, 2011	/s/ David I. Heather David I. Heather Director

March 1, 2011	/s/ Greg McMichael Greg McMichael Director
March 1, 2011	/s/ Randy Stein Randy Stein Director

EXHIBIT 21

LIST OF SUBSIDIARIES

NAME OF SUBSIDIARY	JURISDICTION OF ORGANIZATION
Denbury Operating Company	Delaware
Denbury Onshore, LLC	Delaware
Denbury Pipeline Holdings, LLC	Delaware
Denbury Holdings, Inc.	Delaware
Denbury Green Pipeline - Texas, LLC	Delaware
Greencore Pipeline Company, LLC	Delaware
Denbury Gulf Coast Pipelines, 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. 333-01006, 333-27995, 333-55999, 333-70485, 333-39172, 333-39218, 333-63198, 333-90398, 333-106253, 333-116249, 333-143848, 333-160178 and 333-167480), and Form S-4 (No. 333-163521) of Denbury Resources Inc. of our report dated March 1, 2011 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
March 1, 2011

Exhibit 23(b)

DEGOLYER AND MACNAUGHTON
5001 SPRING VALLEY ROAD
SUITE 800 EAST
Dallas, Texas 75244

March 1, 2011

Denbury Resources, Inc.
5320 Legacy Drive
Plano, Texas 75024

Ladies and Gentlemen:

We hereby consent to the use of the name DeGolyer and MacNaughton, to references to DeGolyer and MacNaughton, to the inclusion of our “Letter Report dated February 8, 2011, regarding the proved reserves of Denbury Resources”, and to the inclusion of information taken from our “Appraisal Report as of December 31, 2010 on Certain Properties owned by Denbury Resources Inc. SEC Case”, “Appraisal Report as of December 31, 2009 on Certain Properties owned by Denbury Resources Inc. SEC Case”, and “Appraisal Report as of December 31, 2008 on Certain Properties owned by Denbury Resources Inc. SEC Case”, in the Annual Report on Form 10-K of Denbury Resources Inc. for the year ended December 31, 2010.

Very truly yours,

/s/ DeGolyer and MacNaughton
DeGOLYER and MacNAUGHTON
Texas Registered Engineering Firm F-716

Exhibit 31 (a)

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.

Dated: March 1, 2011

/s/ Phil Rykhoek
Phil Rykhoek
Chief Executive Officer

Exhibit 31(b)

CERTIFICATION UNDER SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Mark C. Allen, 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.

Dated: March 1, 2011

/s/ Mark C. Allen
Mark C. Allen
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, 2010 (the Report) of Denbury Resources Inc. (Denbury) as filed with the Securities and Exchange Commission on March 1, 2011, 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.

Dated: March 1, 2011

/s/ Phil Rykhoek
Phil Rykhoek
Chief Executive Officer

Dated: March 1, 2011

/s/ Mark C. Allen
Mark C. Allen
Sr. Vice President and Chief Financial Officer