



a future

full of **energy**

Denbury Resources Inc.

2003 Annual Report

Where will our children get their **energy** in the **future**? Denbury has the **solution**. By using naturally occurring carbon dioxide to recover **more oil** from depleted oil fields in the United States, Denbury's **strategy** will not only **benefit** current shareholders but also create resources our children will **inherit**. Our children are the feature of this report.



Brittney Waites, Age 5

Lindsey Jenkins, Age 6



Jada Speed, Age 6



FINANCIAL HIGHLIGHTS

Amounts in thousands, unless otherwise noted

	Year Ended December 31,					Average Annual Growth ⁽²⁾
	2003	2002	2001 ⁽¹⁾	2000	1999	
Production (daily)						
Oil (Bbls)	18,894	18,833	16,978	15,219	12,090	12%
Natural gas (Mcf)	94,858	100,443	85,238	37,078	27,948	36%
BOE (6:1)	34,704	35,573	31,185	21,399	16,748	20%
Revenues	333,014	285,152	285,111	181,651	82,990	42%
Unit sales price (excluding hedges)						
Oil (per Bbl)	27.47	22.36	21.34	25.89	15.03	16%
Natural gas (per Mcf)	5.66	3.31	4.12	4.45	2.42	24%
Unit sales price (including hedges)						
Oil (per Bbl)	24.52	22.27	21.65	23.50	13.08	17%
Natural gas (per Mcf)	4.45	3.35	4.66	3.57	2.34	17%
Cash flow from operations	197,615	159,600	185,047	95,972	41,200	48%
Income before accounting change⁽³⁾	53,941	46,795	56,550	142,227	4,614	85%
Net income⁽³⁾	56,553	46,795	56,550	142,227	4,614	87%
Average common shares outstanding						
Basic	53,881	53,243	49,325	45,823	39,928	8%
Diluted	55,464	54,365	50,361	46,352	39,987	9%
Income per share before accounting change						
Basic	1.00	0.88	1.15	3.10	0.12	70%
Diluted	0.97	0.86	1.12	3.07	0.12	69%
Net income per share						
Basic	1.05	0.88	1.15	3.10	0.12	72%
Diluted	1.02	0.86	1.12	3.07	0.12	71%
Oil and gas capital investments	158,444	155,637	327,175	134,021	54,967	30%
CO₂ capital investments	22,673	16,445	45,555	—	—	—
Total assets	982,621	895,292	789,988	457,379	252,566	40%
Long-term liabilities	434,845	432,616	360,882	202,428	154,976	29%
Stockholders' equity⁽⁴⁾	421,202	366,797	349,168	216,165	72,428	55%
Proved reserves						
Oil (MBbls)	91,266	97,203	76,490	70,667	51,832	15%
Natural gas (MMcf)	221,887	200,947	198,277	100,550	50,438	45%
MBOE (6:1)	128,247	130,694	109,536	87,425	60,238	21%
Discounted future cash flow before tax— 10%	1,566,371	1,426,220	574,328	1,158,969	462,870	36%
Standardized measure of discounted future net cash flow after tax	1,124,127	1,028,976	505,795	841,299	488,374	23%
Per BOE data (6:1)						
Oil and natural gas revenues	30.43	21.17	22.88	26.13	14.88	20%
Gain (loss) on settlements of derivative contracts	(4.91)	0.07	1.64	(3.23)	(1.54)	34%
Lease operating expenses	(7.06)	(5.48)	(4.84)	(4.94)	(4.25)	14%
Production taxes and marketing expenses	(1.17)	(0.92)	(0.96)	(1.02)	(0.60)	18%
Production netback	17.29	14.84	18.72	16.94	8.49	19%
Operating margin from CO ₂ operations	0.51	0.48	0.38	—	—	—
General and administrative expense	(1.20)	(0.96)	(0.89)	(1.09)	(1.21)	—
Net cash interest expense	(1.61)	(1.73)	(1.74)	(1.54)	(2.22)	(8%)
Current income taxes and other	(0.01)	0.04	(0.06)	(0.07)	0.11	—
Changes in assets and liabilities	0.62	(0.38)	(0.15)	(1.99)	1.57	(21%)
Cash flow from operations	15.60	12.29	16.26	12.25	6.74	23%

(1) We acquired Matrix Oil and Gas, Inc., in July 2001. See Note 2 to the Consolidated Financial Statements.

(2) Four-year compounded annual growth rate computed using 1999 as a base year.

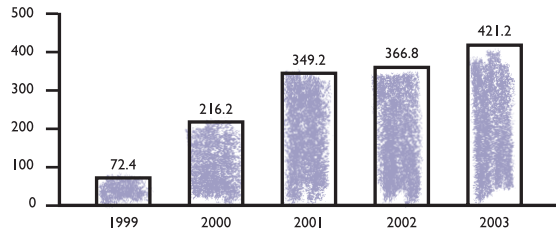
(3) In 2003, we recognized a gain of \$2.6 million for the cumulative effect adoption of SFAS No. 143, "Accounting for Asset Retirement Obligations," (see Note 4 to the Consolidated Financial Statements). In 2000, we recorded a deferred income tax benefit of \$67.9 million related to the reversal of the valuation allowance on our net deferred tax assets.

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

Reporting Format: Unless otherwise noted, the disclosures in this report have (i) production volumes expressed on a net revenue interest basis, and (ii) gas volumes converted to equivalent barrels at 6:1.

MESSAGE TO SHAREHOLDERS

Shareholder's Equity
in millions of dollars



We at Denbury believe that oil and natural gas is getting harder and harder to find, both in North America and overseas. Recognizing this, about five years ago we began developing a play to use carbon dioxide (CO₂) to breathe new life into old depleted fields and to increase the amount of oil recovered from these fields. The viability of this play is based on our ownership of a large natural source of CO₂ in Mississippi and prior pilot studies by major companies during the '70s and '80s that demonstrated that the process should work. Producers in West Texas have since also proved this concept, demonstrating that large scale flooding of old oil fields with CO₂ is attractive as long as sufficient CO₂ is available at a reasonable cost.

Today, we own the only known significant natural source of CO₂ east of the Rocky Mountain region, a 180-mile pipeline system that we currently use to supply our active CO₂ floods, and a majority of the depleted oil fields located within 100 miles of our CO₂ source that are future flood candidates. During January 2004, we produced approximately 220 MMcf/d of CO₂ that we used primarily in our tertiary recovery operations to produce over 6,000 barrels of oil per day. At December 31, 2003, we owned approximately 1.6 Tcf of proven CO₂ reserves (including about 162.6 Bcf of CO₂ dedicated to a volumetric production payment), enough CO₂ to support tertiary operations to produce 35.3 MMBbls of proven oil reserves located in our fields in Western Mississippi, plus another 40 to 55 MMBbls of potential reserves in the same area (phase I of our overall program). During 2004, we hope to increase our proven CO₂ reserves and production rates with four additional CO₂ wells planned at our CO₂ field at Jackson Dome. These incremental CO₂ reserves

can then be used to not only increase our daily production rates and proven reserves in Western Mississippi, but also expand our program to Eastern Mississippi (phase II of our program) where we have specifically identified another 80 MMBbls of potential oil reserves in five specific fields. Beyond these specific projects identified for phase II, we believe that significant additional potential for tertiary operations exists in the eastern part of the state. We are also looking at potential acquisitions in these and other areas, including Louisiana, to provide additional inventory for future phases. We believe that we are the only company positioned to develop these potential oil reserves because of our exclusive ownership of the CO₂ resource.

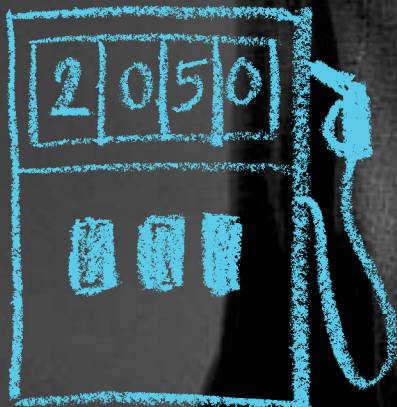
CO₂ Operations

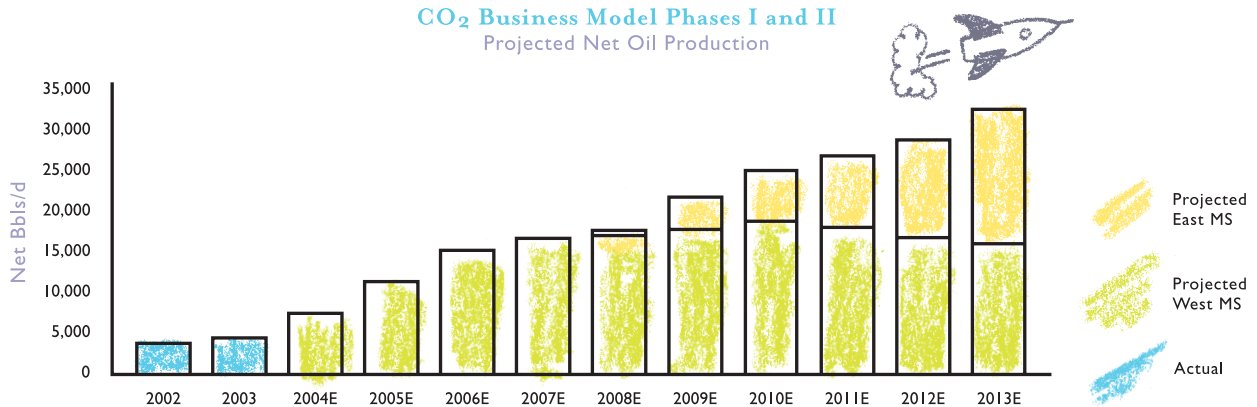
During 2003, we saw excellent results of our labor at Mallalieu Field in Southwest Mississippi, the first full CO₂ flood that we initiated. We have increased production at Mallalieu from approximately 70 Bbls/d at the time we acquired it in 2001, to an average of 2,378 Bbls/d during the fourth quarter of 2003, and production has continued to increase since that time. Our overall economics here have been very compelling thus far, as our year-end 2003 proven PV-10 Value (at SEC prices) of approximately \$218 million at Mallalieu Field, compares favorably to a net unrecovered investment of only \$24.5 million, with the expectation that we will add additional reserves, production and value here in future years. In total, our production from tertiary carbon dioxide flooding has increased 36% per annum, from an initial rate of approximately 1,350 Bbls/d, when we acquired Little Creek in 1999, to a fourth quarter 2003 average of approximately 5,579 Bbls/d, currently representing approximately 16% of our total production

What will the world use
for energy when I'm 50
years old?!

Morgan McDaniel, Age 7

Oil will still be the most
important component
of energy in 2050, even
though supplies will
be limited.





on a BOE basis. Since the fourth quarter, tertiary related oil production has continued to increase, averaging over 6,000 Bbls/d in January 2004. This play is performing very well.

We have completed an initial evaluation of the oil potential from tertiary operations in Eastern Mississippi by reviewing five fields that we expect to be part of the first phase of operations in that area. These fields have an estimated 80 MMBbls of potential net oil reserves recoverable from tertiary operations. This is only the first portion of our planned long-term development in Eastern Mississippi. While this study is preliminary and requires significant additional work and review, including a determination of precise costs and the best location for a CO₂ pipeline to this part of the state, and further refinement of the economics, preliminarily this project appears to have reasonable economics at NYMEX oil prices in the low to mid twenties. When we combine the potential in Eastern Mississippi with our tertiary operations in Western Mississippi, we project a 21% compound annual growth rate in oil production from tertiary operations through 2013, with production peaking near 32,000 Bbls/d. By that time, we expect that other areas or phases should be ready, allowing us to continue our tertiary oil production growth beyond 2013.

Proved Reserves

An independent reservoir engineering firm, DeGolyer and MacNaughton, hired by our independent audit committee, has prepared our reserve report for the last three years. A professional reservoir engineer sits on our audit committee and actively monitors the

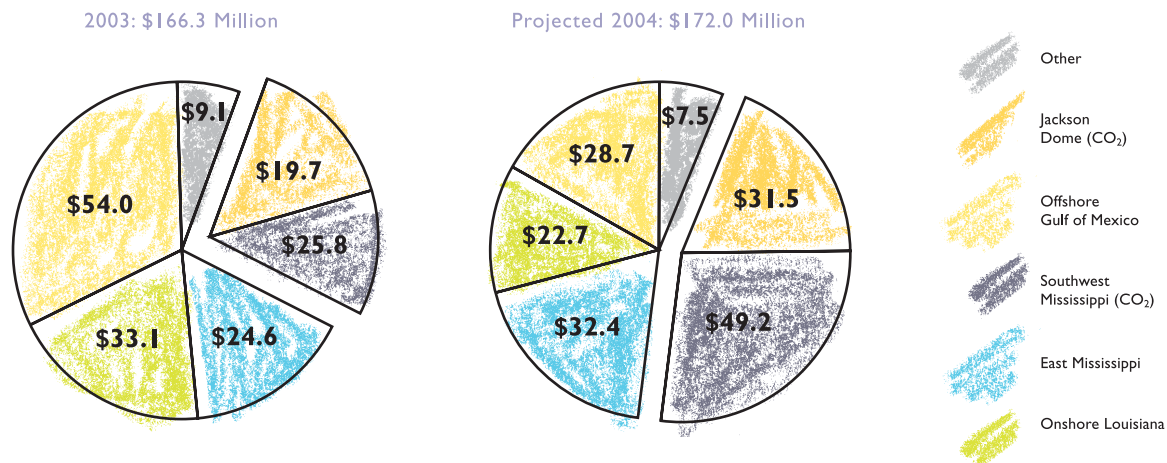
evaluation and reporting process. This helps to ensure that there is an open dialogue and exchange of information between management and the independent engineers, and that any potential conflicts or disagreements are brought to the attention of the audit committee. The proven reserves are indisputably the primary asset of our company, and accordingly we are dedicated to applying the highest corporate governance standards possible to ensure that our reserves are fairly stated. At December 31, 2003, we had total proved reserves of 128.2 MMBOE, a 5% increase over our proved reserves at December 31, 2002, after adjusting for the 8.3 MMBOE of proved reserves sold during 2003. This equates to a finding cost for 2003 of approximately \$8.58 per BOE, making our three-year finding cost approximately \$7.36 per BOE, still one of the best in the industry. While our most important assets, the tertiary recovery operations, are performing well, we experienced some disappointment with our 2003 results in certain other areas. Our drilling results in the Gulf of Mexico and Southern Louisiana were not as good as we had hoped, and some of our higher exploration potential failed to materialize, contributing to our higher than normal finding cost. As a result, we continue to shift more and more of our focus to tertiary operations, a more predictable operation with less risk.

Other Operations

We have been developing low-risk regional gas opportunities in the Selma Chalk around Heidelberg Field in Mississippi and in the Barnett Shale west of Fort Worth, Texas. We plan more of this type of development in 2004 in light of the current and

Capital Budget ⁽¹⁾

(1) Excludes acquisitions; includes allocated capitalized overhead



projected high natural gas prices and our results to date. Heidelberg Field is our single largest natural gas property on a proved reserve basis (51.9 Bcf) and was our third largest natural gas producer during 2003, averaging 10.3 MMcf/d. We have scaled back our projected 2004 expenditures in Louisiana and offshore, although we still plan to drill some medium to higher risk prospects, primarily for natural gas, as the opportunities present themselves. In addition, we are also considering sales of some of our lower-priority properties during 2004, including our offshore operations. Our focus is always on increasing our net asset value per share, and we are confident that our low-risk predictable reserve additions from the CO₂ tertiary operations will help accomplish our goals for growth in net asset value. As other companies struggle to replace reserves and are forced to make acquisitions, we believe Denbury is in a unique position and will continue to gain recognition for its organic growth inventory.

Commodity Price Outlook

As a further backdrop to our strategy, during 2003, oil prices were once again higher than experts predicted, with an average NYMEX price of approximately \$31.00 per Bbl. For the last 4 years, NYMEX oil prices have averaged \$28.36, considerably higher than the \$18.50 average during the previous 10 years. Although oil prices have undoubtedly been influenced by short-term political and other events, it is our opinion that higher

prices are primarily due to an insufficient supply in light of increasing demand. We believe this situation is likely to continue, and may even tighten further, as there appear to be geological factors that limit future production growth. Regardless of our expectations, we will continue to be cautious with our balance sheet to insulate against downside volatility. We plan to continue the philosophy we adopted several years ago – we do not spend more than we make (excluding an occasional acquisition that may be funded with debt). We are bullish on oil prices and believe we have ideally positioned Denbury, as any price increase enhances the value of both our current proven reserves and our future potential reserves. We have access to low-risk potential reserves that we can acquire at a low finding cost because of our strategic ownership of CO₂ and the exclusive franchise this gives us in our areas of operation.

Gareth Roberts
President and Chief Executive Officer
March 10, 2004

Where does oil come from?

Reed Roberts Age 9

Today, 60% of oil used in
the United States is imported
from other countries.





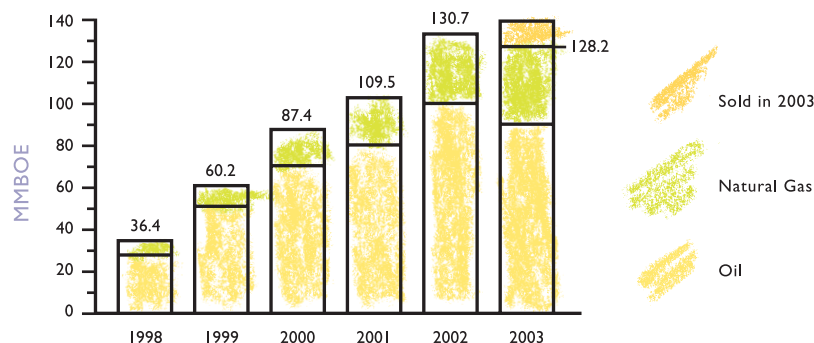
Jay Snyder, Age 4



Alyson Sommerfelt, Age 4

SELECTED OPERATING DATA

Net Proved SEC Reserve Growth



Oil and Gas Reserves

DeGolyer and MacNaughton, independent petroleum engineers located in Dallas, Texas, prepared estimates of our net proved oil and natural gas reserves as of December 31, 2003, 2002 and 2001. The reserve estimates were prepared using constant prices and costs in accordance with the guidelines of the Securities and Exchange Commission ("SEC"). The prices used in preparation of the reserve estimates were based on the market prices in effect as of December 31 of each year, with the appropriate historical adjustments (transportation, gravity, basic sediment and water "BS&W," purchasers' bonuses, Btu, etc.) applied to each field. The reserve estimates do not include any value for probable or possible reserves that may exist, nor do they include any value for undeveloped acreage. The reserve estimates represent our net revenue interests in our properties.

As is the case with our independent accountants, our independent petroleum engineers are retained and their work reviewed by the audit committee of our board of directors. In addition, one of our audit committee members is a petroleum engineer who monitors the entire reserve reporting process. We do not book proved undeveloped reserves until we have committed to perform the required operations, the majority of which are expected to commence within the next year.

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 CO₂ tertiary operations in West Mississippi and our Heidelberg waterfloods in East Mississippi account for approximately 90% of our proved undeveloped oil reserves. We consider these reserves to be lower risk than other proved undeveloped reserves that require drilling at locations offsetting existing production because all of these proved undeveloped reserves are associated with secondary recovery or tertiary recovery operations in fields and reservoirs that historically have 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.

Our proved undeveloped natural gas reserves are not as concentrated as our proved undeveloped oil reserves. The offshore properties we acquired in the 2001 Matrix acquisition account for approximately

48% of our proved undeveloped natural gas reserves. These reserves are typically located up-dip to existing wells or up-dip to wells that previously ceased producing due to water encroachment. These natural gas reserves are confirmed not only by subsurface geology but also by 3D seismic that covers these areas. An additional 24% of our proved undeveloped natural gas reserves

are located in Heidelberg Field, where we continue to have success in-fill drilling the Selma Chalk formation. Our remaining undeveloped natural gas reserves are located within our currently producing reservoirs. Our current plans for 2004 include development of approximately 27% of our proved undeveloped natural gas reserves.

	Year Ended December 31,		
	2003	2002	2001
Estimated Proved Reserves:			
Oil (MBbls)	91,266	97,203	76,490
Natural gas (MMcf)	221,887	200,947	198,277
Oil equivalent (MBOE)	128,247	130,694	109,536
Percentage of total MBOE:			
Proved producing	43%	43%	53%
Proved nonproducing	18%	23%	23%
Proved undeveloped	39%	34%	24%
Representative oil and gas prices: ⁽¹⁾			
Oil – NYMEX	\$ 32.52	\$ 31.20	\$ 19.84
Natural gas – NYMEX Henry Hub	6.19	4.79	2.57
Present Values: ⁽²⁾			
Discounted estimated future net cash flow before income taxes (“PV-10 Value”) (thousands)	\$ 1,566,371	\$ 1,426,220	\$ 574,328
Standardized measure of discounted estimated future net cash flow after income taxes (thousands)	\$ 1,124,127	\$ 1,028,976	\$ 505,795

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

⁽²⁾ Determined based on year-end unescalated prices and costs in accordance with the guidelines of the SEC, discounted at 10% per annum.

*Will the world
ever run out
of oil?*

Sam Snyder, Age 5

**Denbury's carbon
dioxide reserves will
still be recovering
additional barrels of
oil from the southern
United States in 2050.**



Field Summaries

Denbury operates in four primary areas: Louisiana, offshore Gulf of Mexico, Eastern Mississippi and Western Mississippi. Our 18 largest fields (listed below) constitute approximately 85% of our total proved reserves on a BOE basis and 80% on a PV-10 Value basis. Within these 18 fields we own a weighted average 91% working interest and operate

all of these fields. The concentration of value in a relatively small number of fields allows us to benefit substantially from any operating cost reductions or production enhancements we achieve and allows us to effectively manage the properties from our three primary field offices in Houma and Covington, Louisiana, and Laurel, Mississippi.

	Proved Reserves as of December 31, 2003 ⁽¹⁾					2003 Average Production		
	Oil (MMbbls)	Natural Gas (MMcf)	MBOE	BOE % of total	PV-10 Value (\$ '000's)	Oil (Bbls/d)	Natural Gas (Mcf/d)	Average Net Revenue Interest ⁽²⁾
Mississippi CO₂ Floods								
Mallalieu (East & West)	16,026	–	16,026	12.5%	218,041	1,578	–	81%
McComb	11,853	–	11,853	9.2%	103,887	–	–	83%
Little Creek & Lazy Creek	7,432	–	7,432	5.8%	112,666	3,093	–	83%
Total MS CO ₂ floods	35,311	–	35,311	27.5%	434,594	4,671	–	82%
Offshore Gulf of Mexico								
Brazos A-22	173	21,345	3,731	2.9%	44,864	13	1,069	72%
South Marsh Island	211	21,072	3,723	2.9%	86,657	72	7,652	83%
W. Delta 27	622	8,984	2,119	1.7%	41,193	417	8,322	56%
N. Padre A-9	8	10,804	1,809	1.4%	34,751	–	259	39%
Other Offshore	60	27,500	4,643	3.6%	105,990	152	26,465	31%
Total Offshore	1,074	89,705	16,025	12.5%	313,455	654	43,767	48%
Other Mississippi								
Heidelberg (East & West)	35,226	51,853	43,868	34.2%	341,133	5,824	10,265	78%
Eucutta	4,691	–	4,691	3.7%	43,878	1,252	159	69%
King Bee	2,853	–	2,853	2.2%	26,958	554	–	81%
Brookhaven	1,687	–	1,687	1.3%	20,381	452	–	77%
Other Mississippi	8,421	6,104	9,438	7.4%	89,610	3,600	1,309	27%
Total Other Mississippi	52,878	57,957	62,537	48.8%	521,960	11,682	11,733	60%
Louisiana								
Lirette	167	12,276	2,213	1.7%	59,410	288	12,379	58%
S. Chauvin	367	10,663	2,144	1.7%	45,163	155	3,335	37%
Thornwell	177	11,026	2,015	1.6%	62,368	507	12,343	65%
Other Louisiana	1,292	22,176	4,988	3.9%	107,640	878	10,306	39%
Total Louisiana	2,003	56,141	11,360	8.9%	274,581	1,828	38,363	41%
Texas								
Newark (Barnett Shale)	–	18,084	3,014	2.3%	21,781	59	995	71%
Company Total	91,266	221,887	128,247	100%	1,566,371	18,894	94,858	61%

⁽¹⁾ The reserves were prepared using constant prices and costs in accordance with the guidelines of the SEC based on the prices received on a field-by-field basis as of December 31, 2003. The prices at that date were a NYMEX oil price of \$32.52 per Bbl, adjusted by field, and a NYMEX Henry Hub natural gas price average of \$6.19 per MMBtu, also adjusted by field.

⁽²⁾ Only includes wells in which the Company has a working interest as of December 31, 2003.

Oil and Gas Acreage

The following table sets forth Denbury's acreage position at December 31, 2003:

	Developed		Undeveloped		Total	
	Gross	Net	Gross	Net	Gross	Net
Louisiana	24,473	16,693	26,025	18,857	50,498	35,550
Mississippi	84,942	69,374	242,397	33,663	327,339	103,037
Offshore Gulf Coast	122,301	68,782	58,580	52,010	180,881	120,792
Texas, other	5,698	4,405	73,887	16,899	79,585	21,304
Total	237,414	159,254	400,889	121,429	638,303	280,683

Productive Wells

This table sets forth our gross and net productive oil and natural gas wells at December 31, 2003:

	Producing Oil Wells		Producing Natural Gas Wells		Total	
	Gross	Net	Gross	Net	Gross	Net
Louisiana	28	23.2	59	39.1	87	62.3
Mississippi	410	379.9	94	76.6	504	456.5
Offshore Gulf Coast	5	3.4	76	45.3	81	48.7
Texas, other	52	1.6	13	12.0	65	13.6
Total	495	408.1	242	173.0	737	581.1

Drilling Activity

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

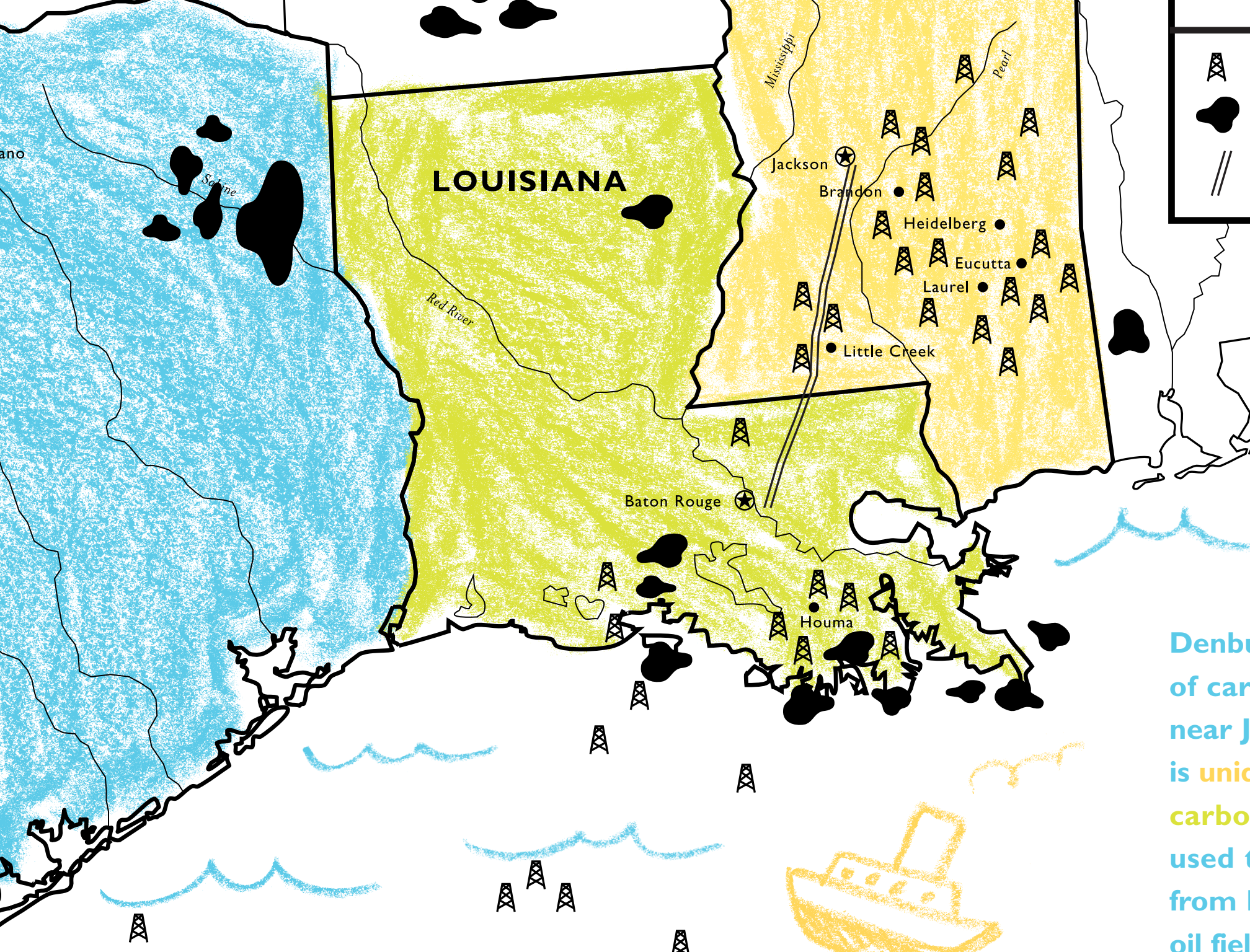
	Year Ended December 31,					
	2003		2002		2001	
	Gross	Net	Gross	Net	Gross	Net
Exploratory Wells: ⁽¹⁾						
Productive: ⁽²⁾	7	5.3	7	4.9	15	9.7
Nonproductive: ⁽³⁾	7	4.8	4	3.2	3	1.4
Development Wells: ⁽¹⁾						
Productive: ⁽²⁾	37	31.3	33	27.1	60	49.9
Nonproductive: ⁽³⁾⁽⁴⁾	3	1.2	2	1.9	—	—
Total	54	42.6	46	37.1	78	61.0

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

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

⁽³⁾ A non-productive well is an exploratory or development well that is not a producing well.

⁽⁴⁾ During 2003, 2002 and 2001, an additional 5, 9 and 24 wells, respectively, were drilled for water or CO₂ injection purposes.



LOUISIANA

Jackson

Brandon

Heidelberg

Eucutta

Laurel

Little Creek

Baton Rouge

Houma

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of car
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How do we get
more oil?

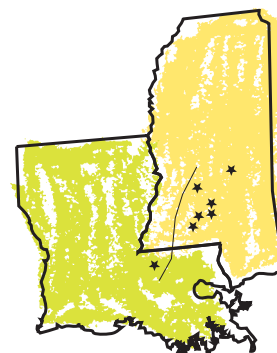
Taylor Krieger, Age 5

**Carbon dioxide is
the easiest way to
recover oil from
depleted reservoirs.**



OPERATIONS REPORT

Locations of our West Mississippi CO₂ related assets (and our CO₂ pipeline)



Our CO₂ Assets

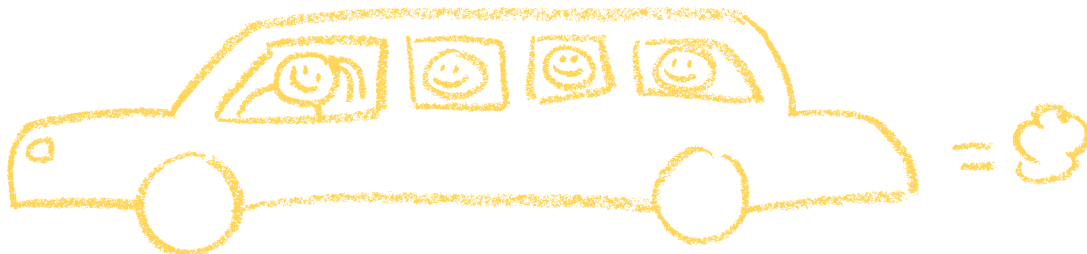
Just over four years ago, we started a new focus area through an acquisition of a carbon dioxide (“CO₂”) tertiary flood in an area very familiar to us, Mississippi. We have subsequently acquired other related assets and are making that focus area a major part of our business. In summary, we are gradually becoming more of a tertiary exploitation company, than a traditional acquire, drill and exploit type of exploration and production company. We particularly like this play as (i) it is lower risk and more predictable than most traditional exploration and development activities, (ii) it provides a reasonable rate of return at relatively low oil prices (upper teens to low twenties), and (iii) we have virtually no competition for this type of activity in our geographic area. Generally, from East Texas to Florida, there are no natural sources of carbon dioxide except our own, and these large volumes of CO₂ that we own drive the play. Our CO₂ comes from an old volcano located near Jackson, Mississippi, discovered in the 1960s while companies were drilling for oil and natural gas. Instead they found CO₂, which at the time was of little use. These CO₂ reserves are found in structural traps in the Buckner, Smackover and Norphlet formations at depths of about 16,000 feet. Some estimates have suggested that there are 12 Tcf of usable CO₂ in this general area.

CO₂ injection is one of the most efficient tertiary recovery mechanisms for producing crude oil; however, because it requires large quantities of CO₂, its use has been restricted to West Texas, Mississippi and other isolated areas where large quantities of CO₂ are available. The CO₂ (in liquid form) acts as a type of solvent for the oil, causing the oil to expand and become mobile, allowing the oil to be recovered along

with the CO₂ as it is produced. The CO₂ is then extracted from the oil, compressed back into a liquid state, and re-injected into the reservoir, with this recycling process occurring several times during the life of the tertiary operations. In a typical oil field up to 50% of the oil in place can be extracted during primary and secondary (waterflooding) recovery operations. Through the use of CO₂ in tertiary operations, it is possible to recover additional oil (for example, 17% based on historical results at Little Creek), almost as much oil as initially recovered during the primary production phase.

We started this play in August 1999, when we acquired our first CO₂ tertiary recovery project, Little Creek Field in Mississippi, a project originally developed by Shell Oil Company. Since our acquisition of this field, we have increased oil production here from 1,350 Bbls/d to an average of 3,201 Bbls/d during the fourth quarter of 2003. Following our success at Little Creek, we embarked upon a strategic program to build a dominant position in this niche play. We recognized that several other fields in the area would also be excellent CO₂ flood candidates because they produced from the same Lower Tuscaloosa formation, shared very similar reservoir characteristics and were in close proximity to each other. Following are highlights of our activities over the last three years:

- In February 2001, we acquired approximately 800 Bcf of proved producing CO₂ reserves for \$42.0 million, a purchase that gave us control of most of the CO₂ supply in Mississippi, as well as ownership and control of a critical 183-mile CO₂ pipeline. This acquisition provided the platform to significantly expand our CO₂ tertiary recovery



operations because it assured us that CO₂ would be available to us on a reliable basis and at a reasonable and predictable cost. Since February 2001, we have acquired two and drilled three additional CO₂ producing wells, doubling our estimated proved CO₂ reserves to approximately 1.6 Tcf as of December 31, 2003 (including approximately 162.6 Bcf of reserves dedicated to a volumetric production payment to Genesis). Today, we own every producing CO₂ well in the region. Although our current proven and potential CO₂ reserves are quite large, in order to continue our tertiary development of oil fields in the area, incremental deliverability of CO₂ is needed. In order to obtain the additional CO₂ deliverability, we plan to drill several additional CO₂ wells in the future, including up to four more wells during 2004, including one side-track operation.

- During 2001 and 2002, we acquired several oil fields in our CO₂ operating area, including the West Mallalieu and McComb Fields. Typical of mature properties in this area, the acquisition costs of both of these fields were relatively low in comparison to their significant reserve potential as tertiary recovery projects. As an example, we acquired West Mallalieu Field in May 2001 for \$4.0 million, and by year-end 2001 had recognized 10.4 MMBOE of proved reserves, with additional future reserve potential in this field. We acquired

McComb Field in 2002 for \$2.3 million, and by year-end 2002 had recognized 8.3 MMBOE of proved reserves with additional future reserve potential here also. We expect the all-in finding and development costs at these fields to average between \$4.00 and \$5.00 per BOE.

- In May 2002, we acquired the 2.0% general partner interest in Genesis Energy, L.P. ("Genesis"). Genesis is engaged in crude oil gathering, marketing and transportation with three primary pipeline systems in Texas, Alabama/Florida and Mississippi. Genesis' Mississippi pipeline runs near several of our tertiary recovery operations in southwest Mississippi and within 25 miles of our Heidelberg Field and several of our other East Mississippi fields. This acquisition has enhanced our marketing position for our Mississippi oil production. Genesis may also function as a financier and operator of new pipelines and gathering systems that are required in order for us to develop these fields.
- In August 2002, we acquired COHO Energy Inc.'s Gulf Coast properties for \$48.2 million, which as of year-end 2002 contained an estimated 15.0 MMBOE (excluding any potential reserves from tertiary recovery). Brookhaven Field, another significant tertiary flood candidate along our CO₂ pipeline, was included in the properties acquired from COHO. By exploiting our scale, regional

What will the earth be like in 2050?

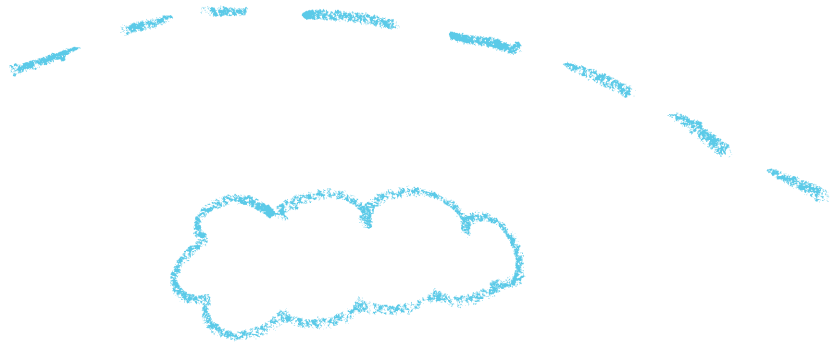
Lauren & Liana Andersen, Age 6

By 2050, we will be living in a world with almost 4 billion more people than today's population of 6.2 billion people.



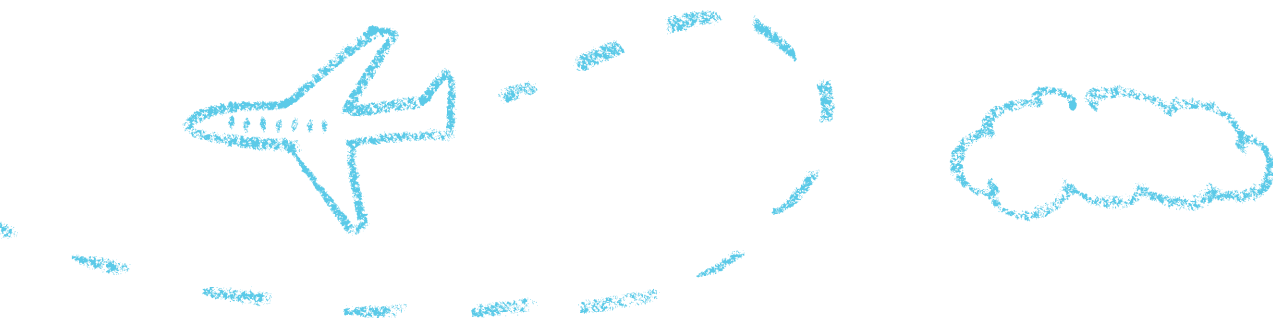


Caroline McCulloch, Age 8



competitive advantage and strategic ownership of the general partner interest in Genesis, we were able to increase the average realized price for post-acquisition production from these properties by approximately \$3.40 per barrel (relative to NYMEX prices) over the prices that COHO realized earlier in 2002. This translates into a 50% increase in the PV-10 Value of the acquisition, using constant prices and the future price strip as of the time of acquisition. Initial development of the Brookhaven CO₂ flood is expected to begin in late 2004. While we have not currently recorded any proved reserves associated with the CO₂ flood at Brookhaven, we believe that this field contains one of the area's most significant opportunities for potential oil reserves using CO₂ tertiary recovery.

- During the fourth quarter of 2003, we sold an average of 64 MMcf/d of CO₂ to commercial users and we used an average of 145 MMcf/d for our tertiary activities. With the acquisition of our latest well, we estimate our current daily CO₂ deliverability is over 250 MMcf/d, and by year-end 2004 we hope to further increase our CO₂ deliverability to approximately 350 MMcf/d. We plan to continue our CO₂ drilling in 2004 and beyond, as we estimate that we will need to be producing around 400 MMcf/d by 2006 in order to meet the projected timetable for our tertiary projects in Southwest Mississippi. During 2004, two of the CO₂ wells we expect to drill will be testing new structures, which if successful, will increase our CO₂ reserves and provide additional deliverability. We believe that it is prudent to add additional reserves and deliverability before we commence with our tentative plans to expand our CO₂ oper-



ations into East Mississippi and/or other regions. We expect to use almost all of the anticipated incremental CO₂ production in our own tertiary recovery operations. Our CO₂ sales to industrial customers are expected to provide us with between five and six million dollars of net cash flow per year, approximately 85% of the 2003 level. The decrease is a result of our 2003 sale of 167.5 Bcf of CO₂ to Genesis pursuant to a volumetric production payment (see discussion below). As of December 31, 2003, the present value of the remaining industrial sales contracts (using pricing provided in the contracts) discounted at 10% per year was approximately \$33 million based on the current life of each contract. We believe the majority of these contracts will be extended beyond their current terms, which would result in additional value.

- In October 2003, we sold 167.5 Bcf of CO₂ to Genesis for \$24.9 million under a volumetric production payment. In conjunction with the sale, we included the assignment of three of our existing long-term commercial CO₂ supply agreements with our industrial customers. Pursuant to the terms of the volumetric production payment, Genesis has specific maximums on the amount of CO₂ they are allowed to take each year, which generally relate to the anticipated volumes of the three industrial customers. We will continue to provide Genesis with certain processing and transportation services in connection with this agreement for a fee of \$0.16 per Mcf of CO₂ delivered to their industrial customers. In a separate transaction, we purchased approximately 689,000 partnership common units of Genesis for \$7.15 per unit, an aggregate purchase price of

\$4.9 million, giving us approximately 9.25% total ownership (2.0% general partner and 7.25% limited partner ownership) of Genesis.

- In February 2004, we disclosed the results of our preliminary study to determine the feasibility of implementing tertiary recovery operations in East Mississippi, in addition to the development of fields along our CO₂ pipeline. We reviewed five fields that we expect to be part of the first phase of operations in this area. While the study is preliminary and requires significant additional work and review, including a determination of the precise costs and best location for a CO₂ pipeline to this part of the state and further refinement of the economics, preliminarily this project appears to have reasonable economics at NYMEX prices in the low to mid twenties. These five fields also appear to have aggregate potential oil reserves of about 80 MMBbls that could be developed through tertiary operations, approximately the same magnitude of potential as those fields along our existing CO₂ pipeline. To be considered proven reserves, these potential tertiary floods must (i) have evidence of a response to CO₂ injections, from either a pilot test, actual response, or by analogy, and (ii) have a commitment from the company to do the project. Our preliminary projections of forecast production for both East and West Mississippi indicate that oil production from tertiary operations could peak at rates of almost 32,000 Bbls/d by 2013. While it is extremely difficult to accurately forecast that far into the future, we do believe that our tertiary recovery operations provide significant long-term production growth potential at reasonable rates of return with relatively low risk.

How much oil do we need?

Dylan Sommerfelt, Age 6

**The world uses 80,000,000
barrels of oil per day and our
industry currently replaces
less than one quarter of that
through new discoveries.**



**Locations of our Little Creek,
Mallalieu and McComb assets**



With anticipated all-in finding and development costs of between \$4.00 and \$5.00 per BOE and anticipated operating costs of around \$10.00 per BOE over the life of each field, these tertiary recovery operations in West Mississippi along our pipeline should prove to be profitable, even at \$18 oil prices, as they produce light sweet oil that receives near NYMEX pricing.

As noted above, we believe there is also significant potential in the future to extend our pipeline to eastern Mississippi and/or southern Louisiana to exploit the use of CO₂ in tertiary recovery operations in these areas. However, there are a few differences that we have noted when comparing these two areas: (i) operating cost in East Mississippi is likely to be one to three dollars per BOE higher than it is for those fields along our CO₂ pipeline, primarily because of the incremental cost of transporting the CO₂ to this new area, (ii) the incremental operating cost may be partially offset by an anticipated lower finding cost, as these East Mississippi fields may not require as many wells to be drilled or re-entered, as more wells are currently active, (iii) there are reservoir related differences, which although not exactly quantified, are expected to improve the overall economics in the eastern area, and (iv) the quality of the oil is different in the two areas. In the eastern part of the state, the oil is generally heavier and usually sour, and thus has a higher negative differential to NYMEX, ranging from one to six dollars per barrel worse than West Mississippi light sweet oil. In summary, while the fields in West Mississippi along our pipeline provide a satisfactory rate of return at NYMEX oil prices of around \$18, our preliminary study indicates that it takes NYMEX oil prices in the low to mid twenties to achieve the same rate of return in East Mississippi.

The western part of Mississippi has produced over 245 MMBbls of light sweet crude oil from Tuscaloosa sandstones at a depth of about 10,000 feet. The application of a theoretical recovery factor of 17% of original oil in place suggests that about 80-100 MMBbls of additional gross reserves may be recovered from fields in this part of the state as a result of CO₂ flooding. To date, we have recognized approximately 49.4 MMBbls (gross) of this potential as proven reserves, of which 6.2 MMBbls (gross) has been produced to date. Obviously, a great deal of work is required before these additional reserves can be recorded as proved reserves, such as additional leasing, reworking/re-entering wells and installing production facilities. We plan to spend around \$80 million in this area during 2004, almost one-half of our current \$172 million 2004 exploration and development budget.

Little Creek, Mallalieu and McComb Fields

Little Creek Field was discovered in 1958, and by 1962 the field had been unitized and waterflooding had commenced. The pilot phase of CO₂ flooding began in 1974 and the first two phases (each in a distinct area of the field) began in 1985. When we acquired the field in 1999, the first two phases were complete and Phase III was in process. We have completed development of Phase III, Phase IV and Phase V and most of the currently planned development work at this field, although we will continue to modify existing patterns and drill wells as necessary to recover the maximum amount of oil or to extend the field into areas which have not benefited from CO₂ injection. Currently there are 29 producing wells and 28 injection wells at Little Creek. Based on the results of the two earliest phases of CO₂ flooding at Little Creek, tertiary recovery has



Bella Burkes, Age 8

increased the ultimate recovery factor in the flooded portion of the field by approximately 17%, as compared to recoveries of approximately 20% for primary recovery and 18% for secondary recovery. The field has produced a cumulative 12.7 MMBbbls (gross) of light sweet crude and we currently estimate that an additional 7.2 MMBbbls (gross) can be recovered.

Production from Little Creek Field was approximately 1,350 Bbbls/d when we acquired it in 1999. During the fourth quarter of 2003, production had increased to an average of 3,201 BOE/d. Although we experienced a temporary shortage of CO₂ deliverability for several months during 2003, our oil production at Little Creek has now recovered and has recently been increasing again. We expect the production from Little Creek to increase further during 2004 by another 500 to 750 BOE/d. At December 31, 2003, we had reserves of 35.3 MMBbbls relating to our tertiary recovery operations. From inception through December 31, 2003, we had net positive cash flow from Little Creek (including Lazy Creek) of \$17.8 million (at the field level), plus the fields have a PV-10 Value, using December 31, 2003 SEC NYMEX pricing, of \$112.7 million.

We purchased West Mallalieu Field in May 2001. Shell Oil Company unitized West Mallalieu Field and commenced a pilot project in 1986. The pilot project, consisting of four 5-spot patterns, has cumulatively produced approximately 2.1 MMBbbls of oil as a result of CO₂ flooding. We have expanded the

pilot project by adding an additional four patterns during 2001, four patterns in 2002 and three patterns in 2003, in addition to an injection well in the East Mallalieu Unit added during 2003. During 2002 we began to see initial response to CO₂ injection as the West Mallalieu Field Unit averaged 778 Bbbls/d during the fourth quarter of 2002. Response in 2003 has continued as production increased to 2,378 Bbbls/d during the fourth quarter of 2003. In contrast to Little Creek Field, West Mallalieu Field was not waterflooded prior to CO₂ injection. Therefore, we believe that the tertiary recovery of oil from West Mallalieu Field Unit as a result of CO₂ injection could exceed the 17% of original oil in place that we expect from Little Creek Field.

We purchased McComb Field in 2002, a field with no pilot programs or tertiary operations at that time and virtually no current oil production. McComb is very close in proximity and analogous to Little Creek and Mallalieu Fields. We commenced tertiary recovery operations in 2003 by substantially completing two patterns, and by November 2003 had started injecting CO₂. We do not expect any oil production response until late 2004 from this activity. As of December 31, 2003, we had 11.9 MMBbbls of proven reserves at McComb Field. During 2004, we expect to add five patterns within McComb field and expand the production facilities. In addition, we also plan on starting an additional CO₂ flood at nearby Smithdale Field during 2004 utilizing the same facilities. We believe that the total potential at McComb and Smithdale Fields



Locations of our Eastern Mississippi assets



is significantly higher than the current proved reserves (at McComb only), and therefore expect to have upward reserve additions here over the next several years as we fully develop these fields.

At December 31, 2003, we have proved reserves of 35.3 MMBbls relating to our tertiary recovery operations. Through December 31, 2003, we have spent a total of \$104.8 million on fields in this area, and have received \$83.0 million in net operating income, leaving us a balance of \$21.8 million to recover for payout. The proved oil reserves in our CO₂ fields have a PV-10 Value, using December 31, 2003 SEC NYMEX pricing, of \$434.6 million.

Heidelberg and East Mississippi

We own interests in 504 wells in the eastern part of the Mississippi salt basin and operate 472 of these wells (94%) from our regional office in Laurel, Mississippi. These fields produced an average of 11,028 Bbls/d and 12.2 MMcf/d during the fourth quarter of 2003. The largest field in the region, and our largest field corporately, is Heidelberg Field, which for the fourth quarter of 2003 produced an average of 7,568 BOE/d. We have been active in this area since Denbury was founded in 1990 and are by far the largest producer in the basin, as well as in the state of Mississippi. Since we have generally owned these eastern Mississippi properties longer than properties in our other regions, they tend to be more fully developed and thus require less capital spending. During

2003, we spent a total of approximately \$24.6 million (excluding acquisitions), drilling 29 wells and performing various workovers, recompletions and other maintenance type projects. Even with the relatively low level of spending here, our production in eastern Mississippi averaged 13,638 BOE/d during 2003, slightly higher than the 2002 average of 13,378 BOE/d. For 2004, we expect our budget in this region to be a little higher than it was in 2003, approximately \$32.4 million, or 19% of our current \$172 million 2004 exploration and development budget.

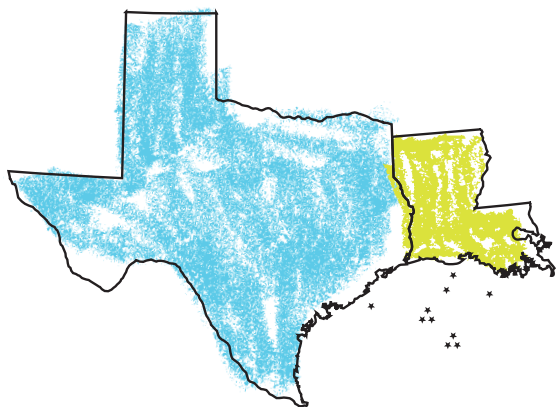
The fields in this region are characterized by structural traps that generate prolific production from stacked or multiple pay sands. As such, they provide opportunities to increase reserves through infield drilling, recompleting wells, improving production efficiency, and in some cases, by water flooding producing reservoirs. Most of our wells in this area produce large amounts of saltwater and require large pumps, which increase the operating costs per barrel relative to our properties in Louisiana that are predominantly natural gas producers. We plan to continue our basic strategy in this region, supplemented by additional waterflooding (secondary recovery). Our biggest future upside in this area will likely be from CO₂ flooding (tertiary recovery). We initiated a study of the feasibility of implementing tertiary recovery operations in East Mississippi during 2003, evaluating several of our existing fields, plus a few other fields in the general area that we do not own. The preliminary results of our study indicate that

How will we make sure we have oil in the future?

Jada Speed, Age 6

Conservation and the efficient use of reserves will be necessary for there to be enough oil for future generations.





Locations of our offshore
Gulf of Mexico assets

there are significant volumes of oil reserves that can be recovered in this area through CO₂ tertiary recovery operations that should provide a reasonable rate of return at NYMEX oil prices in the low to mid twenties. As such, we will be taking steps to increase our CO₂ reserves during 2004 (see "Our CO₂ Assets" above), which if successful, could be used for an expansion of tertiary activities to this area.

Heidelberg Field was acquired from Chevron in December 1997. This field was discovered in 1944 and has produced an estimated 198 MMBbls of oil and 43 Bcf of gas since its discovery. The field is a large salt-cored anticline that is divided into western and eastern segments due to subsequent faulting. There are 11 producing formations in Heidelberg Field containing 40 individual reservoirs, with the majority of the past and current production coming from the Eutaw, Selma Chalk and Christmas sands at depths of 3,500 to 5,000 feet. When we acquired the property, production was approximately 2,800 BOE/d. As a result of our subsequent development work, production for 2003 averaged 7,535 BOE/d.

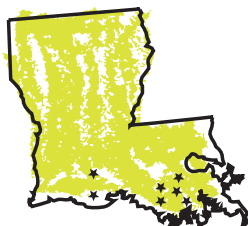
The primary oil production at Heidelberg is from five waterflood units that produce from the Eutaw formation (at approximately 4,400 feet). These units are generally developed although they will require additional work and capital for the next few years. In addition, Heidelberg is our single largest gas field. We began extensive development of the Selma Chalk natural gas reservoir at a depth of 3,700 feet in 2000 and 2001. Previous operators had only partially developed this formation in order to provide fuel gas for the rest of the field. We drilled 13 natural gas wells in 2001, 13 natural gas wells in 2002 and 15 natural gas wells in 2003, increasing the natural gas production at

Heidelberg to an average for 2003 of around 10.3 MMcf/d. We believe that there are opportunities to further reduce the well spacing here and we plan to drill up to 16 additional Selma Chalk wells during 2004. In addition, we have determined additional natural gas reserves can be recovered from the Upper Selma Chalk and recently have increased our fracture stimulation size in one well with positive results. Our 2004 projects include performing the larger fracture treatments on new wells and additional completions in the Upper Selma Chalk in seven wells.

Offshore Gulf of Mexico

During 2003, another area of focus for us was the federal offshore waters of the Gulf of Mexico. Employing the latest 3D seismic techniques and interpretations has allowed us to better understand the complexities of these offshore areas. We own an interest in 81 wells and operate 63 of these wells (78%) from our regional office in Covington, Louisiana. This area became a more significant part of our business in 2001 with the purchase of Matrix Oil & Gas, Inc.

Due to the downturn in natural gas prices that occurred late in 2001, we budgeted little drilling activity offshore during 2002, with spending primarily limited to workovers, recompletions and other maintenance type projects. We drilled only two offshore wells late in 2002, both successful exploration wells at North Padre Island A-9. During 2003, we spent approximately \$54.0 million (excluding acquisitions), significantly higher than the \$13.6 million incurred here (excluding acquisitions) during 2002. We drilled six wells during 2003 (including two wells drilling as of year-end) and completed the platform and production facilities at North Padre A-9, our late 2002 discovery. As is typical of the shorter-life natural gas production in this



Locations of our assets
in southern Louisiana



area, a high level of activity must be maintained or production will decline. Since our spending was reduced during 2002 and most of the 2003 wells were not completed until late in the year, our 2003 production averaged only 47.7 MMcf/d, a decline from our 2002 average of 59.9 MMcf/d. Late in the fourth quarter of 2003, we made 15 well completions, four at Brazos A-21, three at North Padre A-9, three at Chandeaur Sound 69, two at West Cameron 192 and three at West Cameron 427. Although most of these were not completed until the latter half of the fourth quarter, the incremental production was sufficient to at least temporarily arrest the overall production decline in this area. During 2004, with the gradual shifting of our emphasis to our CO₂ play (see above), we have reduced our budgeted offshore spending to approximately \$28.7 million, or about 17% of our \$172 million 2004 exploration and development budget.

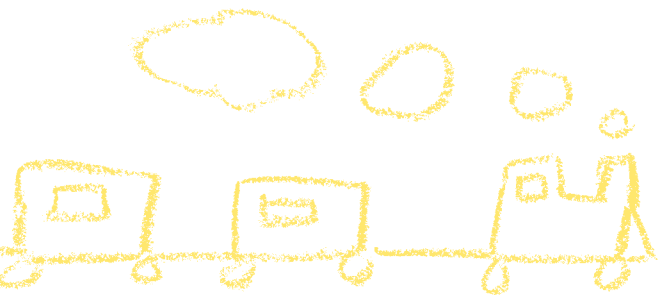
During 2004, we expect to drill three to six offshore wells, with unrisks potential target objectives ranging from 5 Bcf to 55 Bcf, net to our interest. These projects are supported with 3D seismic that is enhanced by modern acquisition techniques and the latest processing techniques and seismic modeling. The application of these techniques allows our geoscientists to better image deeper reservoirs and recognize hydrocarbon indicators in and around these mature prolific fields. Our scheduled wells include both development and exploration prospects at Brazos A-21, South Marsh Island 49, and North Padre A-9. As is the case with all oil and natural gas activity, but perhaps to an even more pronounced degree in the Gulf of Mexico, the timing and drilling of individual wells is subject to, among other things, working interest owner approvals, farm-out agreements, solicitation of participating entities, rig availability and our continual process of upgrading

our prospect inventory. In March 2004 we hired an investment banker to assist us with the sale of our offshore operations. No buyer has been identified as of yet, and if the sales price is less than anticipated, we may withdraw the sales package.

South Louisiana

We own interests in 87 wells in the land and marshes of south Louisiana and operate 74 of these wells (85%) from our regional office in Houma, Louisiana. This region produces primarily natural gas, averaging 39.2 MMcf/d net to our interest in the fourth quarter of 2003, approximately 42% of our total natural gas production. During 2003, we spent approximately \$33.1 million (excluding acquisitions) in this region, approximately 20% of our total exploration and development expenditures, drilling approximately 16 wells, primarily in the Thornwell and Terrebonne Parish areas (Lirette, Bay Baptiste, Bayou Sauveur, Gibson and Lake Gero Fields). For 2004, our spending is expected to be about the same, with a budget of \$22.7 million, or 13% of our \$172 million exploration and development budget.

The majority of our onshore Louisiana fields lie in the Houma embayment area of Terrebonne Parish, including Lirette, Bayou Rambio and South Chauvin Fields, and recent shallow natural gas plays at Lake Gero and Gibson Fields. The advent of 3D seismic data in these geologically complex areas has become a valuable tool in exploration and development. We currently own or have a license covering over 650 square miles of 3D data, and plan to expand our data ownership. During 2003, we expanded our seismic holdings in this area by acquiring an additional 165 square miles of 3D data. We drilled nine wells in Terrebonne Parish during 2003, seven of which were discoveries. In 2004, we plan to drill approximately six wells: three exploratory wells in



or around Lirette Field and three wells that are planned to further exploit shallow gas plays.

We have had good success with a shallow natural gas play in the Lake Gero area of Terrebonne Parish, although our 2003 results were not as good as we had hoped. At Lake Gero, we drilled two successful wells during 2002, another successful well in 2003, followed by one marginal well and one dry hole. These shallow gas reservoirs are approximately 3,000 feet deep, but have the ability to produce from 1.0 to 4.0 MMcf/d. During the fourth quarter of 2003, we drilled similar anomalies in Gibson Field and Bayou Sauveur Fields. As of January 2004, our Gibson well was producing at around 1.7 MMcf/d, with several additional prospects in the area, and our Bayou Sauveur well is producing approximately 1.0 MMcf/d. We plan to drill an additional three shallow gas prospects in Terrebonne Parish during 2004, with another 5 to 15 additional shallow gas prospects in the Terrebonne Parish under review.

We purchased Thornwell Field, located in Cameron and Jeff Davis parishes, in late 2000. Our primary interest in purchasing this field was the substantial upside potential that we believed existed in the continued development of the existing producing zones (Bol Perc), and the exploration potential of the deeper zones (Marg howei and Camerina). All of these prospects were defined by a 110 square mile 3D seismic survey. We had significant activity at this field during 2001 and 2002, with positive results, but reduced our activity during 2003 as the field became more fully developed. During 2003, we drilled one successful Bol Perc well, drilled our first dry hole in the field, and a third well was unsuccessful in the Bol Perc but found pay in a shallower sand. During 2003, we also successfully drilled our first Marg howei test

Chase Daniels, Age 9





in the field. We also recompleted a well that averaged just under 1.0 MMcf/d during the fourth quarter of 2003. Our plans for 2004 are more limited, but do include a Marg howei well and further leasing for future potential exploration prospects.

Thornwell Field is characterized by short-life natural gas properties that have high initial production rates with a good rate of return, but are depleted in two to three years. The high rates of decline have dramatically impacted our overall production rates the last two years, and are expected to continue to do so throughout 2004. Production at Thornwell Field averaged 4,275 BOE/d in 2001, 3,910 BOE/d in 2002 and 2,564 BOE/d in 2003, and is expected to average approximately 1,100 BOE/d during 2004. Even though this field is negatively affecting our overall production growth, the purchase and development of this field has been profitable. From inception through December 31, 2003, we have net positive cash flow (at the field level) of \$18.9 million from our activities at this field. Furthermore, we have remaining proved reserves with a PV-10 Value, using December 31, 2003 constant SEC NYMEX pricing, of \$62.4 million.

Barnett Shale

We own about 20,000 acres of leases in the Fort Worth Basin in North Central Texas that are prospective for natural gas in the Barnett Shale. Six wells were drilled

in 2001, two in 2002 and an additional five in 2003.

In addition to our own drilling during 2003, we entered into a joint venture with another entity to drill up to 60 wells in this area over a 36-month time frame. During 2003, the joint venture partner drilled 10 wells on our acreage and is expected to drill an additional 10 wells by the end of March 2004. Based on our wells, the joint venture wells and the other wells in the immediate area, we believe the majority of our acreage contains productive natural gas in the Barnett Shale with significant reserve potential. During 2004, our plans include the drilling of three horizontal wells to determine if this drilling technique will improve the overall economics. In addition to our own plans, our joint venture partner is expected to drill an additional 15 wells, some of which may be horizontal, in which we plan to participate for our full interest. During 2003, we also addressed an issue of pipeline capacity in our area of the Barnett Shale play by installing additional pipelines to relieve some packed lines. Several of the gas buyers in the area are making plans to install additional pipelines to handle the expected future volumes of gas from this area of the play.

2010

Denbury's oil production from its carbon dioxide (CO₂) floods is expected to be over 25,000 barrels per day.

2020

Denbury's oil production from its CO₂ floods is estimated to be at peak production.

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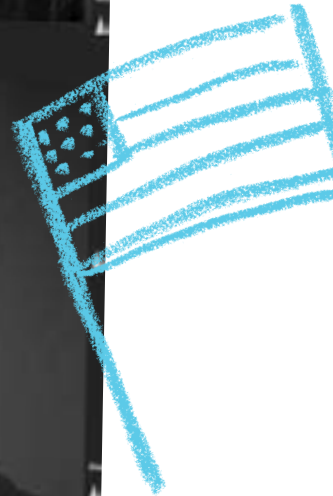
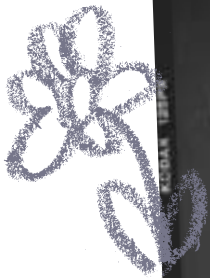
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Daniel Hickson, Age 8



Erin Miller, Age 7



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 .
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.
CO₂	Carbon dioxide.
MBBL	One thousand barrels of crude oil or other liquid hydrocarbons.
MBOE	One thousand BOEs.
MBTU	One thousand Btus.
MCF	One thousand cubic feet of natural gas or CO ₂ .
MCF/D	One thousand cubic feet of natural gas or CO ₂ produced per day.
MCFE	One thousand cubic feet of natural gas equivalent using the ratio of one barrel of crude oil, condensate or natural gas liquids to 6 Mcf of natural gas.
MCFE/D	MCFEs produced per day.
MMBBL	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 .
MMCFE	One thousand MCFE.
MMCFE/D	MMCFEs produced per day.
PV-10 VALUE	When used with respect to oil and natural gas reserves, PV-10 Value means the estimated future gross revenue to be generated from the production of proved reserves, net of estimated production and future development costs, using prices and costs in effect at the determination date, without giving effect to non-property-related expenses such as general and administrative expenses, debt service and future income tax expense or to depreciation, depletion and amortization, discounted to present value using an annual discount rate of 10% in accordance with the guidelines of the Securities and Exchange Commission.
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 .

CONTACT INFORMATION

Corporate Headquarters:	Denbury Resources Inc. 5100 Tennyson Pkwy, Ste. 3000 Plano, Texas 75024 T: 972.673.2000 F: 972.673.2150
Field Offices:	Laurel, MS: T: 601.428.1998 Houma, LA: T: 504.857.9215 Covington, LA: T: 985.893.1530
Data Requests:	Cynthia Rodriguez
Investor Relations:	Laurie Burkes www.denbury.com
Questions re: Press Releases and Stockholder Reports:	Gareth Roberts President and Chief Executive Officer Phil Rykhoek Senior Vice President and Chief Financial Officer Laurie Burkes Investor Relations Manager
Engineering:	Tracy Evans Senior Vice President, Reservoir Engineering
Finance:	Phil Rykhoek Senior Vice President and Chief Financial Officer
Operations:	Mark Worthey Senior Vice President, Operations
Accounting:	Mark Allen Vice President and Chief Accounting Officer
Marketing:	Ron Gramling Vice President, Marketing
Exploration:	Jim Sinclair Vice President, Exploration
Land:	Ray Dubuisson Vice President, Land
Louisiana Division:	George Pecorino Houma, LA
Mississippi Division:	Kerry Allen Laurel, MS
Offshore Division:	Dale Wheeler Covington, LA

Management's Discussion and Analysis of Financial Condition and Results of Operations

We are a growing independent oil and gas company engaged in acquisition, development and exploration activities in the U.S. Gulf Coast region. We are the largest oil and natural gas producer in Mississippi and hold significant operating acreage in the onshore Louisiana and the offshore Gulf of Mexico areas. Our goal is to increase the value of acquired properties through a combination of exploitation, drilling, and proven engineering extraction processes, including secondary and tertiary recovery operations. Our corporate headquarters are in Plano, Texas (a suburb of Dallas), and we have three primary field offices located in Houma and Covington, Louisiana, and Laurel, Mississippi.

Overview

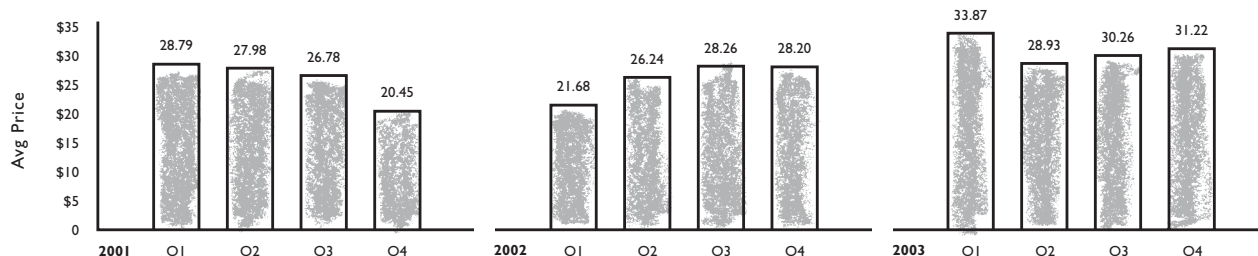
Just over four years ago, we started a new focus area through an acquisition of a carbon dioxide ("CO₂") tertiary flood in an area very familiar to us, Mississippi. We have subsequently acquired other related assets and are making that focus area a major part of our business. In summary, we are gradually becoming more of a tertiary exploitation company than a traditional acquire, drill and exploit type of exploration and production company. We particularly like this play as (i) it is lower risk and more predictable than most traditional exploration and development activities, (ii) it provides a reasonable rate of return at relatively low oil prices (upper teens to low twenties in the area of our current operations), and (iii) we have virtually no competition for this type of activity in our geographic area. Generally, from East Texas to Florida, there are no significant natural sources of carbon dioxide except our own, and these large volumes of CO₂ that we own drive the play.

During the last two years, we have gradually increased the percentage of our spending dedicated to CO₂ related operations. During 2002, we spent approximately 23% of our capital budget on these operations, and during 2003 we spent approximately 27%. During 2004, we anticipate spending approximately 47% of our capital budget on these CO₂ related projects. There are certain short-term ramifications to the gradual shift in focus, the most significant being relatively flat production levels from 2002 through 2004. This results from a shift in capital spending from shorter-life, higher-decline natural gas properties to longer-life oil properties (the tertiary operations) that have lower initial production rates and a longer lead time before production commences. In our tertiary operations, there is a significant delay between the initial capital expenditures and the resulting production, as the operations require installation of certain facilities before CO₂ flooding can commence and there is usually a six- to twelve-month delay between the first injections of CO₂ and resultant oil production. While our production from these tertiary operations has increased each year, during 2003 it did not quite offset the more rapid declines in our natural gas production in both Louisiana and offshore, which have steep decline rates due to their relatively short lives. For similar reasons, we expect our overall production for 2004 to be about the same as in 2003. Although still preliminary, we expect production to be higher in 2005, as the projected increases in production from our tertiary operations should exceed the production declines elsewhere. Our tertiary operations are also contributing to a general increase in operating expenses per BOE, although that increase is partially offset by a gradual improvement in our overall oil price relative to NYMEX. See "CO₂ Operations" under "Results of Operations" below for a more extensive discussion of these operations and their perceived potential.

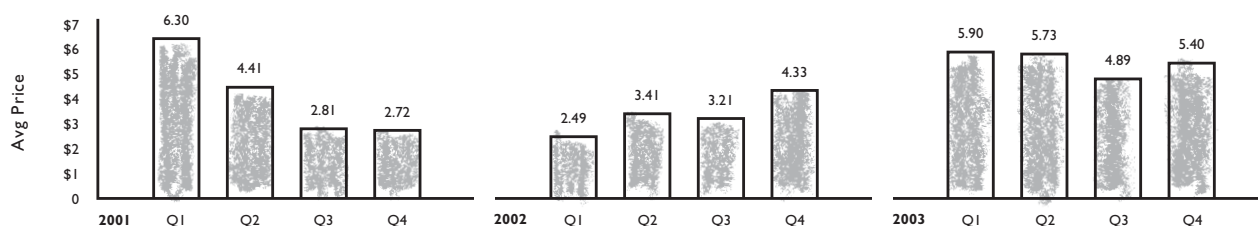
One of our primary financial goals during 2003 was to reduce our total debt to approximately \$300 million by year-end, a proposed \$50 million reduction from the \$350 million outstanding as of December 31, 2002. This target was determined by reviewing our leverage and setting a debt level that we believed to be reasonable in the anticipated near-term price environment. We generally measure leverage using a debt-to-cash flow ratio, cash flow being defined as cash flow from operations. Our target is a debt-to-cash flow ratio of 2 to 1 (or less), using a moderate price deck, which we currently define as oil prices of around \$25.00 per Bbl and natural gas prices of around \$3.50 per Mcf. We were able to accomplish this goal with the net proceeds from the Genesis transactions (see "Genesis Transactions" below), property sales and cash generated from operations, ending the year with \$300 million of total debt. During 2004 and the near future, we plan to spend no more than cash flow from operations, unless we make a significant acquisition, which would likely be financed with debt.

Management's Discussion and Analysis of Financial Condition and Results of Operations

NYMEX Crude Oil Price Listings



NYMEX Natural Gas Price Listings



Our cash flow from operations and net income have been strong during the last three years, primarily because of higher than historical commodity prices. For 2003, the higher commodity prices more than offset a 2% decline in production and higher operating expenses, resulting in a 24% increase in cash flow from operations as compared to 2002. The increase in net income corresponded to the higher cash flow from operations, increasing 21% from 2002 to 2003. Finding costs and the related depreciation and amortization expense on a per BOE basis increased in 2003 because of higher expenditure levels in 2003 than in 2002 in the offshore Gulf of Mexico, which typically has higher finding costs, and because some of our higher potential exploration targets failed to materialize. Our finding and development costs related to our tertiary operations were relatively low (just over \$5.00 per BOE for 2003 including the related future development costs), but they were not sufficient to offset the higher finding and development costs of the offshore and other natural gas properties. See "Results of Operations" for a more thorough discussion of these factors.

Debt Refinancing

In late March 2003, we issued \$225 million of 7.5% Senior Subordinated Notes due 2013 to refinance our \$200 million of then existing 9% Senior Subordinated Notes due 2008. The subordinated debt was refinanced to take advantage of the then current attractive interest rates and to extend the maturity of our long-term debt an additional five years. We estimate that we will save approximately \$2.6 million per year in interest expense as a result of this refinancing. The total cost of the refinancing was approximately \$15.6 million, consisting of the debt issue discount, underwriters' commission and other expenses totaling approximately \$6.6 million, and a \$9.0 million call premium to retire the old notes. The old notes were not retired until April 16, 2003, at the end of the required thirty-day notice period to call the old notes. We had a pre-tax charge to earnings in the second quarter of 2003 of approximately \$17.6 million from the early retirement of the old 9% notes, made up of the \$9.0 million call premium and the write-off of the remaining unamortized discount of \$4.8 million and debt issue costs of \$3.8 million on the old notes. The proceeds from the new issue were used to retire the old 9% subordinated notes in April 2003.

Genesis Transactions

During November 2003, we sold 167.5 Bcf of CO₂ to Genesis Energy, L.P. ("Genesis") for \$24.9 million (\$23.9 million as adjusted for transaction costs and interim cash flow from the effective date until closing) under a volumetric production

Management's Discussion and Analysis of Financial Condition and Results of Operations

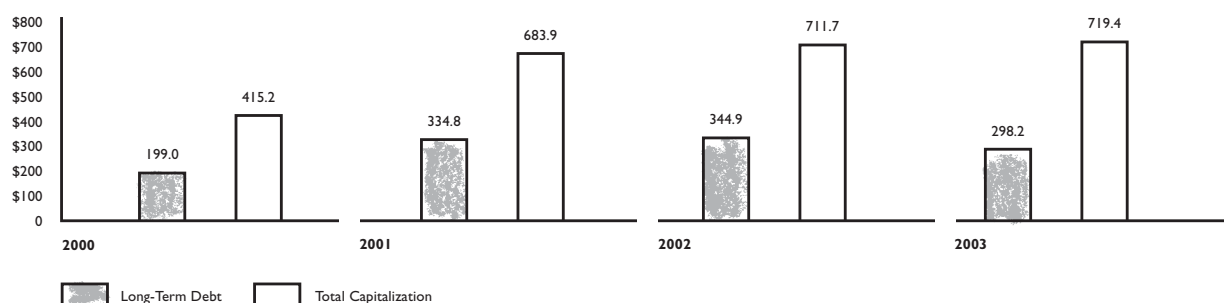
payment ("VPP"). Included in the transaction was the assignment to Genesis of three of our existing long-term CO₂ supply agreements with our industrial customers, which represented approximately 60% of our industrial CO₂ sales volumes at that time. Pursuant to the volumetric production payment, Genesis may take up to 52.5 MMcf of CO₂ per day through 2009, 43.0 MMcf/d from 2010 through 2012 and 25.2 MMcf/d to the end of the term. We provide processing and transportation services to Genesis for a fee of \$0.16 per Mcf in connection with the delivery of CO₂ to the industrial customers.

In a separate transaction, we purchased approximately 689,000 common partnership units of Genesis for \$7.15 per unit for an aggregate purchase price of \$4.9 million, representing approximately 7.25% of Genesis' total outstanding common units, increasing our total ownership of Genesis to 9.25%. We used the net cash proceeds of approximately \$20 million from these two transactions to reduce our bank debt.

Capital Resources and Liquidity

Since our last significant acquisition in the third quarter of 2002, we have generally been reducing our debt with both excess cash flow from operations and proceeds from property sales. In addition to the \$50 million debt reduction during 2003 (see "Overview" above), we repaid approximately \$25 million of bank debt during the fourth quarter of 2002, or a total of approximately \$75 million of repayments during the last fifteen months. By December 31, 2003, we had reached our targeted debt level of \$300 million, so we anticipate that our spending during 2004 will be about the same, or less than, our cash flow from operations, as we do not see the need for further debt reduction. However, there will likely be some minor borrowings and repayments throughout the year in order to manage our working capital and to fund minor acquisitions. We do not anticipate an increase in overall debt during 2004 unless we make a significant acquisition. As of February 27, 2004, our total debt was \$305 million, comprising \$225 million of 7.5% Senior Subordinated Notes due 2013 and \$80 million of bank debt. The incremental borrowings of \$5.0 million since December 31 were to fund an acquisition of another CO₂ producing well, which also included another industrial sales contract, giving us ownership of every producing CO₂ well in the region.

Debt to Total Capitalization in millions of dollars



Capital Spending Forecast

Our 2004 capital budget, excluding acquisitions, is currently approximately \$172 million. Based on current projections, using NYMEX futures prices in place as of the last part of February 2004, this exploration and development spending level is expected to be as much as \$25 million less than our 2004 forecasted cash flow. However, as we have done from time to time in prior years, if commodity prices remain strong, we will likely increase our capital budget throughout the year to more closely match our cash flow from operations. As of February 27, 2004, we had approximately \$140 million of availability on our bank borrowing base, more than we could reasonably expect to use for short-term working capital requirements and enough credit line availability to fund all but the largest acquisitions.

Management's Discussion and Analysis of Financial Condition and Results of Operations

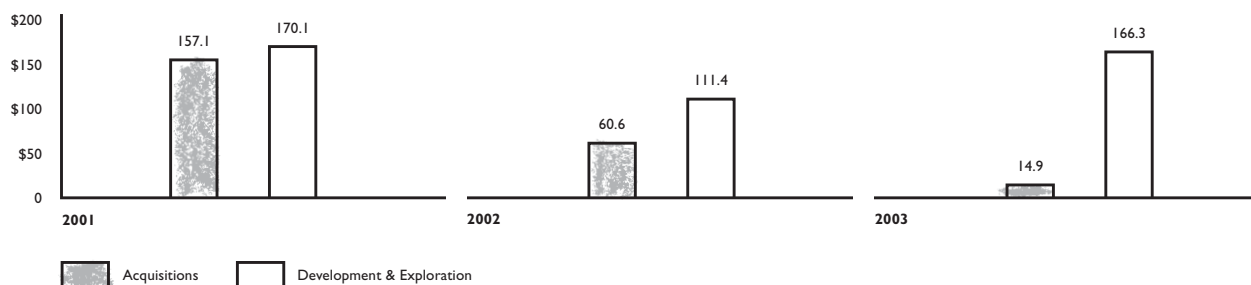
During 2004, we intend to focus on our CO₂ operations, one objective of which will be to develop additional CO₂ reserves and deliverability for a possible future expansion of our CO₂ tertiary floods to other areas, most likely East Mississippi. (See "CO₂ Operations" under "Results of Operations" for a discussion of the production and reserve potential.) This may have a short-term impact on our oil and natural gas production growth, although we believe it will provide long-term value for our shareholders, as it is the first step in expanding our CO₂ operations, adding additional fields as CO₂ flood candidates, and ultimately adding oil reserves. We are also considering the possibility of selling certain lower priority properties during 2004, including our offshore operations, which in the short-term would also reduce production, although the proceeds would likely be used to reduce debt. Ideally, rather than pay down debt, we would like to re-invest any sales proceeds in other properties that could be future potential tertiary flood candidates. In March 2004 we hired an investment banker to assist us with the sale of our offshore operations. No buyer has been identified as yet, and if the sales price is less than anticipated, we may withdraw the sales package.

Our current acquisition focus is to seek additional properties that are potential tertiary flood candidates and to acquire incremental interests in fields that we already own. We continue to review other properties in all of our operating areas where we see additional potential based on our review of 3D seismic or other geologic and geophysical data, although this activity is a lower priority for us than has been the case historically, given our substantial inventory of projects in-house related to tertiary operations. Any acquisitions that we do make will likely be funded with either excess cash flow or bank debt.

Sources and Uses of Capital Resources

During 2003, we generated approximately \$197.6 million of cash flow from operations and generated an additional \$29.4 million of cash from sales of oil and gas properties. The largest single asset sale was the sale of Laurel Field, acquired from COHO in August 2002, which netted us approximately \$25.9 million. Later in the year, we also sold a volumetric production payment to Genesis, which netted us approximately \$20 million of cash (see "Genesis Transactions" above). During 2003, we spent \$146.6 million on oil and natural gas exploration and development expenditures, \$22.7 million on CO₂ capital investments and acquisitions, and approximately \$11.8 million on oil and natural gas property acquisitions, for total capital expenditures of approximately \$181.1 million. In addition, during 2003 we incurred approximately \$15.6 million of costs for the subordinated debt refinancing (see "Debt Refinancing" above). The \$147.3 million of net total expenditures (including the \$15.6 million of debt refinancing costs and net of property sales) was funded by our cash flow from operations, with the balance used to reduce our total debt by approximately \$50.0 million.

Capital Expenditures in millions of dollars



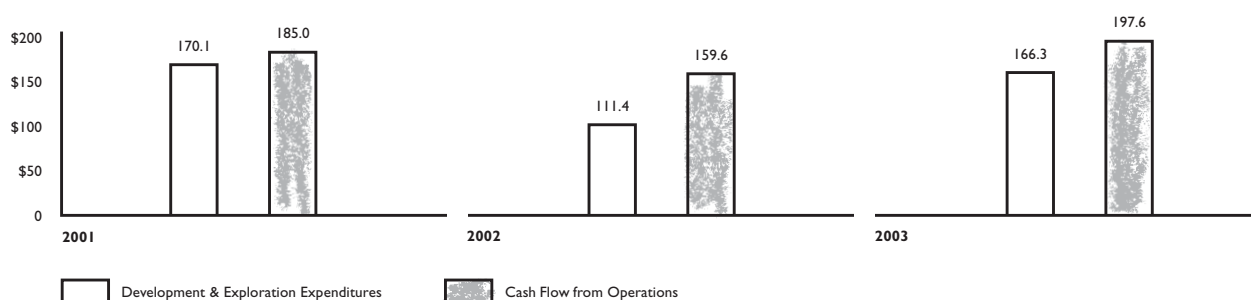
During 2002, we spent approximately \$99.3 million on exploration and development activities, approximately \$56.4 million on acquisitions (the largest being the \$48.2 million acquisition of the COHO properties), and approximately \$16.4 million on CO₂ related capital expenditures, for a total of approximately \$172.1 million. Our exploration and development expenditures included approximately \$62.3 million spent on drilling, \$17.8 million of geological, geophysical and acreage expenditures and \$19.1 million spent on facilities and recompletion costs. The exploration and development expenditures

Management's Discussion and Analysis of Financial Condition and Results of Operations

were funded by cash flow from operations, and the acquisitions were primarily funded by cash flow, supplemented by property dispositions totaling \$7.7 million and incremental bank debt for the year of \$9.1 million.

During 2001, we spent approximately \$170.1 million on exploration and development activities and approximately \$157.1 million on acquisitions (excluding the \$42 million CO₂ acquisition), the largest being the acquisition of Matrix. Our exploration and development expenditures included approximately \$115.9 million spent on drilling, \$18.7 million of geological, geophysical and acreage expenditures and \$35.5 million spent on facilities and recompletion costs. The exploration and development expenditures were funded by cash flow from operations, and the acquisitions were primarily funded by net incremental debt.

Development and Exploration Expenditures vs. Cash Flow from Operations in millions of dollars



Bank Credit Facility

Our bank borrowing base was reaffirmed as of October 1, 2003 at \$220 million as part of the semi-annual review by the banks. During 2003, we amended our credit agreement to increase the percentage of production we are allowed to hedge, setting a maximum of 85% of our forecasted production from our proved reserves for the current year (as defined in the amendment and which may include up to 18 months), a maximum of 70% of the forecasted production for the subsequent year, a maximum of 55% of the forecasted production for the third year and a maximum of 40% of the forecasted production for the fourth year. We also amended the credit agreement to allow us to borrow up to \$20 million in a bond issue from a Mississippi governmental authority, resulting in the exemption or reduction of sales and ad valorem taxes on CO₂ facilities we build through May 2005 in Mississippi. This bond funding arrangement was completed in May 2003. Any borrowings under this bond program will be purchased by the banks in our credit facility, will become part of our outstanding borrowings under our credit line and will accrue interest and be repaid on the same basis as our bank line. Our bank agreement was amended again in December 2003 to accommodate our conversion to a holding company organizational structure, although this amendment did not include any significant changes to the terms or covenants included therein (see "General and Administrative Expenses" under "Results of Operations" and Note 1 to the Consolidated Financial Statements). Our next bank borrowing base redetermination will be as of April 1, 2004, based on December 31, 2003 assets. We do not anticipate any significant changes to our borrowing base at this next review, although we cannot be certain, as there are several subjective aspects to the borrowing base determination.

Off-Balance Sheet Arrangements

Commitments and Obligations

We have no off-balance sheet arrangements, special purpose entities, financing partnerships or guarantees, other than as disclosed in this section, nor do we have any debt or equity triggers based upon our stock or commodity prices. Our dollar denominated obligations that are not on our balance sheet include our operating leases, the largest of which is a \$6.0 million lease financing of certain equipment at our CO₂ recycling facility at Mallalieu Field that commenced in August 2003. We also have several leases relating to office space and other minor equipment leases. We also have dollar

Management's Discussion and Analysis of Financial Condition and Results of Operations

related obligations that are not currently recorded on our balance sheet relating to various obligations for development and exploratory expenditures that arise from our normal capital expenditure program or from other transactions common to our industry. In addition, in order to recover our undeveloped proved reserves, we must also fund the associated future development costs forecasted in our proved reserve reports. For a further discussion of our future development costs and proved reserves, see "Results of Operations – Depletion, Depreciation and Amortization."

At December 31, 2003, we had a total of \$820,000 outstanding in letters of credit. Genesis Energy, Inc., the general partner of which we own 100%, has guaranteed the bank debt of Genesis, which was approximately \$7.0 million as of December 31, 2003, and also included \$21.6 million in letters of credit, of which \$12.5 million secured purchases from Denbury. There are no guarantees by Denbury or any of its other subsidiaries of the debt of Genesis or of Genesis Energy, Inc. We do not have any material transactions with related parties other than sales of production and a VPP sold to Genesis as discussed in Note 3 to our Consolidated Financial Statements.

A summary of our obligations is presented in the following table:

	Payments Due by Period						
Amounts in Thousands	Total	2004	2005	2006	2007	2008	Thereafter
Contractual Obligations:							
Bank debt ^(a)	\$ 75,000	\$ —	\$ —	\$ 75,000	\$ —	\$ —	\$ —
Subordinated debt ^(a)	225,000	—	—	—	—	—	225,000
Operating lease obligations	16,621	2,664	2,784	2,786	2,781	2,670	2,936
Capital expenditure obligations ^(b)	6,657	6,657	—	—	—	—	—
Other long-term liabilities reflected in our Consolidated Balance Sheet:							
Derivative liabilities ^(c)	37,129	37,057	72	—	—	—	—
Other Cash Commitments:							
Future development costs on proved reserves, net of capital obligations ^(d)	268,936	69,329	107,536	24,399	29,548	18,656	19,468
Asset retirement obligations ^(e)	82,733	2,563	4,464	2,725	1,006	2,880	69,095
Total	\$712,076	\$118,270	\$114,856	\$104,910	\$33,335	\$24,206	\$316,499

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

(b) Represents future minimum cash commitments under contracts in place as of December 31, 2003, primarily for 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 six months and are usually part of our normal operating expenses or part of our capital budget, which for 2004 is currently set at \$172 million. In addition, we have recurring expenditures for such things as accounting, engineering and legal fees, software maintenance, subscriptions, and other overhead type items. Normally these do not change materially from year to year and are part of our general and administrative expenses. We have not attempted to estimate these types of 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.

(c) Represents the estimated future payments under our derivative obligations based on the futures market prices as of December 31, 2003. 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, 2003 was a \$44.6 million liability. See further discussion of our derivative contracts in "Market Risk Management" contained in this Management's Discussion and Analysis of Financial Condition and in Note 9 to the Consolidated Financial Statements.

(d) Represents projected capital costs as scheduled in our December 31, 2003 proved reserve report that are necessary in order to recover our proved undeveloped reserves but are not current contractual commitments.

(e) Represents the estimated future asset retirement obligations on an undiscounted basis. The discounted asset retirement obligation of \$43.8 million, as determined under SFAS No. 143, is further discussed in Note 4 to the Consolidated Financial Statements.

Long-term contracts require us to deliver CO₂ to our industrial CO₂ customers at various contracted prices, plus we have a CO₂ delivery obligation to Genesis related to a VPP entered into during 2003 (see "Genesis Transactions" above). Based upon the maximum amounts deliverable as stated in the contracts and the volumetric production payment, we estimate that we may be obligated to deliver up to 412 Bcf of CO₂ to these customers over the next 18 years; however, based on the current level of deliveries, our commitment would likely be reduced to approximately 310 Bcf. The maximum volume required in any given year is approximately 97 MMcf/d, although based on our

Management's Discussion and Analysis of Financial Condition and Results of Operations

current level of deliveries, this would likely be reduced to approximately 70 MMcf/d. Given the size of our proven CO₂ reserves at December 31, 2003 (approximately 1.6 Tcf before deducting approximately 162.6 Bcf for the VPP), our current production capabilities and our projected levels of CO₂ usage for our own tertiary flooding program, we believe that we can meet these delivery obligations.

Results of Operations

CO₂ Operations

Overview. Since 1999, when we acquired our first tertiary oil recovery operation at Little Creek Field, tertiary recovery operations have become increasingly important for us. More importantly, in February 2001 we acquired the sources of CO₂ and a pipeline to transport it to these fields. Since February 2001, we have acquired two and drilled three CO₂ producing wells, doubling our initial proven CO₂ reserves to 1.6 Tcf as of December 31, 2003 (including the 162.6 Bcf of reserves dedicated to a VPP with Genesis). Today, we own every known producing CO₂ well in the region, providing us a significant strategic advantage in the acquisition of other properties in Mississippi and Louisiana that could be further exploited through tertiary recovery. With the latest acquisition, which closed in early January 2004, we are capable of producing approximately 250 MMcf/d of CO₂, about three times the production capacity at the time of our initial acquisition. We have four additional CO₂ wells planned for 2004 (including one side-track operation), which are expected to increase our production capacity to around 350 MMcf/d of CO₂ by the end of 2004, just short of our forecasted maximum requirement of about 400 MMcf/d in 2007 for the planned future projects in southwestern Mississippi along our CO₂ pipeline. During 2004, two of these CO₂ wells will test new structures, which if successful, will both increase our CO₂ reserves and provide additional production capacity. We believe it is prudent to add additional reserves and deliverability before we commence our tentative plans to expand our CO₂ operations to East Mississippi and/or other regions. Based on our current tertiary recovery projects and planned phases of expansion in both Southwest and East Mississippi, we will continue to drill additional CO₂ wells after 2004, attempting to further increase our production capacity to at least 530 MMcf/d of CO₂ production by 2011, in order to meet the delivery requirements for the operations that we currently have modeled. Although we believe that our plans and projections are reasonable and achievable, there could be delays or unforeseen problems in the future which could delay our overall tertiary development program. We believe that such delays, if any, should only be temporary.

Oil Production Potential. Although our oil production from our CO₂ tertiary recovery activities is still relatively modest, we expect it to be an ever increasing portion of our production. Almost all of our incremental CO₂ production is being used for our tertiary recovery operations currently ongoing at Little Creek, Mallalieu and McComb Fields. We have tentatively scheduled tertiary projects at other oil fields along our pipeline, and project that these projects will increase our net tertiary related oil production from its current level of over 6,000 Bbls/d during January 2004, to as much as 18,000 Bbls/d in 2010. As of December 31, 2003, we had approximately 35.3 MMBbls of proven oil reserves related to tertiary operations in these fields along our CO₂ pipeline and have identified and estimated significant additional potential in fields that we own in this area. In addition to the development of the fields along our CO₂ pipeline, we have completed a preliminary study of the feasibility of implementing tertiary recovery operations in East Mississippi, reviewing five fields that we expect to be part of the first phase of operations in this area. While the study is preliminary and requires significant additional work and review, including a determination of the precise costs and best location for a CO₂ pipeline to this part of the state, and further refinement of the economics, preliminarily this project appears to have reasonable economics at NYMEX oil prices in the low to mid twenties. These five fields also appear to have aggregate potential oil reserves of approximately the same magnitude as those fields along our existing CO₂ pipeline. Combining the initial production forecast for both of these areas, the forecasted oil production from tertiary operations could peak at rates of almost 32,000 Bbls/d by 2013. While it is extremely difficult to accurately forecast that far into the future, we do believe that our tertiary recovery operations provide significant long-term production growth potential at reasonable rates of return with relatively low risk.

Management's Discussion and Analysis of Financial Condition and Results of Operations

Financial Statement Impact. The increasing emphasis on CO₂ tertiary recovery projects has made, and will continue to make, an impact on our financial results and certain operating statistics.

- First, there is a significant delay between the initial capital expenditures and the resulting production increases, as these tertiary operations require the building of facilities before CO₂ flooding can commence and usually require six to twelve months before the field responds to the injection of CO₂.
- Secondly, as these tertiary projects are more expensive to operate than our other oil fields because of the cost of injecting and recycling the CO₂ (primarily due to the significant energy requirements to re-compress the CO₂ back into a liquid state for re-injection purposes), our overall operating expenses on a per BOE basis will likely continue to increase as these operations constitute an increasingly larger percentage of our operations. These tertiary recovery fields are expected to average around \$10 per BOE in operating expenses over the life of the field for those projects along our CO₂ pipeline, although the cost per BOE is generally higher at the beginning of each operation. These levels of operating expenses compare to a cost of around \$5 to \$7 per BOE for a more traditional oil property. We allocate the cost to produce and transport the CO₂ between the sales to commercial users and CO₂ used in our own oil fields. The CO₂ operating expenses allocated to our oil fields are recorded as lease operating expenses on those fields.
- Third, while our operating expense on a per BOE basis may rise, our overall oil prices, measured as a discount to NYMEX prices, should continue to improve. These CO₂ operations are all currently conducted in fields that produce light sweet oil and receive oil prices close to, and sometimes actually higher than, NYMEX prices. As this production becomes a larger percentage of our overall production, our overall average differential to NYMEX should decrease. While our oil prices have historically averaged between \$4.00 and \$5.00 below NYMEX prices, our 2002 average was \$3.73 below NYMEX and our 2003 average decreased further to \$3.60 below NYMEX. We expect that this positive trend should continue, subject of course to the normal fluctuations in the marketplace.

2003 Operating Activities. During late July and early August 2003, we upgraded our CO₂ facility at Jackson Dome, increasing the CO₂ processing capacity of our facility by approximately 50%, from around 200 MMcf/d to approximately 300 MMcf/d. This upgrade was performed several months ahead of our original schedule in order to handle the higher than expected production volumes from our CO₂ wells drilled during late 2002 and early 2003. At the same time, we increased the size of our CO₂ processing facility at Mallalieu Field, increasing the amount of CO₂ that we can recycle at that field from approximately 28 MMcf/d to approximately 108 MMcf/d.

Our oil production from our CO₂ tertiary recovery activities increased 18% from 2002 levels of 3,970 Bbls/d to 4,671 Bbls/d during 2003, and to 5,579 Bbls/d during the fourth quarter of 2003. This represents approximately 29% of our total corporate oil production during the fourth quarter of 2003 and approximately 16% of our total corporate production on a BOE basis. We believe that the year-over-year increase would have been more significant had we not curtailed CO₂ production in the second quarter of 2003 due to a leak in a newly installed CO₂ pipeline and a one-week shutdown during the third quarter while the facilities at Jackson Dome were upgraded. Our experience has indicated that any time our CO₂ production and associated injections are curtailed, there is a corresponding drop in our oil production from these projects. While our CO₂ production capability is currently ahead of schedule, as previously noted, temporary curtailments have had a negative short-term effect on our 2003 oil production. Recently we have been injecting more CO₂ than initially forecasted, contributing to the recent increase in the related oil production, as evidenced by the record fourth quarter 2003 production, and a preliminary production estimate of over 6,000 Bbls/d during January 2004. We expect that this oil production will continue to increase, although the increases are not always predictable or consistent.

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We spent approximately \$0.15 per Mcf to produce our CO₂ during 2003, slightly higher than our 2002 annual average of \$0.13 per Mcf, primarily due to higher royalty expenses, as certain of our royalty payments increase if the price of oil increases beyond a certain threshold, and due to approximately \$700,000 of workover expenses on one CO₂ well during the third quarter. The higher overall CO₂ production rates partially offset the workover expenses. Our estimated total cost per thousand cubic feet of CO₂ during 2003 was approximately \$0.22, after inclusion of depreciation and amortization expense, still significantly less than the \$0.34 per thousand cubic feet that we would currently be paying under the purchase contract in place at the time we acquired the CO₂ properties in February 2001.

The higher cost per Mcf of CO₂ during 2003 contributed to a corresponding increase in the operating costs of our tertiary projects, as did higher electricity and other expenses, as we continue to inject and recycle higher volumes of CO₂ each quarter. Furthermore, at Mallalieu Field in August 2003 we commenced lease payments relating to a portion of the upgraded CO₂ facilities there (see "Commitments and Obligations" above). For 2003, our operating costs for our tertiary properties averaged \$11.34 per BOE, higher than our 2002 annual average of \$9.84 per BOE.

In addition to using CO₂ for our tertiary operations, we sell CO₂ to third party industrial users under long-term contracts. Our net operating margin from these sales was \$4.3 million during 2001, \$6.2 million during 2002 and \$6.5 million during 2003. Our average CO₂ production during 2001, 2002 and 2003 was approximately 84 million, 104 million, and 170 million cubic feet per day, of which approximately 53% in 2001, 54% in 2002 and 62% in 2003 was used in our tertiary recovery operations, with the balance sold to third parties for industrial use.

At December 31, 2003, we had proved reserves of 35.3 MMBbls relating to our tertiary recovery operations. Through December 31, 2003, we had spent a total of \$104.8 million on fields involved in this process, and had received \$83.0 million in net cash flow (revenue less operating expenses and capital expenditures), leaving us a balance of \$21.8 million to recover for payout. The proved oil reserves in our CO₂ fields have a PV-10 Value of \$434.6 million, using December 31, 2003 constant NYMEX pricing of \$32.52 per Bbl. These amounts do not include the capital costs or related depreciation and amortization of our CO₂ producing properties. Through December 31, 2003, we have spent a total of \$85.3 million on our CO₂ producing properties, received a total of \$41.3 million in net cash flow (revenue less operating expenses and capital expenditures, including the Genesis volumetric production payment receipts), leaving us a balance of approximately \$44.0 million of unrecovered costs.

CO₂ Related Capital Budget for 2004. Tentatively, we plan to spend approximately \$30 million in 2004 in the Jackson Dome area, over and above what is currently required for our operations in Southwest Mississippi, with the intent to add additional CO₂ reserves and deliverability for future operations. Approximately \$50 million in capital expenditures is budgeted in 2004 for our oil fields with tertiary operations, increasing our combined CO₂ related expenditures to just under 50% of our 2004 capital budget.

Operating Income

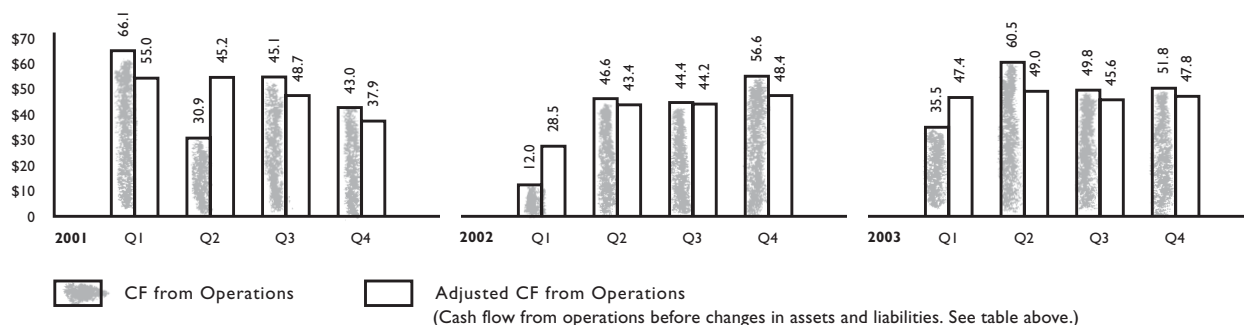
Cash flow from operations and net income have been strong for the last three years, primarily because of higher than historical commodity prices. Production increased 14% from 2001 to 2002, but declined slightly (2%) in 2003 (see also "Overview"). The higher commodity prices in 2003 more than offset the production decline, resulting in higher overall net income and cash flow from operations. Commodity prices were slightly lower in 2002, reducing our overall net income and cash flow during 2002 as compared to 2001.

Management's Discussion and Analysis of Financial Condition and Results of Operations

Amounts in Thousands Except Per Share Amounts	Year Ended December 31,		
	2003	2002	2001
Net income	\$ 56,553	\$ 46,795	\$ 56,550
Net income per common share:			
Basic	\$ 1.05	\$ 0.88	\$ 1.15
Diluted	1.02	0.86	1.12
Adjusted cash flow from operations	\$189,802	\$164,565	\$186,801
Net change in assets and liabilities relating to operations	7,813	(4,965)	(1,754)
Cash flow from operations (GAAP measure)	\$197,615	\$159,600	\$185,047

Adjusted cash flow from operations is a non-GAAP measure that represents cash flow provided by operations before changes in assets and liabilities, as presented in our Consolidated Statements of Cash Flows. In our discussion of cash flow from operations herein, we have elected to discuss these two components of cash flow provided by operations (the GAAP measure).

Cash Flow from Operations by Quarter in millions of dollars



Adjusted cash flow from operations, the non-GAAP measure, measures the cash flow earned or incurred from operating activities without regard to the collection or payment of associated receivables or payables. We believe that this is important to consider separately, as we believe it can often be a better way to discuss changes in operating trends in our business caused by changes in production, prices, operating costs, and so forth, without regard to whether the earned or incurred item was collected or paid during that year. We also use this measure because the collection of our receivables or payment of our obligations has not been a significant issue for our business, but merely a timing issue from one period to the next, with fluctuations generally caused by significant changes in commodity prices or significant changes in drilling activity.

The net change in assets and liabilities relating to operations is also important as it does require or provide additional cash for use in our business; however, we prefer to discuss its effect separately. For instance, as noted above, during 2003, our accounts payable and accrued liabilities increased as a result of our higher drilling activity level late in the year, particularly offshore, increasing our available cash from operations. Conversely, during 2002 we used approximately \$5.0 million of cash to fund a net increase in working capital. This was primarily caused by a high level of drilling and exploitation activity late in 2001 that was not paid (or even due) until 2002.

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

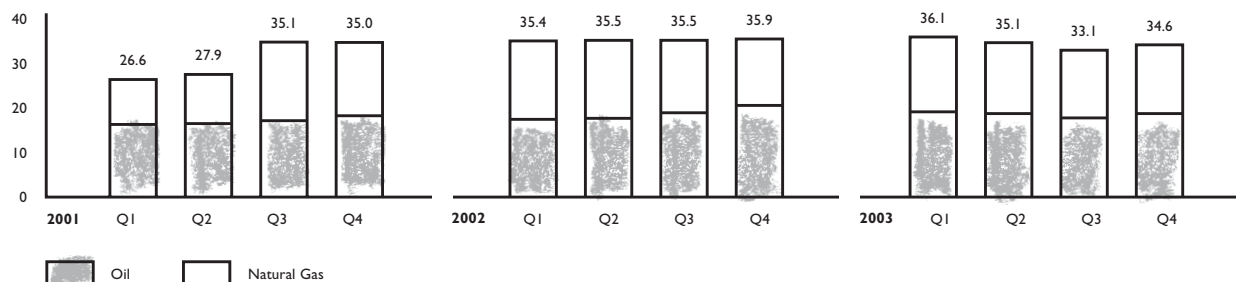
	Year Ended December 31,		
	2003	2002	2001
Average daily production volume			
Bbls	18,894	18,833	16,978
Mcf	94,858	100,443	85,238
BOE ⁽¹⁾	34,704	35,573	31,185
Operating revenues and expenses (thousands)			
Oil sales	\$189,442	\$153,705	\$132,219
Natural gas sales	196,021	121,189	128,179
Gain (loss) on settlements of derivative contracts ⁽²⁾	(62,210)	932	18,654
Total oil and natural gas revenues	\$323,253	\$275,826	\$279,052
Lease operating expenses	\$ 89,439	\$ 71,188	\$ 55,049
Production taxes and marketing expenses	14,819	11,902	10,963
Total production expenses	\$104,258	\$ 83,090	\$ 66,012
CO ₂ sales to industrial customers ⁽³⁾	\$ 8,188	\$ 7,580	\$ 5,210
CO ₂ operating expenses	1,710	1,400	891
CO ₂ operating margin	\$ 6,478	\$ 6,180	\$ 4,319
Unit prices – including impact of hedges⁽²⁾			
Oil price per Bbl	\$ 24.52	\$ 22.27	\$ 21.65
Gas price per Mcf	4.45	3.35	4.66
Unit prices – excluding impact of hedges⁽²⁾			
Oil price per Bbl	\$ 27.47	\$ 22.36	\$ 21.34
Gas price per Mcf	5.66	3.31	4.12
Oil and gas operating revenues and expenses per BOE⁽¹⁾			
Oil and natural gas revenues (including hedges)	\$ 25.52	\$ 21.24	\$ 24.52
Lease operating expenses	\$ 7.06	\$ 5.48	\$ 4.84
Production taxes and marketing expenses	1.17	0.92	0.96
Total production expenses	\$ 8.23	\$ 6.40	\$ 5.80

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

(2) See also "Market Risk Management" below for information concerning the Company's hedging transactions.

(3) For 2003, includes deferred revenue of \$322,000 associated with a volumetric production payment and \$355,000 of transportation income, both from Genesis.

Production by Quarter (Average MBOE per day)



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Production. Average daily production by area for 2001, 2002 and 2003, and each of the quarters of 2003 is listed in the following table (BOE/d).

Operating Area	Average Daily Production (BOE/d)						2003
	2001	2002	First Quarter 2003	Second Quarter 2003	Third Quarter 2003	Fourth Quarter 2003	
Mississippi – non-CO ₂ floods	13,481	13,378	14,537	13,600	13,367	13,066	13,638
Mississippi – CO ₂ floods	2,560	3,970	4,345	4,522	4,227	5,579	4,671
Onshore Louisiana	9,268	8,050	8,509	8,231	7,836	8,320	8,222
Offshore Gulf of Mexico	5,691	9,975	8,544	8,537	7,374	7,357	7,949
Other	185	200	158	160	312	268	224
Total Company	31,185	35,573	36,093	35,050	33,116	34,590	34,704

Our average daily BOE production for 2003 was approximately 2% lower than in 2002, due primarily to production decreases in our offshore Gulf of Mexico properties, offset in part by production increases in our Mississippi CO₂ flood properties. In both the offshore and onshore Louisiana areas, we have experienced production declines from normal depletion, along with delayed production from equipment downtime and well workovers, with the single largest production decrease on a field basis coming from Thornwell Field in Louisiana. Average annual production at this field declined 1,346 BOE/d (principally natural gas), from 2002 to 2003, although we have generally had good success from our acquisition of Thornwell Field in 2000, as evidenced by a net profit (at the field level) to date through December 31, 2003 of \$18.9 million and a remaining PV-10 Value of the reserves at year-end prices of \$62.4 million. However, this field is characterized by relatively short-lived gas production that declines rapidly unless there is constant drilling activity. During 2003, our drilling activity at Thornwell was significantly less than in prior years as the field became more fully developed, contributing to the production decline. This trend is expected to continue into 2004. Partially offsetting the large decrease from Thornwell Field, onshore Louisiana, was the impact of our recent success in the Exxon Fee A-I well in North Lirette Field, which came on production late in the third quarter. A second well drilled in that field commenced production early in the fourth quarter. While both are strong producers, they too are relatively short-lived wells and are expected to decline in the near future.

The production increase in our Mississippi CO₂ flood properties is almost entirely due to increased production at Mallalieu Field, which increased over 1,000 BOE/d from the prior year due to the CO₂ flood that we initiated there during 2002 (see "CO₂ Operations" above for a further discussion of our tertiary properties). Offshore, production declined at several fields during the year, generally due to normal depletion and the short-lived nature of the reserves. Late in the fourth quarter of 2003, we made 15 well completions, four at Brazos A-21, three at North Padre A-9, three at Chandeleur Sound 69, two at West Cameron 192 and three at West Cameron 427. Although most of these were not completed until the latter half of the fourth quarter, the incremental production was sufficient to arrest, at least temporarily, the overall production decline in this area. Depending on our 2004 drilling success, we expect 2004 production offshore to be relatively flat or down slightly when compared with 2003 production.

In addition, there are other factors that have impacted our production. For example, we have had temporary curtailments of CO₂ injections at least twice during 2003, which have delayed the response of additional oil production from these projects (see "CO₂ Operations" above). Our expected production increases from our exploration and development results were also less than anticipated, particularly during the first half of 2003, and we have experienced unexpected delays in drilling and completing offshore wells. In January 2003, we sold one of the largest producing fields acquired in the August 2002 COHO acquisition. Year over year, the properties in the COHO package contributed an additional 908 BOE/d to our annual production average, although there have been more significant fluctuations on a quarterly basis due to the timing of the acquisition and subsequent disposition. Our production for 2003 was weighted slightly toward oil (54%), and

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it appears that we will remain weighted toward oil in the future due to our increasing emphasis on tertiary operations, unless we make an acquisition that is predominantly natural gas.

Our production growth in 2002, as compared to 2001, was primarily related to acquisitions and subsequent development of the acquired fields. During the last three years, our significant acquisitions of oil and natural gas properties have consisted of the \$4.0 million acquisition of Mallalieu Field in May 2001, the \$157.4 million corporate acquisition of Matrix in July 2001 (offshore Gulf of Mexico properties), the \$2.3 million acquisition of McComb Field in September 2002, and the \$48.2 million acquisition of COHO's Gulf Coast properties in August 2002. The biggest impact on 2002 was the effect of a full year of production from the Matrix properties (as compared to six months of production during 2001) and five months of production from the COHO acquisition.

Heidelberg Field, located in Eastern Mississippi, is Denbury's largest single field. At the time of its acquisition in December 1997, Heidelberg Field was producing approximately 2,800 BOE/d. Annual average production under our ownership peaked in 2001 at 7,908 BOE/d, averaging 7,479 BOE/d in 2002 and 7,535 BOE/d for 2003. In its early years, our primary emphasis was on implementing our waterfloods, plus other developmental drilling. During the last few years, we have expanded our development of the natural gas production in the Selma Chalk formation, increasing Heidelberg's natural gas production from almost nothing at the time of acquisition to an average of 10.3 MMcf/d during 2003, the highest level to date, making Heidelberg Field our third largest natural gas producer for 2003, but our second largest during the fourth quarter of 2003. Overall production from this field is expected to remain relatively flat or slightly decline as the waterflood units appear to have reached a plateau, although there may be periodic spikes in the natural gas production as a result of recently drilled natural gas wells and the anticipated production from 16 additional natural gas wells scheduled for 2004.

Oil and Natural Gas Revenues. Our oil and natural gas revenues were relatively flat between 2001 and 2002, but increased 17% between 2002 and 2003. Three factors cause the change in revenues: commodity prices, production levels and hedging receipts or payments. Between 2001 and 2002, revenues decreased by 1%, due primarily to lower hedging receipts. The overall increase in production volumes contributed \$36.6 million in revenue, or a 13% increase, more than offset by the combined 14% reduction in revenues due to a decrease in cash receipts from hedges of \$17.7 million (a 6% decrease) and an overall decrease of \$22.1 million in commodity prices (or an 8% decrease). Between 2002 and 2003, revenues increased by 17%, due primarily to higher commodity prices. The overall increase in commodity prices contributed \$117.3 million in revenue, a 42% increase, partially offset by a reduction in revenues due to a decrease in cash receipts from hedges of \$63.1 million (a 23% decrease) and an overall decrease of \$6.7 million related to the 2% lower production volumes.

During 2003, we paid out \$20.3 million on our oil hedges (\$2.95 per Bbl) and \$41.9 million (\$1.21 per Mcf) on our natural gas hedges relating to swaps and collars we purchased a year or more earlier when commodity prices were lower. About \$15.0 million of the hedge payments related to swaps originally put in place to protect the rate of return for the COHO acquisition in August 2002. During 2002, we had total net receipts on our hedges of \$932,000, paying out \$0.6 million (\$0.09 per Bbl) on our oil hedges but collecting a net \$1.5 million (\$0.04 per Mcf) on our natural gas hedges. During 2001, we collected \$18.7 million in hedge receipts, collecting \$1.9 million (\$0.31 per Bbl) on our oil hedges and \$16.7 million (\$0.54 per Mcf) on our natural gas hedges. Most of the natural gas hedge receipts for 2001 related to funds received from "puts" or floors purchased at the time of the Matrix acquisition in mid-2001. These hedges were purchased at a level just below the then current futures price for natural gas, resulting in cash receipts as natural gas prices dropped significantly during the latter half of that year. See "Market Risk Management" for a further discussion of our hedging activities.

Our net oil and natural gas prices have fluctuated as outlined on the prior table. During 2003, we received the highest weighted average net price per BOE in our history, netting \$25.52 per BOE even after paying out approximately \$4.91 per BOE for hedge losses. This resulted from average NYMEX prices of approximately \$31.00 per Bbl and approximately \$5.45 per MMBtu during the year. In addition, we had one of our best years with regard to our realized net price relative

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to NYMEX prices. During 2001, we received an average discount to NYMEX of \$4.66 per Bbl. This was reduced to an average discount of \$3.73 per Bbl during 2002 and further reduced to an average discount of \$3.60 per Bbl in 2003. While this differential fluctuates from period to period with market conditions, we are gradually improving the overall discount as the amount of light sweet oil production from the tertiary operations continues to grow, improving the overall quality of our product mix. This tertiary production along our CO₂ pipeline receives a premium price, sometimes in excess of NYMEX prices. Year over year, there is generally less fluctuation in our natural gas prices relative to NYMEX. Normally, we receive a slight premium to the NYMEX market, primarily because of the high Btu content of our natural gas. For 2003, we averaged an \$0.18 premium to NYMEX, as compared to a \$0.05 discount in the prior year and a \$0.06 premium during 2001.

Operating Expenses. Lease operating expenses increased to \$7.06 per BOE during 2003, an increase of 29% from the \$5.48 per BOE average during 2002. The expense of two workovers totaling approximately \$2.8 million, relating to mechanical failures at two onshore Louisiana gas wells, was the single biggest source of the increase in the first half of 2003, with several smaller workovers, including one on a CO₂ well (see "CO₂ Operations" above), contributing to the higher expense levels during the third quarter of 2003. As discussed under "CO₂ Operations," the growth in our CO₂ tertiary projects is causing an increase in both gross and per BOE operating expenses. Operating expenses per BOE for the tertiary operations averaged \$11.34 per BOE during 2003 as compared to \$9.84 per BOE during 2002, and on a gross cost basis, operating expenses related to these activities increased from \$14.3 million in 2002 to \$19.3 million during 2003. Other factors contributing to higher operating expenses during 2003 were (i) a full year of expenses on the properties acquired from COHO, which have typically had higher expenses on a per BOE basis than our other oil properties due to their age, their relatively low production rates and their general condition at the time we acquired them in August 2002, (ii) lease fuel costs that increased from \$2.5 million during 2002 to \$4.4 million during 2003 as a result of higher natural gas prices, and (iii) the slight decline in 2003 production rates, which also had an impact on per BOE rates. While our lease operating expenses during the fourth quarter of 2003 were lower than in any other quarter of the year (averaging \$6.78 per BOE), they were still significantly higher than 2002 lease operating expense levels. We anticipate that lease operating expenses will remain at these generally higher levels, and probably gradually increase over time, for the aforementioned reasons.

Our lease operating expenses increased 13% on a per BOE basis between 2001 and 2002. This increase was primarily due to higher than usual workover expenses, principally offshore on the Matrix properties, repairs relating to storm damage from Hurricane Lili that were not covered by insurance or were part of insurance deductibles, higher per BOE costs due to lost production from that storm and Tropical Storm Isidore, higher than average operating expenses on the properties acquired from COHO in August 2002, as significant repairs and clean-up were required, and the general increase caused by growing tertiary operations. Lease operating expenses increased on a gross basis by \$16.1 million, or 29%, between 2001 and 2002.

Production taxes and marketing expenses also increased to \$1.17 per BOE in 2003, as compared to an average per BOE of \$0.92 during 2002. The higher rate during 2003 is primarily due to higher commodity prices, as a significant portion of the severance tax is value based. Marketing expenses were relatively consistent at \$1.8 million during 2003 and \$1.9 million during 2002, primarily related to our offshore properties. Between 2001 and 2002, production taxes and marketing expenses were about the same, or \$0.96 per BOE during 2001 and \$0.92 per BOE during 2002.

General and Administrative Expenses

During the last three years, general and administrative ("G&A") expenses on a per BOE basis have gradually increased from \$0.89 per BOE during 2001 to \$1.20 per BOE during 2003 in line with the overall increase in gross G&A expense. With our slight decrease in production during 2003, the impact on G&A expense per BOE was even more pronounced.

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Amounts in Thousands Except Per BOE and Employee Data	Year Ended December 31,		
	2003	2002	2001
Gross G&A expense	\$ 46,031	\$ 40,149	\$ 33,727
Operator overhead charges	(26,823)	(23,857)	(20,328)
Capitalized exploration expense	(5,507)	(5,325)	(4,102)
	13,701	10,967	9,297
State franchise taxes	1,488	1,459	877
Net G&A expense	\$ 15,189	\$ 12,426	\$ 10,174
Average G&A expense per BOE	\$ 1.20	\$ 0.96	\$ 0.89
Employees as of December 31	374	356	320

Gross G&A expenses increased \$5.9 million, or 15%, between 2002 and 2003. The largest component of the increase was approximately \$1.4 million of expenses spent for consultants hired to help document and test our system of internal controls, a requirement of the Sarbanes-Oxley Act of 2002. The cost of complying with this act and related new laws and regulations is significantly higher than these third party expenses, but most other costs are not as easily measured and identified. The second largest source of the increase was approximately \$630,000 of legal, accounting, bank and other fees associated with the conversion to a holding company organizational structure during December 2003. This corporate restructure is expected to save us around \$750,000 per year in taxes and expenses and provide other future operational benefits. Other factors also contributed to the increase, the most significant being expenses associated with the sale of stock by the Texas Pacific Group in the first and last quarters of 2003, higher year-end expenses for engineering and audit fees, and an overall increase in personnel and associated expenses primarily related to cost of living salary increases. Partially offsetting these increases was a reduction in our 2003 bonuses due to less positive operating results during 2003 in certain areas. An increase in operator overhead recovery charges and capitalized exploration costs in 2003 also partially offset the increase in gross G&A. Our well operating agreements allow us, when we are the operator, to charge a well with a specified overhead rate during the drilling phase and also to charge a monthly fixed overhead rate for each producing well. As a result of the additional operated wells from acquisitions, additional tertiary operations, and drilling activity during the past year, the amount we recovered as operator overhead charges increased by 12% between 2002 and 2003. Capitalized exploration costs increased slightly between 2002 and 2003, along with increases in employee related costs. The net effect of the increases in gross G&A expenses, operator overhead recoveries and capitalized exploration costs was a 22% increase in net G&A expense between 2002 and 2003 and a 25% increase on a per BOE basis.

Most of the G&A increase between 2001 and 2002 was a result of additional personnel hired as part of the Matrix acquisition in July 2001 and COHO acquisition in August 2002. Along with the additional personnel, we had general increases in consultant fees as a result of the higher level of activity. Gross G&A expenses increased 19% between 2001 and 2002, net expenses increased 22%, and expenses increased 8% on a per BOE basis.

Interest and Financing Expenses

Amounts in Thousands Except Per BOE Data	Year Ended December 31,		
	2003	2002	2001
Interest expense	\$ 23,201	\$ 26,833	\$ 22,335
Non-cash interest expense	(1,251)	(2,659)	(1,665)
Cash interest expense	21,950	24,174	20,670
Interest and other income	(1,573)	(1,746)	(849)
Net cash interest expense	\$ 20,377	\$ 22,428	\$ 19,821
Average net cash interest expense per BOE	\$ 1.61	\$ 1.73	\$ 1.74
Average debt outstanding	\$341,496	\$350,556	\$264,792
Average interest rate ⁽¹⁾	6.4%	6.9%	7.8%

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

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Interest expense for 2003 decreased from levels in the prior year primarily due to (i) lower overall interest rates, resulting from an overall drop in market interest rates on our bank debt and due to the refinancing of our subordinated debt (see "Debt Refinancing" above), (ii) a 3% lower average outstanding debt balance during 2003, as we reduced debt by \$50 million during the year, and (iii) reduced debt issue cost amortization resulting from the complete amortization of costs associated with the original maturity of our bank credit line in December 2002 after we refinanced and extended the bank credit line to April 2006.

Our interest expense was \$4.5 million (20%) higher in 2002 than 2001 primarily as a result of higher average debt levels. During 2001, we had total bank borrowings of \$146.0 million, primarily to fund our acquisition of Matrix (\$100.0 million) and the CO₂ acquisition (\$42.0 million). We repaid a total of \$79.1 million during 2001, (i) \$13.0 million of which related to excess cash flow generated from operations early in the year given the unusually high natural gas prices and (ii) \$65.9 million of which represented the net proceeds of our issuance of Series B 9% Senior Subordinated Notes due 2008, in August 2001. During 2002, we borrowed \$49.1 million, primarily to fund the COHO acquisition, and repaid \$40.0 million during the year from excess cash flow, leaving us with \$350 million of total debt outstanding as of December 31, 2002 (excluding the discount). The net effect of these transactions was \$85.8 million higher average debt outstanding during 2002 than in 2001, an increase of 32%. Interest rates decreased during 2002, partially offsetting the higher debt levels.

Depletion, Depreciation and Amortization

Depletion, depreciation and amortization ("DD&A") was at its lowest rate on a per BOE basis in our history in 1999 as a result of our full cost pool writedowns in 1998. Since that time, our DD&A rate has increased each year as our overall finding cost has been greater than the abnormally low DD&A rate in 1999, particularly the finding cost of certain of our acquisitions.

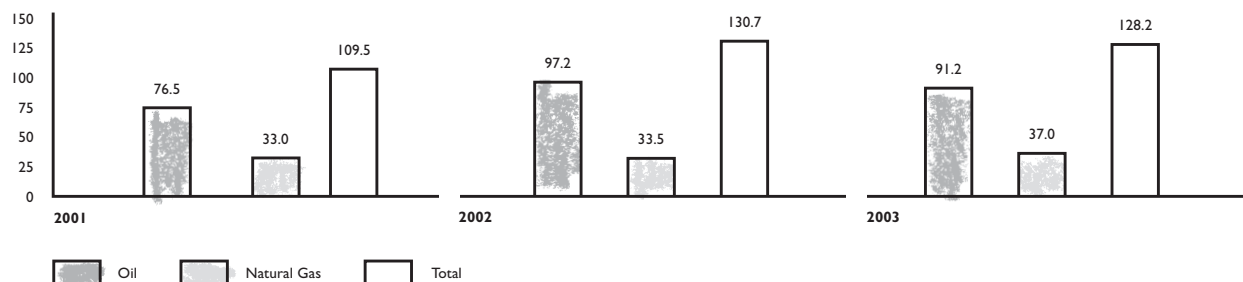
Amounts in Thousands Except Per BOE Data	Year Ended December 31,		
	2003	2002	2001
Depletion and depreciation of oil and natural gas properties	\$87,842	\$87,728	\$66,402
Depletion and depreciation of CO ₂ assets	2,542	1,858	1,572
Asset retirement obligations	2,852	2,951	1,946
Depreciation of other fixed assets	1,472	1,699	1,425
Total DD&A	\$94,708	\$94,236	\$71,345
DD&A per BOE:			
Oil and natural gas properties	\$ 7.16	\$ 6.98	\$ 6.01
CO ₂ assets and other fixed assets	0.32	0.28	0.26
Total DD&A cost per BOE	\$ 7.48	\$ 7.26	\$ 6.27

But for the sale of 8.3 million BOEs in early 2003, our total proved reserve quantities would have increased each of the last three years. Our proved reserves increased from 109.5 MMBOE as of December 31, 2001, to 130.7 MMBOE as of December 31, 2002 and decreased to 128.2 MMBOE as of December 31, 2003. Reserve quantities and associated production are only one side of the DD&A equation, with capital expenditures, asset retirement obligations less related salvage value, and projected future development costs making up the remainder of the calculation.

During 2001, our DD&A rate increased from \$4.62 per BOE in 2000 to an average rate of \$6.27 per BOE (\$7.19 per BOE during the second half of the year after the Matrix acquisition), primarily as result of our acquisition of Matrix in July 2001. This acquisition had a higher than average cost per BOE (\$13.28 per BOE, including unevaluated property costs) because of the high natural gas price environment. Even though the reserves from this acquisition have increased by 6% (or 57% by adding back production) through December 31, 2003, our offshore Gulf of Mexico properties in the aggregate have consistently had higher finding and development costs than our other properties, contributing to the rising DD&A rate.

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Proved Reserves (MMBOE)



During 2002, our DD&A rate increased slightly from the \$7.19 DD&A rate per BOE (after the Matrix acquisition), averaging \$7.26 per BOE for the year. During 2003, the fourth quarter DD&A rate increased to \$8.00 per BOE, increasing the 2003 annual average to \$7.48 per BOE. The higher DD&A was partially due to the higher percentage of capital expenditures spent on our offshore properties, 34% during 2003 as compared to approximately 10% during 2002, where we have a higher overall finding cost. The rate was also affected by less than hoped for drilling results in the Gulf of Mexico and Southern Louisiana, particularly in the fourth quarter, where some of our larger exploration potential failed to materialize. In contrast to our offshore properties, our tertiary operations during 2003 yielded a finding and development cost, including the net change in forecasted future development costs, of just over \$5.00 per BOE, in line with our long-term expectations, helping to partially offset the higher finding and development cost of our offshore and other natural gas properties. DD&A expense on our CO₂ properties increased \$684,000 between 2002 and 2003 (37%) as a result of a 53% increase in our CO₂ production and \$22.7 million of incremental capital cost related to our CO₂ properties incurred during 2003.

Historically, we have provided for the estimated future costs of well abandonment and site reclamation, net of any anticipated salvage, on a unit-of-production basis. This provision was included in DD&A expense and increased each year, along with the general increase in the number of our properties, especially the acquisition of our offshore properties. Effective January 1, 2003, we adopted Statement of Financial Accounting Standards ("SFAS") No. 143, "Accounting for Asset Retirement Obligations." SFAS No. 143 requires that the fair value of a liability for an asset retirement obligation be recorded in the period in which it is incurred, discounted to its present value using our credit adjusted risk-free interest rate, and that the corresponding amount be 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. If the liability is settled for an amount other than the recorded amount, the difference is recorded to the full cost pool, unless significant. The adoption of this statement resulted in a \$2.6 million benefit to net income during the first quarter of 2003 and was recorded as the cumulative effect of a change in accounting principle in our Consolidated Statements of Operations. As part of this adoption, we ceased accruing for site reclamation costs, as had been our practice in the past, and recorded a \$41.0 million liability representing the estimated present value of our retirement obligations, with a \$34.4 million increase to oil and natural gas properties. On an undiscounted basis, we estimated our retirement obligations as of December 31, 2003 to be \$82.7 million, with an estimated salvage value of \$43.3 million, also on an undiscounted basis. DD&A is calculated on the increase to oil and natural gas and CO₂ properties, net of estimated salvage value. We also include the accretion of discount on the asset retirement obligation in our DD&A expense.

Under full cost accounting rules, we are required each quarter to perform a ceiling test calculation. We did not have any full cost pool ceiling test writedowns in 2001, 2002 or 2003 and do not expect to have any such writedowns in the foreseeable future at current commodity price levels.

Management's Discussion and Analysis of Financial Condition and Results of Operations

Income Taxes

During 2001, we began to recognize the amount of enhanced oil recovery credits that we had earned to date from our tertiary projects, which totaled \$5.3 million at year-end 2001. As a result of these credits, our effective tax rate for 2001 was lowered from 37% to 30.5%. Most of this provision was deferred, as we were able to offset our taxable income with our net operating losses ("NOLs"). The current portion of the tax provision was related to alternative minimum taxes that could not be offset by NOLs.

Prior to 2002, our statutory tax rate was 37%. During 2002, we determined that our statutory rate had increased to 38% and adjusted our statutory provision for the year accordingly. The net effective tax rate for 2002 was lower than 38%, primarily due to the recognition of enhanced oil recovery credits, which lowered our overall tax expense. The net effective tax rate for 2003 was 33%, also lower than the effective rate primarily because of the enhanced oil recovery credits. As of December 31, 2003, we had an estimated \$16.6 million of enhanced oil recovery credits to carry forward. We also had approximately \$95.0 million of regular tax net operating loss carryforwards remaining to shelter our future income against regular tax and \$14.9 million of alternative minimum tax net operating loss carryforwards. We were able to generate additional alternative minimum tax net operating loss carryforwards during 2003 as a result of a tax loss for the year, primarily due to the high percentage of expenditures that were intangible drilling costs, a portion of which were deducted for income tax purposes.

Our overall current income tax credit for 2002 was the result of a tax law change that allowed us to offset 100% of our 2001 alternative minimum taxes with our alternative minimum tax net operating loss carryforwards. Prior to the law change, we were able to offset only 90% of our alternative minimum taxes with these carryforwards. This change resulted in a refund of cash taxes paid for 2001 and a reclassification of tax expense between current and deferred taxes, but did not impact our overall effective tax rate.

Amounts in Thousands Except Per BOE Data	Year Ended December 31,		
	2003	2002	2001
Current income tax expense (benefit)	\$ (91)	\$ (406)	\$ 640
Deferred income tax provision	26,303	23,926	24,184
Total income tax provision	\$ 26,212	\$ 23,520	\$ 24,824
Average income tax provision per BOE	\$ 2.07	\$ 1.81	\$ 2.18
Net operating loss carryforwards	94,955	84,891	100,601
Total net deferred tax asset (liability)	(43,538)	(21,777)	(17,433)

Results of Operations on a per BOE Basis

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

Management's Discussion and Analysis of Financial Condition and Results of Operations

Per BOE Data	Year Ended December 31,		
	2003	2002	2001
Oil and natural gas revenues	\$30.43	\$21.17	\$22.88
Gain (loss) on settlements of derivative contracts	(4.91)	0.07	1.64
Lease operating expenses	(7.06)	(5.48)	(4.84)
Production taxes and marketing expenses	(1.17)	(0.92)	(0.96)
Production netback	17.29	14.84	18.72
CO ₂ operating margin relating to industrial sales	0.51	0.48	0.38
General and administrative expenses	(1.20)	(0.96)	(0.89)
Net cash interest expense	(1.61)	(1.73)	(1.74)
Current income taxes and other	(0.01)	0.04	(0.06)
Changes in assets and liabilities	0.62	(0.38)	(0.15)
Cash flow from operations	15.60	12.29	16.26
DD&A	(7.48)	(7.26)	(6.27)
Deferred income taxes	(2.08)	(1.84)	(2.12)
Amortization of derivative contracts and other non-cash hedging adjustments	0.28	0.24	(2.90)
Changes in assets and liabilities, loss on early retirement of debt, change in accounting principle and other non-cash items	(1.86)	0.17	—
Net income	\$ 4.46	\$ 3.60	\$ 4.97

Market Risk Management

We finance some of our acquisitions and other expenditures with fixed and variable rate debt. These debt agreements expose us to market risk related to changes in interest rates. The following table presents the carrying and fair values of our debt, along with average interest rates. The fair value of our bank debt is considered to be the same as the carrying value because the interest rate is based on floating short-term interest rates. The fair value of the subordinated debt is based on quoted market prices. None of our debt has any triggers or covenants regarding our debt ratings with rating agencies.

Amounts in Thousands	Expected Maturity Dates				Carrying Value	Fair Value
	2004-2005	2006	2007	2008		
Variable rate debt:						
Bank debt	\$ —	\$ 75,000	\$ —	\$ —	\$ 75,000	\$ 75,000
(The weighted-average interest rate on the bank debt at December 31, 2003 is 2.4%.)						
Fixed rate debt:						
Subordinated debt, net of discount	\$ —	\$ —	\$ —	\$ —	\$ 223,203	\$ 232,875
(The interest rate on the subordinated debt is a fixed rate of 7.5%.)						

We enter into various financial contracts to hedge our exposure to commodity price risk associated with anticipated future oil and natural gas production. We do not hold or issue derivative financial instruments for trading purposes. These contracts have historically consisted of price floors, collars and fixed price swaps. We generally attempt to hedge between 50% and 75% of our anticipated production each year to provide us with a reasonably certain amount of cash flow to cover most of our budgeted exploration and development expenditures without incurring significant debt, although our hedging percentage may decrease somewhat in the future, as we are stronger financially since lowering our overall debt levels relative to cash flow. When we make an acquisition, we attempt to hedge a large percentage, up to 100%, of the forecasted production for the subsequent one to three years following the acquisition in order to help provide us with a minimum return on our investment. Our recent hedging activity has been predominantly with collars, although for the COHO acquisition, we also used swaps in order to lock in the prices used in our economic forecasts. All of the mark-to-market valuations used for our financial derivatives are provided by external sources and are based on prices that are actively quoted. We manage and control market and counterparty credit risk through established internal control procedures that are reviewed on an ongoing basis. We attempt to minimize credit risk exposure to counterparties through formal credit policies, monitoring procedures, and diversification.

Management's Discussion and Analysis of Financial Condition and Results of Operations

At December 31, 2003, our derivative contracts were recorded at their fair value, which was a net liability of approximately \$44.6 million, an increase of approximately \$9.0 million from the \$35.6 million fair value liability recorded as of December 31, 2002. This change is the result of (i) a decrease in the fair market value of our hedges due to an increase in oil and natural gas commodity prices between December 31, 2002 and December 31, 2003 and (ii) the expiration of certain derivative contracts during 2003 for which we recorded amortization expense of \$1.2 million. Information regarding our current hedging positions and historical hedging results is included in Note 9 to the Consolidated Financial Statements.

Based on NYMEX natural gas futures prices at December 31, 2003, we would expect to make future cash payments of \$11.7 million on our natural gas commodity hedges. If natural gas futures prices were to decline by 10%, the amount we would expect to pay under our natural gas commodity hedges would decrease to \$4.9 million, and if futures prices were to increase by 10% we would expect to pay \$20.3 million. Based on NYMEX crude oil futures prices at December 31, 2003, we would expect to pay \$25.4 million on our crude oil commodity hedges. If crude oil futures prices were to decline by 10%, we would expect to pay \$14.9 million under our crude oil commodity contracts, and if crude oil futures prices were to increase by 10%, we would expect to pay \$36.0 million under our crude oil commodity hedges.

Critical Accounting Policies and Estimates

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

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

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

In our application of full cost accounting for our oil and gas producing activities, we make significant estimates at the end of each period related to accruals for oil and gas revenues, production, capitalized costs and operating expenses. 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.

Management's Discussion and Analysis of Financial Condition and Results of Operations

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

Changes in commodity prices also affect our reserve quantities. For instance, between 2000 and 2001, the significant reduction in commodity prices, particularly oil, reduced the economic lives of our properties and reduced reserve quantities by 8.3 MMBOE. During 2002, both commodity prices rebounded, resulting in an increase to our reserve quantities of approximately 3.5 MMBOE. During 2003, the change related to commodity prices was virtually zero, less than in prior years, as prices were relatively high at both year-end 2002 and year-end 2003. 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. Also, reserve quantities and their ultimate values are the primary factors in determining the borrowing base under our bank credit facility and are determined solely by our banks.

There can also be significant questions as to whether reserves are sufficiently supported by technical evidence to be considered proven. In some cases our proven reserves are less than what we believe to exist because additional evidence, including production testing, is required in order to classify the reserves as proven. In other cases, properties such as certain of our potential tertiary recovery projects may not have proven reserves assigned to them primarily because we have not yet completed a specific plan for development or firmly scheduled such development. We have a corporate policy whereby we do not book proved undeveloped reserves unless the project has been committed to internally, which normally means it is scheduled in our development budget (or at least the commencement of the project is scheduled in the case of longer-term multi-year projects such as waterfloods and tertiary recovery projects). Therefore, particularly with regard to potential reserves from tertiary recovery (our CO₂ operations), there is uncertainty as to whether the reserves should be included as proven or not. We also have a corporate policy whereby proved undeveloped reserves must be economic at long-term historical prices, which during the last two years are significantly less than the year-end prices used in our reserve report. This also can have the effect of eliminating certain projects in a high price environment, as was the case at year-end 2002 and year-end 2003. (See "Depletion, Depreciation and Amortization" under "Results of Operations" above for a further discussion.) All of these factors and the decisions made regarding these issues can have a significant effect on our proven reserves and thus on our DD&A rate, full-cost ceiling test calculation, borrowing base and financial statements.

Asset Retirement Obligations

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

Management's Discussion and Analysis of Financial Condition and Results of Operations

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. Further, we must assess the likelihood that we will be able to recover or utilize our deferred tax assets (primarily our net operating losses and enhanced oil recovery credits). If recovery is not likely, we must record a valuation allowance against such deferred tax assets for the amount we would not expect to recover, which would result in an increase to our income tax expense. As of December 31, 2003, we believe that all of our deferred tax assets recorded on our Consolidated Balance Sheet will ultimately be recovered. If our estimates and judgments change regarding our ability to utilize our deferred tax assets, our tax provision would increase in the period it is determined that recovery is not probable. See Note 7 to the Consolidated Financial Statements for further information concerning our income taxes.

Hedging Activities

We enter into derivative contracts (i.e., hedges) 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. With the adoption of SFAS No. 133 in 2001, every derivative instrument must be recorded on the balance sheet as either an asset or a liability measured at its fair value. If the derivative does not qualify as a hedge or is not designated as a hedge, the change in fair value of the derivative is recognized currently in earnings. If the derivative qualifies for cash flow hedge accounting, the change in fair value of the derivative is recognized in other comprehensive income (equity) to the extent that the hedge is effective and in the income statement to the extent it is ineffective. We recognized ineffectiveness on our hedges of \$600,000 for 2002 and \$282,000 for 2003.

With the significant changes in commodity prices over the last two years, the fair value of our hedges has gone from an asset valued at \$23.5 million at year-end 2001 to a liability of \$44.6 million as of year-end 2003. While most of this change in value is recorded in other comprehensive income, the dramatic swing in commodity prices and the corresponding effect on the fair value of our hedges can cause a dramatic change to our balance sheet. If these hedges were deemed to no longer qualify for hedge accounting at some point in time, as happened to our hedges with Enron in 2001 (see below), then the future changes in value would be reflected in our income statement.

In order to qualify for hedge accounting the relationship between the hedging instruments and the hedged items must be highly effective in achieving the offset of changes in fair values or cash flows attributable to the hedged risk, both at the inception of the hedge and on an ongoing basis. We measure and compute hedge effectiveness on a quarterly basis. If a hedging instrument becomes ineffective, hedge accounting is discontinued and any deferred gains or losses on the cash flow hedge remain in accumulated other comprehensive income until the periods during which the hedges would have otherwise expired. If we determine it probable that a hedged forecasted transaction will not occur, deferred gains or losses on the hedging instrument are recognized in earnings immediately.

All of our current derivative hedging instruments qualify for hedge accounting. However, during 2001 we had derivative contracts with Enron that initially qualified for hedge accounting, but their status changed when Enron filed bankruptcy, causing us to change our accounting treatment of this asset before the hedge expired. As these hedges no longer qualified for hedge accounting due to the counterparty's inability to perform, we recognized a pre-tax write-down of \$24.4 million in the fourth quarter of 2001. As demonstrated by the prior year impact, these adjustments can be material to our financial statements and are unpredictable.

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.

Management's Discussion and Analysis of Financial Condition and Results of Operations

Recent Accounting Pronouncements

SFAS No. 141, "Business Combinations," and SFAS No. 142, "Goodwill and Other Intangible Assets," became effective July 1, 2001 and January 1, 2002, respectively. It is our understanding that questions have been raised as to the proper application by registrants in the oil and gas industry of the provisions of SFAS No. 141 and SFAS No. 142. The Emerging Issues Task Force of the FASB is scheduled to address the relevant issues in its March 2004 meeting. In question is whether the acquisition of contractual mineral interests, including both proved and undeveloped, should be classified separately as "intangible assets" on the balance sheet apart from other oil and gas property costs. Currently, Denbury and virtually all other companies in the oil and gas industry include purchased contractual mineral rights in oil and gas properties on the balance sheet. Until there is further guidance regarding this issue, we will continue to include mineral interests as oil and gas properties on our Consolidated Balance Sheets for mineral interests acquired subsequent to July 1, 2001. Based on the limited guidance available at this time, we estimate that approximately \$196 million at December 31, 2003, and \$206 million at December 31, 2002, of acquisition costs subsequent to July 1, 2001 would be reclassified from oil and gas properties to intangible assets in our December 31, 2003 Consolidated Balance Sheets. The provisions of SFAS No. 141 and 142, if determined to be applicable to the acquisitions of mineral interests in our industry, would impact only the classification of certain amounts on our balance sheet and associated footnote disclosures, and would not impact the Company's results of operations or cash flows.

Forward-Looking Information

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

This Annual Report is not deemed to be "soliciting material" or to be "filed" with the Securities and Exchange Commission or subject to the liabilities of Section 18 of the Securities Act of 1934, except with respect to pages 2, 9-10, 12-13, 17-18, 20-21, 23-25, 27-31 and 33-86 which are incorporated into the Company's Annual Report on Form 10-K.

Independent Auditors' Report

To the Stockholders of Denbury Resources Inc.

We have audited the accompanying consolidated balance sheets of Denbury Resources Inc. and Subsidiaries (the "Company") as of December 31, 2003 and 2002, and the related consolidated statements of operations, cash flows, stockholders' equity and comprehensive income for each of the three years in the period ended December 31, 2003. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2003 and 2002, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2003 in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note I to the financial statements under the caption "Asset Retirement Obligations", the Company changed its method of accounting for asset retirement obligations in 2003 as required by Statement of Financial Accounting Standards No. 143, "Accounting for Asset Retirement Obligations".

Deloitte & Touche LLP

Dallas, Texas
March 8, 2004

Consolidated Balance Sheets

Amounts in Thousands	December 31,	
	2003	2002
Assets		
Current assets		
Cash and cash equivalents	\$ 24,188	\$ 23,940
Accrued production receivables	33,944	34,458
Related party accrued production receivable – Genesis	6,927	3,334
Trade and other receivables, net of allowance of \$238 and \$207	18,080	16,846
Deferred tax asset	25,016	49,886
Total current assets	108,155	128,464
Property and equipment		
Oil and natural gas properties (using full cost accounting)		
Proved	1,409,579	1,245,896
Unevaluated	46,065	45,736
CO ₂ properties and equipment	85,467	62,370
Less accumulated depletion and depreciation	(696,366)	(609,917)
Net property and equipment	844,745	744,085
Investment in Genesis	7,450	2,224
Other assets	22,271	20,519
Total assets	\$ 982,621	\$ 895,292
Liabilities and Stockholders' Equity		
Current liabilities		
Accounts payable and accrued liabilities	\$ 62,349	\$ 49,281
Oil and gas production payable	22,215	17,309
Derivative liabilities	42,010	29,289
Total current liabilities	126,574	95,879
Long-term liabilities		
Long-term debt	298,203	344,889
Asset retirement obligations	41,711	6,845
Derivative liabilities	2,603	6,281
Deferred revenue – Genesis	21,468	—
Deferred tax liability	68,555	71,663
Other	2,305	2,938
Total long-term liabilities	434,845	432,616
Commitments and contingencies (Note 10)		
Stockholders' equity		
Preferred stock, \$.001 par value, 25,000,000 shares authorized; none issued and outstanding	—	—
Common stock, \$.001 par value, 100,000,000 shares authorized; 54,190,042, and 53,539,329 shares issued and outstanding at December 31, 2003 and December 31, 2002, respectively	54	54
Paid-in capital in excess of par	401,709	395,906
Retained earnings (accumulated deficit)	46,656	(9,875)
Accumulated other comprehensive loss	(27,113)	(19,288)
Treasury stock, at cost, 8,162 shares at December 31, 2003	(104)	—
Total stockholders' equity	421,202	366,797
Total liabilities and stockholders' equity	\$ 982,621	\$ 895,292

See Notes to Consolidated Financial Statements.

Consolidated Statements of Operations

Amounts in Thousands Except Per Share Amounts	Year Ended December 31,		
	2003	2002	2001
Revenues			
Oil, natural gas and related product sales			
Unrelated parties	\$336,521	\$251,972	\$260,398
Related party – Genesis	48,942	22,922	—
CO ₂ sales and transportation fees			
Unrelated parties	7,512	7,580	5,210
Related party – Genesis	676	—	—
Gain (loss) on settlements of derivative contracts	(62,210)	932	18,654
Interest income and other	1,573	1,746	849
Total revenues	333,014	285,152	285,111
Expenses			
Lease operating expenses	89,439	71,188	55,049
Production taxes and marketing expenses	14,819	11,902	10,963
CO ₂ operating expenses	1,710	1,400	891
General and administrative	15,189	12,426	10,174
Interest	23,201	26,833	22,335
Loss on early retirement of debt	17,629	—	—
Depletion, depreciation and accretion	94,708	94,236	71,345
Loss on Enron related assets	—	—	25,164
Amortization of derivative contracts and other non-cash hedging adjustments	(3,578)	(3,093)	7,816
Total expenses	253,117	214,892	203,737
Equity in net income of Genesis	256	55	—
Income before income taxes	80,153	70,315	81,374
Income tax provision (benefit)			
Current income taxes	(91)	(406)	640
Deferred income taxes	26,303	23,926	24,184
Income before cumulative effect of change in accounting principle	53,941	46,795	56,550
Cumulative effect of change in accounting principle, net of income taxes of \$1,600	2,612	—	—
Net income	\$ 56,553	\$ 46,795	\$ 56,550
Net income per share – basic			
Income before cumulative effect of change in accounting principle	\$ 1.00	\$ 0.88	\$ 1.15
Cumulative effect of change in accounting principle	0.05	—	—
Net income per share – basic	\$ 1.05	\$ 0.88	\$ 1.15
Net income per share – diluted			
Income before cumulative effect of change in accounting principle	\$ 0.97	\$ 0.86	\$ 1.12
Cumulative effect of change in accounting principle	0.05	—	—
Net income per common share – diluted	\$ 1.02	\$ 0.86	\$ 1.12
Weighted average common shares outstanding			
Basic	53,881	53,243	49,325
Diluted	55,464	54,365	50,361

See Notes to Consolidated Financial Statements.

Consolidated Statements of Cash Flows

Amounts in Thousands	Year Ended December 31,		
	2003	2002	2001
Cash flow from operating activities:			
Net income	\$ 56,553	\$ 46,795	\$ 56,550
Adjustments needed to reconcile to net cash flow provided by operations:			
Depletion, depreciation and accretion	94,708	94,236	71,345
Deferred income taxes	26,303	23,926	24,184
Deferred income – Genesis	(322)	—	—
Loss on early retirement of debt	17,629	—	—
Non-cash loss on Enron related assets	—	—	25,164
Amortization of derivative contracts and other non-cash hedging adjustments	(3,578)	(3,093)	7,816
Amortization of debt issue costs and other	1,121	2,701	1,742
Cumulative effect of change in accounting principle	(2,612)	—	—
Changes in assets and liabilities relating to operations:			
Accrued production receivable	(3,079)	(14,381)	19,399
Trade and other receivables	(1,234)	15,078	(17,622)
Derivative assets and liabilities	—	8,427	(28,043)
Other assets	7	133	863
Accounts payable and accrued liabilities	8,862	(17,217)	23,560
Oil and gas production payable	4,906	3,869	(2,213)
Other liabilities	(1,649)	(874)	2,302
Net cash provided by operating activities	197,615	159,600	185,047
Cash flow used for investing activities:			
Oil and natural gas expenditures	(146,596)	(99,273)	(170,109)
Acquisitions of oil and gas properties	(11,848)	(56,364)	(97,871)
Investment in Genesis	(5,026)	(2,170)	—
Acquisition of CO ₂ assets and capital expenditures	(22,673)	(16,445)	(45,555)
Net purchases of other assets	(2,192)	(3,688)	(1,799)
Increase in restricted cash	(848)	(909)	(3,496)
Net proceeds from CO ₂ production payment – Genesis	23,895	—	—
Proceeds from sales of oil and gas properties	29,410	7,688	—
Net cash used for investing activities	(135,878)	(171,161)	(318,830)
Cash flow from financing activities:			
Bank repayments	(160,000)	(40,000)	(79,130)
Bank borrowings	85,000	49,130	146,000
Repayment of 9% subordinated debt, including redemption premium	(209,000)	—	—
Issuance of 7.5% subordinated debt, net of discount	223,054	—	—
Issuance of 9% subordinated debt, net of discount	—	—	68,528
Issuance of common stock	5,537	3,594	2,594
Costs of debt financing	(4,812)	(719)	(3,026)
Other	(1,268)	—	20
Net cash provided by (used for) financing activities	(61,489)	12,005	134,986
Net increase in cash and cash equivalents	248	444	1,203
Cash and cash equivalents at beginning of year	23,940	23,496	22,293
Cash and cash equivalents at end of year	\$ 24,188	\$ 23,940	\$ 23,496

See 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 Deficit)	Accumulated Other Comprehensive Income (Loss)	Treasury Stock (at cost)		Total Stockholders' Equity
	Shares	Amount				Shares	Amount	
Balance – December 31, 2000	45,979,981	\$46	\$329,339	\$(113,220)	\$ —	—	\$ —	\$216,165
Issued pursuant to employee stock purchase plan	189,485	—	1,546	—	—	—	—	1,546
Issued pursuant to employee stock option plan	209,600	—	1,048	—	—	—	—	1,048
Issued pursuant to directors' compensation plan	7,829	—	63	—	—	—	—	63
Issued in Matrix acquisition	6,569,930	7	59,188	—	—	—	—	59,195
Tax benefit from stock options	—	—	373	—	—	—	—	373
Unrealized gain on cash flow hedge	—	—	—	—	14,228	—	—	14,228
Net income	—	—	—	56,550	—	—	—	56,550
Balance – December 31, 2001	52,956,825	53	391,557	(56,670)	14,228	—	—	349,168
Issued pursuant to employee stock purchase plan	203,893	—	1,928	—	—	—	—	1,928
Issued pursuant to employee stock option plan	370,120	1	1,665	—	—	—	—	1,666
Issued pursuant to directors' compensation plan	8,491	—	82	—	—	—	—	82
Tax benefit from stock options	—	—	674	—	—	—	—	674
Unrealized loss on cash flow hedge	—	—	—	—	(33,516)	—	—	(33,516)
Net income	—	—	—	46,795	—	—	—	46,795
Balance – December 31, 2002	53,539,329	54	395,906	(9,875)	(19,288)	—	—	366,797
Repurchase of common stock	—	—	—	—	—	100,000	(1,276)	(1,276)
Issued pursuant to employee stock purchase plan	94,968	—	1,174	(22)	—	(91,838)	1,172	2,324
Issued pursuant to employee stock option plan	550,090	—	3,213	—	—	—	—	3,213
Issued pursuant to directors' compensation plan	5,655	—	69	—	—	—	—	69
Tax benefit from stock options	—	—	1,347	—	—	—	—	1,347
Unrealized loss on cash flow hedge	—	—	—	—	(7,825)	—	—	(7,825)
Net income	—	—	—	56,553	—	—	—	56,553
Balance – December 31, 2003	54,190,042	\$54	\$401,709	\$ 46,656	\$(27,113)	8,162	\$ (104)	\$421,202

See Notes to Consolidated Financial Statements.

Consolidated Statements of Comprehensive Income

Amounts in Thousands	Year Ended December 31,		
	2003	2002	2001
Net income	\$ 56,553	\$ 46,795	\$ 56,550
Other comprehensive income (loss), net of tax:			
Reclassification adjustments related to settlements of derivative contracts, net of tax of \$22,173, (\$1,758), and (\$5,172), respectively	36,177	(2,868)	(8,806)
Change in fair value of derivative contracts, net of tax of (\$26,969), (\$18,784), and \$12,934, respectively	(44,002)	(30,648)	22,022
Change in accounting principle for derivative contracts, net of tax of \$594	—	—	1,012
Comprehensive income	\$ 48,728	\$ 13,279	\$ 70,778

See Notes to Consolidated Financial Statements.

Notes to Consolidated Financial Statements

Note 1. Significant Accounting Policies

Organization and Nature of Operations

Denbury Resources Inc. is a Delaware corporation, organized under *Delaware General Corporation Law*, engaged in the acquisition, development, operation and exploration of oil and natural gas properties. Denbury has one primary business segment, which is the exploration, development and production of oil and natural gas in the U.S. Gulf Coast region. We also own the rights to a natural source of carbon dioxide ("CO₂") reserves that we use for injection in our tertiary oil recovery operations. We also sell some of the CO₂ we produce to third parties for various industrial uses.

Principles of Reporting and Consolidation

The consolidated financial statements herein have been prepared in accordance with generally accepted accounting principles ("GAAP") and include the accounts of Denbury and its subsidiaries, all of which are wholly owned. In 2002, one of our subsidiaries acquired the general partner of Genesis Energy, L.P. ("Genesis"), a publicly traded master limited partnership. During 2003, we acquired additional partnership units, increasing our ownership interest in Genesis from 2% to 9.25%. We account for our ownership interest in Genesis under the equity method of accounting. Even though we have significant influence over the limited partnership in our role as general partner, because our control is limited by the general partnership agreement we do not consolidate Genesis. See Note 3 for more information regarding our related party transactions with Genesis and summary financial information. All material intercompany balances and transactions have been eliminated.

Effective December 29, 2003, Denbury Resources Inc. changed its corporate structure to a holding company format. The purposes of creating the holding company structure were to better reflect the operating practices and methods of Denbury, to improve its economics, and to provide greater administrative and operational flexibility. As part of this restructure, Denbury Resources Inc. (predecessor entity) merged into a newly formed limited liability company and survived as Denbury Onshore, LLC, a Delaware limited liability company and an indirect subsidiary of the newly formed holding company, Denbury Holdings, Inc. Denbury Holdings, Inc. subsequently assumed the name Denbury Resources Inc. (new entity). The reorganization was structured as a tax free reorganization to Denbury's stockholders and all outstanding capital stock of the original public company was automatically converted into the identical number of and type of shares of the new public holding company. Stockholders' ownership interests in the business did not change as a result of the new structure and shares of the Company remain publicly traded under the same symbol (DNR) on the New York Stock Exchange. The new parent holding company is co-obligor (or guarantor, as appropriate) regarding the payment of principal and interest on Denbury's outstanding debt securities.

Oil and Natural Gas Operations

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

b) Depletion and depreciation. The costs capitalized, including production equipment, are depleted or depreciated on the unit-of-production method, based on proved oil and natural gas reserves as determined by independent petroleum engineers. Oil and natural gas reserves are converted to equivalent units based upon the relative energy content which is six thousand cubic feet of natural gas to one barrel of crude oil.

Notes to Consolidated Financial Statements

c) Asset retirement obligations. On January 1, 2003, we adopted the provisions of Statement of Financial Accounting Standards ("SFAS") No. 143, "Accounting for Asset Retirement Obligations." In general, our future asset retirement obligations relate to future costs associated with plugging and abandonment of our oil and natural gas wells, dismantling our offshore production platforms, and removal of equipment and facilities from leased acreage and returning such land to its original condition. SFAS No. 143 requires that the fair value of a liability for an asset retirement obligation be 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. Prior to the adoption of this new standard, we recognized a provision for our asset retirement obligations each period as part of our depletion and depreciation calculation, based on the unit-of-production method. See Note 4 for more information regarding our change in accounting related to the adoption of SFAS No. 143.

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

e) 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.

f) Proved Reserves. See Note 12 for information on our proved oil and natural gas reserves and the basis on which they are recorded.

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 receivables.

We follow the "sales method" of accounting for our oil and natural gas revenue, whereby we recognize sales 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, 2003 and 2002, our aggregate oil and natural gas imbalances were not material to our consolidated financial statements.

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

Derivative Instruments and Hedging Activities

We enter into 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. On January 1, 2001, we adopted SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," as amended. Upon adoption of SFAS No. 133, we recorded a \$1.6 million increase in our derivative assets to reflect the fair value of our derivative instruments in place at that time and a corresponding increase to accumulated

Notes to Consolidated Financial Statements

other comprehensive income of approximately \$1.0 million, net of tax, in the transition adjustment. This transition adjustment was reclassified out of accumulated other comprehensive income to earnings over the remainder of 2001.

Derivative financial instruments are recorded on the balance sheet as either an asset or a liability measured at fair value. If the derivative does not qualify as a hedge or is not designated as a hedge, the change in fair value of the derivative is recognized currently in earnings. If the derivative qualifies for hedge accounting, the change in fair value of the derivative is recognized either currently in earnings or deferred in other comprehensive income (equity) depending on the type of hedge and to what extent the hedge is effective. All of our current derivative hedging instruments are cash flow hedges.

In order to qualify for hedge accounting the relationship between the hedging instruments and the hedged items must be highly effective in achieving the offset of changes in fair values or cash flows attributable to the hedged risk, both at the inception of the hedge and on an ongoing basis. We measure hedge effectiveness on a quarterly basis. Hedge accounting is discontinued prospectively when a hedging instrument becomes ineffective. We assess hedge effectiveness based on total changes in the fair value of options used in cash flow hedges rather than changes of intrinsic value only. As a result, changes in the entire fair value of option contracts are deferred in accumulated other comprehensive income, to the extent they are effective, until the hedged transaction is completed. If a hedge becomes ineffective, any deferred gains or losses on the cash flow hedge remain in accumulated other comprehensive income until the underlying production related to the derivative hedge has been delivered. If it is determined probable that a hedged forecasted transaction will not occur, and the hedge is not re-designated, deferred gains or losses on the hedging instrument are recognized in earnings immediately.

Receipts and payments resulting from settlements of derivative hedging instruments are recorded in "Gain (loss) on settlements of derivative contracts" included in revenues in the Consolidated Statements of Operations. We apply Derivative Implementation Group Issue G20 in accounting for our net purchased puts and collars, which allows the amortization of the cost of net purchased options over the period of the hedge. We record this amortization and any gains or losses resulting from hedge ineffectiveness in "Amortization of derivative contracts and other non-cash hedging adjustments" under expenses in the Consolidated Statements of Operations. Denbury's hedging activities are further discussed in Note 9.

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

CO₂ Operations

We own and produce CO₂ reserves that are used for our own tertiary oil recovery operations, and in addition, we sell a portion to third party industrial users. We record revenue from our sales of CO₂ to third parties when it is produced and sold. CO₂ used for our own tertiary oil recovery operations is not recorded as revenue in the Consolidated Statements of Operations. Expenses related to the production of CO₂ are allocated between volumes sold to third parties and volumes used for our own use. The expenses related to third party sales are recorded in "CO₂ operating expenses" and the expenses related to our own uses are recorded in "Lease operating expenses" in the Consolidated Statements of Operations. We capitalize acquisitions and the costs of exploring and developing CO₂ reserves. The costs capitalized are

Notes to Consolidated Financial Statements

depleted or depreciated on the unit-of-production method, based on proved CO₂ reserves as determined by independent engineers. We evaluate our CO₂ assets for impairment by comparing the expected future revenues from these assets to their carrying value.

Cash Equivalents

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

Restricted Cash

At December 31, 2003 and 2002, we had approximately \$9.5 million and \$8.7 million, respectively, of restricted cash held in escrow for future site reclamation costs. This restricted cash is included in "Other Assets" in the Consolidated Balance Sheets.

Net Income Per Common Share

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

For each of the three years in the period ended December 31, 2003, 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:

Amounts in Thousands	Year Ended December 31,		
	2003	2002	2001
Weighted average common shares – basic	53,881	53,243	49,325
Effect of diluted securities:			
Stock options	1,583	1,122	1,036
Weighted average common shares – diluted	55,464	54,365	50,361

We did not include in the diluted shares outstanding calculation 1.0 million options in 2003, 1.7 million options in 2002, and 1.8 million options in 2001 because their inclusion would be antidilutive as their exercise prices exceeded the average market price of our common stock during the respective periods.

Stock Option Compensation

We issue stock options to all of our employees under our stock option plan, which is described more fully in Note 8. We account for our stock option plan utilizing the recognition and measurement principles of Accounting Principles Board Opinion 25, "Accounting for Stock Issued to Employees," and its related interpretations. Under these principles, no stock-based employee compensation expense is reflected in net income as long as the stock options have an exercise price equal to the underlying common stock on the date of grant. The following table illustrates the effect on net income and net income per common share if we had applied the fair value provisions of SFAS No. 123, "Accounting for Stock-Based Compensation," as amended by SFAS No. 148, in accounting for our stock option plan.

Notes to Consolidated Financial Statements

Amounts in Thousands Except Per Share Amounts	Year Ended December 31,		
	2003	2002	2001
Net income, as reported	\$56,553	\$46,795	\$56,550
Less: stock-based compensation expense applying fair value based method, net of related tax effects	4,114	2,866	2,763
Pro forma net income	\$52,439	\$43,929	\$53,787
Net income per common share:			
As reported:			
Basic	\$ 1.05	\$ 0.88	\$ 1.15
Diluted	1.02	0.86	1.12
Pro forma:			
Basic	\$ 0.97	\$ 0.83	\$ 1.09
Diluted	0.97	0.83	1.09

The weighted average fair value of options granted using the Black-Scholes option pricing model and the weighted average assumptions used in determining those fair values are as follows:

	2003	2002	2001
Weighted average fair value of options granted	\$ 6.02	\$ 4.17	\$ 5.19
Risk-free interest rate	2.94%	4.05%	4.64%
Expected life	5 years	5 years	5 years
Expected volatility	59.6%	61.4%	63.4%
Dividend yield	—	—	—

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.

Use of Estimates

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

Notes to Consolidated Financial Statements

Reclassifications

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

Recent Accounting Pronouncements

SFAS No. 141, "Business Combinations," and SFAS No. 142, "Goodwill and Other Intangible Assets," became effective July 1, 2001 and January 1, 2002, respectively. It is our understanding that questions have been raised as to the proper application by registrants in the oil and gas industry of the provisions of SFAS No. 141 and SFAS No. 142. The Emerging Issues Task Force of the FASB is scheduled to address the relevant issues in its March 2004 meeting. In question is whether the acquisition of contractual mineral interests, including both proved and undeveloped, should be classified separately as "intangible assets" on the balance sheet apart from other oil and gas property costs. Currently, Denbury and virtually all other companies in the oil and gas industry include purchased contractual mineral rights in oil and gas properties on the balance sheet. Until there is further guidance regarding this issue, we will continue to include mineral interests as oil and gas properties in our Consolidated Balance Sheets for mineral interests acquired subsequent to July 1, 2001. Based on the limited guidance available at this time, we estimate that approximately \$196 million at December 31, 2003, and \$206 million at December 31, 2002, of acquisition costs subsequent to July 1, 2001 would be reclassified from oil and gas properties to intangible assets in our December 31, 2003 Consolidated Balance Sheets. The provisions of SFAS No. 141 and 142, if determined to be applicable to the acquisitions of mineral interests in our industry, would impact only the classification of certain amounts on our balance sheet and associated footnote disclosures, and would not impact the Company's results of operations or cash flows.

In January 2003, the FASB issued Interpretation No. 46 ("FIN 46"), "Consolidation of Variable Interest Entities" and amended the Interpretation in December 2003. FIN 46 requires an investor with a majority of the variable interests (primary beneficiary) in a variable interest entity (VIE) to consolidate the entity and also requires majority and significant variable interest entities to provide certain disclosures. An entity is considered a VIE if (i) the entity lacks sufficient equity to carry on its principal operations, (ii) the equity owners of the entity cannot make decisions about the entity's activities, or (iii) the entity's equity neither absorbs losses nor benefits from gains. Development stage entities that have sufficient equity to finance their activities and entities that are businesses, as defined in FIN 46, are not considered to be VIEs. The provisions of FIN 46 were effective immediately for VIEs created after January 15, 2003, and we have applied the remaining provisions of FIN 46 for the period ending December 31, 2003. We do not have any VIEs that would require consolidation or any significant exposure to VIEs that would require disclosure.

Note 2. Property Transactions

COHO Gulf Coast Properties

In August 2002, we acquired the Gulf Coast properties of COHO Energy, Inc., auctioned in the U.S. Bankruptcy Court in Dallas, Texas. Our net purchase price was \$48.2 million and included nine fields, eight of which are located in Mississippi and one in Texas. At December 31, 2002, these properties had reserves of approximately 15.1 million barrels of oil and net production of approximately 4,000 barrels of oil per day. The Mississippi fields included interests in the Brookhaven, Laurel, Martinville, Soso and Summerland Fields, with such interests representing operational control with working interests in excess of 90%, plus interests in the smaller Bentonia, Cranfield and Glazier Fields.

In February 2003, we sold Laurel Field, acquired in the COHO acquisition, for \$25.9 million and other consideration which included an interest in Atchafalaya Bay Field (where we already owned an interest) and seismic over that area. At December 31, 2002, Laurel Field had approximately 7.4 MMBbls of proved reserves. In March 2003, we sold the Bentonia and Glazier fields for approximately \$1.6 million. The proceeds from the sale of Laurel Field were used to reduce our bank debt.

Notes to Consolidated Financial Statements

Matrix Oil and Gas, Inc.

On July 10, 2001, we completed the acquisition of Matrix Oil & Gas, Inc. ("Matrix"), an independent oil and gas company based in Covington, Louisiana. Under the merger agreement, we paid a total of approximately \$157.4 million, comprised of \$98.2 million (62%) in cash and \$59.2 million (38%) in the form of 6.6 million shares of Denbury's common stock, including post-closing adjustments. The purchase price was allocated to the net assets acquired based on estimated fair market values at the date of acquisition, with the predominant amount allocated to oil and gas properties. As part of our purchase price allocations, we recorded a deferred income tax liability of \$53.1 million to reflect the difference between the book and carryover tax basis of the acquired properties, and we allocated \$30.0 million of the purchase price as unevaluated property to reflect the significant probable and possible reserves that were identified in the acquisition. Based on subsequent drilling activity and our ongoing evaluation of the undeveloped prospects, we have reclassified \$11.6 million of the original \$30.0 million to developed property as of December 31, 2003. Denbury's financial statements include the operations of Matrix from July 1, 2001.

CO₂ Acquisition

On February 2, 2001, we purchased certain CO₂ reserves, production and associated assets from a division of Airgas, Inc., for \$42.0 million. The acquisition included ten producing CO₂ wells and production facilities located near Jackson, Mississippi, and a 183-mile, 20-inch pipeline that is currently transporting CO₂ to our tertiary oil recovery operations, as well as to other commercial customers.

Note 3. Related Party Transactions – Genesis

On May 14, 2002, a newly formed subsidiary of Denbury acquired Genesis Energy, L.L.C. (which was subsequently converted to Genesis Energy, Inc.), the general partner of Genesis, a publicly traded master limited partnership, for total consideration, including expenses and commissions, of approximately \$2.2 million. Genesis has two primary lines of business: crude oil gathering and marketing and pipeline transportation, primarily in Mississippi, Texas, Alabama and Florida. In November 2003, through our subsidiary general partner, we purchased an additional 689,000 partnership common units and 14,000 general partner units of Genesis for \$7.15 per unit, with an aggregate purchase price of approximately \$5.0 million. With these additional units, our ownership interest increased to approximately 9.25% (2.0% general partner ownership and 7.25% limited partner ownership).

We are accounting for our 9.25% ownership in Genesis under the equity method of accounting as we have significant influence over the limited partnership; however, our control is limited under the limited partnership agreement and therefore we do not consolidate Genesis. Our equity in Genesis' net income for 2003 was \$256,000 and for 2002 was \$55,000, representing 2% of Genesis' net income for the period from May 14, 2002 through October 31, 2003 and 9.25% of Genesis' net income for the period from November 1, 2003 through December 31, 2003. Genesis Energy, Inc., the general partner of which we own 100%, has guaranteed the bank debt of Genesis, which was \$7.0 million as of December 31, 2003, and also included \$21.6 million in letters of credit of which \$12.5 million are for Denbury's benefit to secure purchases of oil from Denbury. There are no guarantees by Denbury or any of its other subsidiaries of the debt of Genesis or of Genesis Energy, Inc. Our investment in Genesis of \$7.2 million exceeded our percentage of net equity in the limited partnership at the time of acquisition by approximately \$2.2 million, which represents goodwill and is not subject to amortization.

Genesis has historically been a purchaser of our crude oil and we anticipate future purchases of our crude oil production by Genesis. At December 31, 2003 and 2002, we had a production receivable from Genesis of \$6.9 million and \$3.3 million, respectively. For the year ended December 31, 2003, we recorded oil sales to Genesis of \$48.9 million. Our oil sales to Genesis from the period May 14, 2002 through December 31, 2002 were \$22.9 million. Denbury received other miscellaneous payments from Genesis during 2003, including \$120,000 in director fees for certain executive officers of Denbury that are board members of Genesis, and \$57,000 in pro rata dividend distributions from Genesis.

Notes to Consolidated Financial Statements

CO₂ Volumetric Production Payment

In November 2003, we sold 167.5 Bcf of CO₂ to Genesis for \$24.9 million (\$23.9 million as adjusted for interim cash flows from the September 1, 2003 effective date and transaction costs) under a volumetric production payment ("VPP"). This sale included the assignment of three of our existing long-term commercial CO₂ supply agreements with our industrial customers, which represented approximately 60% of our then current industrial CO₂ sales volumes. Pursuant to the VPP, Genesis may take up to 52.5 MMcf/d through 2009, 43.0 MMcf/d from 2010 through 2012, and 25.2 MMcf/d to the end of the term. We have recorded the net proceeds as deferred revenue and will recognize such revenue as CO₂ is delivered during the term of the VPP. At December 31, 2003, \$23.6 million was recorded as deferred income (\$2.1 million in current liabilities and \$21.5 million long term). During 2003, we recognized deferred revenue of \$322,000 for deliveries under the VPP. We will continue to provide Genesis with certain processing and transportation services in connection with this agreement for a fee of \$0.16 per Mcf of CO₂ delivered to their industrial customers.

Summarized Financial Information of Genesis Energy, L.P.

Amounts in Thousands	Year Ended December 31, 2003	Year Ended December 31, 2002
Revenues	\$657,897	\$ 652,628
Cost of sales	644,157	636,042
Other expenses	14,159	15,576
Income from discontinued operations	13,741	4,082
Net income	\$ 13,322	\$ 5,092

Amounts in Thousands	December 31, 2003	December 31, 2002
Current assets	\$ 88,211	\$ 92,097
Non-current assets	58,904	45,440
Total assets	\$147,115	\$137,537
Current liabilities	\$ 87,244	\$ 96,220
Non-current liabilities	7,000	5,500
Partners' capital	52,871	35,817
Total liabilities and partners' capital	\$147,115	\$137,537

Note 4. Asset Retirement Obligations

On January 1, 2003, we adopted the provisions of SFAS No. 143, "Accounting for Asset Retirement Obligations." In general, our future asset retirement obligations relate to future costs associated with plugging and abandonment of our oil and natural gas wells, dismantling our offshore production platforms, and removal of equipment and facilities from leased acreage and returning such land to its original condition. SFAS 143 requires that the fair value of a liability for an asset retirement obligation be 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. Prior to the adoption of this new standard, we recognized a provision for our asset retirement obligations each period as part of our depletion and depreciation calculation, based on the unit-of-production method.

The adoption of SFAS No. 143 on January 1, 2003, required us to record (i) a \$41.0 million liability for our future asset retirement obligations (an increase of \$34.1 million in our liability for asset retirement obligations that we had recorded at December 31, 2002), (ii) a \$34.4 million increase in oil and natural gas properties, (iii) a \$3.9 million decrease in accumulated depreciation and depletion, and (iv) a \$2.6 million gain as a cumulative effect adjustment of a change in accounting principle, net of taxes.

Notes to Consolidated Financial Statements

The following pro forma data summarizes Denbury's net income and net income per common share as if we had applied the provisions of SFAS No. 143 in prior periods, and as if we had removed the first quarter 2003 cumulative effect adjustment for the adoption of SFAS No. 143:

Amounts in Thousands Except Per Share Amounts	Year Ended December 31,		
	2003	2002	2001
Net income, as reported	\$56,553	\$46,795	\$56,550
Pro forma adjustments to reflect retroactive adoption of SFAS 143	(2,612)	473	503
Pro forma net income	\$53,941	\$47,268	\$57,053
Net income per common share:			
As reported:			
Basic	\$ 1.05	\$ 0.88	\$ 1.15
Diluted	1.02	0.86	1.12
Pro forma:			
Basic	\$ 1.00	\$ 0.89	\$ 1.16
Diluted	0.97	0.87	1.13

The following table summarizes the changes in our asset retirement obligations for the year ended December 31, 2003.

Amounts in Thousands	Year Ended December 31,
	2003
Beginning asset retirement obligation, as of December 31, 2002	\$ 6,845
Cumulative effect adjustment for SFAS No. 143, January 1, 2003	34,110
Liabilities incurred during period	3,405
Liabilities settled during period	(1,007)
Liabilities sold during period	(2,393)
Accretion expense	2,852
Ending asset retirement obligation	\$43,812

At December 31, 2003, \$2.1 million of our asset retirement obligation was classified in "Accounts payable and accrued liabilities" under current liabilities in our Consolidated Balance Sheet. We have escrow accounts that are legally restricted for certain of our asset retirement obligations. The balances of these escrow accounts were \$9.5 million at December 31, 2003, and \$8.7 million at December 31, 2002, and are included in "Other assets" in our Consolidated Balance Sheets. If we had adopted SFAS No. 143 as of January 1, 2002, we estimate that our asset retirement obligations at that date would have been \$34.1 million, based on the same assumptions used in our calculation of our obligations at January 1, 2003.

Note 5. Property and Equipment

Amounts in Thousands	December 31,	
	2003	2002
Oil and natural gas properties:		
Proved properties	\$1,409,579	\$1,245,896
Unevaluated properties	46,065	45,736
Total	1,455,644	1,291,632
Accumulated depletion and depreciation	(690,395)	(606,488)
Net oil and natural gas properties	765,249	685,144
CO ₂ properties	85,467	62,370
Accumulated depletion and depreciation	(5,971)	(3,429)
Net CO ₂ properties	79,496	58,941
Net property and equipment	\$ 844,745	\$ 744,085

Notes to Consolidated Financial Statements

Unevaluated Oil and Natural Gas Properties Excluded From Depletion

Under full cost accounting, we may exclude certain unevaluated costs from the amortization base pending determination of whether proved reserves have been discovered or impairment has occurred. A summary of the unevaluated properties excluded from oil and natural gas properties being amortized at December 31, 2003 and 2002 and the year in which they were incurred follows:

Amounts in Thousands	December 31, 2003				December 31, 2002			
	Costs Incurred During:			Total	Costs Incurred During:			Total
	2003	2002	2001		2002	2001	2000	
Property acquisition costs	\$ 3,640	\$ 6,301	\$ 21,169	\$ 31,110	\$ 7,459	\$ 27,128	\$ 228	\$ 34,815
Exploration costs	6,528	5,291	3,136	14,955	7,526	2,938	457	10,921
Total	\$ 10,168	\$ 11,592	\$ 24,305	\$ 46,065	\$ 14,985	\$ 30,066	\$ 685	\$ 45,736

Costs are transferred into the amortization base on an ongoing basis as the projects are evaluated and proved reserves established or impairment determined. 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. As of December 31, 2003, approximately \$25.1 million of the total unevaluated property balance relates to offshore properties, of which of \$18.4 million relates to the original \$30.0 million classified as unevaluated properties in the Matrix acquisition. These costs will be transferred into the amortization base as the undeveloped areas are tested. We anticipate that the majority of this activity should be completed over the next two to three years.

Note 6. Notes Payable and Long-Term Indebtedness

Amounts in Thousands	December 31,	
	2003	2002
Senior bank loan	\$ 75,000	\$ 150,000
7.5 % Senior Subordinated Notes due 2013	225,000	—
9% Senior Subordinated Notes due 2008	—	125,000
9% Series B Senior Subordinated Notes due 2008	—	75,000
Discount on Senior Subordinated Notes	(1,797)	(5,111)
Total debt	\$ 298,203	\$ 344,889

Senior Bank Loan

In December 2003, we entered into a Fourth Amended and Restated Credit Agreement with our banks to restate the existing credit agreement for our internal reorganization to a holding-company-organizational structure (see Note 1). There were no significant changes to the agreement except to incorporate the new legal entities into the agreement. Earlier in 2003, we amended certain provisions of our credit agreement to (i) increase the percentage of our oil and natural gas production that we are allowed to hedge, setting a maximum of 85% of our forecasted production from our proved reserves for the current year (as defined in the amendment and may include up to 18 months), a maximum of 70% of forecasted production for the subsequent year, a maximum of 55% of forecasted production for the third year and a maximum of 40% of forecasted production for the fourth year, and (ii) to allow us to borrow up to \$20 million in a bond issue from a Mississippi governmental authority in order to receive certain exemptions or reductions in sales and ad valorem taxes on certain qualified expenditures in Mississippi through May 2005. Any borrowings under this bond program will be purchased by the banks in our credit facility, will become part of our outstanding borrowings under our credit line and will accrue interest and be repaid on the same basis as our bank line. The borrowing base remained at \$220 million, leaving a borrowing capacity of approximately \$145 million as of December 31, 2003.

Notes to Consolidated Financial Statements

The bank credit facility is secured by substantially all of our producing oil and natural gas properties and contains several restrictions including, among others: (i) a prohibition on the payment of dividends, (ii) a requirement for a minimum equity balance, (iii) a requirement to maintain positive working capital, as defined, (iv) a minimum interest coverage test and (v) a prohibition of most debt and corporate guarantees. We were in compliance with all of our bank covenants as of December 31, 2003. Our bank credit facility provides for a semi-annual redetermination of the borrowing base on April 1 and October 1. At the April 2001 redetermination, our borrowing base was increased from \$150 million to \$200 million and was further increased at the October 2001 redetermination to \$220 million. It has not changed since that time. Borrowings under the credit facility are generally in tranches that can have maturities up to one year. Interest on any borrowings are based on LIBOR plus an applicable margin as determined by the borrowings outstanding. The facility matures in April 2006.

As of December 31, 2003, we had \$75 million outstanding under the facility, at a weighted average interest rate of 2.4%, \$820,000 of letters of credit outstanding and a borrowing base of \$220 million. The next scheduled redetermination of the borrowing base will be as of April 1, 2004, based on December 31, 2003 assets and proved reserves.

Subordinated Debt Issuance of 7.5% Senior Subordinated Notes due 2013

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

The notes mature on April 1, 2013 and interest on the notes is payable each April 1 and October 1. We may redeem the notes at our option beginning April 1, 2008 at the following redemption prices: 103.75% after April 1, 2008, 102.5% after April 1, 2009, 101.25% after April 1, 2010, and 100% after April 1, 2011 and thereafter. In addition, prior to April 1, 2006, we may redeem up to 35% of the notes at a redemption price of 107.5% with net cash proceeds from a stock offering. The indenture under which the notes were issued is essentially the same as the indenture covering our previously outstanding 9% notes. 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 notes are not subject to any sinking fund requirements. All of our significant subsidiaries fully and unconditionally guarantee this debt.

In connection with our internal reorganization to a holding-company-organizational structure (see Note 1), we entered into a First Supplemental Indenture dated December 29, 2003, which did not require the consent of the holders of the 7.5% Senior Subordinated Notes due 2013. The supplemental indenture made Denbury Resources Inc. and Denbury Onshore, LLC, co-obligors of this debt. All of our significant subsidiaries continue to fully and unconditionally guarantee this debt. There were no other significant changes as part of the amendment.

Redemption of 9% Senior Subordinated Notes due 2008 (Including Series B Notes)

On April 16, 2003, we redeemed our \$200 million of 9% Senior Subordinated Notes due 2008 at an aggregate cost of \$209.0 million, including a \$9.0 million call premium. As a result of this early redemption, we recorded a before-tax charge to earnings in the second quarter of 2003 of \$17.6 million (\$11.5 million after tax), which included the \$9.0 million call premium and the write-off of the remaining discount and debt issuance costs associated with these notes.

Notes to Consolidated Financial Statements

Indebtedness Repayment Schedule

As of December 31, 2003, our indebtedness, excluding the discount on our senior subordinated debt, is repayable over the next five years and thereafter as follows:

Amounts in Thousands

2004	\$ —
2005	—
2006	75,000
2007	—
2008	—
Thereafter	225,000
Total indebtedness	\$300,000

Note 7. Income Taxes

Our income tax provision (benefit) is as follows:

Amounts in Thousands	Year Ended December 31,		
	2003	2002	2001
Current income tax expense (benefit)			
Federal	\$ (91)	\$ (419)	\$ 614
State	—	13	26
Total current income tax expense (benefit)	(91)	(406)	640
Deferred income tax expense			
Federal	23,864	21,822	22,637
State	2,439	2,104	1,547
Total deferred income tax expense	26,303	23,926	24,184
Total income tax expense	\$26,212	\$23,520	\$24,824

Our current income tax expense in 2001 was for alternative minimum taxes that could not be offset by our alternative minimum tax net operating losses, and conversely, our current income tax benefit in 2002 is primarily related to tax law changes in 2002 that allowed us to receive a refund of our alternative minimum taxes paid for 2001.

At December 31, 2003, we had net operating loss carryforwards for U.S. federal income tax purposes of \$95.0 million and \$14.9 million for alternative minimum tax purposes. As a result of the acquisition of Matrix and other prior ownership changes, the utilization of some of our net operating loss carryforwards is subject to limitations imposed by the Internal Revenue Code of 1986. However, we do not expect such limitations to have an effect on our ability to use these net operating loss carryforwards. Our net operating loss carryforwards are scheduled to expire as follows:

Amounts in Thousands	Income Tax	Alternative
		Minimum Tax
Year		
2018	\$54,698	\$ —
2019	21,356	12,054
2020	10,187	2,154
2021	8,467	213
2022	30	—
2023	217	524

In 2001, we began to recognize a benefit for the amount of enhanced oil recovery credits earned from our tertiary recovery projects. The total credits earned to date are approximately \$16.6 million. These credits begin to expire in 2020.

Notes to Consolidated Financial Statements

Deferred income taxes relate to temporary differences based on tax laws and statutory rates in effect at the December 31, 2003 and 2002 balance sheet dates. At December 31, 2003 and 2002, our deferred tax assets and liabilities were as follows:

Amounts in Thousands	December 31,	
	2003	2002
Deferred tax assets:		
Loss carryforwards	\$ 35,998	\$ 32,266
Tax credit carryover	978	1,069
Enhanced oil recovery credit carryforwards	16,578	9,927
Derivative hedging contracts	16,617	11,822
Other	90	79
Total deferred tax assets	70,261	55,163
Deferred tax liabilities:		
Property and equipment	(112,200)	(76,940)
Asset retirement obligations	(1,600)	—
Total deferred tax liabilities	(113,800)	(76,940)
Total net deferred tax liability	\$ (43,539)	\$ (21,777)

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

Amounts in Thousands	Year Ended December 31,		
	2003	2002	2001
Income tax provision calculated using the federal statutory income tax rate	\$28,054	\$24,587	\$28,481
State income taxes	2,398	2,121	1,623
Enhanced oil recovery credits	(4,687)	(3,394)	(5,280)
Other	447	206	—
Total income tax expense	\$26,212	\$23,520	\$24,824

Note 8. Stockholders' Equity

Authorized

We are authorized to issue 100 million shares of common stock, par value \$.001 per share, and 25 million shares of preferred stock, par value \$.001 per share. The preferred shares may be issued in one or more series with rights and conditions determined by the board of directors.

Stock Repurchase Plan

In August 2003, we adopted a stock repurchase plan ("Plan") to purchase shares of our common stock on the NYSE in order for such repurchased shares to be reissued to our employees who participate in Denbury's Employee Stock Purchase Plan (see Employee Stock Purchase Plan below). The Plan provides for purchases through an independent broker of 50,000 shares of Denbury's common stock per fiscal quarter for a period of approximately twelve months, or a total of 200,000 shares, beginning August 13, 2003 and ending on July 31, 2004. Purchases are to be made at prices and times determined at the discretion of the independent broker, provided however that no purchases may be made during the last ten business days of a fiscal quarter. During 2003, we purchased 100,000 shares at an average cost of \$12.77 per share. On September 30, 2003 and December 31, 2003, we reissued 48,013 and 43,825, respectively, of these shares under Denbury's Employee Stock Purchase Plan.

Notes to Consolidated Financial Statements

Stock Option Plan

As of December 31, 2003, we had a total of 8,195,587 shares of common stock authorized for issuance pursuant to our Stock Option Plan, of which 1,040,530 shares were available for issuance. Under the terms of the plan, incentive and non-qualified options may be issued to officers, key employees and consultants. Options generally become exercisable over a four-year vesting period with the specific terms of vesting determined by the board of directors at the time of grant. The options expire over terms not to exceed ten years from the date of grant, 90 days after termination of employment or permanent disability or one year after the death of the optionee. The options are granted at the fair market value at the time of grant, which is generally defined as the average closing price of our common stock for the ten trading days prior to issuance. The plan is administered by the Stock Option Committee of Denbury's board of directors.

The following is a summary of our stock option activity:

	Year Ended December 31,					
	2003		2002		2001	
	Number of Options	Weighted Average Price	Number of Options	Weighted Average Price	Number of Options	Weighted Average Price
Outstanding at beginning of year	4,997,475	\$ 8.46	4,616,333	\$ 8.40	3,802,122	\$ 8.03
Granted	956,384	11.33	921,341	7.50	1,222,141	9.00
Exercised	(550,090)	5.77	(370,120)	4.51	(209,600)	5.00
Forfeited	(29,567)	7.72	(170,079)	10.30	(198,330)	8.53
Outstanding at end of year	5,374,202	\$ 9.25	4,997,475	\$ 8.46	4,616,333	\$ 8.40
Exercisable at end of year	2,311,834	\$10.21	2,267,497	\$10.26	1,858,072	\$ 9.49

The following is a summary of stock options outstanding at December 31, 2003:

Range of Exercise Prices	Options Outstanding			Options Exercisable	
	Number of Options Outstanding at 12/31/03	Weighted Average Remaining Contractual Life	Weighted Average Exercise Price	Number of Options Exercisable at 12/31/03	Weighted Average Exercise Price
\$ 3.77 - 5.50	1,203,973	5.4	\$ 4.13	736,784	\$ 4.23
\$ 5.51 - 8.00	957,217	7.1	7.06	175,258	6.94
\$ 8.01 - 11.50	2,176,331	7.7	10.09	411,252	9.42
\$11.51 - 14.50	602,679	3.5	13.34	554,538	13.38
\$14.51 - 22.25	434,002	3.8	18.38	434,002	18.38
	5,374,202	6.3	\$ 9.25	2,311,834	\$10.21

Employee Stock Purchase Plan

We have a Stock Purchase Plan that is authorized to issue up to 1,750,000 shares of common stock to all full-time employees. As of December 31, 2003, there are 406,466 authorized shares remaining to be issued under the plan. In accordance with the plan, employees may contribute up to 10% of their base salary and Denbury matches 75% of their contribution. The combined funds are used to purchase previously unissued Denbury common stock at its current market value at the end of each quarter. We recognize compensation expense for the 75% company matching portion, which totaled \$997,000, \$822,000 and \$666,000 for the years ended December 31, 2003, 2002 and 2001, respectively. This plan is administered by the Stock Purchase Plan Committee of Denbury's board of directors.

Notes to Consolidated Financial Statements

401(k) Plan

Denbury offers a 401(k) Plan to which employees may contribute tax deferred earnings subject to Internal Revenue Service limitations. Up to 3% of an employee's compensation, as defined by the plan, is matched by Denbury at 100% and an employee's contribution between 3% and 6% of compensation is matched by Denbury at 50%. Denbury's match is vested immediately. During 2003, 2002 and 2001, Denbury's matching contributions were \$1,067,000, \$884,000 and \$670,000, respectively, to the 401(k) Plan.

Note 9. Derivative Hedging Contracts

We enter into various financial contracts to hedge our exposure to commodity price risk associated with anticipated future oil and natural gas production. We do not hold or issue derivative financial instruments for trading purposes. These contracts have historically consisted of price floors, collars and fixed price swaps. We generally attempt to hedge up to 75% of our anticipated production each year (depending on our overall debt level) to provide us with a reasonably certain amount of cash flow to cover a majority of our budgeted exploration and development expenditures without incurring significant debt. When we make an acquisition, we attempt to hedge a large percentage, up to 100%, of the forecasted production for the subsequent one to three years following the acquisition in order to help provide us with a minimum return on our investment. Our recent hedging activity has been predominantly with collars, although for the 2002 COHO acquisition, we also used swaps in order to lock in the prices used in our economic forecasts. All of the mark-to-market valuations used for our financial derivatives are provided by external sources and are based on prices that are actively quoted. We manage and control market and counterparty credit risk through established internal control procedures, which are reviewed on an ongoing basis. We attempt to minimize credit risk exposure to counterparties through formal credit policies, monitoring procedures, and diversification.

The following is a summary of the net gain (loss) representing cash receipts and payments on our hedge settlements:

Amounts in Thousands	Year Ended December 31,		
	2003	2002	2001
Oil Hedge Contracts	\$(20,337)	\$ (598)	\$ 1,925
Gas Hedge Contracts	(41,873)	1,530	16,729
Net gain (loss)	\$(62,210)	\$ 932	\$ 18,654

Some of our derivative contracts require us to pay a premium that we amortize over the contract periods. This expense is included in "Amortization of derivative contracts and other non-cash hedging adjustments" in our Consolidated Statements of Operations. For the years ended December 31, 2003 and 2002, we recorded premium amortization expense of \$1.2 million and \$9.7 million, respectively. Also, for the year ended December 31, 2003, we reclassified \$5.1 million related to our former Enron hedges (discussed below) out of accumulated other comprehensive income into income and recorded hedge ineffectiveness of \$282,000 which is also included in "Amortization of derivative contracts and other non-cash hedging adjustments."

Loss on Enron Hedges

In conjunction with the acquisition of Matrix in July 2001, we purchased commodity hedges to protect our investment. These hedges, in the form of price floors, covered nearly all of the forecasted production from the acquired properties through the end of 2003 at floor prices ranging from \$3.75 to \$4.25 per MMBtu. Due to the falling natural gas prices in the latter half of 2001, we collected approximately \$12.7 million on these hedges. The price floors relating to 2002 and 2003 were purchased from Enron Corporation, which filed bankruptcy in December 2001. We sold our bankruptcy claim against Enron in February 2002 for net proceeds of approximately \$9.2 million. In total, we collected approximately \$21.9 million from the price floors relating to the Matrix acquisition, resulting in a net cash gain of approximately \$3.9 million over the cost of the floors. Because of the rise in natural gas prices since December 2001, we would not have collected

Notes to Consolidated Financial Statements

anything on the price floors relating to 2003, even if Enron had not filed bankruptcy, as the natural gas NYMEX prices during 2003 were above \$3.75 (the floor price for 2003). We calculate that our total cash loss due to Enron's bankruptcy was approximately \$5.4 million, representing the difference between what we would have collected during 2002 and the \$9.2 million that we obtained from selling the bankruptcy claim.

When Enron filed for bankruptcy during the fourth quarter of 2001, these Enron hedges ceased to qualify for hedge accounting treatment, which changed the accounting treatment for those hedges as of that point in time as required by SFAS No. 133. The result is that any future changes in the current market value of these assets must be reflected in the income statement and any remaining accumulated other comprehensive income at the time of the accounting change must be recognized over the original expected life of the hedges. To adjust the value of the Enron hedges down to the market value at December 31, 2001, which was determined to be the amount that we received from the sale of our claims in February 2002, we recorded a pre-tax write-down of \$24.4 million in the fourth quarter of 2001. We also had a claim against Enron for production receivables relating to November 2001 natural gas production that was also sold in February 2002, which resulted in an overall total pre-tax loss on our Enron related assets of \$25.2 million. The after-tax balance in accumulated other comprehensive income related to these Enron hedges was approximately \$11.6 million at the point they no longer qualified for hedge accounting. Accordingly, we recognized pre-tax income attributable to the Enron hedges during 2002 of approximately \$13.4 million and recognized pre-tax income during 2003 of approximately \$5.1 million. The three-year total pre-tax net loss on the Enron hedges was approximately \$5.9 million, which approximates the difference between the amount collected and paid for the Enron portion of the associated price floors.

Hedging Contracts at December 31, 2003

Crude Oil Contracts:

Crude Oil Contracts:		NYMEX Contract Prices Per Bbl				Estimated Fair Value at Dec. 31, 2003
Type of Contract and Period	Bbls/d	Swap Price	Floor Price	Collar Price		
				Floor	Ceiling	
Swap Contracts						
Jan. 2004 - Dec. 2004	2,500	\$22.89	\$ —	\$ —	\$ —	\$ (6,625)
Jan. 2004 - Dec. 2004	4,500	23.00	—	—	—	(11,746)
Jan. 2004 - Dec. 2004	2,500	23.08	—	—	—	(6,453)

Natural Gas Contracts:

Type of Contract and Period		NYMEX Contract Prices Per MMBtu					Estimated Fair Value at Dec. 31, 2003
		MMBtu/d	Swap Price	Floor Price	Collar Price		
					Floor	Ceiling	
Collar Contracts							
Jan. 2004 - Dec. 2004		30,000	\$ —	\$ —	\$ 3.50	\$ 4.45	\$(12,527)
Jan. 2004 - Dec. 2004		15,000	—	—	3.00	5.87	(2,285)
Jan. 2004 - Dec. 2004		15,000	—	—	3.00	5.82	(2,374)
Jan. 2005 - Dec. 2005		15,000	—	—	3.00	5.50	(2,603)

At December 31, 2003, our derivative contracts were recorded at their fair value, which was a net liability of \$44.6 million. To the extent our hedges are considered effective, this fair value liability, net of income taxes, is included in Accumulated other comprehensive income (loss) reported under Stockholders' equity in our Consolidated Balance Sheets. The balance in accumulated other comprehensive loss of \$27.1 million at December 31, 2003, represents the deficit in the fair market value of our derivative contracts as compared to the cost of our hedges, net of income taxes. Of the \$27.1 million in accumulated other comprehensive loss as of December 31, 2003, \$25.5 million relates to current hedging contracts that will expire within the next 12 months and \$1.6 million relates to contracts that expire after December 31, 2004.

Notes to Consolidated Financial Statements

Note 10. Commitments and Contingencies

We have operating leases for the rental of office space, equipment, and vehicles that totaled \$16.6 million, \$1.7 million and \$1.6 million for the years ended December 31, 2003, 2002 and 2001, respectively. In August 2003, we entered into a \$6.0 million lease financing arrangement for certain equipment at our CO₂ processing facility at Mallalieu Field. This lease term is for seven years with monthly payments of approximately \$81,000 per month. At December 31, 2003, long-term commitments for these items require the following future minimum rental payments:

Amounts in Thousands

2004	\$ 2,664
2005	2,784
2006	2,786
2007	2,781
2008	2,670
Thereafter	2,936
Total lease commitments	\$16,621

Long-term contracts require us to deliver CO₂ to our industrial CO₂ customers at various contracted prices, plus we have a CO₂ delivery obligation to Genesis related to a VPP entered into during 2003 (see "Genesis Transactions" above). Based upon the maximum amounts deliverable as stated in the contracts and the volumetric production payment, we estimate that we may be obligated to deliver up to 412 Bcf of CO₂ to these customers over the next 18 years; however, based on the current level of deliveries, our commitment would likely be reduced to approximately 310 Bcf. The maximum volume required in any given year is approximately 97 MMcf/d, although based on our current level of deliveries, this would likely be reduced to approximately 70 MMcf/d. Given the size of our proven CO₂ reserves at December 31, 2003 (approximately 1.6 Tcf before deducting approximately 162.6 Bcf for the VPP), our current production capabilities and our projected levels of CO₂ usage for our own tertiary flooding program, we believe that we can meet these delivery obligations.

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

We are involved in various lawsuits, claims and regulatory proceedings incidental to our businesses. In the opinion of management, the outcome of such matters will not have a material adverse effect on our consolidated financial position, results of operations or cash flows.

Note 11. Supplemental Information

Significant Oil and Natural Gas Purchasers

Oil and natural gas sales are made on a day-to-day basis or under short-term contracts at the current area market price. The loss of any purchaser would not be expected to have a material adverse effect upon our operations. For the year ended December 31, 2003, we had two significant purchasers that each accounted for 10% or more of our oil and natural gas revenues: Hunt Refining (15%) and Genesis (12%). For the year ended December 31, 2002, two purchasers each accounted for 10% or more of our natural gas revenues: Hunt Refining (14%) and Genesis (11%). For the year ended December 31, 2001, four purchasers each accounted for 10% or more of our oil and natural gas revenues: Conoco (14%), Hunt Refining (13%), EOTT Energy (12%), and Dynegy (12%).

Notes to Consolidated Financial Statements

Accounts Payable and Accrued Liabilities

Amounts in Thousands	December 31,	
	2003	2002
Accounts payable	\$33,321	\$26,243
Accrued exploration and development costs	7,546	3,984
Accrued interest	4,272	6,248
Advances payable	4,430	5,951
Accrued compensation	2,806	3,633
Asset retirement obligations – current	2,101	—
Deferred revenues – Genesis	2,105	—
Other	5,768	3,222
Total	\$62,349	\$49,281

Supplemental Cash Flow Information

Amounts in Thousands	Year Ended December 31,		
	2003	2002	2001
Interest paid	\$23,525	\$24,636	\$17,451
Income taxes paid (refunded)	184	(1,304)	2,482

In 2001, in connection with our acquisition of Matrix, we recorded non-cash increases to property and equipment resulting from the issuance of common stock in the amount of \$59.2 million and the recording of deferred taxes in the amount of \$53.1 million.

Fair Value of Financial Instruments

Amounts in Thousands	December 31,			
	2003		2002	
	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
Senior bank debt	\$ 75,000	\$ 75,000	\$150,000	\$150,000
7.5% Senior Subordinated notes due 2013	223,203	232,875	—	—
9% Senior Subordinated Notes due 2008	—	—	125,000	129,113
9% Series B Senior Subordinated Notes due 2008	—	—	69,889	77,468

As of December 31, 2003 and 2002, the carrying value of our bank debt approximated fair value based on the fact that our bank debt is subject to short-term floating interest rates that approximated the rates available to us at those periods. The fair values of our senior subordinated notes are based on quoted market prices. 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 12. 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.

Notes to Consolidated Financial Statements

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

Amounts in Thousands	Year Ended December 31,		
	2003	2002	2001
Property acquisitions:			
Proved ⁽¹⁾	\$ 22,307	\$ 56,364	\$ 127,066
Unevaluated	3,955	4,342	37,051
Exploration	34,050	29,985	36,836
Development	98,132	64,946	126,222
Asset retirement obligations	3,405	—	—
Total costs incurred⁽²⁾	\$161,849	\$155,637	\$327,175

(1) Excludes deferred taxes recorded in the acquisition of Matrix of \$53.1 million in 2001.

(2) Capitalized general and administrative costs that directly relate to exploration and development activities were \$5.5 million, \$5.3 million and \$4.1 million for the years ended December 31, 2003, 2002 and 2001, 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:

Amounts in Thousands	Year Ended December 31,		
	2003	2002	2001
Oil, natural gas and related product sales	\$385,463	\$274,894	\$260,398
Gain (loss) on settlements of derivative contracts	(62,210)	932	18,654
Total revenues	323,253	275,826	279,052
Lease operating costs	89,439	71,188	55,049
Production taxes and marketing expenses	14,819	11,902	10,963
Depletion, depreciation and accretion	90,694	90,679	68,348
Loss on Enron related assets	—	—	25,164
Amortization of derivative contracts and other non-cash hedging adjustments	(3,578)	(3,093)	7,816
Net operating income	131,879	105,150	111,712
Income tax provision	45,427	36,563	36,053
Results of operations from oil and natural gas producing activities	\$ 86,452	\$ 68,587	\$ 75,659
Depletion, depreciation and accretion per BOE	\$ 7.16	\$ 6.98	\$ 6.01

Oil and Natural Gas Reserves

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

We have a corporate policy whereby we do not book proved undeveloped reserves until we have committed to perform the required development operations, the majority of which we generally expect to commence within the next year. We also have a corporate policy whereby proved undeveloped reserves must be economic at prices significantly lower than the year-end prices used in our reserve report, at prices closer to historical averages.

Notes to Consolidated Financial Statements

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,					
	2003		2002		2001	
	Oil (MBbl)	Gas (MMcf)	Oil (MBbl)	Gas (MMcf)	Oil (MBbl)	Gas (MMcf)
Balance at beginning of year	97,203	200,947	76,490	198,277	70,667	100,550
Revisions of previous estimates	2,958	(25,451)	(408)	(22,975)	4,344	(631)
Revisions due to price changes	50	(152)	3,020	2,660	(7,800)	(2,745)
Extensions and discoveries	1,059	68,408	2,326	51,819	2,308	66,448
Improved recovery ⁽¹⁾	4,009	—	—	—	1,667	—
Production	(6,896)	(34,623)	(6,874)	(36,662)	(6,197)	(31,112)
Acquisition of minerals in place	838	14,541	23,383	9,360	11,501	65,767
Sales of minerals in place	(7,955)	(1,783)	(734)	(1,532)	—	—
Balance at end of year	91,266	221,887	97,203	200,947	76,490	198,277
Proved developed reserves						
Balance at beginning of year	62,398	142,812	54,722	169,897	52,353	77,358
Balance at end of year	53,804	144,750	62,398	142,812	54,722	169,897

(1) Improved recovery additions result from the application of secondary recovery methods such as water-flooding or tertiary recovery methods such as CO₂ flooding.

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

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

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

	December 31,		
	2003	2002	2001
Oil (NYMEX)	\$32.52	\$ 31.20	\$19.84
Natural Gas (NYMEX Henry Hub)	6.19	4.79	2.57

Notes to Consolidated Financial Statements

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

Amounts in Thousands	2003	December 31, 2002	2001
Future cash inflows	\$ 4,059,424	\$ 3,787,077	\$ 1,786,884
Future production costs	(1,120,741)	(1,044,193)	(655,363)
Future development costs	(300,981)	(268,269)	(178,546)
Future net cash flows before taxes	2,637,702	2,474,615	952,975
10% annual discount for estimated timing of cash flows	(1,071,331)	(1,048,395)	(378,647)
Discounted future net cash flows before taxes	1,566,371	1,426,220	574,328
Discounted future income taxes	(442,244)	(397,244)	(68,533)
Standardized measure of discounted future net cash flows	\$ 1,124,127	\$ 1,028,976	\$ 505,795

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:

Amounts in Thousands	2003	Year Ended December 31, 2002	2001
Beginning of year	\$1,028,976	\$ 505,795	\$ 841,299
Sales of oil and natural gas produced, net of production costs	(281,205)	(191,803)	(194,386)
Net changes in sales prices	141,932	694,646	(838,124)
Extensions and discoveries, less applicable future development and production costs	235,228	151,926	123,214
Improved recovery ⁽¹⁾	40,663	—	5,045
Previously estimated development costs incurred	52,874	34,931	64,072
Revisions of previous estimates, including revised estimates of development costs, reserves and rates of production	(157,989)	(50,855)	(13,290)
Accretion of discount	142,622	57,433	115,897
Acquisition of minerals in place	44,856	160,899	152,931
Sales of minerals in place	(78,830)	(5,285)	—
Net change in income taxes	(45,000)	(328,711)	249,137
End of year	\$1,124,127	\$ 1,028,976	\$ 505,795

(1) Improved recovery additions result from the application of secondary recovery methods such as water flooding or tertiary recovery methods such as CO₂ flooding.

CO₂ Reserves

Based on engineering reports prepared by DeGolyer and MacNaughton, our CO₂ reserves, on a working interest basis, were estimated at approximately 1.6 Tcf at December 31, 2003 (includes 162.6 Bcf of reserves dedicated to a volumetric production payment), 1.6 Tcf at December 31, 2002, and 815 Bcf at December 31, 2001.

Notes to Consolidated Financial Statements

Note 13. Condensed Consolidating Financial Information

On December 29, 2003, we amended the indenture for our 7.5% Senior Subordinated Notes due 2013 to reflect our new holding company organizational structure (see Note 1 and Note 6). As part of this restructuring our indenture was amended so that both Denbury Resources Inc. and Denbury Onshore, LLC became co-obligors of our subordinated debt. Prior to this restructure, Denbury Resources Inc. was the sole obligor. Our subordinated debt is fully and unconditionally guaranteed by Denbury Resources Inc.'s significant subsidiaries. Genesis Energy, Inc., the subsidiary that holds the Company's investment in Genesis Energy, L.P., is not a guarantor of our subordinated debt. The results of our equity interest in Genesis is reflected through the equity method by one of our significant subsidiaries, Denbury Gathering & Marketing. The following is condensed consolidating financial information for Denbury Resources Inc., Denbury Onshore, LLC, and significant subsidiaries:

Condensed Consolidating Balance Sheets

Amounts in Thousands	December 31, 2003				
	Denbury Resources, Inc. (Parent and Co-obligor)	Denbury Onshore, LLC (Issuer and Co-obligor)	Guarantor Subsidiaries	Eliminations	Denbury Resources Inc. Consolidated
Assets					
Current assets	\$ 1	\$ 85,109	\$ 23,045	\$ —	\$ 108,155
Property and equipment	—	553,205	291,540	—	844,745
Investment in subsidiaries (equity method)	421,201	—	210,803	(624,554)	7,450
Other assets	—	18,019	4,252	—	22,271
Total assets	\$421,202	\$656,333	\$529,640	\$(624,554)	\$982,621
Liabilities and Stockholders' Equity					
Current liabilities	\$ —	\$ 119,364	\$ 7,210	\$ —	\$ 126,574
Long-term liabilities	—	333,616	101,229	—	434,845
Stockholders' equity	421,202	203,353	421,201	(624,554)	421,202
Total liabilities and stockholders' equity	\$421,202	\$656,333	\$529,640	\$(624,554)	\$982,621

Amounts in Thousands	December 31, 2002			
	Denbury Resources, Inc. (Parent and Issuer)	Guarantor Subsidiaries	Eliminations	Denbury Resources Inc. Consolidated
Assets				
Current assets	\$ 111,063	\$ 17,401	\$ —	\$ 128,464
Property and equipment	528,754	215,331	—	744,085
Investment in subsidiaries (equity method)	169,309	2,224	(169,309)	2,224
Other assets	16,881	3,638	—	20,519
Total assets	\$826,007	\$238,594	\$(169,309)	\$895,292
Liabilities and Stockholders' Equity				
Current liabilities	\$ 87,101	\$ 8,778	\$ —	\$ 95,879
Long-term liabilities	372,109	60,507	—	432,616
Stockholders' equity	366,797	169,309	(169,309)	366,797
Total liabilities and stockholders' equity	\$826,007	\$238,594	\$(169,309)	\$895,292

Notes to Consolidated Financial Statements

Condensed Consolidating Statements of Operations

Year Ended December 31, 2003

Amounts in Thousands	Denbury Resources, Inc. (Parent and Co-obligor)	Denbury Onshore, LLC (Issuer and Co-obligor)	Guarantor Subsidiaries	Eliminations	Denbury Resources Inc. Consolidated
Revenues	\$ —	\$238,072	\$94,942	\$ —	\$333,014
Expenses	—	196,392	56,725	—	253,117
Income before the following:	—	41,680	38,217	—	79,897
Equity in net earnings of subsidiaries	56,553	—	40,667	(96,964)	256
Income before income taxes and cumulative effect of change in accounting principle	56,553	41,680	78,884	(96,964)	80,153
Income tax provision	—	5,250	20,962	—	26,212
Net income before cumulative effect of change in accounting principle	56,553	36,430	57,922	(96,964)	53,941
Cumulative effect of a change in accounting principle, net of income tax	—	3,981	(1,369)	—	2,612
Net income (loss)	\$ 56,553	\$ 40,411	\$56,553	\$ (96,964)	\$ 56,553

Year Ended December 31, 2002

Amounts in Thousands	Denbury Resources, Inc. (Parent and Issuer)	Guarantor Subsidiaries	Eliminations	Denbury Resources Inc. Consolidated
Revenues	\$231,147	\$ 54,005	\$ —	\$285,152
Expenses	166,805	48,087	—	214,892
Income before the following:	64,342	5,918	—	70,260
Equity in net earnings of subsidiaries	3,456	55	(3,456)	55
Income (loss) before income taxes	67,798	5,973	(3,456)	70,315
Income tax benefit	21,003	2,517	—	23,520
Net income (loss)	\$ 46,795	\$ 3,456	\$ (3,456)	\$ 46,795

Year Ended December 31, 2001

Amounts in Thousands	Denbury Resources, Inc. (Parent and Issuer)	Guarantor Subsidiaries	Eliminations	Denbury Resources Inc. Consolidated
Revenues	\$261,678	\$ 23,433	\$ —	\$285,111
Expenses	181,346	22,391	—	203,737
Income before the following:	80,332	1,042	—	81,374
Equity in net earnings of subsidiaries	653	—	(653)	—
Income (loss) before income taxes	80,985	1,042	(653)	81,374
Income tax provision	24,435	389	—	24,824
Net income (loss)	\$ 56,550	\$ 653	\$ (653)	\$ 56,550

Notes to Consolidated Financial Statements

Condensed Consolidating Statements of Cash Flows

Year Ended December 31, 2003

Amounts in Thousands	Denbury Resources, Inc. (Parent and Co-obligor)	Denbury Onshore, LLC (Issuer and Co-obligor)	Guarantor Subsidiaries	Eliminations	Denbury Resources Inc. Consolidated
Cash flow from operations	\$ —	\$ 146,639	\$ 50,976	\$ —	\$ 197,615
Cash flow from investing activities	—	(81,256)	(54,622)	—	(135,878)
Cash flow from financing activities	1	(61,490)	—	—	(61,489)
Net increase (decrease) in cash flow	1	3,893	(3,646)	—	248
Cash, beginning of period	—	20,281	3,659	—	23,940
Cash, end of period	\$ 1	\$ 24,174	\$ 13	\$ —	\$ 24,188

Year Ended December 31, 2002

Amounts in Thousands	Denbury Resources, Inc. (Parent and Issuer)	Guarantor Subsidiaries	Eliminations	Denbury Resources Inc. Consolidated
Cash flow from operations	\$ 146,132	\$ 13,468	\$ —	\$ 159,600
Cash flow from investing activities	(154,908)	(16,253)	—	(171,161)
Cash flow from financing activities	12,005	—	—	12,005
Net increase (decrease) in cash flow	3,229	(2,785)	—	444
Cash, beginning of period	17,052	6,444	—	23,496
Cash, end of period	\$ 20,281	\$ 3,659	\$ —	\$ 23,940

Year Ended December 31, 2001

Amounts in Thousands	Denbury Resources, Inc. (Parent and Issuer)	Guarantor Subsidiaries	Eliminations	Denbury Resources Inc. Consolidated
Cash flow from operations	\$ 154,034	\$ 31,013	\$ —	\$ 185,047
Cash flow from investing activities	(294,253)	(24,577)	—	(318,830)
Cash flow from financing activities	134,986	—	—	134,986
Net increase (decrease) in cash flow	(5,233)	6,436	—	1,203
Cash, beginning of period	22,285	8	—	22,293
Cash, end of period	\$ 17,052	\$ 6,444	\$ —	\$ 23,496

Notes to Consolidated Financial Statements

Note 14. Unaudited Quarterly Information

In Thousands Except Per Share Amounts	March 31	June 30	Sept. 30	Dec. 31
2003				
Revenues	\$ 86,432	\$ 84,188	\$ 79,415	\$ 82,979
Expenses ⁽¹⁾	58,910	76,660	56,691	60,856
Income before accounting change ⁽²⁾	18,453	5,129	15,149	15,210
Net income ⁽²⁾	21,065	5,129	15,149	15,210
Income per share before accounting change:				
Basic	0.34	0.10	0.28	0.28
Diluted	0.33	0.09	0.27	0.27
Net income per share:				
Basic	0.39	0.10	0.28	0.28
Diluted	0.38	0.09	0.27	0.27
Cash flow from operations	35,509	60,542	49,789	51,775
Cash flow used for investing activities	(18,139)	(54,742)	(35,495)	(27,502)
Cash flow provided by (used for) financing activities	119,860	(147,622)	(5,534)	(28,193)
2002				
Revenues	\$ 55,447	\$ 73,433	\$ 74,524	\$ 81,748
Expenses	49,924	53,842	52,906	58,220
Net income	4,546	13,498	13,459	15,292
Net income per share:				
Basic	0.09	0.25	0.25	0.29
Diluted	0.08	0.25	0.25	0.28
Cash flow from operations	12,032	46,572	44,379	56,617
Cash flow used for investing activities	(27,129)	(32,069)	(80,622)	(31,341)
Cash flow provided by (used for) financing activities	5,970	(8,697)	38,992	(24,260)

(1) In the second quarter of 2003, we incurred a \$17.6 million (\$11.5 million net of income tax) loss on early retirement of debt (see Note 6).

(2) In the first quarter of 2003, we recognized a gain of \$2.6 million for the cumulative effect adoption of SFAS 143, "Accounting for Asset Retirement Obligations" (see Note 4).

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 March 1, 2004, to the best of our knowledge, Denbury's common stock was held of record by approximately 5,700 holders.

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.

	NYSE	
	High	Low
2003		
First quarter	\$11.59	\$10.18
Second quarter	13.86	10.25
Third quarter	13.95	11.65
Fourth quarter	14.24	11.23
2003 annual	\$14.24	\$10.18
2002		
First quarter	\$ 8.50	\$ 6.20
Second quarter	10.42	7.91
Third quarter	10.35	7.80
Fourth quarter	11.97	9.45
2002 annual	\$11.97	\$ 6.20

CORPORATE INFORMATION

Board of Directors

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

David I. Heather
President
The Scotia Group
Dallas, Texas

David B. Miller
Senior Managing Director
EnCap Investments L.L.C.
Dallas, Texas

William S. Price, III
Principal
Texas Pacific Group
San Francisco, California

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

Jeffrey Smith
Principal
Texas Pacific Group
San Francisco, California

Wieland F. Wettstein
Executive V.P.
Finex Financial
Corporation, Ltd.
Calgary Alberta

Carrie Wheeler
Principal
Texas Pacific Group
San Francisco, California

Officers

Gareth Roberts
President & C.E.O.

Tracy Evans
Senior Vice President,
Reservoir Engineering

Phil Rykhoek
Senior Vice President
and Chief Financial Officer

Mark Worthey
Senior Vice President, Operations

Mark Allen
Vice President and
Chief Accounting Officer

Ron Gramling
Vice President, Marketing

Ray Dubuisson
Vice President, Land

Jim Sinclair
Vice President, Exploration

Corporate Headquarters

5100 Tennyson Parkway,
Suite 3000
Plano, Texas 75024
Telephone (972) 673-2000
Fax (972) 673-2150

Register and Transfer Agent

American Stock Transfer
and Trust Company
New York, NY

Legal Counsel

Jenkins & Gilchrist

Bankers

Bank One (Agent)

Auditors

Deloitte & Touche LLP

Evaluation Engineers

DeGolyer & MacNaughton

Stock Exchange

New York Stock Exchange
Trading Symbol: DNR

For Further Information

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

You may contact our board members by addressing a letter to:

Denbury Resources Inc.,
Attn: Corporate Secretary, or by
e-mail to secretary@denbury.com

We will send shareholders a copy of our 2003 Annual Report on Form 10-K filed with the SEC, or any of our corporate governance documents, without charge, upon written request to Laurie Burkes at the Company's headquarters. This report can also be accessed at our website, www.denbury.com. We have included our Section 302 certifications by the CEO and CFO in our Form 10-K filed with the SEC.

Annual Meeting

The annual meeting of stockholders will be held on May 12, 2004, at 3:00 P.M., local time, at the Denbury offices located at:

5100 Tennyson Parkway, Suite 3000
Plano, Texas 75024.

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



DENBURY RESOURCES INC.

5100 Tennyson Parkway Suite 3000 • Plano, TX 75024

Phone: 972.673.2000 • Fax: 972.673.2150

www.denbury.com