GENESIS ENERGY LP
Form 10-K
March 15, 2007

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

Form 10-K

x ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(D) OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended December 31, 2006

OR

¨ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(D) OF THE SECURITIES EXCHANGE ACT OF 1934

Commission file number 1-12295

GENESIS ENERGY, L.P.
(Exact name of registrant as specified in its charter)

Delaware	**76-0513049**
(State or other jurisdictions of incorporation or organization)	*(I.R.S. Employer Identification No.)*
500 Dallas, Suite 2500, Houston, TX	**77002**
(Address of principal executive offices)	*(Zip code)*
Registrant's telephone number, including area code:	**(713) 860-2500**

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

Title of Each Class on Which Registered	**Name of Each Exchange on Which Registered**
Common Units	American Stock Exchange

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

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Exchange Act of 1934.

Yes ¨ No x

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act.

Yes ¨ No x

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Act during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

Yes x No ¨

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of “accelerated filer and large accelerated filer” in Rule 12b-2 of the Exchange Act.

Large accelerated filer ¨ Accelerated filer x Non-accelerated filer ¨

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2) of the Act).

Yes ¨ No x

The aggregate market value of the common units held by non-affiliates of the Registrant on June 30, 2006 (the last business day of Registrant’s most recently completed second fiscal quarter) was approximately $177,537,000 based on $13.98 per unit, the closing price of the common units as reported on the American Stock Exchange. At March 1, 2007, the Registrant had 13,784,441 common units were outstanding.

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FORWARD-LOOKING INFORMATION

The statements in this Annual Report on Form 10-K that are not historical information may be "forward looking statements" within the meaning of the various provisions of the Securities Act of 1933 and the Securities Exchange Act of 1934. All statements, other than historical facts, included in this document that address activities, events or developments that we expect or anticipate will or may occur in the future, including things such as plans for growth of the business, future capital expenditures, competitive strengths, goals, references to future goals or intentions and other such references are forward-looking statements. These forward-looking statements are identified as any statement that does not relate strictly to historical or current facts. They use words such as "anticipate," "believe," "continue," "estimate," "expect," "forecast," "intend," "may," "plan," "position," "projection," "strategy" or "will" or th terms or other variations of them or by comparable terminology. In particular, statements, expressed or implied, concerning future actions, conditions or events or future operating results or the ability to generate sales, income or cash flow are forward-looking statements. Forward-looking statements are not guarantees of performance. They involve risks, uncertainties and assumptions. Future actions, conditions or events and future results of operations may differ materially from those expressed in these forward-looking statements. Many of the factors that will determine these results are beyond our ability or the ability of our affiliates to control or predict. Specific factors that could cause actual results to differ from those in the forward-looking statements include:

- *demand for, the supply of, changes in forecast data for, and price trends related to crude oil, liquid petroleum, natural gas and natural gas liquids or "NGLs" in the United States, all of which may be affected by economic activity, capital expenditures by energy producers, weather, alternative energy sources, international events, conservation and technological advances;*
- *throughput levels and rates;*
- *changes in, or challenges to, our tariff rates;*
- *our ability to successfully identify and consummate strategic acquisitions, make cost saving changes in operations and integrate acquired assets or businesses into our existing operations;*
- *service interruptions in our liquids transportation systems, natural gas transportation systems or natural gas gathering and processing operations;*
- *shut-downs or cutbacks at refineries, petrochemical plants, utilities or other businesses for which we transport crude oil, natural gas or other products or to whom we sell such products;*
- *changes in laws or regulations to which we are subject;*
- *our inability to borrow or otherwise access funds needed for operations, expansions or capital expenditures as a result of existing debt agreements that contain restrictive financial covenants;*
- *loss of key personnel;*
- *the effects of competition, in particular, by other pipeline systems;*
- *hazards and operating risks that may not be covered fully by insurance;*
- *the condition of the capital markets in the United States;*

- *loss of key customers;*
- *the political and economic stability of the oil producing nations of the world; and*
- *general economic conditions, including rates of inflation and interest rates.*

You should not put undue reliance on any forward-looking statements. When considering forward-looking statements, please review the risk factors described under "Risk Factors" discussed in Item 1A. Except as required by applicable securities laws, we do not intend to update these forward-looking statements and information.

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PART I

Items 1 and 2. Business and Properties

General

We are a growth-oriented midstream energy partnership that was formed in 1996 as a master limited partnership, or MLP. We have a diverse portfolio of customers and assets, including pipeline transportation of primarily crude oil and, to a lesser extent, natural gas and carbon dioxide, or CO_2, in the Gulf Coast region of the United States. In conjunction with our crude oil pipeline transportation operations, we operate a crude oil gathering and marketing business, which helps ensure a base supply of crude oil for our pipelines. We also participate in industrial gas activities, including a CO_2 supply business, which is associated with the CO_2 tertiary oil recovery process being used in Mississippi by an affiliate of our general partner. We also own a 50% interest in a joint venture that processes natural gas to produce syngas and high-pressure steam. During 2006 we acquired a 50% interest in a joint venture that produces and distributes liquid CO_2 for use in the food, beverage, chemical and oil industries. We attempt to minimize our exposure to changes in the prices of energy commodities by structuring our compensation arrangements for each service we provide in a manner that is not directly linked to commodity prices.

We conduct our business through three primary segments:

Pipeline Transportation—Our core business is the transportation of crude oil for others for a fee. The rates on substantially all of our pipelines are regulated by the Federal Energy Regulatory Commission, or FERC, or the Railroad Commission of Texas. Our 235-mile Mississippi System provides shippers of crude oil in Mississippi indirect access to refineries, pipelines, storage, terminaling and other crude oil infrastructure located in the Midwest. Our 90-mile Texas System extends from West Columbia to Webster, Webster to Texas City and Webster to Houston. Our 100-mile Jay System originates in southern Alabama and the panhandle of Florida and extends to a point near Mobile, Alabama. On a much smaller scale, we also transport CO_2 and natural gas for a fee.

Crude Oil Gathering and Marketing—We conduct certain crude oil aggregating operations, which involve purchasing, gathering and transporting by trucks and pipelines operated by us and trucks, pipelines and barges operated by others, and reselling, that (among other things) help ensure a base supply source for our crude oil pipeline systems. Our profit for those services is derived from the difference between the price at which we re-sell crude oil less the price at which we purchase that crude oil, minus the associated costs of aggregation and any cost of supplying credit. The most substantial component of our aggregating costs relates to operating our fleet of leased trucks. Our crude oil gathering and marketing activities provide us with an extensive expertise, knowledge base and skill set that facilitate our ability to capitalize on regional opportunities which arise from time to time in our market areas. Usually, this segment experiences limited commodity price risk because we generally make back-to-back purchases and sales, matching our sale and purchase volumes on a monthly basis.

Industrial Gases.

- *CO_2* — We supply CO_2 to industrial customers under seven long-term contracts, with an average remaining contract life of 10 years. We acquired those contracts, as well as the CO_2 necessary to satisfy substantially all of the obligations under those contracts, in three separate transactions with affiliates of our general partner. Our compensation for supplying CO_2 to our industrial customers is the effective difference between the price at which we sell our CO_2 under each contract and the price at which we acquired our CO_2 pursuant to our volumetric production payments (also known as VPPs), minus transportation costs. We expect our CO_2 contracts to provide stable cash flows until they expire. Prior to the expiration, we intend to extend or replace those contracts.

- *Syngas*—Through our 50% interest in a joint venture, we receive a proportionate share of fees under a processing agreement covering a facility that manufactures syngas and high-pressure steam. Under that processing agreement, Praxair provides the raw materials to be processed and receives the syngas and steam produced by the facility. Praxair has the exclusive right to use the facility through at least 2016, which Praxair has the option to extend for two additional five year terms. Praxair also is our partner in the joint venture and owns the remaining 50% interest.

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- *Sandhill* - Through our 50% interest in a joint venture, we participate in the production and distribution of liquid carbon dioxide for use in the food, chemical and oil industries. The Sandhill facility acquires CO_2 from us under one of the long-term supply contracts described above.

We conduct our operations through subsidiaries and joint ventures. As is common with publicly-traded partnerships, or MLPs, our general partner is responsible for operating our business, including providing all necessary personnel and other resources.

Our General Partner and Our Relationship with Denbury Resources Inc.

We continue to benefit from our affiliation with Denbury Resources Inc. (NYSE: DNR), which indirectly owns our general partner and a 9.25% ownership interest in us. Denbury is a publicly traded oil and gas exploration and production company with operations located primarily in Mississippi, Louisiana and Texas. As a result of its emphasis on the tertiary recovery of crude oil using CO_2 flooding, Denbury has become the largest producer (based on average barrels produced per day) of crude oil in the State of Mississippi, and owns approximately 5.5 trillion cubic feet of proved CO_2 reserves as of December 31, 2006.

In addition to its ownership interests in us, we have other significant commercial arrangements with Denbury. Denbury (including its subsidiaries) is:

- the only shipper (other than us) on our Mississippi System, utilizing approximately 90% of the current daily throughput;

- the company that sold us seven long-term CO_2 sales contracts with industrial customers, along with the CO_2 necessary to satisfy substantially all of our obligations under those contracts (280.0 billion cubic feet (Bcf) of CO_2 under three separate VPPs);

- the operator of the fields in which our CO_2 reserves are located; and

- the sole shipper on our Brookhaven CO_2 pipeline.

Denbury is a uniquely situated energy company. It is one of only a handful of producers in the U.S. that possess extensive CO_2 tertiary recovery expertise, as well as large quantities of low-cost CO_2 reserves. Denbury is conducting the largest CO_2 tertiary recovery operations in the Eastern Gulf Coast of the U.S., an area with many mature oil reservoirs that potentially contain substantial volumes of recoverable crude oil. We believe our relationship with Denbury, as well as the geographic proximity of our operations to Denbury's, provides us opportunities to develop new crude oil transportation and CO_2 opportunities.

Although Denbury is not obligated to enter into any transactions with (or to offer any opportunities to) us, Denbury has expressed indications of interest in selling to us (and entering into arrangements under which Denbury would have the exclusive right to utilize) specified CO_2 infrastructure assets, including some that have not yet been placed in-service, subject to the satisfaction of certain conditions. Those conditions include the negotiation of material terms, the execution of definitive agreements, the existence of adequate credit support and our acquisition (by construction or purchase) of assets that are not related to Denbury's operations in an amount at least equal to 150% of the amount of new acquisitions or financings we complete with Denbury. We hope the consummation of such arrangements might lead to other opportunities with Denbury in the future.

Our Objective and Strategies

Our objective is to operate as a growth-oriented midstream MLP with a focus on increasing cash flow, earnings and return to our unitholders by becoming one of the leading providers of pipeline transportation, crude oil gathering and marketing and industrial gas services in the regions in which we operate. Our management team is committed to increasing the amount of cash available for distribution by executing the following strategies:

- Increasing throughput on our existing assets.
- Pursuing organic growth opportunities through construction and expansion opportunities.
- Pursuing accretive acquisitions and expanding our footprint.
- Leveraging our CO_2 expertise, along with our relationship with Denbury, to create new opportunities with Denbury and third parties.

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- Capitalizing on the regional crude oil supply and demand imbalances that exist in our market areas through our marketing and distribution expertise.

- Emphasizing services for which the compensation is not linked to commodity prices (like gathering and transportation) and managing commodity risks by using contractual arrangements.

- Maintaining a balanced and diversified portfolio of midstream energy and industrial gases interests and assets.

- Maintaining a sound capital structure.

- Sharing capital costs and risks through joint ventures and strategic alliances.

Our Key Strengths

Based on the following competitive strengths, we believe we are well positioned to execute our strategies and ultimately achieve our objective:

- *Quality Asset Base*. We have a quality asset base characterized by:

- *Strategic Locations*. Our Mississippi System is adjacent to several oil fields operated by Denbury, which is the sole shipper (other than us) on our Mississippi System. To our knowledge, our Jay System is the only system serving the Florida panhandle and southwest Alabama.

- *Additional Throughput Capacity*. All of our systems have additional throughput capacity which allows us to transport additional volumes at minimal additional cost to us.

- *Cash Flow Stability*. Our relatively low exposure to commodity price fluctuations, diversified asset base and long-term contracts related to our industrial gases operations provide us with a stable source of cash flows.

- *A Unique Platform in Industrial Gases*. We believe we have the potential to expand our CO_2 business and leverage that expertise, along with our relationship with Denbury, to create a unique growth platform in industrial gases, an area not currently as competitive as other midstream industry activities.

- *Strong Relationship with Denbury*. We have a strong relationship with Denbury, which is the indirect owner of our general partner and the largest exploration and production company (based on average barrels produced per day) currently operating in Mississippi. Denbury is the sole shipper (other than us) on our Mississippi System, and its extensive CO_2 reserves and operations provide us the opportunity to expand our crude oil transportation and CO_2 opportunities.

- *Financial Flexibility and Strong Distribution Coverage*. We have the financial flexibility to pursue growth projects. As of December 31, 2006, we had a credit facility with a maximum credit amount of $500 million and an initial committed amount of $125 million. Our borrowing base as of December 31, 2006 was approximately $82 million. The commitment amount can be increased up to the maximum facility amount for acquisitions or internal growth projects with approval of the lenders. Likewise, the borrowing base may be increased to the extent of earnings before interest, taxes, depreciation and amortization, or EBITDA, attributable to acquisitions. We had $8 million of long-term debt and $4.6 million of letters of credit outstanding and we have approximately $70 million of borrowing capacity under our credit facility available on December 31, 2006.

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Insulation from Commodity Price Risks. Many of our contractual arrangements help insulate our operating cash flows from changes in energy commodity prices. Our compensation arrangements include fee-based arrangements, back-to-back purchases and sales, and tolling-type arrangements, which in general do not vary with changes in the price of the underlying commodity. We also use hedges from time to time to mitigate the impact of fluctuations in energy commodity prices on our segment margins.

- *Balanced and Diversified Operations*. We have a balanced portfolio of customers and assets and a proven track record of cash flow diversification. Our operations include the pipeline transportation of crude oil and, to a lesser extent, CO_2 and natural gas in the Gulf Coast; crude oil gathering and marketing primarily around our Gulf Coast crude oil pipelines; and industrial gas activities.

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Recent Developments

New Credit Facility

On November 15, 2006, we replaced our existing credit facility with a $500 million Senior Secured Revolving Credit Agreement between Genesis Crude Oil, L.P. and a syndicate of lenders. Our new credit facility, with a maximum facility amount of $500 million, is with a group of banks led by Fortis Capital Corp. and Deutsche Bank Securities Inc. The initial committed amount under our facility is $125 million, of which a maximum of $50 million may be used for letters of credit. The committed amount represents the amount the banks have committed to fund pursuant to the terms of the credit agreement. The borrowing base under the facility at December 31, 2006 was approximately $82 million, and it will be recalculated quarterly and at the time of acquisitions. The borrowing base represents the amount that can be borrowed or utilized for letters of credit from a credit standpoint based on our EBITDA, computed in accordance with the provisions of our credit facility. The commitment amount may be increased up to the maximum facility amount for acquisitions and internal growth projects with approval of the lenders. Likewise, the borrowing base may be increased to the extent of EBITDA attributable to acquisitions.

Distribution Increases

On November 14, 2006, we paid a cash distribution of $0.20 per unit for the quarter ended September 30, 2006. This was the fifth consecutive quarter in which we increased our distribution by $0.01 per unit. We increased our distribution again for the quarter ended December 31, 2006, with a distribution of $0.21 per unit to unitholders of record as of February 2, 2007 paid on February 14, 2007.

New Management Team

On August 8, 2006, we hired three senior executive officers: Grant E. Sims, former CEO of Leviathan Gas Pipeline Partners, L.P., was appointed as the new Chief Executive Officer and a member of the Board of Directors; Joseph A. Blount, Jr., former President and Chief Operating Officer of Unocal Midstream & Trade, was appointed as President and Chief Operating Officer; and Brad N. Graves, former Vice President of Enterprise Products Partners, L.P., was appointed as Executive Vice President of Business Development. This management team is responsible for designing and implementing a growth-oriented strategy that will include acquisitions from third parties, development projects and, ultimately, acquisitions from (or lease or financing arrangements with) Denbury. The new management team will have the opportunity to earn up to 20% of the equity interest in our general partner (currently owned 100% by Denbury) subject to meeting certain performance criteria.

Acquisition of Sandhill Joint Venture

On April 1, 2006, we acquired a 50% partnership interest in Sandhill Group, LLC for $5 million from Magna Carta Group, LLC. Magna Carta holds the other 50% interest in Sandhill. Sandhill is a limited liability company that owns a CO_2 processing facility located in Brandon, Mississippi. Sandhill is engaged in the production and distribution of liquid carbon dioxide for use in the food, chemical and oil industries. The facility acquires CO_2 from us under a long-term supply contract that we acquired in 2005 from Denbury.

The acquisition was financed with cash on hand. The terms of the acquisition include earnout provisions such that additional payments of up to $2.0 million would be paid by us to Magna Carta if Sandhill achieves targeted performance levels during the seven years between 2006 and 2012 inclusive. We have also guaranteed to Sandhill's lender 50% of the outstanding debt of $4.5 million, or $2.25 million. We believe that our investment in Sandhill will provide opportunities to expand our footprint in our industrial gases activities.

Description of Segments and Related Assets

Pipeline Transportation

Our core business is the transportation of crude oil for others for a fee. Through the pipeline systems we own and operate, we transport crude oil for our gathering and marketing operations and other shippers pursuant to tariff rates regulated by the Federal Energy Regulatory Commission, or FERC, or the Railroad Commission of Texas. Accordingly, we offer transportation services to any shipper of crude oil, if the products tendered for transportation satisfy the conditions and specifications contained in the applicable tariff. Pipeline revenues are a function of the level of throughput and the particular point where the crude oil was injected into the pipeline and the delivery point. We also can earn revenue from pipeline loss allowance volumes. In exchange for bearing the risk of pipeline volumetric losses, we deduct volumetric pipeline loss allowances and crude quality deductions. Such allowances and deductions are offset by measurement gains and losses. When the allowances and deductions exceed measurement losses, the net pipeline loss allowance volumes are earned and recognized as income and inventory available for sale valued at the market price for the crude oil.

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The margins from our pipeline operations are generated by the difference between the revenues from regulated published tariffs, pipeline loss allowance revenues and the fixed and variable costs of operating and maintaining our pipelines.

We own and operate three common carrier crude oil pipeline systems. Our 235-mile Mississippi System provides shippers of crude oil in Mississippi indirect access to refineries, pipelines, storage, terminaling and other crude oil infrastructure located in the Midwest. Our 100-mile Jay System originates in southern Alabama and the panhandle of Florida and extends to a point near Mobile, Alabama. Our 90-mile Texas System extends from West Columbia to Webster, Webster to Texas City and Webster to Houston. On a much smaller scale, we also transport CO_2 and natural gas for a fee.

Mississippi System. Our Mississippi System extends from Soso, Mississippi to Liberty, Mississippi and includes tankage at various locations with an aggregate storage capacity of 200,000 barrels. This System is adjacent to several oil fields operated by Denbury, which is the sole shipper (other than us) on our Mississippi System. As a result of its emphasis on the tertiary recovery of crude oil using CO_2 flooding, Denbury has become the largest producer (based on average barrels produced per day) of crude oil in the State of Mississippi. As Denbury continues its tertiary recovery activities and increases its production, we expect increased demand for our crude oil transportation services.

We restructured some of our crude oil gathering, marketing and transportation arrangements with Denbury in 2004 to provide for a fee-based arrangement with Denbury under which we transport its crude oil on our regulated pipelines in our Pipeline Transportation Segment. We effected that restructuring by implementing an “incentive” tariff. Under our incentive tariff, the average rate per barrel that we charge during any month decreases as our aggregate throughput for that month increases above specified thresholds. Prior to this restructuring, we handled most of our Mississippi arrangements with Denbury using purchases and sales through our Crude Oil Gathering and Marketing Segment, in which we purchased crude oil from others (including Denbury) and gathered, transported and resold that crude in the market. The new tariff arrangement has improved our rate of return.

Over the last several years, we have initiated and completed several projects that increased the capacity of our Mississippi System. We added tankage and other equipment. During 2006, we reconditioned a 35-mile segment of our Mississippi pipeline so that we could ship crude oil from Denbury’s fields in the Martinville area. During 2004, we constructed a 10-mile, 10-inch CO_2 pipeline that is connected to Denbury’s 183 mile pipeline that transports CO_2 from their Jackson Dome CO_2 reservoir. Our pipeline moves the CO_2 to the Brookhaven oil field to be used by Denbury in tertiary recovery. We entered into a contract granting Denbury the exclusive right to use that CO_2 pipeline through 2012 in exchange for a monthly demand and commodity charge. We constructed an 11-mile, 8-inch extension to our Mississippi oil pipeline next to the CO_2 pipeline to transport the crude oil from the Brookhaven field to our existing pipeline. We also constructed a 5-mile extension from our existing Mississippi crude oil pipeline to Denbury’s Olive field during 2004. We undertook those projects in response to increasing crude oil production in the area. We expect those production rates to continue to increase primarily as a result of the broad-based CO_2 tertiary recovery projects that Denbury is currently undertaking and has announced it will undertake in the future. We intend to develop other organic growth opportunities related to our Mississippi System.

Jay System. Our Jay System begins near oil fields in southern Alabama and the panhandle of Florida and extends to a point near Mobile, Alabama. Our Jay System includes tankage with 230,000 barrels of storage capacity, primarily at Jay station. Recent changes in ownership of the more mature producing fields in the area surrounding our Jay System have led to interest in further development activities regarding those fields which may lead to increases in production. Additional, new wells have been drilled in the area. This new production produces greater tariff revenue for us due to the greater distance that the crude oil travels on the pipeline. This increased revenue, increases in tariff rates each year on the remaining segments of the pipeline, sales of pipeline loss allowance volumes, and operating efficiencies that have decreased operating costs have contributed to increase our cash flows from the Jay System.

Texas System. The active segments of the Texas System extend from West Columbia to Webster, Webster to Texas City and Webster to Houston. These segments include approximately 90 miles of pipe. The Texas System receives all of its volume from connections to other pipeline carriers. We charge a tariff rate for our transportation services, with the tariff rate per barrel of crude oil varying with the distance from injection point to delivery point. We entered into a joint tariff with TEPPCO Crude Pipeline, L.P. (TEPPCO) to receive oil from their system at West Columbia and a joint tariff with TEPPCO and ExxonMobil Pipeline Company to receive oil from their systems at Webster. We also continue to receive barrels from a connection with Seminole Pipeline Company at Webster. We own tankage with approximately 110,000 barrels of storage capacity associated with the Texas System. We lease an additional approximately 165,000 barrels of storage capacity for our Texas System in Webster. We have a tank rental reimbursement agreement effective January 1, 2005 with the primary shipper on our Texas System to reimburse us for the lease of this storage capacity at Webster.

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Natural Gas Pipelines. In January 2005, we acquired natural gas pipeline and gathering systems located in Texas, Louisiana and Oklahoma from Multifuels Energy Asset Group, L.P. These systems are comprised of approximately 45 miles of pipeline and related assets.

Customers

Denbury, a large independent energy company, is the sole shipper (other than us) on our Mississippi System. The customers on our Jay and Texas Systems are primarily large, energy companies. Revenues from customers of this segment did not account for more than ten percent of our consolidated revenues.

Competition

Competition among common carrier pipelines is based primarily on posted tariffs, quality of customer service and proximity to production, refineries and connecting pipelines. We believe that high capital costs, tariff regulation and the cost of acquiring rights-of-way make it unlikely that other competing crude oil pipeline systems, comparable in size and scope to our pipelines, will be built in the same geographic areas in the near future.

Industrial Gases

Our industrial gases segment is a natural outgrowth from our core business. Because of the substantial CO_2 flooding tertiary recovery operations being utilized around our Mississippi System, we became familiar with CO_2-related activities and, ultimately, began our CO_2 business in 2003. Our relationships with industrial customers who use CO_2 have expanded, which has introduced us to potential opportunities associated with other industrial gases, such as syngas (also known as synthetic gas), which is a combination of carbon monoxide and hydrogen.

CO_2

We supply CO_2 to industrial customers under seven long-term CO_2 sales contracts. We acquired those contracts, as well as the CO_2 necessary to satisfy substantially all of our expected obligations under those contracts, in three separate transactions with Denbury. Since 2003, we have purchased those contracts, along with three VPPs representing 280.0 Bcf of CO_2 (in the aggregate), from Denbury for a total of $43.1 million in cash. We sell our CO_2 to customers who treat the CO_2 and sell it to end users for use for beverage carbonation and food chilling and freezing. Our compensation for supplying CO_2 to our industrial customers is the effective difference between the price at which we sell our CO_2 under each contract and the price at which we acquired our CO_2 pursuant to our VPPs, minus transportation costs. We expect our CO_2 contracts to provide stable cash flows until they expire, at which time we intend to extend or replace those contracts, including acquiring the necessary CO_2 supply from wholesalers. At December 31, 2006, we have 210.5 Bcf of CO_2 remaining under the VPPs.

Currently, all of our CO_2 supply is from naturally occurring sources - our VPPs. We believe we have an adequate supply to service existing contracts through their terms. When our VPPs expire, we will have to obtain our CO_2 supply from Denbury, from other sources, or discontinue the CO_2 supply business. Denbury will have no obligation to provide us with CO_2, and has the right to compete with us. See "Risks Related to Our Partnership Structure" for a discussion of the potential conflicts of interest between Denbury and us.

One of the parties that we supply with CO_2 under a long-term sales contract is Sandhill Group, LLC. On April 1, 2006, we acquired a 50% interest in Sandhill Group, LLC as discussed below.

Syngas

On April 1, 2005, we acquired from TCHI, Inc., a wholly-owned subsidiary of ChevronTexaco Global Energy, Inc., a 50% partnership interest in T&P Syngas for $13.4 million in cash, which we funded with proceeds from our credit facility. T&P Syngas is a partnership which owns a facility located in Texas City, Texas that manufactures syngas and high-pressure steam. Under a long-term processing agreement, the joint venture receives fees from its sole customer, Praxair Hydrogen Supply, Inc. during periods when processing occurs, and Praxair has the exclusive right to use the facility through at least 2016, which Praxair has the option to extend for two additional five year terms. Praxair also is our partner in the joint venture and owns the remaining 50% interest.

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Sandhill

On April 1, 2006, we acquired from Magna Carta Group, LLC a 50% partnership interest in Sandhill for $5.0 million in cash, which we funded with cash on hand. Magna Carta owns the remaining 50% of Sandhill. Sandhill is a limited liability company that owns a CO_2 processing facility located in Brandon, Mississippi. Sandhill is engaged in the production and distribution of liquid carbon dioxide for use in the food, chemicals and oil industries. The facility acquires CO_2 from us under a long-term supply contract that we acquired in 2005 from Denbury. This contract expires in 2023, and provides for a daily contract quantity of 16,000 Mcf per day with a take-or-pay minimum quantity of 2,500,000 Mcf.

Customers

Five of the seven contracts for supplying CO_2 are with large international companies. One of the remaining contracts is with Sandhill Group, LLC, of which we own 50%. The remaining contract is with a smaller company with a history in the CO_2 business. Revenues from this segment did not account for more than ten percent of our consolidated revenues.

The sole customer of T&P Syngas is Praxair, a worldwide provider of industrial gases.

Sandhill sells to approximately 25 customers, with sales to two of those customers representing approximately 40% of Sandhill's total revenues of approximately $11 million in 2006. Sandhill has long-term relationships with those customers and has not experienced collection problems with them.

Competition

Currently, all of our CO_2 supply is from naturally occurring sources - our VPPs. We believe we have an adequate supply to service existing contracts through their terms. In the future we may have to obtain our CO_2 supply from manufactured processes. Naturally-occurring CO_2, like that from the Jackson Dome area, occurs infrequently, and only in limited areas east of the Mississippi River, including the fields controlled by Denbury. Our industrial CO_2 customers have facilities that are connected to Denbury's CO_2 pipeline to make delivery easy and efficient. Once our existing VPPs expire, we will have to obtain CO_2 from Denbury or other suppliers should we choose to remain in the CO_2 business, and the competition and pricing issues we will face at that time are uncertain.

With regard to sales of CO_2, our contracts have take-or-pay provisions requiring minimum volumes each year for each customer that must be paid for even if the CO_2 is not taken.

Due to the long-term contract and location of our syngas facility, as well as the costs involved in establishing a competing facility, we believe it is unlikely that competing facilities will be established for our syngas processing services.

Sandhill has competition from the other industrial customers to whom we supply CO_2. As discussed above, the limited amounts of naturally-occurring CO_2 east of the Mississippi River makes it difficult for competitors of Sandhill to significantly increase their production or sales.

<u>*Crude Oil Gathering and Marketing*</u>

Our crude oil gathering and marketing operations are concentrated in Texas, Louisiana, Alabama, Florida and Mississippi. These operations, which involve purchasing, gathering and transporting by trucks and pipelines operated by us and trucks, pipelines and barges operated by others, and reselling, help to ensure (among other things) a base supply source for our crude oil pipeline systems. Our profit for those services is derived from the difference between the price at which we re-sell the crude oil less the price at which we purchase that crude oil, minus the associated costs of aggregation and any cost of supplying credit. The most substantial component of our aggregating costs relates to operating our fleet of leased trucks. Usually, this segment experiences limited commodity price risk because we generally make back-to-back purchases and sales, matching our sale and purchase volumes on a monthly basis.

Segment margin from our crude oil gathering and marketing operations varies from period to period, depending, to a significant extent, upon changes in the supply of and demand for crude oil and the resulting changes in U.S. crude oil inventory levels. Generally, as we purchase crude oil, we simultaneously establish a margin by selling crude oil for physical delivery to third party users, such as independent refiners or major oil companies. Through these transactions, we seek to maintain a position that is substantially balanced between crude oil purchases, on the one hand, and sales or future delivery obligations, on the other hand. We do not acquire and hold crude oil, futures contracts or other derivative products for the purpose of speculating on crude oil price changes. When our positions become unbalanced such that we have inventory, we will use derivative instruments to hedge that inventory until such time as we can sell it into the market.

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When the crude oil markets are in contango (oil prices for future deliveries are higher than for current deliveries), we may purchase for our account and store crude oil as inventory in our storage tanks that we have purchased at lower prices in the current month for delivery at higher prices in future months. When we purchase inventory, we simultaneously enter into a contract to sell the inventory in a future period, either with a counterparty or in the crude oil futures market.

Usually, fluctuations in the market price of crude oil do not materially impact us. When market prices for crude oil increase, we must pay more for crude oil, but we normally are able to sell it for more. To the extent we have crude oil inventories, market price changes can impact us if we do not have effective hedges in place.

As of December 31, 2006, we provided crude oil gathering services through our fleet of 48 leased tractor-trailers. The trucking fleet generally hauls the crude oil to one of the approximately 50 pipeline injection stations owned or leased by us. We may sell the crude oil as it exits our injection station and enters the pipeline, or we may ship the crude oil on the pipeline to a point further along the distribution chain. We also transport purchased crude oil on trucks, barges and pipelines operated by third parties.

Producer Services

Crude oil purchasers who buy from producers compete on the basis of competitive prices and quality of services. We believe that our ability to offer high-quality field and administrative services to producers is a key factor in our ability to maintain volumes of purchased crude oil and to obtain new volumes. High-quality field services include efficient gathering capabilities, availability of trucks, willingness to construct gathering pipelines where economically justified, timely pickup of crude oil from tank batteries at the lease or production point, accurate measurement of crude oil volumes received, avoidance of spills and effective management of pipeline deliveries. Accounting and other administrative services include securing division orders (statements from interest owners affirming the division of ownership in crude oil purchased by the Partnership), providing statements of the crude oil purchased each month, disbursing production proceeds to interest owners and calculating and paying production taxes on behalf of interest owners. In order to compete effectively, we must make prompt and correct payment of crude oil production proceeds on a monthly basis, together with the correct payment of all severance and production taxes associated with such proceeds.

Our credit standing is an important consideration for parties from whom we purchase crude oil. In order to assure our ability to perform our obligations under crude oil purchase agreements, various credit arrangements are negotiated with suppliers. These arrangements include open lines of credit directly with us, guarantees or letters of credit.

Customers

Our customers are primarily large integrated and independent energy companies. During 2006, more than ten percent of our consolidated revenues were generated from sales of crude oil to each of three customers, Occidental Energy Marketing, Inc. (20.3%), Shell Oil Company (19.2%) and Calumet Specialty Products Partners, L.P. (10.9%). We do not believe that the loss of any of these customers would have a material adverse effect on us as crude oil is a readily marketable commodity. Generally sales of crude oil settle within 30 days of the month of the delivery.

Competition

In the crude oil gathering and marketing business, there is intense competition for leasehold purchases of crude oil. The number and location of our pipeline systems and trucking facilities give us access to domestic crude oil production throughout our area of operations. We have considerable flexibility in marketing the volumes of crude oil that we purchase, without dependence on any single customer or transportation or storage facility.

Our largest competitors in the purchase of leasehold crude oil production are Plains Marketing, L.P., Shell (US) Trading Company, GulfMark Energy, Inc. and TEPPCO Partners, L.P. Additionally, we compete with many regional or local gatherers who may have significant market share in the areas in which they operate. Competitive factors include price, personal relationships, range and quality of services, knowledge of products and markets, availability of trade credit and capabilities of risk management systems.

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As part of the sale of our Texas Gulf Coast operations to TEPPCO, we agreed not to compete in a 40 county area for five years from the effective date of the transaction of October 31, 2003.

Credit Exposure

Due to the nature of our operations, a disproportionate percentage of our trade receivables constitute obligations of oil companies. This industry concentration has the potential to impact our overall exposure to credit risk, either positively or negatively, in that our customers could be affected by similar changes in economic, industry or other conditions. However, we believe that the credit risk posed by this industry concentration is offset by the creditworthiness of our customer base. Our portfolio of accounts receivable is comprised in large part of integrated and independent energy companies with stable payment experience. The credit risk related to contracts which are traded on the NYMEX is limited due to the daily cash settlement procedures and other NYMEX requirements.

When we market crude oil, we must determine the amount, if any, of the line of credit we will extend to any given customer. We have established various procedures to manage our credit exposure, including initial credit approvals, credit limits, collateral requirements and rights of offset. Letters of credit, prepayments and guarantees are also utilized to limit credit risk to ensure that our established credit criteria are met. We use similar procedures to manage our exposure to our customers in the pipeline transportation and industrial gases segments.

Employees

To carry out various purchasing, gathering, transporting and marketing activities, our general partner employed, at December 31, 2006, approximately 190 employees. None of the employees are represented by labor unions, and we believe that relationships with our employees are good.

Organizational Structure

Genesis Energy, Inc., a Delaware corporation, serves as our sole general partner and as the general partner of our operating partnership, Genesis Crude Oil, L.P., and all of its subsidiary partnerships. Our general partner is owned by Denbury Gathering & Marketing, Inc., a subsidiary of Denbury Resources Inc. Below is a chart depicting our ownership structure.

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(1) Our general partner owns all of our incentive distribution rights. Our general partner has agreed to enter into contracts with our Senior Executives that will include terms providing for the ability of those executives to earn up to 20 percent of the equity in the 2% general partner interest. See additional discussion at "Item 11. Executive Compensation."

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Regulation

Pipeline Tariff Regulation

The interstate common carrier pipeline operations of the Jay and Mississippi Systems are subject to rate regulation by FERC under the Interstate Commerce Act, or ICA. FERC regulations require that oil pipeline rates be posted publicly and that the rates be “just and reasonable” and not unduly discriminatory.

Effective January 1, 1995, FERC promulgated rules simplifying and streamlining the ratemaking process. Previously established rates were “grandfathered”, limiting the challenges that could be made to existing tariff rates. Increases from grandfathered rates of interstate oil pipelines are currently regulated by the FERC primarily through an index methodology, whereby a pipeline is allowed to change its rates based on the year-to-year change in an index. Under the regulations, we are able to change our rates within prescribed ceiling levels that are tied to the Producer Price Index for Finished Goods. Rate increases made pursuant to the index will be subject to protest, but such protests must show that the portion of the rate increase resulting from application of the index is substantially in excess of the pipeline's increase in costs.

In addition to the index methodology, FERC allows for rate changes under three other methods—a cost-of-service methodology, competitive market showings (“Market-Based Rates”), or agreements between shippers and the oil pipeline company that the rate is acceptable (“Settlement Rates”). The pipeline tariff rates on our Mississippi and Jay Systems are either rates that were grandfathered and have been changed under the index methodology, or Settlement Rates. None of our tariffs have been subjected to a protest or complaint by any shipper or other interested party.

Our intrastate common carrier pipeline operations in Texas are subject to regulation by the Railroad Commission of Texas. The applicable Texas statutes require that pipeline rates be non-discriminatory and provide a fair return on the aggregate value of the property of a common carrier, after providing reasonable allowance for depreciation and other factors and for reasonable operating expenses. Most of the volume on our Texas System is now shipped under joint tariffs with TEPPCO and Exxon. Although no assurance can be given that the tariffs we charge would ultimately be upheld if challenged, we believe that the tariffs now in effect can be sustained.

Our natural gas gathering pipelines and CO_2 pipeline are subject to regulation by the state agencies in the states in which they are located.

Environmental Regulations

We are subject to stringent federal, state and local laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection. These laws and regulations may require the acquisition of permits for regulated activities, limit or prohibit operations on environmentally sensitive lands such as wetlands or wilderness areas, result in capital expenditures to limit or prevent emissions or discharges, and place burdensome restrictions on the management and disposal of wastes. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, the imposition of remedial obligations, and the imposition of injunctive obligations. Changes in environmental laws and regulations occur frequently, and any changes that result in more stringent and costly operating restrictions, emission control, waste handling, disposal, cleanup, and other environmental requirements have the potential to have a material adverse effect on our operations. While we believe that we are in substantial compliance with current environmental laws and regulations and that continued compliance with existing requirements would not materially affect us, there is no assurance that this trend will continue in the future.

The Comprehensive Environmental Response, Compensation, and Liability Act, as amended, or CERCLA, also known as the "Superfund" law, and analogous state laws impose liability, without regard to fault or the legality of the original conduct, on certain classes of persons, including current owners and operators of a contaminated facility, owners and operators of the facility at the time of contamination, and those parties arranging for waste disposal at a contaminated facility. Such "responsible persons" may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment and for damages to natural resources. In cases of environmental contamination, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment. We also may incur liability under the Resource Conservation and Recovery Act, as amended, or RCRA, which imposes requirements relating to the management and disposal of solid and hazardous wastes.

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We currently own or lease, and have in the past owned or leased, properties that have been in use for many years by various persons including third parties over whom we have no control in connection with the gathering and transportation of hydrocarbons including crude oil. We also may generate, handle and dispose of regulated materials in the course of our operations. We may therefore be subject to liability and regulation under CERCLA, RCRA and analogous state laws for hydrocarbons or other wastes that may have been disposed of or released on or under those properties or under other locations where such wastes have been taken for disposal. Under these laws and regulations, we could be required to undertake investigations into suspected contamination, remove previously disposed wastes, remediate environmental contamination, restore affected properties, or undertake measures to prevent future contamination.

The Federal Water Pollution Control Act, as amended, also known as the “Clean Water Act” and the Oil Pollution Act, or OPA, and analogous state laws and regulations promulgated thereunder impose restrictions and controls regarding the discharge of pollutants, including crude oil, into federal and state waters. The Clean Water Act and OPA provide administrative, civil and criminal penalties for any unauthorized discharges of pollutants, including oil, and imposes liabilities for the costs of remediation of spills. Federal and state permits for water discharges also may be required. OPA also requires operators of offshore facilities and certain onshore facilities near or crossing waterways to provide financial assurance generally ranging from $10 million in state waters to $35 million in federal waters to cover potential environmental cleanup and restoration costs. This amount can be increased to a maximum of $150 million under certain limited circumstances where the Minerals Management Service believes such a level is justified based on the worst case spill risks posed by the operations. We have developed an Integrated Contingency Plan to satisfy components of the OPA as well as the federal Department of Transportation, the federal Occupational Safety Health Act, or OSHA, and state laws and regulations. We believe this plan meets regulatory requirements as to notification, procedures, response actions, response resources and spill impact considerations in the event of an oil spill.

On December 20, 1999, we had a spill of crude oil from our Mississippi System. Approximately 8,000 barrels of oil spilled from the pipeline near Summerland, Mississippi, and discharged into surface water. The spill was cleaned up, with ongoing monitoring and clean-up activity expected to continue for an undetermined period of time. The oil spill clean up and related costs have thus far been covered by insurance and the financial impact to us for the cost of the clean-up has not been material. We expect our insurance carrier to continue paying for monitoring and clean-up costs and we do not expect future costs to us to be material. During 2004, we finalized agreements with the United States Environmental Protection Agency, or EPA, and the Mississippi Department of Environmental Quality, or MDEQ, pursuant to which we paid a $3.0 million fine with respect to this spill. The fine was not covered by insurance and was recorded to expense in 2001 and 2002.

The Clean Air Act, as amended, and analogous state and local laws and regulations restrict the emission of air pollutants including volatile organic compounds or “VOCs”, impose permit requirements and other obligations. VOC emissions may occur from the handling or storage of crude oil and other petroleum products. Both federal and state laws impose substantial penalties for violation of these applicable requirements.

Under the National Environmental Policy Act, or NEPA, a federal agency, commonly in conjunction with a current permittee or applicant, may be required to prepare an environmental assessment or a detailed environmental impact statement before taking any major action, including issuing a permit for a pipeline extension or addition that would affect the quality of the environment. Should an environmental impact statement or environmental assessment be required for any proposed pipeline extensions or additions, NEPA may prevent or delay construction or alter the proposed location, design or method of construction.

Safety and Security Regulations

Our crude oil, natural gas and CO_2 pipelines are subject to construction, installation, operation and safety regulation by the Department of Transportation, or DOT, and various other federal, state and local agencies. The Pipeline Safety Act of 1992, among other things, amends the Hazardous Liquid Pipeline Safety Act of 1979, or HLPSA, in several important respects. It requires the Pipeline and Hazardous Materials Safety Administration of DOT to consider environmental impacts, as well as its traditional public safety mandates, when developing pipeline safety regulations. In addition, the Pipeline Safety Improvement Act of 2005 mandates the establishment by DOT of pipeline operator qualification rules requiring minimum training requirements for operators, the development of standards and criteria to evaluate contractors' methods to qualify their employees and requires that pipeline operators provide maps and other records to the DOT. It also authorizes the DOT to require that pipelines be modified to accommodate internal inspection devices, to mandate the evaluation of emergency flow restricting devices for pipelines in populated or sensitive areas, and to order other changes to the operation and maintenance of petroleum pipelines. Significant expenses could be incurred in the future if additional safety measures are required or if safety standards are raised and exceed the current pipeline control system capabilities.

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On March 31, 2001, the DOT promulgated Integrity Management Plan, or IMP, regulations. The IMP regulations require that we perform baseline assessments of all pipelines that could affect a High Consequence Area, or HCA, including certain populated areas and environmentally sensitive areas. Due to the proximity of all of our pipelines to water crossings and populated areas, we have designated all of our pipelines as affecting HCAs. The integrity of these pipelines must be assessed by internal inspection, pressure test, or equivalent alternative new technology.

The IMP regulation required us to prepare an Integrity Management Plan that details the risk assessment factors, the overall risk rating for each segment of pipe, a schedule for completing the integrity assessment, the methods to assess pipeline integrity, and an explanation of the assessment methods selected. The risk factors to be considered include proximity to population areas, waterways and sensitive areas, known pipe and coating conditions, leak history, pipe material and manufacturer, adequacy of cathodic protection, operating pressure levels and external damage potential. The IMP regulations require that the baseline assessment be completed by March 31, 2009, with 50% of the mileage assessed by September 30, 2005. Reassessment is then required every five years. As testing is complete, we are required to take prompt remedial action to address all integrity issues raised by the assessment. No assurance can be given that the cost of testing and the required rehabilitation identified will not be material costs to us that may not be fully recoverable by tariff increases. At December 31, 2006, we had completed assessments and repairs on the major sections of our pipelines.

We have developed a Risk Management Plan as part of our IMP. This plan is intended to minimize the offsite consequences of catastrophic spills. As part of this program, we have developed a mapping program. This mapping program identified HCAs and unusually sensitive areas along the pipeline right-of-ways in addition to mapping of shorelines to characterize the potential impact of a spill of crude oil on waterways.

States are responsible for enforcing the federal regulations and more stringent state pipeline regulations and inspection with respect to hazardous liquids pipelines, including crude oil and CO_2 pipelines, and natural gas pipelines that do not engage in interstate operations. In practice, states vary considerably in their authority and capacity to address pipeline safety. We do not anticipate any significant problems in complying with applicable state laws and regulations in those states in which we operate.

Our crude oil pipelines are also subject to the requirements of the federal Department of Transportation regulations requiring qualification of all pipeline personnel. The Operator Qualification, or OQ, program required operators to develop and submit a written program. The regulations also required all pipeline operators to develop a training program for pipeline personnel and to qualify them on covered tasks at the operator’s pipeline facilities. The intent of the OQ regulations is to ensure a qualified workforce by pipeline operators and contractors when performing covered tasks on the pipeline and its facilities, thereby reducing the probability and consequences of incidents caused by human error.

Our crude oil operations are also subject to the requirements of OSHA and comparable state statutes. We believe that our crude oil pipelines and trucking operations have been operated in substantial compliance with OSHA requirements, including general industry standards, record keeping requirements and monitoring of occupational exposure to regulated substances. Various other federal and state regulations require that we train all employees in pipeline and trucking operations in HAZCOM and disclose information about the hazardous materials used in our operations. Certain information must be reported to employees, government agencies and local citizens upon request.

In general, we expect our expenditures in the future to comply with higher industry and regulatory safety standards such as those described above to increase over historical levels. While the total amount of increased expenditures cannot be accurately estimated at this time, we anticipate that we will spend a total of approximately $1.0 to 1.5 million each year for testing and improvements under the IMP.

We operate our fleet of leased trucks as a private carrier. Although a private carrier that transports property in interstate commerce is not required to obtain operating authority from the relevant agency, the carrier is subject to certain motor carrier safety regulations issued by the DOT. The trucking regulations cover, among other things, driver operations, maintaining log books, truck manifest preparations, the placement of safety placards on the trucks and trailer vehicles, drug testing, safety of operation and equipment, and many other aspects of truck operations. We are also subject to OSHA with respect to our trucking operations. We are subject to federal EPA regulations for the development of written Spill Prevention Control and Countermeasure, or SPCC, Plans. All trucking facilities have a current SPCC Plan and employees have received training on the SPCC Plans and regulations. Annually, trucking employees receive training regarding the transportation of hazardous materials.

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Since the terrorist attacks of September 11, 2001, the United States Government has issued numerous warnings that energy assets could be the subject of future terrorist attacks. We have instituted security measures and procedures in conformity with DOT guidance. We will institute, as appropriate, additional security measures or procedures indicated by the DOT or the Transportation Safety Administration (an agency of the Department of Homeland Security, which has assumed responsibility from the DOT). None of these measures or procedures should be construed as a guarantee that our assets are protected in the event of a terrorist attack.

Commodities Regulation

When we use futures and options contracts that are traded on the NYMEX, these contracts are subject to strict regulation by the Commodity Futures Trading Commission and the rules of the NYMEX.

Summary of Tax Considerations

The tax consequences of ownership of common units depend on the owner's individual tax circumstances. However, the following is a brief summary of material tax consequences of owning and disposing of common units.

Partnership Status; Cash Distributions

We are classified for federal income tax purposes as a partnership based upon our meeting certain requirements imposed by the Internal Revenue Code (the Code), which we must meet every year. The owners of common units are considered partners so long as they do not loan their common units to others to cover short sales or otherwise dispose of those units. Accordingly, we pay no federal income taxes, and each common unitholder is required to report on the unitholder's federal income tax return the unitholder's share of our income, gains, losses and deductions. In general, cash distributions to a common unitholder are taxable only if, and the extent that, they exceed the tax basis in the common units held.

Partnership Allocations

In general, our income and loss is allocated to the general partner and the unitholders for each taxable year in accordance with their respective percentage interests in the Partnership (including, with respect to the general partner, its incentive distribution right), as determined annually and prorated on a monthly basis and subsequently apportioned among the general partner and the unitholders of record as of the opening of the first business day of the month to which they related, even though unitholders may dispose of their units during the month in question. A unitholder is required to take into account, in determining federal income tax liability, the unitholder's share of income generated by us for each taxable year of the Partnership ending within or with the unitholder's taxable year, even if cash distributions are not made to the unitholder. As a consequence, a unitholder's share of our taxable income (and possibly the income tax payable by the unitholder with respect to such income) may exceed the cash actually distributed to the unitholder by us. At any time incentive distributions are made to the general partner, gross income will be allocated to the recipient to the extent of those distributions.

Basis of Common Units

A unitholder's initial tax basis for a common unit is generally the amount paid for the common unit. A unitholder's basis is generally increased by the unitholder's share of our taxable income and decreased, but not below zero, by the unitholder's share of our tax losses and distributions.

Limitations on Deductibility of Partnership Losses

In the case of taxpayers subject to the passive loss rules (generally, individuals and closely-held corporations), any partnership losses are only available to offset future income generated by us and cannot be used to offset income from other activities, including passive activities or investments. Any losses unused by virtue of the passive loss rules may be fully deducted if the unitholder disposes of all of the unitholder's common units in a taxable transaction with an unrelated party.

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Section 754 Election

We have made the election pursuant to Section 754 of the Code, which will generally result in a unitholder being allocated income and deductions calculated by reference to the portion of the unitholder's purchase price attributable to each asset of the Partnership.

Disposition of Common Units

A unitholder who sells common units will recognize gain or loss equal to the difference between the amount realized and the adjusted tax basis of those common units. A unitholder may not be able to trace basis to particular common units for this purpose. Thus, distributions of cash from us to a unitholder in excess of the income allocated to the unitholder will, in effect, become taxable income if the unitholder sells the common units at a price greater than the unitholder's adjusted tax basis even if the price is less than the unitholder's original cost. Moreover, a portion of the amount realized (whether or not representing gain) will be ordinary income.

State, Local and Other Tax Considerations

In addition to federal income taxes, unitholders will likely be subject to other taxes, such as state and local income taxes, unincorporated business taxes, and estate, inheritance or intangible taxes that are imposed by the various jurisdictions in which a unitholder resides or in which we do business or own property. A unitholder may be required to file state income tax returns and to pay taxes in various states. A unitholder may be subject to penalties for failure to comply with such requirement. In certain states, tax losses may not produce a tax benefit in the year incurred (if, for example, we have no income from sources within that state) and also may not be available to offset income in subsequent taxable years. Some states may require us, or we may elect, to withhold a percentage of income from amounts to be distributed to a unitholder who is not a resident of the state. Withholding, the amount of which may be more or less than a particular unitholder's income tax liability owed to the state, may not relieve the nonresident unitholder from the obligation to file an income tax return. Amounts withheld may be treated as if distributed to unitholders for purposes of determining the amounts distributed by us.

It is the responsibility of each prospective unitholder to investigate the legal and tax consequences, under the laws of pertinent states and localities, of the unitholder's investment in us. Further, it is the responsibility of each unitholder to file all U.S. federal, state and local tax returns that may be required of the unitholder.

Ownership of Common Units by Tax-Exempt Organizations and Certain Other Investors

An investment in common units by tax-exempt organizations (including IRAs and other retirement plans), regulated investment companies (mutual funds) and foreign persons raises issues unique to such persons. Virtually all income allocated to a unitholder that is a tax-exempt organization is unrelated business taxable income and, thus, is taxable to such a unitholder. Recent legislation treats net income derived from the ownership of certain publicly traded partnerships (including us) as qualifying income to a regulated investment company. However, this legislation is only effective for taxable years beginning after October 22, 2004, the date of enactment. Furthermore, a unitholder who is a nonresident alien, foreign corporation or other foreign person is regarded as being engaged in a trade or business in the United States as a result of ownership of a common unit and, thus, is required to file federal income tax returns and to pay tax on the unitholder's share of our taxable income. Finally, distributions to foreign unitholders are subject to federal income tax withholding.

Website Access to Reports

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

Item 1A. Risk Factors

Risks Related to Our Business

We may not have sufficient cash from operations to pay the current level of quarterly distribution following the establishment of cash reserves and payment of fees and expenses, including payments to our general partner.

The amount of cash we distribute on our units principally depends upon margins we generate from our crude oil gathering and marketing operations, margins from the pipeline transportation operations and sales of CO_2, which will fluctuate from quarter to quarter based on, among other things:

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- the prices at which we purchase and sell crude oil;
- the volumes of crude oil we transport;
- the volumes of CO_2 we sell;
- the level of our operating costs;
- the level of our general and administrative costs; and
- prevailing economic conditions.

In addition, the actual amount of cash we will have available for distribution will depend on other factors that include:

- the level of capital expenditures we make, including the cost of acquisitions (if any);
- our debt service requirements;
- fluctuations in our working capital;
- restrictions on distributions contained in our debt instruments;
- our ability to borrow under our working capital facility to pay distributions; and
- the amount of cash reserves established by our general partner in its sole discretion in the conduct of our business.

You should also be aware that our ability to pay distributions each quarter depends primarily on our cash flow, including cash flow from financial reserves and working capital borrowings, and is not solely a function of profitability, which will be affected by non-cash items. As a result, we may make cash distributions during periods when we record losses and we may not make distributions during periods when we record net income.

Our profitability and cash flow is dependent on our ability to increase or, at a minimum, maintain our current commodity -- oil, natural gas and CO_2 -- volumes, which often depends on actions and commitments by parties beyond our control.

Our profitability and cash flow is dependent on our ability to increase or, at a minimum, maintain our current commodity--oil, natural gas and CO_2--volumes. We access commodity volumes through two sources, producers and service providers (including gatherers, shippers, marketers and other aggregators). Depending on the needs of each customer and the market in which it operates, we can either provide a service for a fee (as in the case of our pipeline transportation operations) or we can purchase the commodity from our customer and resell it to another party (as in the case of oil marketing and CO_2 operations).

Our source of volumes depends on successful exploration and development of additional oil and natural gas reserves by others and other matters beyond our control.

The oil, natural gas and other products available to us are derived from reserves produced from existing wells, which reserves naturally decline over time. In order to offset this natural decline, our energy infrastructure assets must access additional reserves. Additionally, some of the projects we have planned or recently completed are dependent on reserves that we expect to be produced from newly discovered properties that producers are currently developing.

Finding and developing new reserves is very expensive, requiring large capital expenditures by producers for exploration and development drilling, installing production facilities and constructing pipeline extensions to reach new wells. Many economic and business factors out of our control can adversely affect the decision by any producer to explore for and develop new reserves. These factors include the prevailing market price of the commodity, the capital budgets of producers, the depletion rate of existing reservoirs, the success of new wells drilled, environmental concerns, regulatory initiatives, cost and availability of equipment, capital budget limitations or the lack of available capital, and other matters beyond our control. Additional reserves, if discovered, may not be developed in the near future or at all. We cannot assure you that production will rise to sufficient levels to allow us to maintain or increase the commodity volumes we are experiencing.

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We face intense competition to obtain commodity volumes.

Our competitors--gatherers, transporters, marketers, brokers and other aggregators--include independents and major integrated energy companies, as well as their marketing affiliates, who vary widely in size, financial resources and experience. Some of these competitors have capital resources many times greater than ours and control substantially greater supplies of crude oil.

Even if reserves exist in the areas accessed by our facilities and are ultimately produced, we may not be chosen by the producers to gather, transport, store or otherwise handle any of these reserves. We compete with others for any such volumes on the basis of many factors, including:

- geographic proximity to the production;
- costs of connection;
- available capacity;
- rates; and
- access to markets.

Additionally, third-party shippers do not have long-term contractual commitments to ship crude oil on our pipelines. A decision by a shipper to substantially reduce or cease to ship volumes of crude oil on our pipelines could cause a significant decline in our revenues. In Mississippi, we are dependent on interconnections with other pipelines to provide shippers with a market for their crude oil, and in Texas, we are dependent on interconnections with other pipelines to provide shippers with transportation to our pipeline. Any reduction of throughput available to our shippers on these interconnecting pipelines as a result of testing, pipeline repair, reduced operating pressures or other causes could result in reduced throughput on our pipelines that would adversely affect our cash flows and results of operations.

Fluctuations in demand for crude oil, such as those caused by refinery downtime or shutdowns, can negatively affect our operating results. Reduced demand in areas we service with our pipelines can result in less demand for our transportation services. In addition, certain of our field and pipeline operating costs and expenses are fixed and do not vary with the volumes we gather and transport. These costs and expenses may not decrease ratably or at all should we experience a reduction in our volumes gathered by truck or transmitted by our pipelines. As a result, we may experience declines in our margin and profitability if our volumes decrease.

Fluctuations in commodity prices could adversely affect our business.

Oil, natural gas, other petroleum product and CO_2 prices are volatile and could have an adverse effect on a portion of our profits and cash flow. Our operations are affected by price reductions. Price reductions can materially reduce the level of exploration, production and development operations, as well as pipeline and marketing volumes.

Prices for commodities can fluctuate in response to changes in supply, market uncertainty and a variety of additional factors that are beyond our control.

Our operations are dependent upon demand for crude oil by refiners in the Midwest and on the Gulf Coast.

Any decrease in this demand for crude oil by the refineries or connecting carriers to which we deliver could adversely affect our business. Those refineries' need for crude oil also is dependent on the competition from other refineries, the impact of future economic conditions, fuel conservation measures, alternative fuel requirements, government regulation or technological advances in fuel economy and energy generation devices, all of which could reduce demand for our services.

We are exposed to the credit risk of our customers in the ordinary course of our crude oil gathering and marketing activities.

When we market crude oil, we must determine the amount, if any, of the line of credit we will extend to any given customer. Since typical sales transactions can involve tens of thousands of barrels of crude oil, the risk of nonpayment and nonperformance by customers is an important consideration in our business. In those cases where we provide division order services for crude oil purchased at the wellhead, we may be responsible for distribution of proceeds to all parties. In other cases, we pay all of or a portion of the production proceeds to an operator who distributes these proceeds to the various interest owners. These arrangements expose us to operator credit risk. As a result, we must determine that operators have sufficient financial resources to make such payments and distributions and to indemnify and defend us in case of a protest, action or complaint. Even if our credit review and analysis mechanisms work properly, there can be no assurance that we will not experience losses in dealings with other parties.

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Our indebtedness could adversely restrict our ability to operate, affect our financial condition and prevent us from fulfilling our obligations under our debt instruments and making distributions.

We have outstanding indebtedness and the ability to incur more indebtedness. As of December 31, 2006, we had $8 million of outstanding senior secured indebtedness.

We and all of our subsidiaries must comply with various affirmative and negative covenants contained in our credit facilities. Among other things, these covenants limit the ability of us and our subsidiaries to:

- incur additional indebtedness or liens;
- make payments in respect of or redeem or acquire any debt or equity issued by us;
- sell assets;
- make loans or investments;
- make guarantees;
- enter into any hedging agreement for speculative purposes;
- acquire or be acquired by other companies; and
- amend some of our contracts.

The restrictions under our indebtedness may prevent us from engaging in certain transactions which might otherwise be considered beneficial to us and could have other important consequences to you. For example, they could:

- increase our vulnerability to general adverse economic and industry conditions;
- limit our ability to make distributions; to fund future working capital, capital expenditures and other general partnership requirements; to engage in future acquisitions and construction or development activities; or to otherwise fully realize the value of our assets and opportunities because of the need to dedicate a substantial portion of our cash flow from operations to payments on our indebtedness or to comply with any restrictive terms of our indebtedness;
- limit our flexibility in planning for, or reacting to, changes in our businesses and the industries in which we operate; and
- place us at a competitive disadvantage as compared to our competitors that have less debt.

We may incur additional indebtedness (public or private) in the future, either under our existing credit facilities, by issuing debt instruments, under new credit agreements, under joint venture credit agreements, under capital leases or synthetic leases, on a project-finance or other basis, or a combination of any of these. If we incur additional indebtedness in the future, it likely would be under our existing credit facility or under arrangements which may have terms and conditions at least as restrictive as those contained in our existing credit facilities. Failure to comply with the terms and conditions of any existing or future indebtedness would constitute an event of default. If an event of default occurs, the lenders will have the right to accelerate the maturity of such indebtedness and foreclose upon the collateral, if any, securing that indebtedness. If an event of default occurs under our joint ventures' credit facilities, we may be required to repay amounts previously distributed to us and our subsidiaries. In addition, if there is a change of control as described in our credit facility that would be an event of default, unless our creditors agreed otherwise, under our credit facility, any such event could limit our ability to fulfill our obligations under our debt instruments and to make cash distributions to unitholders which could adversely affect the market price of our securities.

Our operations are subject to federal and state environmental protection and safety laws and regulations.

Our operations are subject to the risk of incurring substantial environmental and safety related costs and liabilities. In particular, our operations are subject to environmental protection and safety laws and regulations that restrict our operations, impose relatively harsh consequences for noncompliance, and require us to expend resources in an effort to maintain compliance. Moreover, the transportation and storage of crude oil involves a risk that crude oil and related hydrocarbons may be released into the environment, which may result in substantial expenditures for a response action, significant government penalties, liability to government agencies for natural resources damages, liability to private parties for personal injury or property damages, and significant business interruption. These costs and liabilities could rise under increasingly strict environmental and safety laws, including regulations and enforcement policies, or claims for damages to property or persons resulting from our operations. If we are unable to recover such resulting costs through increased rates or insurance reimbursements, our cash flows and distributions to our unitholders could be materially affected

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Our CO_2 operations primarily relate to our volumetric production payment interests, which are a finite resource and projected to deplete around 2016.

The cash flow from our CO_2 operations primarily relates to our volumetric production payments, which are projected to terminate around 2016. Unless we are able to obtain a replacement supply of CO_2 and enter into sales arrangements that generate substantially similar economics, our cash flow could decline significantly around 2016.

Our CO_2 operations are exposed to risks related to Denbury's operation of their CO_2 fields, equipment and pipeline.

Because Denbury Resources produces the CO_2 and transports the CO_2 to our customers, any major failure of its operations could have an impact on our ability to meet our obligations to our CO_2 customers. We have no other supply of CO_2 or method to transport it to our customers. Sandhill relies on us for its supply of CO_2 therefore our share of the earnings of Sandhill would also be impacted by any major failure of Denbury's operations.

The CO_2 supplied by Denbury Resources to us for our sale to our customers could fail to meet the quality standards in the contracts due to impurities or water vapor content. If the CO_2 were below specifications, we could be contractually obligated to provide compensation to our customers for the costs incurred in raising the CO_2 quality to serviceable levels required by our contracts.

Fluctuations in demand for CO_2 by our industrial customers could materially impact our profitability.

Our customers are not obligated to purchase volumes in excess of specified minimum amounts in our contracts. As a result, fluctuations in our customers' demand due to market forces or operational problems could result in a reduction in our revenues from our sales of CO_2.

Our wholesale CO_2 industrial operations are dependent on five customers.

If one or more of those customers experience financial difficulties such that they fail to purchase their required minimum take-or-pay volumes, our cash flows could be adversely affected and we cannot assure you that an unanticipated deterioration in their ability to meet their obligations to us might not occur.

We may not be able to fully execute our growth strategy if we encounter tight capital markets or increased competition for qualified assets.

Our strategy contemplates substantial growth through the development and acquisition of a wide range of midstream and other energy infrastructure assets while maintaining a strong balance sheet. This strategy includes constructing and acquiring additional assets and businesses to enhance our ability to compete effectively, diversify our asset portfolio and, thereby, provide more stable cash flow. We regularly consider and enter into discussions regarding, and are currently contemplating, additional potential joint ventures, stand-alone projects and other transactions that we believe will present opportunities to realize synergies, expand our role in the energy infrastructure business, and increase our market position and, ultimately, increase distributions to unitholders.

We will need new capital to finance the future development and acquisition of assets and businesses. Limitations on our access to capital will impair our ability to execute this strategy. Expensive capital will limit our ability to develop or acquire accretive assets. Although we intend to continue to expand our business, this strategy may require substantial capital, and we may not be able to raise the necessary funds on satisfactory terms, if at all.

In addition, we are experiencing increased competition for the assets we purchase or contemplate purchasing. Increased competition for a limited pool of assets could result in our not being the successful bidder more often or our acquiring assets at a higher relative price than that which we have paid historically. Either occurrence would limit our ability to fully execute our growth strategy. Our ability to execute our growth strategy may impact the market price of our securities.

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Our growth strategy may adversely affect our results of operations if we do not successfully integrate the businesses that we acquire or if we substantially increase our indebtedness and contingent liabilities to make acquisitions.

We may be unable to integrate successfully businesses we acquire. We may incur substantial expenses, delays or other problems in connection with our growth strategy that could negatively impact our results of operations. Moreover, acquisitions and business expansions involve numerous risks, including:

- difficulties in the assimilation of the operations, technologies, services and products of the acquired companies or business segments;

- inefficiencies and complexities that can arise because of unfamiliarity with new assets and the businesses associated with them, including unfamiliarity with their markets; and

- diversion of the attention of management and other personnel from day-to-day business to the development or acquisition of new businesses and other business opportunities.

If consummated, any acquisition or investment also likely would result in the incurrence of indebtedness and contingent liabilities and an increase in interest expense and depreciation, depletion and amortization expenses. A substantial increase in our indebtedness and contingent liabilities could have a material adverse effect on our business, as discussed above.

Our actual construction, development and acquisition costs could exceed our forecast, and our cash flow from construction and development projects may not be immediate.

Our forecast contemplates significant expenditures for the development, construction or other acquisition of energy infrastructure assets, including some construction and development projects with technological challenges. We may not be able to complete our projects at the costs currently estimated. If we experience material cost overruns, we will have to finance these overruns using one or more of the following methods:

- using cash from operations;

- delaying other planned projects;

- incurring additional indebtedness; or

- issuing additional debt or equity.

Any or all of these methods may not be available when needed or may adversely affect our future results of operations.

Fluctuations in interest rates could adversely affect our business.

In addition to our exposure to commodity prices, we also have exposure to movements in interest rates. The interest rates on our credit facility are variable. Our results of operations and our cash flow, as well as our access to future capital and our ability to fund our growth strategy, could be adversely affected by significant increases or decreases in interest rates.

Our use of derivative financial instruments could result in financial losses.

We use financial derivative instruments and other hedging mechanisms from time to time to limit a portion of the adverse effects resulting from changes in commodity prices, although there are times when we do not have any hedging mechanisms in place. To the extent we hedge our commodity price exposure, we forego the benefits we would otherwise experience if commodity prices were to increase. In addition, we could experience losses resulting from our hedging and other derivative positions. Such losses could occur under various circumstances, including if our counterparty does not perform its obligations under the hedge arrangement, our hedge is imperfect, or our hedging policies and procedures are not followed.

A natural disaster, catastrophe or other interruption event involving us could result in severe personal injury, property damage and environmental damage, which could curtail our operations and otherwise adversely affect our assets and cash flow.

Some of our operations involve risks of severe personal injury, property damage and environmental damage, any of which could curtail our operations and otherwise expose us to liability and adversely affect our cash flow. Virtually all of our operations are exposed to the elements, including hurricanes, tornadoes, storms, floods and earthquakes.

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If one or more facilities that are owned by us or that connect to us is damaged or otherwise affected by severe weather or any other disaster, accident, catastrophe or event, our operations could be significantly interrupted. Similar interruptions could result from damage to production or other facilities that supply our facilities or other stoppages arising from factors beyond our control. These interruptions might involve significant damage to people, property or the environment, and repairs might take from a week or less for a minor incident to six months or more for a major interruption. Any event that interrupts the fees generated by our energy infrastructure assets, or which causes us to make significant expenditures not covered by insurance, could reduce our cash available for paying our interest obligations as well as unitholder distributions and, accordingly, adversely impact the market price of our securities. Additionally, the proceeds of any property insurance maintained by us may not be paid in a timely manner or be in an amount sufficient to meet our needs if such an event were to occur, and we may not be able to renew it or obtain other desirable insurance on commercially reasonable terms, if at all.

FERC regulation and a changing regulatory environment could affect our cash flow.

The FERC extensively regulates certain of our energy infrastructure assets engaged in interstate operations. Our intrastate pipeline operations are regulated by state agencies. This regulation extends to such matters as:

- rate structures;
- rates of return on equity;
- recovery of costs;
- the services that our regulated assets are permitted to perform;
- the acquisition, construction and disposition of assets; and
- to an extent, the level of competition in that regulated industry.

Given the extent of this regulation, the extensive changes in FERC policy over the last several years, the evolving nature of federal and state regulation and the possibility for additional changes, the current regulatory regime may change and affect our financial position, results of operations or cash flows.

Terrorist attacks aimed at the partnership's facilities could adversely affect the business.

On September 11, 2001, the United States was the target of terrorist attacks of unprecedented scale. Since the September 11 attacks, the U.S. government has issued warnings that energy assets, specifically the nation's pipeline infrastructure, may be the future targets of terrorist organizations. These developments have subjected our operations to increased risks. Any future terrorist attack at our facilities, those of our customers and, in some cases, those of other pipelines, could have a material adverse effect on our business.

Denbury is the only shipper (other than us) on our Mississippi System.

Denbury Resources is our only customer on the Mississippi System. This relationship may subject our operations to increased risks. Any adverse developments concerning Denbury Resources could have a material adverse effect on our Mississippi System business. Neither our partnership agreement nor any other agreement requires Denbury Resources to pursue a business strategy that favors us or utilizes our Mississippi System. Denbury Resources may compete with us and may manage their assets in a manner that could adversely affect our Mississippi System business.

We cannot cause our joint ventures to take or not to take certain actions unless some or all of the joint venture participants agree.

Due to the nature of joint ventures, each participant (including us) in our joint ventures has made substantial investments (including contributions and other commitments) in that joint venture and, accordingly, has required that the relevant charter documents contain certain features designed to provide each participant with the opportunity to participate in the management of the joint venture and to protect its investment in that joint venture, as well as any other assets which may be substantially dependent on or otherwise affected by the activities of that joint venture. These participation and protective features include corporate governance structures that consists of a management committee composed of four members, only two of which are appointed by us. In addition, the other 50% owner in each of our joint ventures operates the joint venture facilities. Thus, without the concurrence of the other joint venture participant, we cannot cause our joint ventures to take or not to take certain actions, even though those actions may be in the best interest of the joint ventures or us.

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Our syngas operations are dependent on one customer.

Our syngas joint venture has dedicated 100% of its syngas processing capacity to one customer pursuant to a processing contract. The contract term expires in 2016, unless our customer elects to extend the contract for two additional five year terms. If our customer reduces or discontinues its business with us, or if we are not able to successfully negotiate a replacement contract with our sole customer after the expiration of such contract, or if the replacement contract is on less favorable terms, the effect on us will be adverse. In addition, if our sole customer for syngas processing were to experience financial difficulties such that it failed to provide volumes to process, our cash flow from the syngas joint venture could be adversely affected. We believe this customer is creditworthy, but we cannot assure you that unanticipated deterioration of their abilities to meet their obligations to the syngas joint venture might not occur.

Risks Related to Our Partnership Structure

Denbury and its affiliates have conflicts of interest with us and limited fiduciary responsibilities, which may permit them to favor their own interests to your detriment.

Denbury Resources indirectly owns and controls our general partner. Conflicts of interest may arise between Denbury Resources and its affiliates, including our general partner, on the one hand, and us and our unitholders, on the other hand. As a result of these conflicts, our general partner may favor its own interest and the interest of its affiliates or others over the interest of our unitholders. These conflicts include, among others, the following situations:

- neither our partnership agreement nor any other agreement requires Denbury Resources to pursue a business strategy that favors us or utilizes our assets. Denbury Resources' directors and officers have a fiduciary duty to make these decisions in the best interest of the stockholders of Denbury Resources;

- Denbury Resources may compete with us. Denbury Resources owns the largest reserves of CO_2 used for tertiary oil recovery east of the Mississippi River and may manage these reserves in a manner that could adversely affect our CO_2 business;

- our general partner is allowed to take into account the interest of parties other than us, such as Denbury Resources, in resolving conflicts of interest;

- our general partner may limit its liability and reduce its fiduciary duties, while also restricting the remedies available to our unitholders for actions that, without the limitations, might constitute breaches of fiduciary duty;

- our general partner determines the amount and timing of asset purchases and sales, capital expenditures, borrowings, including for incentive distributions, issuance of additional partnership securities, reimbursements and enforcement of obligations to the general partner and its affiliates, retention of counsel, accountants and service providers, and cash reserves, each of which can also affect the amount of cash that is distributed to our unitholders;

- our general partner determines which costs incurred by it and its affiliates are reimbursable by us and the reimbursement of these costs and of any services provided by our general partner could adversely affect our ability to pay cash distributions to our unitholders;

- our general partner controls the enforcement of obligations owed to us by our general partner and its affiliates;

- our general partner decides whether to retain separate counsel, accountants or others to perform services for us; and

- in some instances, our general partner may cause us to borrow funds in order to permit the payment of distributions even if the purpose or effect of the borrowing is to make incentive distributions.

Denbury is not obligated to enter into any transactions with (or to offer any opportunities to) us, although we expect to continue to enter into substantial transactions and other activities with Denbury Resources and its subsidiaries because of the businesses and areas in which we and Denbury Resources currently operate, as well as those in which we plan to operate in the future. Denbury has expressed indications of interest in selling to us (and entering into arrangements under which Denbury would have the exclusive right to utilize) specified CO_2 infrastructure assets, including some that have not yet been placed in-service, subject to the satisfaction of certain conditions. Those conditions include the negotiation of material terms, the execution of definitive agreements, the existence of adequate credit support and our acquisition (by construction and purchase) of assets that are not related to Denbury's operations in an amount at least equal to 150% of the amount of new acquisitions or financings we complete with Denbury.

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Some more recent transactions in which we, on the one hand, and Denbury Resources and its subsidiaries, on the other hand, had a conflict of interest include:

- transportation services
- pipeline monitoring services; and
- CO_2 volumetric production payment.

In addition, Denbury Resources' beneficial ownership interest in our outstanding partnership interests could have a substantial effect on the outcome of some actions requiring partner approval. Accordingly, subject to legal requirements, Denbury Resources makes the final determination regarding how any particular conflict of interest is resolved.

Even if unitholders are dissatisfied, they cannot easily remove our general partner.

Unlike the holders of common stock in a corporation, unitholders have only limited voting rights on matters affecting our business and, therefore, limited ability to influence management's decisions regarding our business.

Unitholders did not elect our general partner or its board of directors and will have no right to elect our general partner or its board of directors on an annual or other continuing basis. The board of directors of our general partner is chosen by the stockholders of our general partner. In addition, if the unitholders are dissatisfied with the performance of our general partner, they will have little ability to remove our general partners. As a result of these limitations, the price at which the common units trade could be diminished because of the absence or reduction of a takeover premium in the trading price.

The vote of the holders of at least a majority of all outstanding units (excluding any units held by our general partner and its affiliates) is required to remove the general partner without cause, as defined in the partnership agreement. If our general partner is removed without cause, (i) Denbury Resources will have the option to acquire a substantial portion of our Mississippi pipeline system at 110% of its then fair market value, and (ii) our general partner will have the option to convert its interest in us (other than its common units) into common units or to require our replacement general partner to purchase such interest for cash at its then fair market value. In addition, unitholders' voting rights are further restricted by our partnership agreement providing that any units held by a person that owns 20% or more of any class of units then outstanding, other than the general partner, its affiliates, their transferees, and persons who acquired such units with the prior approval of the board of directors of the general partner, cannot vote on any matter. Our partnership agreement also contains provisions limiting the ability of unitholders to call meetings or to acquire information about our operations, as well as other provisions limiting the unitholders' ability to influence the manner of direction of management.

As a result of these provisions, the price at which our common units trade may be lower because of the absence or reduction of a takeover premium.

The control of our general partner may be transferred to a third party without unitholder consent, which could affect our strategic direction and liquidity.

Our general partner may transfer its general partner interest to a third party in a merger or in a sale of all or substantially all of its assets without the consent of the unitholders. Furthermore, there is no restriction in our partnership agreement on the ability of the owner of our general partner from transferring its ownership interest in the general partner to a third party. The new owner of the general partner would then be in a position to replace the board of directors and officers of the general partner with its own choices and to control the decisions taken by the board of directors and officers.

In addition, unless our creditors agreed otherwise, we would be required to repay the amounts outstanding under our credit facilities upon the occurrence of any change of control described therein. We may not have sufficient funds available or be permitted by our other debt instruments to fulfill these obligations upon such occurrence. A change of control could have other consequences to us depending on the agreements and other arrangements we have in place from time to time, including employment compensation arrangements.

Our general partner and its affiliates may sell units or other limited partner interests in the trading market, which could reduce the market price of common units.

As of December 31, 2006, our general partner and its affiliates own 1,019,441 (approximately 7%) of our common units. In the future, they may acquire additional interest or dispose of some or all of their interest. If they dispose of a substantial portion of their interest in the trading markets, the sale could reduce the market price of common units. Our partnership agreement, and other agreements to which we are party, allow our general partner and certain of its subsidiaries to cause us to register for sale the partnership interests held by such persons, including common units. These registration rights allow our general partner and its subsidiaries to request registration of those partnership interests and to include any of those securities in a registration of other capital securities by us.

Our general partner has anti-dilution rights.

Whenever we issue equity securities to any person other than our general partner and its affiliates, our general partner and its affiliates have the right to purchase an additional amount of those equity securities on the same terms as they are issued to the other purchasers. This allows our general partner and its affiliates to maintain their percentage partnership interest in us. No other unitholder has a similar right. Therefore, only our general partner may protect itself against dilution caused by the issuance of additional equity securities.

Due to our significant relationships with Denbury, adverse developments concerning Denbury could adversely affect us, even if we have not suffered any similar developments.

Through its subsidiaries, Denbury Resources owns 100 percent of our general partner and has historically, with its affiliates, employed the personnel who operate our businesses. Denbury Resources is a significant stakeholder in our limited partner interests, and as with many other energy companies, is a significant customer of ours.

We may issue additional common units without unitholders' approval, which would dilute their ownership interests.

We may issue an unlimited number of limited partner interests of any type without the approval of our unitholders.

The issuance of additional common units or other equity securities of equal or senior rank will have the following effects:

- our unitholders' proportionate ownership interest in us will decrease;
- the amount of cash available for distribution on each unit may decrease;
- the relative voting strength of each previously outstanding unit may be diminished; and
- the market price of our common units may decline.

Our general partner has a limited call right that may require you to sell your common units at an undesirable time or price.

If at any time our general partner and its affiliates own more than 80% of the common units, our general partner will have the right, but not the obligation, which it may assign to any of its affiliates or to us, to acquire all, but not less than all, of the common units held by unaffiliated persons at a price not less than their then-current market price. As a result, you may be required to sell your common units at an undesirable time or price and may not receive any return on your investment. You may also incur a tax liability upon a sale of your units.

The interruption of distributions to us from our subsidiaries and joint ventures may affect our ability to make payments on indebtedness or cash distributions to our unitholders.

We are a holding company. As such, our primary assets are the equity interests in our subsidiaries and joint ventures. Consequently, our ability to fund our commitments (including payments on our indebtedness) and to make cash distributions depends upon the earnings and cash flow of our subsidiaries and joint ventures and the distribution of that cash to us. Distributions from our joint ventures are subject to the discretion of their respective management committees. Further, each joint venture's charter documents typically vest in its management committee sole discretion regarding distributions. Accordingly, our joint ventures may not continue to make distributions to us at current levels or at all.

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We do not have the same flexibility as other types of organizations to accumulate cash and equity to protect against illiquidity in the future.

Unlike a corporation, our partnership agreement requires us to make quarterly distributions to our unitholders of all available cash reduced by any amounts reserved for commitments and contingencies, including capital and operating costs and debt service requirements. The value of our units and other limited partner interests will decrease in direct correlation with decreases in the amount we distribute per unit. Accordingly, if we experience a liquidity problem in the future, we may not be able to issue more equity to recapitalize.

Tax Risks to Common Unitholders

The IRS could treat us as a corporation for tax purposes, which would substantially reduce the cash available for distribution to our unitholders.

The after-tax economic benefit of an investment in the common units depends largely on our being treated as a partnership for federal income tax purposes. We have not requested, and do not plan to request, a ruling from the IRS on this or any other tax matter affecting us.

If we were treated as a corporation for federal income tax purposes, we would pay federal income tax on our income at the corporate tax rate, which is currently a maximum of 35%. Distributions to you may be taxed again as corporate dividends, and no income, gains, losses or deductions would flow through to you. Because a tax would be imposed upon us as a corporation, our cash available for distribution to you would be substantially reduced. If we were treated as a corporation, there would be a material reduction in the after-tax return to the unitholders, likely causing a substantial reduction in the value of our common units.

Current law may change so as to cause us to be treated as a corporation for federal income tax purposes or otherwise subject us to entity-level taxation. In addition, because of widespread state budget deficits, several states are evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise or other forms of taxation. If any state were to impose a tax upon us as an entity, the cash available for distribution to you would be reduced. The partnership agreement provides that if a law is enacted or existing law is modified or interpreted in a manner that subjects us to taxation as a corporation or otherwise subjects us to entity-level taxation for federal, state or local income tax purposes, the minimum quarterly distribution amount and the target distribution amounts will be adjusted to reflect the impact of that law on us.

A successful IRS contest of the federal income tax positions we take may adversely affect the market for our common units, and the cost of any IRS contest will be borne by our unitholders and our general partner.

We have not requested a ruling from the IRS with respect to our treatment as a partnership for federal income tax purposes or any other matter affecting us. The IRS may adopt positions that differ from the conclusions of our counsel or from the positions we take. It may be necessary to resort to administrative or court proceedings to sustain some or all of our counsel's conclusions or the positions we take. A court may not agree with some or all of our counsel's conclusions or positions we take. Any contest with the IRS may materially and adversely impact the market for our common units and the price at which they trade. In addition, our costs of any contest with the IRS will be borne indirectly by our unitholders and our general partner, and these costs will reduce our cash available for distribution.

Our unitholders may be required to pay taxes on income from us even if they do not receive any cash distributions from us.

You will be required to pay any federal income taxes and, in some cases, state and local income taxes on your share of our taxable income even if you receive no cash distributions from us. You may not receive cash distributions from us equal to your share of our taxable income or even the tax liability that results from that income.

Tax gain or loss on disposition of common units could be different than expected.

If you sell your common units, you will recognize a gain or loss equal to the difference between the amount realized and your tax basis in those common units. Prior distributions to you in excess of the total net taxable income you were allocated for a common unit, which decreased your tax basis in that common unit, will, in effect, become taxable income to you if the common unit is sold at a price greater than your tax basis in that common unit, even if the price is less than your original cost. A substantial portion of the amount realized, whether or not representing gain, may be ordinary income. In addition, if you sell your units, you may incur a tax liability in excess of the amount of cash you receive from the sale.

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Tax-exempt entities, regulated investment companies and foreign persons face unique tax issues from owning common units that may result in adverse tax consequences to them.

Investment in common units by tax-exempt entities, such as individual retirement accounts (known as IRAs), regulated investment companies (known as mutual funds) and non U.S. persons raises issues unique to them. For example, a significant amount of our income allocated to organizations exempt from federal income tax, including individual retirement accounts and other retirement plans, may be unrelated business taxable income and will be taxable to such a unitholder. Recent legislation treats net income derived from the ownership of certain publicly traded partnerships (including us) as qualifying income to a regulated investment company. However, this legislation is only effective for taxable years beginning after October 22, 2004, the date of enactment. Distributions to non-U.S. persons will be reduced by withholding tax at the highest effective tax rate applicable to individuals, and non U.S. unitholders will be required to file federal income tax returns and pay tax on their share of our taxable income.

We are registered as a tax shelter. This may increase the risk of an IRS audit of us or our unitholders.

We are registered with the IRS as a "tax shelter." Our tax shelter registration number is 97043000153. The federal income tax laws require that some types of entities, including some partnerships, register as tax shelters in response to the perception that they claim tax benefits that may be unwarranted. As a result, we may be audited by the IRS and tax adjustments may be made. Any unitholder owning less than a 1% profit interest in us has very limited rights to participate in the income tax audit process. Further, any adjustments in our tax returns will lead to adjustments in your tax returns and may lead to audits of your tax returns and adjustments of items unrelated to us. You would bear the cost of any expense incurred in connection with an examination of your tax return.

We will treat each purchaser of common units as having the same tax benefits without regard to the units purchased. The IRS may challenge this treatment, which could adversely affect the value of our common units.

Because we cannot match transferors and transferees of common units, we adopt depreciation and amortization positions that may not conform with all aspects of applicable Treasury regulations. A successful IRS challenge to those positions could adversely affect the amount of tax benefits available to a common unitholder. It also could affect the timing of these tax benefits or the amount of gain from a sale of common units and could have a negative impact on the value of the common units or result in audit adjustments to the common unitholder's tax returns.

Our unitholders will likely be subject to state and local taxes in states where they do not live as a result of an investment in units.

In addition to federal income taxes, you will likely be subject to other taxes, including foreign, state and local taxes, unincorporated business taxes and estate inheritance or intangible taxes that are imposed by the various jurisdictions in which we do business or own property, even if you do not live in any of those jurisdictions. You will likely be required to file foreign, state and local income tax returns and pay state and local income taxes in some or all of these jurisdictions. Further, you may be subject to penalties for failure to comply with those requirements. We own assets and do business in Texas, Louisiana, Mississippi, Alabama, Florida, and Oklahoma. Louisiana, Mississippi, Alabama, Florida, and Oklahoma currently impose a personal income tax. It is your responsibility to file all United States federal, foreign, state and local tax returns. Our counsel has not rendered an opinion on the state or local tax consequences of an investment in the common units.

Item 1B. Unresolved Staff Comments

None.

Item 3. Legal Proceedings

We are involved from time to time in various claims, lawsuits and administrative proceedings incidental to our business. In our opinion, the ultimate outcome, if any, of such proceedings is not expected to have a material adverse effect on our financial condition, results of operations or cash flows. (See Note 17. Commitments and Contingencies.)

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

No matters were submitted to a vote of the security holders during the fiscal year covered by this report.

PART II

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

Our common units are listed on the American Stock Exchange under the symbol "GEL". The following table sets forth, for the periods indicated, the high and low sale prices per common unit and the amount of cash distributions paid per common unit.

	Price Range		Cash
	High	Low	Distributions [(1)]
2007			
First Quarter (through March 1, 2007)	$ 20.00	$ 18.76	$ 0.21
2006			
First Quarter	$ 12.85	$ 11.25	$ 0.17
Second Quarter	$ 14.14	$ 10.25	$ 0.18
Third Quarter	$ 19.18	$ 11.20	$ 0.19
Fourth Quarter	$ 20.65	$ 14.48	$ 0.20
2005			
First Quarter	$ 12.60	$ 8.50	$ 0.15
Second Quarter	$ 10.00	$ 8.25	$ 0.15
Third Quarter	$ 12.15	$ 9.22	$ 0.15
Fourth Quarter	$ 12.00	$ 9.61	$ 0.16

(1) Cash distributions are shown in the quarter paid and are based on the prior quarter's activities.

At March 1, 2007, there were 13,784,441 common units outstanding, including 1,019,441 common units held by our general partner. As of December 31, 2006, there were approximately 5,800 record holders of our common units, which include holders who own units through their brokers "in street name."

We distribute all of our available cash, as defined in our partnership agreement, within 45 days after the end of each quarter to Unitholders of record and to our general partner. Available cash consists generally of all of our cash receipts less cash disbursements, adjusted for net changes to cash reserves. Cash reserves are the amounts deemed necessary or appropriate, in the reasonable discretion of our general partner, to provide for the proper conduct of our business or to comply with applicable law, any of our debt instruments or other agreements. The full definition of available cash is set forth in our partnership agreement and amendments thereto, which is filed as an exhibit to this Form 10-K.

In addition to its 2% general partner interest, our general partner is entitled to receive incentive distributions if the amount we distribute with respect to any quarter exceeds levels specified in our partnership agreement.

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Item 6. Selected Financial Data

The table below includes selected financial and other data for the Partnership for the years ended December 31, 2006, 2005, 2004, 2003, and 2002 *(in thousands, except per unit and volume data).*

	Year Ended December 31,				
	2006	2005	2004	2003	2002
Income Statement Data:					
Revenues:					
Crude oil gathering and marketing [1]	$ 873,268	$ 1,038,549	$ 901,902	$ 641,684	$ 639,143
Pipeline transportation, including natural gas sales	29,947	28,888	16,680	15,134	13,485
CO_2 marketing	15,154	11,302	8,561	1,079	-
Total revenues	918,369	1,078,739	927,143	657,897	652,628
Costs and expenses:					
Crude oil and field operating [1]	865,902	1,034,888	897,868	633,776	629,245
Pipeline transportation, including natural gas purchases	17,521	19,084	8,137	10,026	9,576
CO_2 marketing transportation costs	4,842	3,649	2,799	355	-
General and administrative expenses	13,573	9,656	11,031	8,768	7,864
Depreciation and amortization	7,963	6,721	7,298 (2)	4,641	4,603
(Gain) loss from sales of surplus assets	(16)	(479)	33	(236)	(705)
Total costs and expenses	909,785	1,073,519	927,166	657,330	650,583
Operating income (loss) from continuing operations	8,584	5,220	(23)	567	2,045
Earnings from equity in joint ventures	1,131	501	-	-	-
Interest expense, net	(1,374)	(2,032)	(926)	(986)	(1,035)
Income (loss) from continuing operations before cumulative effect of change in accounting principle, income taxes and minority intersst	8,341	3,689	(949)	(419)	1,010
Income tax credit	11	-	-	-	-
Minority interest	(1)	-	-	-	-
Income (loss) from continuing operations before cumulative effect of change in accounting principle	8,351	3,689	(949)	(419)	1,010
Income (loss) from discontinued operations	-	312	(463)	13,741	4,082
Cumulative effect of changes in accounting principle	30	(586)	-	-	-

Net income (loss)	$	8,381	$	3,415	$	(1,412)	$	13,322	$	5,092
Net income (loss) per common unit - basic and diluted:										
Continuing operations	$	0.59	$	0.38	$	(0.10)	$	(0.05)	$	0.12
Discontinued operations		-		0.03		(0.05)		1.55		0.46
Cumulative effect of change in accounting principle		-		(0.06)		-		-		-
Net income (loss)	$	0.59	$	0.35	$	(0.15)	$	1.50	$	0.58
Cash distributions per common unit	$	0.74	$	0.61	$	0.60	$	0.15	$	0.20

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	Year Ended December 31,				
	2006	2005	2004	2003	2002
Balance Sheet Data (at end of period):					
Current assets	$ 99,992	$ 90,449	$ 77,396	$ 88,211	$ 92,830
Total assets	191,087	181,777	143,154	147,115	137,537
Long-term liabilities	8,991	955	15,460	7,000	5,500
Minority interests	522	522	517	517	515
Partners' capital	85,662	87,689	45,239	52,354	35,302
Other Data:					
Maintenance capital expenditures (3)	967	1,543	939	4,178	4,211
Volumes - continuing operations:					
Crude oil pipeline (bpd)	61,585	61,296	63,441	66,959	71,870
CO_2 sales (Mcf per day)	72,841	56,823	45,312	36,332 (4)	-
Crude oil gathering and marketing:					
Wellhead (bpd)	33,853	39,194	45,919	45,015	47,819
Total (bpd)	37,180	52,943	60,419	56,805	73,429

(1) Crude oil gathering and marketing revenues, costs and volumes are reflected net of buy/sell arrangements since April 1, 2006.
(2) In 2004, we recorded an impairment charge of $0.9 million related to our pipeline transportation operations.
(3) Maintenance capital expenditures are capital expenditures to replace or enhance partially or fully depreciated assets to sustain the existing operating capacity or efficiency of our assets and extend their useful lives.
(4) Represents average daily volume for the two month period in 2003 that we owned the assets.

The table below summarizes our unaudited quarterly financial data for 2006 and 2005 (in thousands, except per unit data).

	2006 Quarters			
	First	Second	Third	Fourth
Revenues	$ 263,602	$ 233,343	$ 229,551	$ 191,873
Operating income	$ 2,370	$ 3,357	$ 1,688	$ 1,169
Income from continuing operations	$ 2,561	$ 3,444	$ 1,695	$ 651
Cumulative effect adjustment	$ 30	$ -	$ -	$ -
Net income	$ 2,591	$ 3,444	$ 1,695	$ 651
Income from continuing operations per common unit - basic and diluted	$ 0.18	$ 0.24	$ 0.12	$ 0.05
Net income per common unit - basic and diluted	$ 0.18	$ 0.24	$ 0.12	$ 0.05

	2005 Quarters			
	First	Second	Third	Fourth
Revenues	$ 256,600	$ 257,144	$ 300,577	$ 264,418

Operating income (loss) - continuing operations	$	2,843	$	1,006	$	(109)	$	1,480
Income (loss) from continuing operations	$	2,488	$	752	$	(641)	$	1,090
Income (loss) from discontinued operations	$	282	$	(9)	$	45	$	(6)
Cumulative effect adjustment	$	-	$	-	$	-	$	(586)
Net income (loss)	$	2,770	$	743	$	(596)	$	498
Income from continuing operations per common unit - basic and diluted	$	0.26	$	0.08	$	(0.06)	$	0.10
Net income (loss) per common unit - basic and diluted	$	0.29	$	0.08	$	(0.06)	$	0.05

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

Included in Management's Discussion and Analysis are the following sections:

- Overview of 2006
- Significant Events in 2006
- Critical Accounting Policies
- Results of Operations
- Liquidity and Capital Resources
- Commitments and Off-Balance Sheet Arrangements
- Other Matters
- New Accounting Pronouncements

In the discussions that follow, we will focus on two measures that we use to manage the business and to review the results of our operations. Those two measures are segment margin and Available Cash before Reserves. Our profitability depends to a significant extent upon our ability to maximize segment margin. Segment margin is calculated as revenues less cost of sales and operating expense, and does not include depreciation and amortization. Segment margin also includes our equity in the operating income of joint ventures. A reconciliation of segment margin to income from continuing operations is included in our segment disclosures in Note 10 to the consolidated financial statements. Available Cash before Reserves is a non-GAAP measure calculated as net income with several adjustments, the most significant of which are the elimination of gains and losses on asset sales, except those from the sale of surplus assets, the addition of non-cash expenses such as depreciation, the replacement with the amount recognized as our equity in the income of joint ventures with the available cash generated from those ventures, and the subtraction of maintenance capital expenditures, which are expenditures to sustain existing cash flows but not to provide new sources of revenues. For additional information on Available Cash before Reserves and a reconciliation of this measure to cash flows from operations, see "Liquidity and Capital Resources - Non-GAAP Financial Measure" below.

Overview of 2006

We conduct our business through three segments - pipeline transportation (primarily of crude oil), crude oil gathering and marketing, and industrial gases. We have a diverse portfolio of customers and assets, including pipeline transportation of primarily crude oil and, to a lesser extent, natural gas and CO_2 in the Gulf Coast region of the United States. In conjunction with our crude oil pipeline transportation operations, we operate a crude oil gathering and marketing business, which (among other things) helps ensure a base supply of crude oil for our pipelines. We participate in industrial gas activities, including a CO_2 supply business, which is associated with the CO_2 tertiary oil recovery process being used in Mississippi by an affiliate of our general partner. We generate revenues by selling crude oil and industrial gases, by charging fees for the transportation of crude oil, natural gas and CO_2 on our pipelines, and through our joint venture in T&P Syngas Supply Company, by charging fees for services to produce syngas for our customer from the customer's raw materials. Our focus is on the margin we earn on these revenues, which is calculated by subtracting the costs of the crude oil, the costs of transporting the crude oil, natural gas and CO_2 to the customer, and the costs of operating our assets. We also report our share of the earnings of our joint ventures, T&P Syngas and Sandhill.

Our objective is to operate as a growth-oriented midstream MLP with a focus on increasing cash flow, earnings and return to our unitholders by becoming one of the leading providers of pipeline transportation, crude oil gathering and marketing and industrial gas services in the regions in which we operate. Increases in cash flow generally result in increases in Available Cash before Reserves, which we distribute quarterly to our unitholders. During 2006, we generated $18.8 million of Available Cash before Reserves, and distributed $10.4 million to our unitholders. During 2006, cash provided by operations was $11.3 million.

In 2006, we generated net income and earnings of $8.4 million and $0.59 per unit. The results for 2006 include increased segment margin from all segments of our business. Increases in our unit price, the issuance of additional rights and the adoption of a new accounting pronouncement increased our field operating costs, pipeline operating costs and general and administrative expenses by a total of $1.9 million as we recognized expense related to our stock appreciation rights, or SAR, plan. Transition costs totaling $1.4 million related to a change in our senior management team also increased our general and administrative costs.

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As result of the equity capital we raised in December 2005 in connection with a public offering of newly issued limited partner units, we reduced our outstanding debt under our revolving credit facility during 2006 resulting in a reduction in interest expense for the year. We wrote off unamortized costs totaling $0.6 million related to our prior credit facility when we replaced the facility in November 2006. $0.1 million of these costs are included in general and administrative expenses and $0.5 million are included in interest expense.

We increased our cash distribution by $0.01 each quarter during 2006 and increased our cash distribution again to $0.21 per unit for the fourth quarter of 2006. This distribution was paid in February 2007.

Significant Events in 2006

New Credit Facility

We replaced our existing credit facility with a maximum $500 million Senior Secured Revolving Credit Agreement dated November 15, 2006 between Genesis Crude Oil, L.P. and a syndicate of lenders. The initial committed amount under our facility is $125 million. The committed amount represents the amount the banks have committed to fund pursuant to the terms of the credit agreement. The borrowing base under the facility is approximately $82 million, and will be recalculated quarterly and at the time of acquisitions. The borrowing base represents the amount that can be borrowed or utilized for letters of credit from a credit standpoint based on our EBITDA, computed in accordance with the provisions of our credit facility. The commitment amount can be increased up to the maximum facility amount for acquisitions or internal growth projects with approval of the lenders. Likewise, the borrowing base may be increased to the extent of EBITDA attributable to acquisitions.

New Management Team

On August 8, 2006, we hired three senior executive officers: Grant E. Sims, former CEO of Leviathan Gas Pipeline Partners, L.P. was appointed as the new Chief Executive Officer and a member of the Board of Directors; Joseph A. Blount, Jr., former President and Chief Operating Officer of Unocal Midstream & Trade, was appointed as President and Chief Operating Officer; and Brad N. Graves, former Vice President of Enterprise Products Partners, L.P., was appointed as Executive Vice President of Business Development. This management team will be responsible for designing and implementing a growth-oriented strategy that will include acquisitions from third parties, development projects and, ultimately, acquisitions from (or lease arrangements with) Denbury. The new management team will have the opportunity to earn up to 20% of the equity interest in our general partner (currently owned 100% by Denbury) subject to meeting certain performance criteria. See additional discussion in “Item 11 - Executive Compensation” below.

Acquisition of Sandhill Joint Venture

On April 1, 2006, we acquired a 50% partnership interest in Sandhill Group, LLC for $5 million from Magna Carta Group, LLC. Magna Carta holds the other 50% interest in Sandhill. Sandhill is a limited liability company that owns a CO_2 processing facility located in Brandon, Mississippi. Sandhill is engaged in the production and distribution of liquid carbon dioxide for use in the food, beverage, chemical and oil industries. The facility acquires CO_2 from us under a long-term supply contract that we acquired in 2005 from Denbury.

The acquisition was financed with cash on hand. The terms of the acquisition include earnout provisions such that additional payments of up to $2.0 million would be paid by us to Magna Carta if Sandhill achieves targeted performance levels during the seven years between 2006 and 2012 inclusive. We have also guaranteed to Sandhill’s lender 50% of the outstanding debt of $4.5 million, or $2.25 million.

Sandhill is managed by a management committee consisting of two representatives each from Magna Carta and us. Our equity in the earnings of Sandhill is included in our industrial gases segment. Additional discussion of the earnout provisions and guaranty of Sandhill's debt is included in Note 7 to the financial statements and in "Commitments and Off-Balance Sheet Arrangements" below.

Critical Accounting Policies and Estimates

The preparation of consolidated financial statements in conformity with accounting principles generally accepted in the United States requires us to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities, if any, at the date of the consolidated financial statements and the reported amounts of revenues and expenses during the reporting period. Although we believe these estimates are reasonable, actual results could differ from those estimates. Significant accounting policies that we employ are presented in the notes to the consolidated financial statements (See Note 2. Summary of Significant Accounting Policies.)

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Critical accounting policies and estimates are those that are most important to the portrayal of our financial results and positions. These policies require management's judgment and often employ the use of information that is inherently uncertain. Our most critical accounting policies pertain to revenue and expense accruals, hedging activities, our stock appreciation rights plan accrual, pipeline loss allowance recognition, depreciation, amortization and impairment of long-lived assets, asset retirement obligations and contingent and environmental liabilities. We discuss these policies below.

Revenue and Expense Accruals

Information needed to record our revenues is generally available to allow us to record substantially all of our revenue-generating transactions based on actual information. The accruals that we are required to make for revenues are generally insignificant.

We routinely make accruals for expenses due to the timing of receiving third party information and reconciling that information to our records. These accruals can include some crude oil purchase costs and expenses for operating our assets such as contractor charges for goods and services provided. For crude oil purchases transported on our trucks or our pipelines, we have access to the volumetric and pricing data so that we can record these transactions based on actual information. Accounting for crude oil purchases that involve third party transportation services sometimes require us to make estimates, as the necessary volumetric data is not available within the timeframe needed. By balancing our crude oil purchase and sales volumes with the change in our inventory positions, we believe we can make reasonable estimates of the unavailable data.

We believe our estimates for revenue and expense items are reasonable, but there can be no assurance that actual amounts will not vary from estimated amounts.

Hedging Activities

The provisions of SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities*, as amended and interpreted, require that estimates be made of the effectiveness of derivatives as hedges and the fair value of derivatives. The actual results of the transactions involving the derivative instruments will most likely differ from the estimates. We make very limited use of derivative instruments; however, when we do, we base these estimates on information obtained from third parties and from our own internal records.

Stock Appreciation Rights Plan Accrual

We accrue for the fair value of our liability for the stock appreciation rights we have issued to our employees and directors under the provisions of SFAS No. 123(R), *Share-Based Payments,* as amended and interpreted. These provisions require us to make estimates that affect the determination of the fair value of the outstanding stock appreciation rights, including estimates of the expected life of the rights, expected forfeiture rates of the rights, expected future volatility of our unit price and expected future distribution yield on our units. We base our estimates of these factors on historical experience and internal data. The actual timing and amounts of payments to employees that will ultimately be made under the SAR plan will most like differ from the estimates that are used in determining fair value.

Pipeline Loss Allowance Recognition

Numerous factors can cause crude oil volumes to expand and contract. These factors include temperature of both the crude oil and the surrounding atmosphere and the quality of the crude oil, in addition to inherent imprecision of measurement equipment. As a result of these factors, crude oil volumes fluctuate, which can result in losses in volumes of crude oil in the custody of the pipeline that belongs to the shippers. In order to compensate the pipeline for bearing the risk of actual losses in volumes that occur, the pipeline generally has established in its tariffs the right to make volumetric deductions from the shippers for quality and volumetric fluctuations. We refer to these deductions as pipeline loss allowances.

We compare these allowances to the actual volumetric gains and losses of the pipeline and the net gain or loss is recorded as revenue or expense, based on prevailing market prices at that time. When net gains occur, the pipeline company has crude oil inventory. When net losses occur, we reduce any recorded inventory on hand and record a liability for the purchase of crude oil that we must make to replace the lost volumes. We reflect inventories in the financial statements at the lower of the recorded value or the market value at the balance sheet date. We value liabilities to replace crude oil at current market prices. The crude oil in inventory can then be sold, resulting in additional revenue if the sales price exceeds the inventory value.

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We cannot predict future pipeline loss allowance revenue because these revenues depend on factors beyond management's control such as the crude oil quality and temperatures, as well as crude oil market prices.

Depreciation, Amortization and Impairment of Long-Lived Assets

In order to calculate depreciation and amortization we must estimate the useful lives of our fixed assets at the time the assets are placed in service. We base our calculation of the useful life of an asset on our experience with similar assets. Experience, however, can cause us to change our estimates, thus impacting the future calculation of depreciation and amortization.

When events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable, we review our assets for impairment in accordance with SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*. We compare the carrying value of the fixed asset to the estimated undiscounted future cash flows expected to be generated from that asset. Estimates of future net cash flows include estimating future volumes, future margins or tariff rates, future operating costs and other estimates and assumptions consistent with our business plans. Should the undiscounted future cash flows be less than the carrying value, we record an impairment charge to reflect the asset at fair value.

Asset Retirement Obligations

Some of our assets, primarily related to our pipeline operations segment, have obligations regarding removal and restoration activities when the asset is abandoned. Additionally, we generally have obligations to remove crude oil injection stations located on leased sites. We estimate the fair values of these obligations based on current costs, inflation estimates and other factors in order to record the liabilities. We also must estimate the ultimate timing of the performance of these liabilities in determining the fair value of the obligations. We revise these estimates as information becomes available that affects the assumptions we made.

Liability and Contingency Accruals

We accrue reserves for contingent liabilities including environmental remediation and potential legal claims. When our assessment indicates that it is probable that a liability has occurred and the amount of the liability can be reasonably estimated, we make accruals. We base our estimates on all known facts at the time and our assessment of the ultimate outcome, including consultation with external experts and counsel. We revise these estimates as additional information is obtained or resolution is achieved.

We also make estimates related to future payments for environmental costs to remediate existing conditions attributable to past operations. Environmental costs include costs for studies and testing as well as remediation and restoration. We sometimes make these estimates with the assistance of third parties involved in monitoring the remediation effort.

We are currently conducting remediation of subsurface soil and groundwater hydrocarbon contamination at the former Jay Trucking Facility. The total estimated remediation and related costs are $1.3 million, which we expect to share with other responsible parties. In 2005, we recorded a liability of $0.5 million as our estimated share of this liability. We currently have no reason to believe that this remediation will have a material financial effect on our financial position, results of operation, or cash flows.

We believe our estimates for contingent liabilities are reasonable, but we cannot assure you that actual amounts will not vary from estimated amounts.

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Results of Operations

The contribution of each of our segments to total segment margin in each of the last three years was as follows:

	Year Ended December 31,		
	2006	2005	2004
	(in thousands)		
Pipeline transportation	$ 12,426	$ 9,804	$ 8,543
Industrial gases	11,443	8,154	5,762
Crude oil gathering and marketing	7,366	3,661	4,034
Total segment margin	$ 31,235	$ 21,619	$ 18,339

Pipeline Transportation Segment

We operate three common carrier crude oil pipeline systems in a four state area. We refer to these pipelines as our Mississippi System, Jay System and Texas System. Volumes shipped on these systems for the last three years are as follows (barrels per day):

Pipeline System	2006	2005	2004
Mississippi	16,931	16,021	12,589
Jay	13,351	13,725	14,440
Texas	31,303	31,550	36,413

The Mississippi System begins in Soso, Mississippi and extends to Liberty, Mississippi. At Liberty, shippers can transfer the crude oil to a connection to Capline, a pipeline system that moves crude oil from the Gulf Coast to refineries in the Midwest. The system has been improved to handle the increased volumes produced by Denbury and transported on the pipeline. In order to handle future increases in production volumes in the area that are expected, we have made capital expenditures for tank, station and pipeline improvements and we intend to make further improvements. See *Capital Expenditures* under “Liquidity and Capital Resources” below.

Denbury is the largest producer (based on average barrels produced per day) of crude oil in the State of Mississippi. Our Mississippi System is adjacent to several of Denbury’s existing and prospective oil fields. As Denbury continues to acquire and develop old oil fields using CO_2 based tertiary recovery operations, Denbury expects to add crude oil gathering and CO_2 supply infrastructure to those fields, which could create some opportunities for us.

Beginning in September 2004, Denbury became a shipper on the Mississippi System, under an incentive tariff designed to encourage shippers to increase volumes shipped on the pipeline. Prior to this point, Denbury sold its production to us before it entered the pipeline.

In the fourth quarter of 2004, we constructed two segments of crude oil pipeline to connect producing fields operated by Denbury to our Mississippi System. One of these segments was placed in service in 2004 and the other began operations in the first quarter of 2005. Denbury pays us a minimum payment each month for the right to use these pipeline segments. We account for these arrangements as direct financing leases.

The Jay pipeline system in Florida/Alabama ships crude oil from fields with relatively short remaining production lives. Recent changes in the ownership of the more mature producing fields in the area surrounding our Jay System have led to interest in further development of these fields which may lead to increases in production. Additionally, new wells have been drilled in the area. This new production produces greater tariff revenue for us due to the greater distance that the crude oil is transported on the pipeline. This increased revenue, increases in tariff rates each year on the remaining segments of the pipeline, sales of pipeline loss allowance volumes, and operating efficiencies that have decreased operating costs have contributed to increase our cash flows from the Jay System.

Volumes on our Texas System averaged 31,303 barrels per day during 2006. The crude oil that enters our system comes to us at West Columbia where we have a connection to TEPPCO’s South Texas System and at Webster where we have connections to two other pipelines. One of these connections at Webster is with ExxonMobil Pipeline and is used to receive volumes that originate from TEPPCO’s pipelines. We have a joint tariff with TEPPCO under which we earn $0.22 per barrel on the majority of the barrels we deliver to the shipper’s facilities. Substantially all of the volume being shipped on our Texas System goes to two refineries on the Texas Gulf Coast.

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Our Texas System is dependent on the connecting carriers for supply, and on the two refineries for demand for our services. Volumes on the Texas System have declined since the sale to TEPPCO in 2003 of a portion of our Texas System as a result of changes in the supply available for the two refineries to acquire and ship on our pipeline and changes TEPPCO made to the operations of the pipeline segments it acquired from us. We lease tankage in Webster on the Texas System of approximately 165,000 barrels. We have a tank rental reimbursement agreement effective January 1, 2005 with the primary shipper on our Texas System to reimburse us for the expense of leasing of that storage capacity. Volumes on the Texas System may continue to fluctuate as refiners on the Texas Gulf Coast compete for crude oil with other markets connected to TEPPCO's pipeline systems.

We operate a CO_2 pipeline in Mississippi to transport CO_2 from Denbury's main CO_2 pipeline to Brookhaven oil field. Denbury has the exclusive right to use this CO_2 pipeline. This arrangement has been accounted for as a direct financing lease.

Historically, the largest operating costs in our crude oil pipeline segment have consisted of personnel costs, power costs, maintenance costs and costs of compliance with regulations. Some of these costs are not predictable, such as failures of equipment, or are not within our control, like power cost increases. We perform regular maintenance on our assets to keep them in good operational condition and to minimize cost increases.

Operating results from operations for our pipeline transportation segment were as follows.

	Year Ended December 31,		
	2006	2005	2004
		(in thousands)	
Crude oil tariffs and revenues from direct financing leases of crude oil pipelines	$ 14,309	$ 13,490	$ 13,048
Sales of crude oil pipeline loss allowance volumes	6,472	4,672	3,475
Revenues from direct financing leases of CO_2 pipelines	340	359	25
Tank rental reimbursements and other miscellaneous revenues	621	566	132
Total revenues from crude oil and CO_2 tariffs, including revenues from direct financing leases	21,742	19,087	16,680
Revenues from natural gas tariffs and sales	8,205	9,801	-
Natural gas purchases	(7,593)	(9,343)	-
Pipeline operating costs	(9,928)	(9,741)	(8,137)
Segment margin	$ 12,426	$ 9,804	$ 8,543
Volumes per day:			
Crude oil pipeline - barrels	61,585	61,296	63,441

Year Ended December 31, 2006 Compared with Year Ended December 31, 2005

Pipeline segment margin increased $2.6 million, or 27%, for 2006, as compared to 2005. Revenues from crude oil and CO_2 tariffs and related sources were responsible for the increase for the period. Net profit from natural gas transportation and sales increased slightly, with that increase offset by an increase in pipeline operating costs.

Tariff revenues from transportation of crude oil and CO_2 increased $0.8 million in 2006 compared to the prior year period due primarily to increased tariffs on all systems. Additionally the receipt and delivery points for the crude oil varied in 2006, with proportionately more volume at locations with higher per barrel tariffs. Total volumes on all three systems were consistent with 2005 volumes.

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Higher market prices for crude oil added $1.8 million to pipeline loss allowance revenues. During 2006, average crude oil market prices, as referenced by the prices posted by Shell Trading (US) Company for West Texas/New Mexico Intermediate grade crude oil, were $9.71 higher than in 2005. Fluctuations in the future in crude oil market prices will affect our revenues from sales of crude oil pipeline loss allowance volumes. Tank rental reimbursements and other miscellaneous revenues increased by $0.1 million.

Net profit from natural gas pipeline activities increased in total $0.1 million from 2005 amounts. Fluctuations in natural gas market prices created variances between the annual periods in revenues from natural gas sales and costs of natural gas purchases.

Operating costs increased $0.2 million. A decrease in 2006 in costs for regulatory testing and repairs of $0.6 million was offset by increased power costs of $0.2 million, increases in safety and insurance costs totaling $0.3 million and expense related to our SAR plan of $0.3 million.

Year Ended December 31, 2005 Compared with Year Ended December 31, 2004

Pipeline segment margin increased $1.3 million, or 15%, for 2005, as compared to 2004. Revenues from crude oil and CO_2 tariffs and related sources added $2.4 million of the increase for the period and $0.5 million of the increase resulted from net profit from natural gas transportation and sales acquired in 2005. Pipeline operating cost increases offset $1.6 million of the revenue increases.

Crude oil and CO_2 tariff revenues increased $0.8 million in 2005 compared to the prior year period due to the combination of higher tariffs and higher volumes on the systems with higher per barrel tariffs. Volumes on our pipelines were affected briefly by hurricanes in both periods. The effects of lower tariffs and volumes on the Texas System were generally offset by increased volumes and tariffs on the Mississippi System.

Higher market prices for crude oil added $1.2 million to pipeline loss allowance revenues. The CO_2 pipeline did not exist until December 2004, and the natural gas gathering pipelines were acquired in the first quarter of 2005.

Operating costs increased $1.6 million. In 2004, as well as in 2005, we incurred costs for regulatory testing and repairs resulting from that testing. Those costs were approximately $0.6 million greater in 2005. Operational costs for personnel, contract services, liability insurance and equipment maintenance accounted for most of the remaining increase.

Industrial Gases Segment

Our industrial gases segment includes the results of our CO_2 sales to industrial customers and our share of the operating income of our 50% joint venture interests in T&P Syngas and Sandhill.

CO_2

We supply CO_2 to industrial customers under seven long-term CO_2 sales contracts. We acquired those contracts, as well as the CO_2 necessary to satisfy substantially all of our expected obligations under those contracts, in three separate transactions with Denbury. Since 2003, we have purchased those contracts, along with three VPPs representing 280.0 Bcf of CO_2 (in the aggregate), from Denbury for a total of $43.1 million in cash. We sell our CO_2 to customers who treat the CO_2 and sell it to end users for use for beverage carbonation and food chilling and freezing or for uses in tertiary crude oil recovery or chemical processes. Our compensation for supplying CO_2 to our industrial customers is the effective difference between the price at which we sell our CO_2 under each contract and the price at which we acquired our CO_2 pursuant to our VPPs, minus transportation costs. We expect our CO_2 contracts to provide stable cash flows until they expire, at which time we intend to extend or replace those contracts, including acquiring the necessary CO_2 supply from wholesalers. At December 31, 2006, we have 210.5 Bcf of CO_2 remaining under the VPPs.

The terms of our contracts with the industrial CO_2 customers include minimum take-or-pay and maximum delivery volumes. The maximum daily contract quantity per year in the contracts totals 97,625 Mcf. Under the minimum take-or-pay volumes, the customers must purchase a total of 51,048 Mcf per day whether received or not. Any volume purchased under the take-or-pay provision in any year can then be recovered in a future year as long as the minimum requirement is met in that year. In the three years ended December 31, 2006, all of our customers purchased more than their minimum take-or-pay quantities.

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Our seven industrial contracts expire at various dates beginning in 2010 and extending through 2023. The sales contracts contain provisions for adjustments for inflation to sales prices based on the Producer Price Index, with a minimum price.

The industrial customers treat the CO_2 and transport it to their own customers. The primary industrial applications of CO_2 by these customers include beverage carbonation and food chilling and freezing. Based on historical data for 2004 through 2006, we expect some seasonality in our sales of CO_2. The dominant months for beverage carbonation and freezing food are from April to October, when warm weather increases demand for beverages and the approaching holidays increase demand for frozen foods. The table below depicts these seasonal fluctuations. The average daily sales (in Mcfs) of CO_2 for each quarter in 2006 and 2005 under these contracts (including volumes sold by Denbury on the contracts we acquired in the fourth quarter of 2005) were as follows:

Quarter	2006	2005
First	66,565	67,434
Second	73,980	73,307
Third	82,244	77,264
Fourth	68,452	77,089

Syngas

We recognize our share of the earnings of T&P Syngas in each period. We are amortizing the excess of the price we paid for our interest in T&P Syngas over our share of the equity of T&P Syngas over the remaining useful life of the assets of T&P Syngas. This excess of $4.0 million is being amortized over eleven years. We receive cash distributions from T&P Syngas quarterly.

Sandhill

We recognize our share of the earnings of Sandhill in each period. We paid $3.8 million more for our interest in Sandhill than our share of the equity on the balance sheet of Sandhill at the date of acquisition. This excess of the purchase price over our share of the equity of Sandhill has been allocated to the property and equipment and intangible assets based on the fair value of those assets, with the remaining $0.7 million allocated to goodwill. We are amortizing the amount allocated to property, equipment and intangibles over the remaining useful lives of those assets. The amount allocated to goodwill will be reviewed for impairment periodically. We receive cash distributions from Sandhill quarterly.

Operating Results

Operating results for our industrial gases segment were as follows.

	Year Ended December 31,		
	2006	2005	2004
		(in thousands)	
Revenues from CO_2 sales	$ 15,154	$ 11,302	$ 8,561
CO_2 transportation and other costs	(4,842)	(3,649)	(2,799)
Equity in earnings of joint ventures	1,131	501	-
Segment margin	$ 11,443	$ 8,154	$ 5,762
Volumes per day:			
CO_2 sales - Mcf [(1)]	72,841	56,823	45,312

(1) 2005 and 2004 volumes only include volumes sold by us.

The increasing margins from the industrial gases segment between 2004 and 2005 and from 2005 to 2006 are primarily attributable to the acquisitions we made in 2004 and 2005 in this segment. The average revenue per Mcf sold increased by more than 4% in each year, due to inflation adjustments in the contracts and variations in the volumes sold under each contract.

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Transportation costs for the CO_2 on Denbury's pipeline have increased due to the increased volume and the effect of the annual inflation factor in the rate paid to Denbury. The rate per Mcf in 2006 increased 3% over the 2005 rate. The rate in 2005 increased 4% over the 2004 rate.

Our share of the operating income of T&P Syngas for 2006 and for the nine month period we owned it in 2005 was $1.5 million and $0.8 million, respectively. We reduced the amount we recorded as our equity in T&P Syngas by $0.4 million and $0.3 million as amortization of the excess purchase price of T&P Syngas in each year, respectively. During 2006, T&P Syngas paid us distributions totaling $2.0 million, and we received a distribution of $0.6 million in 2007 attributable to the fourth quarter of 2006. During 2005 we received distributions totaling $0.8 million.

Our share of the operating income of Sandhill for the nine month period we owned it in 2006 was $0.1 million. We reduced that amount by $0.2 million for the amortization of the excess of the purchase price of Sandhill. During 2006, we received distributions from Sandhill totaling $0.1 million.

Crude Oil Gathering and Marketing Operations

We conduct certain crude oil aggregating operations, which involve purchasing, gathering, transporting by trucks and pipelines owned by us and trucks, pipelines and barges operated by others, and reselling, that help ensure a base supply source for our crude oil pipeline systems. Our profit for those services is derived from the difference between the price at which we re-sell crude oil less the price at which we purchase that crude oil, minus the associated costs of aggregation and any cost of supplying credit. The most substantial component of our aggregating costs relates to operation our fleet of leased trucks. Our crude oil gathering and marketing activities provide us with an extensive expertise, knowledge base and skill set that facilitates our ability to capitalize on regional opportunities which arise from time to time in our market areas. Usually this segment experiences limited commodity price risk because we generally make back-to-back purchases and sales, matching our sale and purchase volumes on a monthly basis.

The commodity price (for purchases and sales) of crude oil does not necessarily bear a relationship to segment margin as those prices normally impact revenues and costs of sales by approximately equivalent amounts. Because period-to-period variations in revenues and costs of sales are not generally meaningful in analyzing the variation in segment margin for our gathering and marketing operations, these changes are not addressed in the following discussion. Additionally, beginning in April 2006, we now present the margin on certain transactions under buy/sell arrangements on a net basis as required by the provisions of Emerging Issues Task Force Issue No. 04-13, "Accounting for Purchases and Sales of Inventory with the Same Counterparty,"

Generally, as we purchase crude oil, we simultaneously establish a margin by selling crude oil for physical delivery to third party users, such as independent refiners or major oil companies. Through these transactions, we seek to maintain a position that is substantially balanced between crude oil purchases, on the one hand, and sales or future delivery obligations, on the other hand. We do not hold crude oil, futures contracts or other derivative products to speculate on crude oil price changes. When our positions become unbalanced such that we have inventory, we will use derivative instruments to hedge that inventory until such time as we can sell it into the market.

When the crude oil markets are in contango, (oil prices for future deliveries are higher than for current deliveries), we may store crude oil, as inventory in our storage tanks, that we have purchased at lower prices in the current month for delivery at higher prices in future months. When we purchase this inventory, we simultaneously enter into a contract to sell the inventory in the future period, either with a counterparty or in the crude oil futures market. The maximum storage available to us for use in this strategy is approximately 120,000 barrels, although maintenance activities on our pipelines impact the availability of this storage capacity. We generally will account for this inventory and the related derivative hedge as a fair value hedge in accordance with Statement of Financial Accounting Standards No. 133. See Note 10 to the Consolidated Financial Statements.

Most of our contracts for the purchase and sale of crude oil have components in the pricing provisions such that the price paid or received is adjusted for changes in the market price for crude oil. The pricing in the majority of our purchase contracts contain the market price component, a bonus that is not fixed, but instead is based on another market factor and a deduction to cover the cost of transporting the crude oil and to provide us with a margin. Contracts will sometimes also contain a grade differential which considers the chemical composition of the crude oil and its appeal to different customers. Typically the pricing in a contract to sell crude oil will consist of the market price components and the grade differentials. The margin on individual transactions is then dependent on our ability to manage our transportation costs and to capitalize on grade differentials.

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Field operating costs consist of the costs to operate our fleet of 48 leased trucks used to transport crude oil, and the costs to maintain the trucks and assets used in the crude oil gathering operation. Approximately 60% of these costs are variable and increase or decrease with volumetric changes. These costs include payroll and benefits (as drivers are paid on a commission basis based on volumes), maintenance costs for the trucks (as we lease the trucks under full service maintenance contracts under which we pay a maintenance fee per mile driven), and fuel costs. Fuel costs also fluctuate based on changes in the market price of diesel fuel. Fixed costs include the base lease payment for the vehicle, insurance costs and costs for environmental and safety related operations.

Operating results from continuing operations for our crude oil gathering and marketing segment were as follows.

	Year Ended December 31,		
	2006	2005	2004
		(in thousands)	
Revenues	$ 873,268	$ 1,038,549	$ 901,902
Crude oil costs	(851,671)	(1,018,896)	(883,988)
Field operating costs	(14,231)	(15,992)	(13,880)
Segment margin	$ 7,366	$ 3,661	$ 4,034
Volumes per day:			
Crude oil total - barrels	37,180	52,943	60,419
Crude oil truck transported only - barrels	3,368	3,084	1,742

Year Ended December 31, 2006 as Compared to Year Ended December 31, 2005

Our crude oil gathering and marketing segment margin increased by slightly more than double the prior year period. A decrease in field costs of $1.8 million combined with $1.9 million of increased segment margin from the two other factors resulted in a total increase of $3.7 million.

The majority of the decrease in field costs from the 2005 level related to a reduction in the size of our fleet. When we leased new trucks late in 2005, we reduced the size of the fleet to better match the volumes being purchased. This reduction in fleet size reduced personnel and truck lease costs. The new trucks also required less repair costs in the first year of the lease. During 2005 we also recorded a reserve of $0.5 million for 40% of the expected costs to remediate Jay Trucking Station, which made costs in that period higher than 2006. (See additional discussion at Note 17 to the Consolidated Financial Statements.) Higher fuel costs offset part of the reduction. Average fuel costs during 2006 increased more than $0.30 per gallon, or 13 percent, over the 2005 level. We also recorded expense in field operating costs in the 2006 period of $0.3 million related to our SAR plan.

A $0.3 million increase in revenues from volumes that we transported for a fee but did not purchase increased segment margin. Approximately 52% of the total transportation fee revenue related to volumes transported for Denbury from their wellhead locations to our pipeline using our trucks. We also provide these transportation services for third parties to move crude oil from wellhead locations to destinations designated by those third parties.

Approximately $0.7 million of the remaining increase in segment margin resulted again from a focus on eliminating less profitable volumes, and increasing profitability on the volumes retained by maximizing the benefits to us of fluctuations in prices in the regions in which we operate. Additionally, while we have been in a contango crude oil price market for most of 2005 and 2006, the contribution to segment margin from our inventory hedges has been approximately $0.9 million greater in the 2006 period.

Year Ended December 31, 2005 as Compared to Year Ended December 31, 2004

Crude oil gathering and marketing segment margins from continuing operations decreased $0.4 million in 2005 from the prior year period. An increase in field costs of $2.1 million was offset by $1.7 million of increased segment margin from four other factors.

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The majority of the increase in field costs over 2004 related to higher fuel costs, higher employee costs and the costs related to additional tractor/trailers we leased beginning in the third quarter of 2004. We also recorded a reserve of $0.5 million for 40% of the expected costs to remediate Jay Trucking Station. (See additional discussion at Note 17 to the Consolidated Financial Statements.)

Partially offsetting the higher field costs were increases in four factors. These factors were:

- A $0.4 million increase in revenues from volumes that we transported for a fee but did not purchase. Approximately 63% of the total transportation fee revenue related to volumes transported for Denbury. Through August 31, 2004, we purchased Denbury's crude oil at the wellhead. Beginning in September 2004, Denbury started selling its production to the end-market directly, and we provide transportation services for fees in our trucks and in our pipeline.

- An increase in the average difference between the sales price and the purchase price of crude oil increased segment margin by $0.7 million, despite a 7,786 barrel per day decrease in purchased volumes.

- A $0.4 million realized gain from a fair value hedge of inventory. Due to market conditions in the second quarter, we elected to hold inventory and hedge it in the market. We sold this inventory in the fourth quarter realizing the gain.

A $0.2 million decrease in credit costs related to crude oil transactions.

Other Costs and Interest

General and administrative expenses were as follows.

	Year Ended December 31,		
	2006	2005	2004
		(in thousands)	
Expenses excluding effect of stock appreciation rights plan, bonus plan and management team transition	$ 9,007	$ 8,903	$ 9,662
Bonus plan expense	1,747	1,235	218
Stock appreciation rights plan expense (credit)	1,279	(482)	1,151
Management team transition costs and write-off of deferred charges from prior credit facility	1,540	-	-
Total general and administrative expenses	$ 13,573	$ 9,656	$ 11,031

Year Ended December 31, 2006 Compared with Year Ended December 31, 2005

In total general and administrative expenses, increased by $3.9 million, however the effects of our SAR and bonus plans, transition costs related to the change in our management team and the write-off of deferred charges related to our prior credit facility caused that increase. Excluding these items, general and administrative expenses in 2006 and 2005 were approximately $9.0 million.

As a result of the improvement in our financial results in 2006, our accrual under our bonus plan increased by $0.5 million. The bonus plan for employees is described in Item 11, "Executive Compensation" below. The plan provides for a bonus pool based on the amount of Available Cash before reserves generated. In 2006, we generated more available cash than in 2005, resulting in a larger bonus expense.

In 2006, we adopted a new accounting pronouncement that changed the method by which we record expense related to our SAR plan. (See additional discussion in “Cumulative Effect Adjustments” below and in Note 14 to the Consolidated Financial Statements.) The SAR plan for employees and directors is a long-term incentive plan whereby rights are granted for the grantee to receive cash equal to the difference between the grant price and common unit price at date of exercise. The rights vest over several years. As a result of this accounting change, general and administrative expense for SARs increased by $1.7 million from a credit to expense in 2005 to a charge to expense in 2006 of $1.3 million. In prior periods, the charge or credit to our earnings related to our SAR plan was primarily a function of the change in the market price for our common units from the prior period end. Under the new method of accounting for the outstanding SARs, we determine the fair value of the SARs at the end of each period and the fair value is charged to expense over the period during which the employee vests in the SARs.

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Finally, we recorded transition costs of $1.4 million, primarily in the form of severance costs, when our management team changed in August 2006. When we replaced our credit facility in November 2006, we wrote-off $0.1 million of unamortized deferred legal costs related to our prior facility.

Year Ended December 31, 2005 Compared with Year Ended December 31, 2004

General and administrative expenses, excluding the effects of our bonus plan and stock appreciation rights, or SAR, plan, decreased $0.8 million in 2005 from the 2004 level. In 2004, we incurred expenses of $1.3 million for professional services to assist us in the internal control documentation and assessment provisions of the Sarbanes-Oxley Act including additional audit fees related to this process. In 2005 we formed an internal audit department to perform the testing and evaluation of our internal controls. The total costs related to internal control documentation, testing and assessment declined $0.7 million between the two periods. Other administrative costs decreased $0.1 million.

Under the prior method of accounting for our SAR plan, we recorded expense based on changes to the market price for our units. Our unit price was $12.60 at December 31, 2004. At December 31, 2005, the unit price was $11.65, resulting in a non-cash credit of $0.5 million for 2005.

Depreciation, amortization and impairment expense increased $1.2 million between 2005 and 2006. The majority of this increase related to amortization of our CO_2 assets. Amortization of the CO_2 assets increased due to the additional CO_2 volumes sold in the 2006 period as compared to 2005. These additional sales related primarily to the CO_2 contracts acquired in the fourth quarter of 2005.

Depreciation, amortization and impairment decreased by $0.6 million in 2005 from the 2004 level. 2004 included a charge of $0.9 million to write-down the value of the segment of our Mississippi System from Liberty to Baton Rouge to its estimated salvage value.

Interest expense, net was as follows:

	Year Ended December 31,		
	2006	2005	2004
	(in thousands)		
Interest expense, including commitment fees	$ 781	$ 1,831	$ 743
Capitalized interest	(9)	(35)	(76)
Amortization of facility fees	300	307	303
Write-off of facility fees and other fees	500	-	-
Interest income	(198)	(71)	(44)
Net interest expense	$ 1,374	$ 2,032	$ 926

Total net interest expense in 2006 was $0.7 million less than in 2005. Interest expense including commitment fees was $1.1 million lower due to average outstanding bank debt that was $15.8 million lower and an interest rate that was 1.3% higher. Our equity offering in December 2005 was used to repay outstanding debt from acquisitions in 2005 and prior years, resulting in the lower average debt balance in 2006. Market interest rates rose in 2006 from 2005 levels, however the impact to us was minor because of our lower debt balances. During 2006, our average daily debt outstanding was $3.4 million.

As a result of the termination of our prior credit facility to enter into the new facility we obtained in November 2006, we wrote-off $0.5 million of deferred facility fees related to the prior credit facility. Interest income in 2006 was greater than in 2005 due to cash we had available in the first quarter of the year to invest from the public offering.

In 2005, our net interest expense increased by $1.1 million. Variances in debt outstanding (primarily due to the acquisition of assets throughout 2005), increases in market interest rates and an increase on June 1, 2004 in the size of our credit facility to $100 million resulted in greater interest expense and commitment fees.

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Net gain/loss on disposal of surplus assets. In 2006, 2005 and 2004 we sold surplus assets no longer used in our operations, recognizing small gains in 2006 and 2005 and a small loss in 2004.

Discontinued Operations

In the fourth quarter of 2003, we sold a significant portion of our Texas Pipeline System and the related crude oil gathering and marketing operations to TEPPCO Crude Oil, L.P. Additionally we sold other segments of our Texas Pipeline System that had been idled in 2002 to Blackhawk Pipeline, L.P., an affiliate of Multifuels, Inc. We abandoned in place other remaining segments not sold to these parties in 2003.

We agreed not to compete with TEPPCO in a 40-county area in Texas surrounding the pipeline for a five-year period. We retained responsibility for environmental matters related to the operations sold to TEPPCO for the period prior to the sale date, subject to certain conditions. Our responsibility to indemnify TEPPCO for environmental matters in connection with this transaction will cease in October 2013. We do not expect the effects of this indemnification to have a material effect on our results of operations in the future.

During 2005, we sold assets that had been idled as a result of the sale to TEPPCO, receiving $0.3 million and recognizing a gain of $0.3 million. During 2004, we incurred costs totaling $0.5 million related to the dismantlement of assets that we abandoned in 2003.

Cumulative Effect Adjustments

2006

On January 1, 2006, we adopted the provisions of SFAS No. 123(R). In December 2004, the FASB issued SFAS No. 123 (revised December 2004), "Share-Based Payments". The adoption of this statement requires that the compensation cost associated with our stock appreciation rights plan, which upon exercise will result in the payment of cash to the employee, be re-measured each reporting period based on the fair value of the rights. Before the adoption of SFAS 123(R), we accounted for the stock appreciation rights in accordance with FASB Interpretation No. 28, "Accounting for Stock Appreciation Rights and Other Variable Stock Option or Award Plans" which required that the liability under the plan be measured at each balance sheet date based on the market price of our common units on that date. Under SFAS 123(R), the liability will be calculated using a fair value method that will take into consideration the expected future value of the rights at their expected exercise dates.

We have elected to calculate the fair value of the rights under the plan using the Black-Scholes valuation model. This model requires that we consider the expected volatility of the market price for our common units, the current price of our common units, the exercise price of the rights, the expected life of the rights, the current risk free interest rate, and our expected annual distribution yield. This valuation is then applied to the vested rights outstanding and to the non-vested rights based on the percentage of the service period that has elapsed. The valuation is adjusted for expected forfeitures of rights (due to terminations before vesting, or expirations after vesting). The liability amount accrued on the balance sheet is adjusted to this amount with the adjustment reflected in the statement of operations.

The estimates that we made upon the adoption of this standard at January 1, 2006 included the following assumptions:

- In determining the expected life of the rights, we used the simplified method allowed by the Securities and Exchange Commission. We have very limited experience with employee exercise patterns, as our plan was initiated on December 31, 2003. The simplified method produces an initial expected life of 6.25 years for those rights we issued that vest 25% per year for four years, and an initial expected life of 7 years for those rights we issued that fully vest at the end of a four-year period.

- The expected volatility of our units was computed using the historical period we believe is representative of future expectations. We determined the period to use as the historical period by considering our distribution history and distribution yield. The expected volatility used in the fair value calculations was approximately 33% at January 1, 2006 and 32% at December 31, 2006.

- The risk-free interest rate was determined from the current yield for U.S. Treasury zero-coupon bonds with a term similar to the remaining expected life of the rights.

- In determining our expected future distribution yield, we considered our history of distribution payments, our expectations for future payments, and the distribution yields of entities similar to us.

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- We estimated the expected forfeitures of non-vested rights and expirations of vested rights. As our stock appreciation rights plan was not put in place until December 31, 2003, we have very limited experience with employee forfeiture and expiration patterns. We reviewed the history available to us as well as employee turnover patterns in determining the rates to use. We also used different estimates for different groups of employees.

At December 31, 2005, we had a recorded liability of $0.8 million, computed under the provisions of FASB Interpretation No. 28. We calculated the effect of adoption of SFAS 123(R) at January 1, 2006, and determined that our recorded liability at December 31, 2005 should be reduced by $30,000. This reduction is reflected as income from the cumulative effect of the adoption of a new accounting principle on our statement of operations. We do not believe the effect of adoption of this accounting principle at January 1, 2005 would have been material. The adjustment of the liability to its fair value at December 31, 2006, resulted in total expense of $1.9 million for 2006, of which $1.3 million is included in general and administrative expenses and $0.3 million is included in each of field operating costs and pipeline operating costs.

2005

On December 31, 2005, we adopted FASB Interpretation No. 47, “Accounting for Conditional Asset Retirement Obligations, an interpretation of FASB Statement No. 143”, or FIN 47. FIN 47 clarified that the term “conditional asset retirement obligation”, as used in SFAS No. 143, “Accounting for Asset Retirement Obligations”, refers to a legal obligation to perform an asset retirement activity in which the timing and/or method of settlement are conditioned upon a future event that may or may not be within our control. Although uncertainty about the timing and/or method of settlement may exist and may be conditioned upon a future event, the obligation to perform the asset retirement activity is unconditional. Accordingly, we are required to recognize a liability for the fair value of a conditional asset retirement obligation if the fair value of the liability can be reasonably estimated.

Some of our assets, primarily related to our pipeline operations segment, have obligations regarding removal activities when the asset is abandoned or retired. Additionally, we generally have obligations to remove crude oil injection stations located on leased sites. These assets are actively in use in our operations and the timing of the abandonment of these assets cannot be determined. Accordingly, under the provisions of FIN 47, we have made an estimate of the fair value of our obligations.

Upon adoption of FIN 47, we recorded a fixed asset and a liability for the estimated fair value of the asset retirement obligations at the time we acquired the related assets. This $0.3 million fixed asset is being depreciated over the life of the related assets. The accretion of the discount on the liability and the depreciation through December 31, 2005 were recorded in the statement of operations as a cumulative effect adjustment totaling $0.5 million. Additionally, we reflected our share of the asset retirement obligation recorded in accordance with FIN 47 of our equity method joint venture as a cumulative affect adjustment of $0.1 million.

See Note 4 to the Consolidated Financial Statements for the pro forma impact for the periods ended December 31, 2005 and 2004 of the adoption of FIN 47 if it had been adopted at the beginning of each of those periods.

Liquidity and Capital Resources

Capital Resources

We replaced our existing credit facility with a $500 million Senior Secured Revolving Credit Agreement dated November 15, 2006 between Genesis Crude Oil, L.P. and a syndicate of lenders. This new credit facility, with a maximum facility amount of $500 million, is with a group of banks led by Fortis Capital Corp. and Deutsche Bank Securities Inc. The initial committed amount under our facility is $125 million, of which a maximum of $50 million may be used for letters of credit. The committed amount represents the amount the banks have committed to fund pursuant to the terms of the credit agreement. The borrowing base under the facility at December 31, 2006 was approximately $82 million, and it will be recalculated quarterly and at the time of acquisitions. The borrowing base represents the amount that can be borrowed or utilized for letters of credit from a credit standpoint based on our EBITDA, computed in accordance with the provisions of our credit facility. The commitment amount may be increased up to the maximum facility amount for acquisitions and internal growth projects with approval of the lenders. Likewise, the borrowing base may be increased to the extent of pro forma additional EBITDA attributable to acquisitions. At December 31, 2006, we had $8.0 million of debt outstanding and $4.6 million in letters of credit outstanding under the facility. Due to the revolving nature of loans under our credit facility, additional borrowings and periodic repayments and re-borrowings may be made until the maturity date of November 15, 2011.

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Interest on amounts borrowed under the new facility is equal to (i) either the applicable Eurodollar settlement rate, or LIBOR Rate, or the higher of the federal funds rate plus ½ of 1% or Fortis's prime rate for the relevant period, or Prime Rate, at our option, plus (ii) the applicable margin rate. We are required to pay our credit facility lenders a fee based upon amounts committed but not utilized by outstanding borrowings or letters of credit, as well as certain other fees.

We must comply with various affirmative and negative covenants contained in our new credit facility. Among other things, these covenants limit our ability to:

- incur additional indebtedness or liens;
- sell assets;
- make loans, investments or guarantees;
- acquire or be acquired by other companies;
- enter into or amend certain existing agreements; and
- enter into any hedging agreement for speculative purposes.

Our new credit facility covenants also require us to achieve specific minimum financial metrics. For example, we must maintain a debt service coverage ratio of at least 3.0 to 1.0 and a leverage ratio of no more than 5.5 to 1.0. In general, the debt service coverage ratio calculation compares EBITDA (as adjusted in accordance with the credit facility), to interest expense. At December 31, 2006, the calculation resulted in a ratio of 25.0 to 1.0. The leverage ratio calculation compares our consolidated funded debt (as calculated in accordance with the credit facility) to EBITDA (as adjusted) At December 31, 2006, this calculation resulted in a ratio of 0.5 to 1.0. Our credit facility also requires that we meet or exceed a funded indebtedness to capitalization ratio. Our credit facility includes provisions for the temporary adjustment of the required ratios following acquisitions. If we meet these financial metrics and are not otherwise in default under our credit facility, we may make quarterly distributions; however the amount of such distributions may not exceed the sum of the distributable cash (as defined in the credit agreement) generated by us for the eight most recent quarters, less the sum of the distributions made with respect to those quarters. At December 31, 2006, the excess of distributable cash over distributions was $17.6 million.

The covenants described above could prevent us from engaging in certain transactions which might otherwise be considered beneficial to us. For example, they could:

- increase our vulnerability to general adverse economic and industry conditions;
- limit our ability to make distributions; to fund future working capital, capital expenditures and other general partnership requirements; to engage in future acquisitions and construction or development activities; or to otherwise fully realize the value of our assets and opportunities because of the need to dedicate a substantial portion of our cash flow from operations to payments on our indebtedness or to comply with any restrictive terms of our indebtedness; and
- limit our flexibility in planning for, or reacting to, changes in our businesses and the industries in which we operate.

Our credit facility contains customary events of default, including for non-payment of principal and interest, failure to comply with any covenant, default under certain other of our indebtedness, the incurrence of specified amounts of liabilities relating to adverse judgments, unpaid ERISA obligations or environmental claims, and the occurrence of a change in control.

Our credit facility is secured by a guarantee from all of our restricted subsidiaries (as defined in our credit agreement) and us and by liens on substantially all of the assets of those parties. Our credit facility is non-recourse to our general partner, except to the extent of its pledge of its 0.01% general partner interest in our operating partnership.

Our average daily outstanding balance under our credit facilities during 2006 was $3.4 million. The average interest rate we paid during this same period was 8.42%.

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Capital Expenditures

A summary of our capital expenditures in the three years ended December 31, 2006, 2005, and 2004 is as follows:

	Years Ended December 31,		
	2006	2005	2004
		(in thousands)	
Maintenance capital expenditures:			
Mississippi pipeline systems	$ 355	$ 1,147	$ 505
Jay pipeline system	122	7	28
Texas pipeline system	134	102	122
Crude oil gathering assets	175	34	159
Administrative and other assets	181	253	125
Total maintenance capital expenditures	967	1,543	939
Growth capital expenditures (including construction in progress and investments in joint ventures)			
Mississippi pipeline systems	360	1,059	7,371
Natural gas gathering assets	-	3,110	-
CO_2 contracts	-	14,446	4,723
T&P Syngas investment	-	13,418	-
Sandhill investment	5,042	-	-
Other industrial gases investments	1,016	-	-
Crude oil gathering assets	-	260	161
Total growth capital expenditures	6,418	32,293	12,255
Total capital expenditures	$ 7,385	$ 33,836	$ 13,194

We have no commitments to make capital expenditures; however, we anticipate that our maintenance capital expenditures for 2007 will be approximately $2.3 million. These expenditures are expected to relate primarily to the replacement of a tank on the Texas System and improvements on our Mississippi System. Based on the information available to us at this time, we do not anticipate that future capital expenditures for compliance with regulatory requirements will be material.

Expenditures for capital assets to grow the partnership distribution will depend on our access to debt and equity capital discussed below in "*Sources of Future Capital*." We will look for opportunities to acquire assets from other parties that meet our criteria for stable cash flows. The arrangement that Denbury has made with our new senior executive management team provide incentives to them to make such acquisitions. See "Item 11. Executive Compensation" for a description of these arrangements.

Although Denbury is not obligated to enter into any transactions with (or to offer any opportunities to) us, Denbury has expressed indications of interest in selling to us (and entering into arrangements under which Denbury would have the exclusive right to utilize) specified CO_2 infrastructure assets, including some that have not yet been placed in-service, subject to the satisfaction of certain conditions. Those conditions include the negotiation of material terms, the execution of definitive agreements, the existence of adequate credit support and our acquisition (by construction or purchase) of assets that are not related to Denbury's operations in an amount at least equal to 150% of the amount of new acquisitions or financings we complete with Denbury. We hope the consummation of such arrangements might lead to other opportunities with Denbury in the future.

Sources of Future Capital

Our credit facility provides us with maximum borrowing capacity of $500 million for acquisitions and working capital requirements. The commitment amount of $125 million at December 31, 2006 can be increased to the maximum capacity with lenders approval based on pro forma estimates of EBITDA from acquisitions or internal growth projects. The facility is a revolving facility. At December 31, 2006, we had $8.0 million of debt outstanding under the facility.

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We expect to use cash flows from operating activities to fund cash distributions and maintenance capital expenditures needed to sustain existing operations. Future acquisitions or capital projects for our expansion will require funding through borrowings under our credit facility or from proceeds from equity offerings, or a combination of the two sources of funds.

Cash Flows

Our primary sources of cash flows have been operations, credit facilities and the issuance of equity. Our primary uses of cash flows are capital expenditures and distributions. A summary of our cash flows is as follows:

	Years Ended December 31,		
	2006	2005	2004
		(in thousands)	
Cash provided by (used in):			
Operating activities	$ 11,262	$ 9,490	$ 9,702
Investing activities	$ (6,842)	$ (31,809)	$ (12,805)
Financing activities	$ (5,201)	$ 23,340	$ 2,312

Operating. Our operating cash flows are affected significantly by changes in items of working capital. We have had situations where other parties have prepaid for purchases or paid more than was due, resulting in fluctuations in one period as compared to the next until the party recovers the excess payment. The timing of capital expenditures and the related effect on our recorded liabilities also affects operating cash flows.

Our accounts receivable settle monthly and collection delays generally relate only to discrepancies or disputes as to the appropriate price, volume or quality of crude oil delivered. Of the $89.1 million aggregate receivables on our consolidated balance sheet at December 31, 2006, approximately $87.5 million, or 98.2%, were less than 30 days past the invoice date.

Investing. During 2006, we utilized cash flows in investing activities by acquiring a 50% interest in Sandhill for $5.0 million. We expended $2.3 million for other investments and capital improvements. Offsetting these expenditures was the receipt of returns of our investment in T&P Syngas in the form of distributions totaling $0.5 million.

We utilized cash flows in investing activities in 2005 by making a $13.4 million investment in T&P Syngas, acquiring another CO_2 contract for $14.4 million and making investments in property and equipment of $6.1 million, including $3.1 million for the natural gas gathering assets acquired from Multifuels. Offsetting these expenditures was the receipt of $1.6 million for the sale of idle assets. We also received returns of our investment in T&P Syngas in the form of distributions totaling $0.4 million.

Cash flows used in investing activities in 2004 were $12.8 million. Capital expenditures for construction of pipeline assets and the acquisition of a second volumetric payment from Denbury were the primary uses of cash for investing.

Financing. Net cash of $5.2 million was utilized in financing activities. We paid distributions totaling $10.4 million to our limited partners and our general partner during the year. We borrowed $8.0 million under our credit facility, and paid $2.7 million in legal and bank fees in November 2006 to obtain our new credit facility.

In 2005, financing activities provided net cash of $23.3 million. We issued 4,140,000 new limited partner units to the public and 330,630 new limited partner units to our general partner. Additionally, our general partner contributed funds to maintain its 2% general partner interest. In total these activities provided $44.8 million to us. A portion of these funds were utilized to eliminate our bank debt, and we also paid distributions totaling $5.8 million to our partners.

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In 2004, financing activities provided net cash of $2.3 million. Borrowings provided $8.8 million of cash flow. We utilized $0.8 million of these funds to pay fees related to the credit agreement we obtained in June 2004. Distributions to our partners utilized $5.7 million.

Distributions

We are required by our partnership agreement to distribute 100% of our available cash (as defined therein) within 45 days after the end of each quarter to unitholders of record and to our general partner. Available cash consists generally of all of our cash receipts less cash disbursements adjusted for net changes to reserves. Our credit facility also includes a restriction on the amount of distributions we can pay in any quarter. At December 31, 2006, our restricted net assets (as defined in Rule 4-03 (e)(3) of Regulation S-X) were $68.2 million.

We increased our distribution by $0.01 per unit each quarter beginning with the distribution for the third quarter of 2005 as shown in the table below.

Distribution For	Date Paid	Per Unit Amount		Total Amount (000's)	
Fourth quarter 2004	February 2005	$	0.15	$	1,426
First quarter 2005	May 2005	$	0.15	$	1,426
Second quarter 2005	August 2005	$	0.15	$	1,426
Third quarter 2005	November 2005	$	0.16	$	1,521
Fourth quarter 2005	February 2006	$	0.17	$	2,391
First quarter 2006	May 2006	$	0.18	$	2,532
Second quarter 2006	August 2006	$	0.19	$	2,672
Third quarter 2006	November 2006	$	0.20	$	2,813
Fourth quarter 2006	February 2007	$	0.21	$	2,954

Our general partner is entitled to receive incentive distributions if the amount we distribute with respect to any quarter exceeds levels specified in our partnership agreement. Under the quarterly incentive distribution provisions, our general partner is entitled to receive 13.3% of any distributions to our common unitholders in excess of $0.25 per unit, 23.5% of any distributions to our common unitholders in excess of $0.28 per unit, and 49% of any distributions to our common unitholders in excess of $0.33 per unit, without duplication. The likelihood and timing of the payment of any incentive distributions will depend on our ability to increase the cash flow from our existing operations and to make accretive acquisitions. In addition, our partnership agreement authorizes us to issue additional equity interests in our partnership with such rights, powers and preferences (which may be senior to our common units) as our general partner may determine in its sole discretion, including with respect to the right to share in distributions and profits and losses of the partnership. We did not pay any incentive distributions during 2006.

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Available Cash before Reserves for the year ended December 31, 2006 is as follows (in thousands):

Net income	$	8,381
Depreciation and amortization		7,963
Cash received from direct financing leases not included in income		531
Cash effects of sales of certain assets		51
Effects of available cash generated by investments in joint ventures not included in income		1,401
Non-cash charges		1,471
Maintenance capital expenditures		(967)
Available Cash before reserves	$	18,831

We have reconciled Available Cash (a non-GAAP measure) to cash flow from operating activities (the GAAP measure) for the year ended December 31, 2006 below. For the year ended December 31, 2006, cash flows provided by operating activities were $11.3 million.

Non-GAAP Financial Measure

This annual report includes the financial measures of Available Cash, which measures often are referred to as "non-GAAP" measures because they are not contemplated by or referenced in accounting principles generally accepted in the U.S., also referred to as GAAP. The accompanying schedules provide reconciliations of those non-GAAP financial measures to their most directly comparable GAAP financial measure. Our non-GAAP financial measures should not be considered as alternatives to GAAP measures such as net income, operating income, cash flow from operating activities or any other GAAP measure of financial performance. We believe that investors benefit from having access to the same financial measures being utilized by management, lenders, analysts and other market participants.

Available Cash before reserves, also referred to as distributable cash flow, is commonly used as a supplemental financial measure by management and by external users of financial statements, such as investors, commercial banks, research analysts and rating agencies, to assess: (1) the financial performance of our assets without regard to financing methods, capital structures or historical cost basis; (2) the ability of our assets to generate cash sufficient to pay interest cost and support our indebtedness; (3) our operating performance and return on capital as compared to those of other companies in the midstream energy industry, without regard to financing and capital structure; and (4) the viability of projects and the overall rates of return on alternative investment opportunities. Because Available Cash excludes some, but not all, items that affect net income or loss and because these measures may vary among other companies, the Available Cash data presented in this Annual Report on Form 10-K may not be comparable to similarly titled measures of other companies. The GAAP measure most directly comparable to Available Cash is net cash provided by operating activities.

Available Cash before reserves is a measure used by our management to compare cash flows generated by us to the cash distribution paid to our limited partners and general partner. This is an important financial measure to our public unitholders since it is an indicator of our ability to make distributions. Specifically, this financial measure aids investors in determining whether or not we are generating cash flows at a level that can support a quarterly cash distribution to the partners. Lastly, Available Cash before Reserves (also referred to as distributable cash flow) is the quantitative standard used throughout the investment community with respect to publicly-traded partnerships.

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The reconciliation of Available Cash before reserves (a non-GAAP measure) to cash flow from operating activities (the GAAP measure) for the year ended December 31, 2006, is as follows (in thousands):

Cash flows from operating activities	$	11,262
Adjustments to reconcile operating cash flows to Available Cash:		
Maintenance capital expenditures		(967)
Proceeds from sales of certain assets		67
Amortization and write-off of credit facility issuance fees		(969)
Effects of available cash generated by investments in joint ventures not included in cash flows from operating activities		967
Cash effects of exercises under SAR Plan		(364)
Other items affecting Available Cash		(38)
Net effect of changes in operating accounts not included in calculation of Available Cash		8,873
Available Cash before reserves	$	18,831

Commitments and Off-Balance Sheet Arrangements

Contractual Obligation and Commercial Commitments

In addition to our credit facility discussed above, we have contractual obligations under operating leases as well as commitments to purchase crude oil. The table below summarizes our obligations and commitments at December 31, 2006.

	Payments Due by Period									
Commercial Cash Obligations and Commitments		2007		2008 and 2009		2010 and 2011		After 2011		Total
Long-term debt [1]	$	-	$	-	$	8,000	$	-	$	8,000
Estimated interest payable on long-term debt [2]		700		1,402		1,310		-		3,412
Operating lease obligations		2,724		3,845		1,705		274		8,548
Unconditional purchase obligations [3]		103,078		-		-		-		103,078
Total Contractual Cash Obligations	$	106,502	$	5,247	$	11,015	$	274	$	123,038

(1) Our credit facility allows us to repay and re-borrow funds at any time through the maturity date of November 15, 2011.

(2) Interest on our long-term debt is at market-based rates. The amount shown for interest payments represents the amount that would be paid if the debt outstanding at December 31, 2006 remained outstanding through the maturity date through the final maturity date of November 15, 2011 and interest rates remained at the December 31, 2006 market levels through November 15, 2011.

(3) The unconditional purchase obligations included above are contracts to purchase crude oil, generally at market-based prices. For purposes of this table, market prices at December 31, 2006, were used to value the obligations. Actual obligations may differ from the amounts included above.

In additional to the contractual cash obligations included above, we also have a contingent obligation related to our acquisition of a 50% interest in Sandhill, which could require us to pay an additional $2 million for our interest. See additional discussion in the section on Sandhill in Note 7 to the consolidated financial statements.

We have guaranteed 50% of the $4.5 million debt obligation to a bank of Sandhill; however, we believe we are not likely to be required to perform under this guarantee as Sandhill is expected to make all required payments under the debt obligation. See additional discussion in the section on Sandhill in Note 7 to the consolidated financial statements.

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Off-Balance Sheet Arrangements

We have no off-balance sheet arrangements, special purpose entities, or financing partnerships, other than as disclosed under *Contractual Obligation and Commercial Commitments* above, nor do we have any debt or equity triggers based upon our unit or commodity prices.

Other Matters

Crude Oil Contamination Litigation

We were named one of the defendants in a petition filed on January 11, 2001, in the 125th District Court of Harris County, Texas, Cause No. 2001-01176. Pennzoil-Quaker State Company, or PQS, was seeking property damages, loss of use and business interruption suffered as a result of a fire and explosion that occurred at the Pennzoil Quaker State refinery in Shreveport, Louisiana, on January 18, 2000. PQS claimed the fire and explosion were caused, in part, by Genesis selling to PQS crude oil that was contaminated with organic chlorides. In December 2003, our insurers settled this litigation for $12.8 million. The settlement of this litigation had no effect on our results of operations.

PQS is also a defendant in five consolidated class action/mass tort actions brought by neighbors living in the vicinity of the PQS Shreveport, Louisiana refinery in the First Judicial District Court, Caddo Parish, Louisiana, Cause Nos. 455,647-A. 455,658-B, 455,655-A, 456,574-A, and 458,379-C. PQS has brought third party claims against us for indemnity with respect to the fire and explosion of January 18, 2000. We believe that the claims against us are without merit and intend to vigorously defend ourselves in this matter.

Environmental

In 1992, Howell Crude Oil Company entered into a sublease with Koch Industries, Inc., covering a one acre tract of land located in Santa Rosa County, Florida to operate a crude oil trucking station, known as Jay Station. The sublease provided that Howell would indemnify Koch for environmental contamination on the property under certain circumstances. Howell operated the Jay Station from 1992 until December of 1996 when this operation was sold to us by Howell. We operated the Jay Station as a crude oil trucking station until 2003. Koch has indicated that it has incurred certain investigative and/or other costs, for which Koch alleges some or all should be reimbursed by us, under the indemnification provisions of the sublease for environmental contamination on the site and surrounding areas. Koch has also alleged that we are responsible for future environmental obligations relating to the Jay Station.

Howell was acquired by Anadarko Petroleum Corporation, or Anadarko, in 2002. During the second quarter of 2005, we entered into a joint defense and cost allocation agreement with Anadarko. Under the terms of the joint allocation agreement, we agreed to reasonably cooperate with each other to address any liabilities or defense costs with respect to the Jay Station. Additionally under the Joint Allocation Agreement, Anadarko will be responsible for sixty percent of the costs related to any liabilities or defense costs incurred with respect to contamination at the Jay Station.

We were formed in 1996 by the sale and contribution of assets from Howell and Basis Petroleum, Inc. Anadarko's liability with respect to the Jay Station is derived largely from contractual obligations entered into upon our formation. We believe that Basis has contractual obligations under the same formation agreements. We intend to seek recovery for Basis' share of potential liabilities and defense costs with respect to the Jay Station.

We have developed a plan of remediation for affected soil and groundwater at Jay Station which has been approved by appropriate state regulatory agencies. We have accrued an estimate of our share of future liability for this matter in the amount of $0.5 million. The time period over which our liability would be paid is uncertain and could be several years. This liability may decrease if indemnification and/or cost reimbursement is obtained by us for Basis' potential liabilities with respect to this matter. At this time, our estimate of potential obligations does not assume any specific amount contributed on behalf of the Basis obligations, although we believe that Basis is responsible for a significant part of these potential obligations.

Insurance

We maintain insurance of various types that we consider adequate to cover our operations and properties. The insurance policies are subject to deductibles that we consider reasonable. The policies do not cover every potential risk associated with operating our assets, including the potential for a loss of significant revenues. Consistent with the coverage available in the industry, our policies provide limited pollution coverage, with broader coverage for sudden and accidental pollution events. Additionally, as a result of the events of September 11, 2001, the cost of insurance available to the industry has risen significantly, and insurers have excluded or reduced coverage for losses due to acts of terrorism and sabotage.

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Since September 11, 2001, warnings have been issued by various agencies of the United States Government to advise owners and operators of energy assets that those assets may be a future target of terrorist organizations. Any future terrorist attacks on our assets, or assets of our customers or competitors could have a material adverse effect on our business.

We believe that we are adequately insured for public liability and property damage to others as a result of our operations. However, we cannot assure you that an event not fully insured or indemnified against will not materially and adversely affect our operations and financial condition. Additionally, we cannot assure you that we will be able to maintain insurance in the future at rates that we consider reasonable.

New Accounting Pronouncements

FASB Interpretation No. 48

In July 2006, the Financial Accounting Standards Board, or FASB, issued FASB Interpretation No. 48, “Accounting for Uncertainty in Income Taxes - an interpretation of FASB Statement No. 109”, or FIN 48, which clarifies the accounting and disclosure for uncertainty in tax positions, as defined. FIN 48 seeks to reduce the diversity in practice associated with certain aspects of the recognition and measurement related to accounting for income taxes. This interpretation is effective for fiscal years beginning after December 15, 2006. We do not expect that the adoption of FIN 48 will have a material impact on our results of operations or financial position.

SFAS 157

In September 2006, the FASB issued SFAS No. 157, “Fair Value Measurements”, or SFAS 157. SFAS 157 defines fair value, establishes a framework for measuring fair value in accordance with accounting principles generally accepted in the United States, and expands disclosures about fair value measurements. SFAS 157 is effective for fiscal years beginning after November 15, 2007, with earlier adoption encouraged. Any amounts recognized upon adoption as a cumulative effect adjustment will be recorded to the opening balance of retained earnings in the year of adoption. We have not yet determined the impact of SFAS 157 on our financial condition or results of operations.

SFAS 159

In February 2007, the FASB issued SFAS No. 159, “The Fair Value Option for Financial Assets and Financial Liabilities”, or SFAS 159. SFAS 159 permits entities to choose to measure many financial assets and financial liabilities at fair value. Unrealized gains and losses on items for which the fair value option has been elected are reported in earnings. SFAS 159 is effective for fiscal years beginning after November 15, 2007. We are currently assessing the impact of SFAS 159 on our consolidated financial statements.

Item 7a. Quantitative and Qualitative Disclosures about Market Risk

We are exposed to market risks primarily related to volatility in crude oil prices and interest rates.

Our primary price risk relates to the effect of crude oil price fluctuations on our inventories and the fluctuations each month in grade and location differentials and their effect on future contractual commitments. We utilize NYMEX commodity based futures contracts and forward contracts to hedge our exposure to these market price fluctuations as needed. At December 31, 2006, we had entered into NYMEX future contracts that will settle during February 2007. These contracts either do not qualify for hedge accounting or are fair value hedges, therefore the fair value of these derivatives have received mark-to-market treatment in current earnings. This accounting treatment is discussed further under Note 2 to our Consolidated Financial Statements.

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	Sell (Short) Contracts		Buy (Long) Contracts	
Futures Contracts				
Contract volumes (1,000 bbls)		95		7
Weighted average price per bbl	$	62.85	$	61.87
Contract value (in thousands)	$	5,971		433
Mark-to-market change (in thousands)		(171)		(6)
Market settlement value (in thousands)	$	5,800	$	427

The table above presents notional amounts in barrels, the weighted average contract price, total contract amount and total fair value amount in U.S. dollars. Fair values were determined by using the notional amount in barrels multiplied by the December 31, 2006 quoted market prices on the NYMEX.

We are also exposed to market risks due to the floating interest rates on our credit facility. Our debt bears interest at the LIBOR Rate or Prime Rate plus the applicable margin. We do not hedge our interest rates. At December 31, 2006, we had $8.0 million of debt outstanding under our credit facility.

Item 8. Financial Statements and Supplementary Data

The information required hereunder is included in this report as set forth in the "Index to Consolidated Financial Statements" on page 81.

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

None.

Item 9A. Controls and Procedures

We maintain disclosure controls and procedures and internal controls designed to ensure that information required to be disclosed in our filings under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission's rules and forms. Our chief executive officer and chief financial officer, with the participation of our management, have evaluated our disclosure controls and procedures as of the end of the period covered by this Annual Report on Form 10-K and have determined that such disclosure controls and procedures are effective in providing reasonable assurance of the timely recording, processing, summarizing and reporting of information, and in accumulation and communication of information to management all material respects in providing to them on a timely basis material information relating to us (including our consolidated subsidiaries) required to be disclosed in this annual report.

There were no changes during our last fiscal quarter that materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Management's Report on Internal Control over Financial Reporting

Management of the Partnership is responsible for establishing and maintaining effective internal control over financial reporting as defined in Rules 13a-15(f) under the Securities and Exchange Act of 1934. The Partnership's internal control over financial reporting is designed to provide reasonable assurance to the Partnership's management and board of directors regarding the preparation and fair presentation of published financial statements.

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

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Management assessed the effectiveness of the Partnership's internal control over financial reporting as of December 31, 2006. In making this assessment, management used the criteria established in Internal Control - Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on our assessment, we believe that, as of December 31, 2006, the Partnership's internal control over financial reporting is effective based on those criteria.

Management's assessment of the effectiveness of internal control over financial reporting as of December 31, 2006, has been audited by Deloitte & Touche LLP, the independent registered public accounting firm who also audited the Partnership's consolidated financial statements. Deloitte & Touche's attestation report on management's assessment of the Partnership's internal control over financial reporting appears below.

Report of Independent Registered Public Accounting Firm on Internal Control over Financial Reporting

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of Genesis Energy, Inc. and Unitholders of
Genesis Energy, L.P.
Houston, Texas

We have audited management's assessment, included in the accompanying Management's Report on Internal Control over Financial Reporting, that Genesis Energy, L.P. and subsidiaries (the "Partnership") maintained effective internal control over financial reporting as of December 31, 2006, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Partnership's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on management's assessment and an opinion on the effectiveness of the Partnership's internal control over financial reporting based on our audit.

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

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

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

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In our opinion, management's assessment that the Partnership maintained effective internal control over financial reporting as of December 31, 2006, is fairly stated, in all material respects, based on the criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Also in our opinion, the Partnership maintained, in all material respects, effective internal control over financial reporting as of December 31, 2006, based on the criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements and financial statement schedule as of and for the year ended December 31, 2006 of the Partnership and our report dated March 14, 2007, expressed an unqualified opinion on those financial statements and financial statement schedule, and included an explanatory paragraph relating to the required adoption of new accounting principles for accounting for equity-based payments and conditional asset retirement obligations.

/s/ DELOITTE & TOUCHE LLP
Houston, Texas

March 14, 2007

Item 9B. Other Information

None.

Part III

Item 10. Directors, Executive Officers and Corporate Governance

Management of Genesis Energy, L.P.

Genesis Energy, Inc., our general partner, manages our operations and activities. Our general partner is not elected by our unitholders and will not be subject to re-election on a regular basis in the future. Unitholders are not entitled to elect the directors of our general partner or directly or indirectly participate in our management or operation. Our general partner owes a fiduciary duty to our unitholders, but our partnership agreement contains various provisions modifying and restricting the fiduciary duty. Our general partner is liable, as general partner, for all of our debts (to the extent not paid from our assets), except for indebtedness or other obligations that are made expressly nonrecourse to it. Our general partner therefore may cause us to incur indebtedness or other obligations that are nonrecourse to it.

The directors of our general partner oversee our operations. Our general partner has eight directors. Denbury, indirectly, elects all members to the board of directors of our general partner, three of which are independent as defined under the independence standards established by the American Stock Exchange, or AMEX. The AMEX does not require a listed limited partnership like us to have a majority of independent directors on the board of directors of our general partner or to establish a compensation committee or a nominating committee. While we currently have a compensation committee, it does not satisfy the independence standards established by the AMEX, and we are not required to maintain a compensation committee in the future.

The compensation committee oversees compensation decisions for the employees of the general partner, as well as the compensation plans of our general partner. The members of the Compensation Committee are Gareth Roberts, Susan O. Rheney and Herbert I. Goodman, all of whom are non-employee directors of our general partner. The

Compensation Committee adopted a written Compensation Committee charter that is available on our website.

In addition, our general partner has an audit committee of three directors who meet the independence and experience standards established by AMEX and the Securities Exchange Act of 1934, as amended. Susan O. Rheney, Herbert I. Goodman and J Conley Stone serve as the members of the audit committee. The audit committee assists the board in its oversight of the quality and integrity of our financial statements and our compliance with legal and regulatory requirements and partnership policies and controls. The audit committee oversees our anonymous complaint procedure established for our employees. The audit committee has the sole authority to retain and terminate our independent registered public accounting firm, approve all auditing services and related fees and the terms thereof, and pre-approve any non-audit services to be rendered by our independent registered public accounting firm. The audit committee also is responsible for confirming the independence and objectivity of our independent registered public accounting firm. Our independent registered public accounting firm is given unrestricted access to the audit committee. The Board of Directors believes that Susan O. Rheney qualifies as an audit committee financial expert as such term is used in the rules and regulations of the SEC. The audit committee adopted a written Audit Committee Charter in August 2003. The full text of the Audit Committee Charter is available on our website.

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Three independent members of the board of directors of our general partner serve on a conflicts committee to review specific matters that the board believes may involve conflicts of interest. Ms. Rheney and Messrs. Goodman and Stone serve as the members of the conflicts committee. When requested to by the general partner, the conflicts committee determines if the resolution of the conflict of interest is fair and reasonable to us. The members of the conflicts committee may not be officers or employees of our general partner or directors, officers, or employees of its affiliates, and must meet the independence and experience standards established by the AMEX and the Securities Exchange Act of 1934, as amended, to serve on an audit committee of a board of directors, and certain other requirements. Any matters approved by the conflicts committee in good faith will be conclusively deemed to be fair and reasonable to us, approved by all of our partners, and not a breach by our general partner of any duties it may owe us or our unitholders.

As is common with publicly-traded partnerships, we do not have any employees. All of our executive management personnel are employees of our general partner. Such personnel devote all of their time to conduct our business and affairs. The officers of our general partner manage the day-to-day affairs of our business, operate our business, and provide us with general and administrative services. We reimburse our general partner for allocated expenses of operational personnel who perform services for our benefit, allocated general and administrative expenses and certain direct expenses.

Directors and Executive Officers of the General Partner

Set forth below is certain information concerning the directors and executive officers of the general partner. All executive officers serve at the discretion of the general partner.

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Name	Age	Position
Gareth Roberts	54	Director and Chairman of the Board
Grant E. Sims	51	Director and Chief Executive Officer
Mark C. Allen	38	Director
Ronald T. Evans	44	Director
Herbert I. Goodman	84	Director
Susan O. Rheney	47	Director
Phil Rykhoek	50	Director
J. Conley Stone	75	Director
Joseph A. Blount, Jr.	46	President and Chief Operating Officer
Brad N. Graves	40	Executive Vice President, Business Development
Ross A. Benavides	53	Chief Financial Officer, General Counsel and Secretary
Kerry W. Mazoch	60	Vice President, Crude Oil Acquisitions
Karen N. Pape	48	Vice President and Controller

Gareth Roberts has served as a Director and Chairman of the Board of our general partner since May 2002. Mr. Roberts is President, Chief Executive Officer and a director of Denbury Resources Inc. and has been employed by Denbury since 1992.

Grant E. Sims has served as Director and Chief Executive Officer of our general partner since August 2006. Mr. Sims had been a private investor since 1999. He was affiliated with Leviathan Gas Pipeline Partners, L.P. from 1992 to 1999, serving as the Chief Executive Officer and a director beginning in 1993 until he left to pursue personal interests, including investments. Leviathan (subsequently known as El Paso Energy Partners, L.P. and then GulfTerra Energy Partners, L.P.) was a NYSE listed master limited partnership

Mark C. Allen has served as a director of our general partner since June 2006. Mr. Allen is Vice President and Chief Accounting Officer of Denbury, and has been employed by Denbury since April 1999.

Ronald T. Evans has served as a director of our general partner since May 2002. Mr. Evans is Senior Vice President of Reservoir Engineering of Denbury and has been employed by Denbury since September 1999.

Herbert I. Goodman has served as a director of our general partner since January 1997. During 2001, he served as the Chief Executive Officer of PEPEX.NET, LLC, which provides electronic trading solutions to the international oil industry. From 2002 to 2005, he served as Chairman of PEPEX.NET, LLC. He was Chairman of IQ Holdings, Inc., a manufacturer and marketer of petrochemical-based consumer products until 2004. From 1988 until 1996 he was Chairman and Chief Executive Officer of Applied Trading Systems, Inc., a trading and consulting business.

Susan O. Rheney has served as a director of our general partner since March 2002. Ms. Rheney is a private investor and formerly was a principal of The Sterling Group, L.P., a private financial and investment organization, from 1992 to 2000.

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Phil Rykhoek has served as a director of our general partner since May 2002. Mr. Rykhoek is Chief Financial Officer, Senior Vice President, Secretary and Treasurer of Denbury, and has been employed by Denbury since 1995.

J. Conley Stone has served as a director of our general partner since January 1997. From 1987 to his retirement in 1995, he served as President, Chief Executive Officer, Chief Operating Officer and Director of Plantation Pipe Line Company, a common carrier liquid petroleum products pipeline transporter.

Joseph A. Blount, Jr. has served as President and Chief Operating Officer of our general partner since August 2006. Mr. Blount served as President and Chief Operating Officer of Unocal Midstream & Trade from March of 2000 to September of 2005. In such capacity, Mr. Blount oversaw the worldwide marketing of Unocal's natural gas, crude oil and condensate resources, the development and management of its pipeline, terminal and storage assets, and its commodity risk management activities. Upon the acquisition of Unocal by Chevron in September of 2005, Mr. Blount left to pursue personal interests, including investments.

Brad N. Graves has served as Executive Vice President, Business Development of our general partner since August 2006. Mr. Graves was Vice President of Commercial Offshore Operations for Enterprise Products Partners L.P. from January to August 2006. From January of 2003 to December of 2005, Mr. Graves served as Director of Crude Oil and Platform Services for Enterprise and, before it was merged into Enterprise, GulfTerra Energy Partners, L.P. Mr. Graves acted as the Director of Crude Oil Pipelines for GulfTerra from January of 2000 to January of 2003.

Ross A. Benavides has served as Chief Financial Officer of our general partner since October 1998. He has served as General Counsel and Secretary since December 1999.

Kerry W. Mazoch has served as Vice President, Crude Oil Acquisitions, of our general partner since August 1997.

Karen N. Pape has served as Vice President and Controller of our general partner since March 2002. Ms. Pape served as Controller and as Director of Finance and Administration of our general partner since December 1996.

Code of Ethics

We have adopted a code of ethics that is applicable to, among others, the principal financial officer and the principal accounting officer. The Genesis Energy Financial Employee Code of Professional Conduct is posted at our website, where we intend to report any changes or waivers.

Section 16(a) Compliance

Section 16(a) of the Securities Exchange Act of 1934 requires the officers and directors of our general partner and persons who own more than ten percent of a registered class of the equity securities of the Partnership to file reports of ownership and changes in ownership with the SEC and the American Stock Exchange. Based solely on our review of the copies of such reports received by us, or written representations from certain reporting persons that no Forms 5 was required for those persons, we believe that during 2006 our officers and directors complied with all applicable filing requirements in a timely manner.

Item 11. Executive Compensation

Under the terms of our partnership agreement, we are required to reimburse our general partner for expenses relating to managing our operations, including salaries and bonuses of employees employed on behalf of the Partnership, as well as the costs of providing benefits to such persons under employee benefit plans and for the costs of health and life insurance. See "Certain Relationships and Related Transactions."

Compensation Discussion and Analysis

The Compensation Committee of the Board of Directors, or the Committee, currently consists of the Chairman of the Board and two independent directors. The Committee is responsible for making recommendations to the Board regarding compensation policies, incentive compensation policies, employee benefit plans, and recommends awards thereunder. The Committee recommends specific compensation levels for our chief executive officer and other executive officers. The Committee also administers our Stock Appreciation Rights Plan, Bonus Plan, and Severance Protection Plan. Our Board has adopted a Compensation Committee Charter setting forth the Committee's purpose and responsibilities.

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We have two classes of executive officers for which we have applied distinct compensation strategies. The Senior Executives are Grant E. Sims, our chief executive officer, Joseph A. Blount, Jr. , our president and chief operating officer, and Brad N. Graves, our executive vice president of business development. The Other Executives are Ross A. Benavides, our chief financial officer and general counsel, Karen N. Pape, our vice president and controller, and Kerry W. Mazoch, our vice president crude oil acquisitions. The treatment of the two classes of executive officers will be addressed separately.

Objectives of the Compensation Program. Our compensation programs are designed by the Committee to attract, retain, and motivate key personnel who possess the skills and qualities necessary to perform effectively in a master limited partnership in the industries in which we operate. We pay base salaries at a level that we feel are appropriate for the skills and qualities of the individual employees based on their past performance and current responsibilities with the Partnership. We reward employees primarily for the effort and results of the team or Partnership as a whole, rather than compensating only for individual performance.

The elements of the compensation program for our Senior Executives consist of:

- base salaries,
- a General Partner Interest plan (long-term incentive plan),
- other compensation (including contributions to the 401(k) plan and annual term life insurance premiums).

The elements of our Company-wide compensation program that applies to the Other Executives and to all employees except the Senior Executives consist of:

- base salaries,
- a Bonus Plan (annual performance-based cash incentive compensation),
- a Stock Appreciation Rights plan (long-term incentive plan),
- a Severance Protection Plan, and
- other compensation (including contributions to the 401(k) plan and annual term life insurance premiums).

As described in more detail below, we believe that the combination of base salaries, Bonus Plan, a Stock Appreciation Rights Plan and the General Partner Interest Plan provides an appropriate balance of short-term and long-term incentives, cash and non-cash based compensation, and an alignment of the incentives for our executives and employees with the interests of our common unitholders and Denbury, the owner of our general partner. Our Bonus Plan is driven by the generation of Available Cash, which is an important metric of value for our unitholders, before reserves and bonuses. Our Stock Appreciation Rights Plan is linked primarily to the appreciation in our common unit price. The General Partner Interest Plan that has the potential to provide interests in the general partner and associated incentive distributions rights to our Senior Executives is based on the completion of accretive third-party acquisitions that would trigger drop-down transactions from Denbury that support value creation for our common unitholders.

In the event of a financial statement restatement, we do not currently have a specific policy or penalty in most of our compensation programs. However, such an event would likely affect the Bonus Plan and stock appreciation rights awarded by the Committee each year which consider overall company performance.

Senior Executives

During 2006, we determined that it was in the best interest of the general partner and our unitholders for our executives to focus increased attention on growing the Partnership by transactions other than with the Denbury. We believe that the value created for the general partner and for the common unitholders from acquiring assets from Denbury would be enhanced if we were to grow the Partnership by making significant third-party investments (i.e. acquisitions, investments in joint ventures, subsequent organic growth projects, etc.) For master limited partnerships, value is created for the unitholders by generating sustainable, long-term, growing distributions. To generate distribution growth, we believe we will need to deploy significant capital, as we currently do not have sufficient organic growth opportunities to generate the distribution growth we want to achieve.

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In order to implement this strategy, the Senior Executives were hired on August 8, 2006. The compensation program for these executives, in the form of base salaries and a general partner interest program, is designed to reward them for growing the Partnership by making accretive third-party acquisitions. Most of the compensation awarded to the Senior Executives is expected to come from this non-cash equity based general partner interest program.

Base Salaries. At the time they were hired, we agreed to enter into employment agreements with the Senior Executives for a four-year term with provisions customary for the industry (including at least the same fringe benefits, other than participation in the cash bonus plan and SAR plan, as are provided to other executive officers of the Partnership). The base salaries for the Senior Executives were determined as an aggregate amount of $810,000, to be allocated among the three executives in the discretion of the chief executive officer. The aggregate salary was allocated to Mr. Sims, Mr. Blount, and Mr. Graves in the amounts of $310,000, $270,000, and $230,000 per year, respectively. The aggregate salaries will be increased if the market capitalization of the Partnership increases for consecutive 90 day periods to: $600 million market capitalization ($900,000 annual aggregate salaries); to $1.0 billion ($990,000 annual aggregate salaries); and above $1.0 billion (annual aggregate salary increases of 10 percent for each $300 million market capitalization increase). The base salary was based on several factors. These factors include the objectives of the Partnership to make third-party acquisitions, the nature and responsibility of the positions (including the size and complexity of the Partnership), the expertise of the three executives, the track record of the Senior Executives in creating value at other master limited partnerships or midstream businesses, and the competitiveness of the marketplace. We believe we were competing to hire the Senior Executives with private equity firms seeking to develop midstream energy master limited partnerships. While no directly comparable offers were made to the Senior Executives by private equity firms, we believe that their aggregate salaries are comparable to salaries that they potentially would have been offered by private equity firms for similar positions. The formula for salary increases was designed to reward the Senior Executives if they are successful in growing the Partnership and to increase their compensation to be commensurate with the scope of their responsibilities in leading a larger enterprise.

General Partner Interest Plan. We agreed to enter into contracts with the Senior Executives that will include terms providing for the ability of the Senior Executives to earn up to 20 percent of the equity in the general partner of the Partnership (currently owned by a wholly-owned subsidiary of Denbury) if the Senior Executives complete acquisition transactions, from parties other than affiliates of the general partner, that earn (using a look-back provision) a minimum un-levered internal rate of return of at least 8 percent. In our judgment, the 20 percent equity position in the general partner would be comparable to the earn-in provision that potentially would be offered by private equity firms under similar circumstances. Earning and vesting of equity interest in the general partner will be based on the following schedule:

Cumulative Amount of Acquisitions from Third Parties	Percentage Vested in General Partner Interest
$150 million	2.0%
$300 million	4.0%
$450 million	6.0%
$600 million	8.0%
$750 million	10.0%
$900 million	12.0%
$1,050 million	14.0%
$1,200 million	16.0%
$1,350 million	18.0%
$1,500 million	20.0%

Additionally, if approved by Denbury's board of directors and our audit committee (including receipt of required fairness opinions for both parties), and Denbury's lenders, Denbury agrees to sell to Genesis midstream CO_2 assets owned by Denbury (currently expected to be the two existing and one currently planned CO_2 pipeline with a currently estimated aggregate replacement value of at least $300 million), and contract for exclusive use of those assets on commercially acceptable terms (including preserving Denbury's uninterrupted exclusive use of those assets in the event of Genesis' sale or bankruptcy) at an expected rate of return of 12 percent to Genesis over 12 years or longer, but only if, at the time of each sale by Denbury, the sale will not make the ratio of gross value of (1) consummated transactions, that at the time of sale are expected to earn a minimum un-levered internal rate of return of 8 percent to (2) assets sold by Denbury to be less than 1.5 to 1.

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The earning of interests in the general partner creates a long-term non-cash equity-based compensation plan for the Senior Executives. The term over which the general partner interests are earned is a function of the time during which accretive third-party acquisitions are made. Since the Senior Executives can earn equity interests in the general partner rather than in the Partnership, this arrangement has no dilutive effect to equity for our common unitholders. As the Senior Executives earn their interests in the general partner, they also earn correlative incentive distribution rights. Consequently, on a long-term basis, the Senior Executives will be incentivized to grow the distribution for our common unitholders. Further, compensation from the general partner interest plan is effectively coming from Denbury rather than from the Partnership as it will not affect Available Cash or cash flow to the Partnership.

While the Senior Executives are incentivized to make accretive third-party acquisitions, the earning of interests in the general partner by the Senior Executives is not dependent upon increasing our distributions. Distribution policy will continue to be made by the Board of Directors based upon the determination that we are generating sustainable cash flow after adjustments for appropriate reserves. No assurance can be made that our distributions will be increased following the completion of significant third-party acquisitions or drop-down transactions.

The Senior Executives will have change of control protection on 16 percent of the equity in the general partner (if not already vested, but capped at 16 percent), triggered by a change of control of Denbury or our general partner.

We have agreed to reimburse the Senior Executives for out-of-pocket transaction costs incurred in connection with the consummation of the employment agreements and general partner interest agreement up to an aggregate amount of $75,000.

We have not completed the employment agreements with the Senior Executives nor have we completed the agreement with the Senior Executives for the earning of general partner interests. We are in negotiations to complete those agreements. No assurances can be made that the agreements will be completed between us and the senior executive team or that changes will not be made to the terms described above. Under the provisions of SFAS 123(R) and the SEC rules regarding push-down accounting, the expense related to the general partner interest compensation will be included in our financial statements beginning in the period after the general partner interest plan agreements are completed.

The Other Executives

The Other Executives participate in compensation programs that are available to our entire employee population. The elements of the Company wide compensation program consist of competitive base salaries, a bonus plan, a stock appreciation rights plan, a severance plan, and other benefits. Additionally the Other Executives currently participate in a retention plan with a group of senior management personnel.

Base Salaries. The Committee seeks to establish and maintain base salaries for our Other Executives at a competitive level based on several factors. These factors include the objectives of the Partnership, the nature and responsibility of the position (considering the size and complexity of the Partnership), the expertise of the individual executive, and the recommendation of the chief executive officer. In making recommendations, the Committee exercises subjective judgment using no specific weights for these factors. This is the primary part of the compensation package whereby a distinction is made for individual performance of the Other Executives. The other components of their compensation plan are consistent among employee groups and generally are proportional to base salary and bonuses. For 2006, the Compensation Committee approved salary increases for the Other Executive and Mr. Gorman, our former CEO, totaling 4.3 percent of their salaries in 2005. Mr. Gorman received $10,000 as his annual increase. Average salary increases for all other employees were 3.5 percent for 2006. For 2007, all other employees received average salary increases of approximately 3 percent. The Other Executives received average salary increases of approximately 7 percent, in significant part, based on the recommendation of the CEO.

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Bonus Plan. In May 2003, the Compensation Committee of the Board of our general partner approved a Bonus Plan for all employees of our general partner. The Senior Executives are excluded from participation in the Bonus Plan. The Bonus Plan is paid at the discretion of the Board of Directors based on the recommendation of Compensation Committee, and can be amended or changed at any time. Since the determination of whether bonuses will be paid each year and in what amounts is determined by the Compensation Committee on a Partnership-wide basis, the Other Executives receive bonuses only if all employees receive bonuses.

The Bonus Plan is based on the amount of money we generate for distributions to our unitholders. We will make a contribution to the Bonus Pool every time we have earned $2,042,288 of Available Cash (as defined in the Partnership Agreement) before reserves excluding the effects of the bonus accrual made so far during the year for bonuses and such other adjustments as are made from time to time in the sole discretion of the Compensation Committee. Each $2,042,288 earned is referred to as a "Bucket". We expect the primary reason for adjusting the size of the Bucket will be for issuance of additional equity.

If we issue additional common units, the Bucket size will be increased proportionally based on the number of additional common units issued. Whenever we earn a Bucket, we will contribute a portion of that Bucket to the Bonus Pool. For each additional Bucket, a larger percentage of the Bucket will be contributed to the Bonus Pool. Contributions will be deducted from the Bonus Pool if Available Cash before reserves earned for the year decreases. A maximum of nine Buckets are available under the Bonus Plan. There will be no contribution for partial Buckets.

Contributions to the Bonus Pool will be made in accordance with the following schedule:

Bucket Number	Bucket Size	Contribution to Bonus Pool	Year-to-Date Available Cash before Reserves and Bonus Accrual	Year-to-Date Contributions to Bonus Pool
1	$ 2,042,288	$ 60,000	$ 2,042,288	$ 60,000
2	$ 2,042,288	$ 120,000	$ 4,084,576	$ 180,000
3	$ 2,042,288	$ 120,000	$ 6,126,864	$ 300,000
4	$ 2,042,288	$ 240,000	$ 8,169,152	$ 540,000
5	$ 2,042,288	$ 300,000	$ 10,211,440	$ 840,000
6	$ 2,042,288	$ 360,000	$ 12,253,728	$ 1,200,000
7	$ 2,042,288	$ 360,000	$ 14,296,016	$ 1,560,000
8	$ 2,042,288	$ 360,000	$ 16,338,304	$ 1,920,000
9	$ 2,042,288	$ 360,000	$ 18,380,592	$ 2,280,000

The Bonus Pool will be distributed as follows:

- Each eligible employee will receive a bonus after the end of the year equal to a specified percentage of their year-to-date gross wages. Certain compensation, such as car allowances and relocation expenses, will be excluded from the calculation. Each employee must be a regular, full-time active employee, not on probation, at the time the bonus is paid in order to receive a bonus. The date of payment of the bonuses is at the discretion of management, but bonuses will not be paid until after annual earnings have been released to the public.

- There will be four levels of participation in the Plan. Employees in each level will be eligible for a bonus each year in accordance with the following table. The determination of what level applies to each employee will be made by the Compensation Committee based on the recommendation of the Chief Executive Officer. The Executive Officers are included in Level Four.

- The percentage of adjusted year-to-date gross wages paid as a bonus will be a function of the number of Buckets earned during the year and the employee's Participation Level in the Bonus Plan. The bonus amount each employee is entitled to receive will be determined in accordance with the table shown below. The bonus may be adjusted up or down to reflect individual performance.

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- The total of all bonuses paid may not exceed the total Bonus Pool. Should the amount of bonuses calculated in accordance with the table below exceed the total Bonus Pool available, all calculated bonuses will be reduced proportionately. Should the adjusted amount of bonuses calculated in accordance with the table below be less than the Bonus Pool, the Bonus Pool shall be reduced to the calculated amount.

The bonus percentage that each employee group will receive based on the number of Buckets earned is as follows:

	Cumulative Percentage								
Participation Level	1 Bucket	2 Buckets	3 Buckets	4 Buckets	5 Buckets	6 Buckets	7 Buckets	8 Buckets	9 Buckets
One	0.495%	1.480%	2.470%	4.460%	6.000%	7.000%	8.000%	9.000%	10.000%
Two	0.495%	1.480%	2.470%	4.460%	8.000%	11.000%	14.000%	17.000%	20.000%
Three	0.495%	1.480%	2.470%	4.460%	8.000%	15.000%	20.000%	25.000%	30.000%
Four	0.495%	1.480%	2.470%	4.460%	8.000%	16.000%	24.000%	32.000%	40.000%

For 2006, we achieved nine Buckets under the plan and paid total bonuses under the Bonus Plan of $1.8 million or approximately 19 percent of total eligible compensation. These bonuses were paid in March 2007.

The Bonus Plan is designed to enhance the financial performance of the Partnership by rewarding employees for achieving financial performance objectives that are aligned with the interests of the unitholders. Since Available Cash is an important factor in determining the amount of distributions to our unitholders and is a significant factor in the market's perception of the value of common units of a master limited partnership, we believe the Bonus Plan is designed to reward employees on a basis that is aligned with the interests of the unitholders. The plan is designed so that six buckets generate a bonus equal to 10 percent of total base compensation if we generate sufficient Available Cash before reserves and after bonus compensation to meet our targeted minimum quarterly distribution of $0.80 per unit on total units outstanding. The maximum of nine buckets is designed to limit the bonus to approximately 20 percent of total compensation and to limit the bonus to 40 percent of the compensation for the highest compensated Group Four, to which the Other Executives are assigned. We believe that this generates a bonus that represents a meaningful level of compensation for the employee population and that encourages employees to operate as a unified team to generate results that are aligned with the interests of the unitholders.

Retention Plan. On August 29, 2006, the Board of Directors of our general partner also approved retention bonuses for the Other Executives and seven other management employees of the Partnership. If the Other Executives are still employed on September 1, 2007, they will receive retention bonuses in amounts ranging from 30% to 35% of their base compensation levels as of August 29, 2006. Additionally, this retention bonus will be included in the calculation of the bonus they will receive for 2007, under the terms of our Bonus Plan. These retention bonuses are designed to reward these individuals for their support in the transition of the new Senior Executive Management Team.

Stock Appreciation Rights Plan. In December 2003, the Board approved a Stock Appreciation Rights plan. or SAR. Under the terms of this plan, all regular, full-time active employees and the members of the Board, excluding the Senior Executives, are eligible to participate in the plan. The plan is administered by the Compensation Committee of the Board, who shall determine, in its full discretion, the number of rights to award, the grant date of the rights and the formula for allocating rights to the participants and the strike price of the rights awarded.

Generally, each participant will receive an allocation of a number of rights equal to the authorized number of rights multiplied by a fraction, the numerator of which is such participant's maximum annual bonus under the Bonus Plan and the denominator of which is the total of the maximum annual bonuses for all such participants under the Bonus Plan. The Committee has discretion to adjust individual allocations and has done so in 2006 at the recommendation of the CEO.

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In 2003, for the initial grant, we issued SARs equal to approximately 4.5 percent of our outstanding units. For the 2004 and 2005 annual grants, the rights issued equated to approximately 1.125 percent of the units outstanding at the time of the grant, or 106,381 and 105,964 respectively. For the December 2006 annual grant, the amount equal to approximately 1.125 percent of outstanding units was reduced by the number of units that would have been granted to the Senior Executives had they participated in the Plan to 132,865. Additionally, on August 29, 2006, all employees were granted SARs equal to one-fourth of the number of SARs granted at December 31, 2005, or 22,864. This special grant was made to compensate all employees for supporting the transition to the new Senior Executive Team.

The exercise price of the annual awards of rights has been the average of the closing market price of our units for the ten days prior to the date of the grant. This methodology has been used by the Committee for annual grants so that the exercise price is not unduly influenced by trading of our units on one particular date. The volume of units that trade each day is frequently very small, such that one small trade can occur and have a significant influence on the price. Additionally, we may see unusual trading occur in the late months of the year at prices that do not necessarily correspond to the latest market prices. This methodology is subject to change for any grant in the future. The additional grant made to employees on August 29, 2006 was priced at the closing market price for our units, as the Committee believed that the reasons for and purpose of this grant supported a different method for determining the exercise price.

Our new employees receive SAR grants at the end of the quarter following their date of hire, with additional Awards to be granted each year as part of the annual review of compensation by our Compensation Committee. An employee's initial Award generally vests 25% per year over a period of four years, while annual Awards generally cliff vest 100% at four years from the grant date. The goal of our long-term incentive program for all employees is to provide each employee with awards that cliff vest each year. Additional details operate the operation of the SAR Plan are included below.

We accrue for the fair value of our liability for the stock appreciation rights we have issued to our employees and directors under the provisions of SFAS No. 123(R), *Share-Based Payments,* as amended and interpreted. These provisions require us to make estimates that affect the determination of the fair value of the outstanding stock appreciation rights, including estimates of the expected life of the rights, expected forfeiture rates of the rights, expected future volatility of our unit price and expected future distribution yield on our units. We base our estimates of these factors on historical experience and internal data. A summary of the assumptions used for the valuation at December 31, 2006 is included in Note 14 of the Notes to our Consolidated Financial Statements. The actual timing and amounts of payments to employees that will ultimately be made under the SAR plan will most likely differ from the estimates that are used in determining fair value. Since the value of our common units is affected more by actual cash distributions and Available Cash and expectations for growth of the Partnership, which factors are not fully contemplated under the methodology of SFAS 123(R), our Committee does not consider the accounting method for the SAR plan in determining the amount of SARs to grant our employees and Other Executives.

Our entire long-term incentive compensation plan for the Other Executives and employees is made in the form of cash-based rather than equity-based compensation. All of our employees and directors other than the Senior Executives participate in the SAR plan. We are a partnership. We believe that the administration of issuing small numbers of partnership units to the entire employee population and the tax reporting by the employees of taxable income from a partnership make it excessively complex to administer an equity-based long-term incentive plan. Consequently, we currently do not have any equity based compensation plans for our Other Executives.

Severance Benefits. We believe that companies should provide reasonable severance benefits to employees. With respect to Other Executives, these severance benefits should reflect the fact that it may be difficult for employees to find comparable employment within a short period of time. Although we typically pay severance when we terminate any employee unless such termination is for "cause", we do not have any pre-defined severance benefits for our Other

Executives, except in the case of a change in control, a plan adopted in June 2005. This plan is described under "Change of Control" below.

On August 8, 2006, Mr. Gorman, who had served as CEO, resigned. The severance compensation paid to Mr. Gorman consisted of a lump-sum payment of $1.2 million and approximately $11,500 for assistance in the transition for the new senior executives. He also received $10,000 in placement consulting services with a third-party.

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Change of Control. It is our belief that the interests of unitholders will best be served if the interests of our Other Executives are aligned with theirs. Providing change of control benefits should eliminate, or at least reduce, the reluctance of management to pursue potential change of control transactions that may be in the best interests of our unitholders. Our Senior Executives are not covered under the Severance Protection Plan or the Stock Appreciation Rights Plan. Change in control protection will be provided for them in the employment agreements and the general partner interest agreement when completed. See the Senior Executive Team section above.

We have two benefits for our employees and Other Executives in the event of a change of control: (i) our cash Severance Protection Plan, and (ii) vesting of Stock Appreciation Rights. Under the terms of our severance plan, an employee is entitled to receive a severance payment if a change of control occurs and the employee is terminated within two years of that change (i.e. a “double trigger” award). The severance plan will not apply to any employee who is terminated for cause or by an employee’s own decision for other than good reason (e.g., change of job status or a required move of more than 25 miles). If entitled to severance payments under the terms of the severance plan, Mr. Benavides and Ms. Pape will receive three times their annual salary and bonus, Mr. Mazoch and certain other members of management will receive two times their annual salary and bonus, and all other employees will receive between one-third to one and one-half times their annual salary and bonus depending upon their salary level and length of service with us. All employees will also receive medical and dental benefits for one-half the number of months for which they receive severance benefits.

A change in control is defined in the Severance Protection Plan. Generally, a change in control is a change in the control of Denbury, a disposition by Denbury of more than 50% of our general partner, or a transaction involving the disposition of substantially all of the assets of Genesis.

The severance plan also provides that if our Other Executive Officers are subject to the “parachute payment” excise tax, then the Partnership will pay the employee under the severance plan an additional amount to “gross up” the severance payment so that the employee will receive the full amount due under the terms of the severance plan after payment of the excise tax.

If a participant in our Stock Appreciation Rights Plan is terminated within one year of a change in control, all stock appreciation rights would immediately vest.

Based upon a hypothetical termination date of December 31, 2006, the change of control termination benefits for our named executive officers (excluding Mr. Gorman who is no longer employed by us, and the Senior Executive Team for whom the terms of their change in control benefits have not been completed) would have been as follows (based on the closing price for our units of $19.48 at that time):

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		Ross A. Benavides		Kerry W. Mazoch		Karen N. Pape
If termination date is between January 1, 2007 and December 30, 2007						
Severance plan payment	$	768,600	$	474,000	$	590,940
Healthcare and other insurance benefits		7,967		9,355		7,510
Fair market value of stock appreciation rights		224,728		212,580		171,888
Total	$	1,001,295	$	695,935	$	770,338
If termination date is between December 31, 2007 and December 31, 2008						
Severance plan payment	$	768,600	$	474,000	$	590,940
Healthcare and other insurance benefits		7,967		9,355		7,510
Fair market value of stock appreciation rights		162,386		153,607		124,204
Total	$	938,953	$	636,962	$	722,654

Other Benefits**.** Our Senior Executives and Other Executives participate in our benefit plans on the same terms as our other employees. These plans include medical, dental, disability and life insurance, and matching and profit-sharing contributions to our 401(k) plan. As reflected in the Summary Compensation Table, the cost to Genesis of the 401(k) matching contributions and profit-sharing contributions and term life premiums aggregated $60,584 in 2006 for our Senior Executives and Other Executives.

Our only retirement benefits are our 401k plan and a retirement vesting provision included in our Stock Appreciation Rights Plan. We do not have any pension plans or post-retirement medical benefits.

Board Process**.** During the fourth quarter of each year, management reviews the entire partnership’s compensation, based on recommendations from their subordinates, and makes a proposal to the Committee. Final review of this recommendation is made by the Committee at our normally-recurring December committee and board meetings, although depending on the magnitude of the anticipated changes, there may be several Committee meetings and discussions with management in advance of the December meeting. The Committee approves all compensation and long-term awards for all executive officers, considering the recommendation of the CEO with regard to compensation for the other executives. Our Committee also reviews and approves our overall compensation programs for all employees or any significant changes to these programs. This Committee is the administrator of all of our compensation plans (other than our 401(k) plan, health and other fringe benefit plans), including our Bonus Plan and Stock Appreciation Rights Plan under which all of our long-term equity awards are granted. The Board of Directors reviews and ratifies the compensation package based on a recommendation from the Committee. Following approval of the entire compensation program, salary increases have been made during the first quarter of the following year, and bonuses are paid in early March of the following year, and the annual recurring SAR awards are made effective on the last business day of December.

Compensation Committee Report

The information contained in this report shall not be deemed to be soliciting material or filed with the SEC or subject to the liabilities of Section 18 of the Exchange Act, except to the extent that the Partnership specifically incorporates it by reference into a document filed under the Securities Act of the Exchange Act.

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The Compensation Committee has reviewed and discussed with management the Compensation Discussion and Analysis included above. Based on the review and discussions, the Committee recommended to the Board, and the Board has approved, that the Compensation Discussion and Analysis be included in this Form 10-K.

This report is submitted by the Committee.

Gareth Roberts (Chairman)
Susan O. Rheney
Herbert I. Goodman

Executive Compensation
Summary Compensation Table

The following table summarizes certain information regarding the compensation paid or accrued by Genesis during 2006 to those persons who served as Chief Executive Officer and Chief Financial Officer, and three other executive officers receiving the most compensation in 2006 (the "Named Executive Officers").

2006 Summary Compensation Table

Name & Principal Position	Year	Salary ($)	Stock Awards [1] ($)	Non-Equity Incentive Plan Compensation [2] ($)	All Other Compensation ($)	Total ($)
Grant E. Sims [3] Chief Executive Officer (Principal Executive Officer)	2006	$ 112,077	-	-	56 (4)	$ 112,133
Mark J. Gorman [5] Former Chief Executive Officer and President (Former Principal Executive Officer)	2006	$ 190,894	$ 28,167 (6)	-	$ 1,232,958 (7)	$ 1,452,019
Ross A. Benavides Chief Financial Officer and General Counsel (Principal Financial Officer)	2006	$ 195,000	$ 101,231 (8)	$ 78,000	$ 16,668 (9)	$ 390,899
Joseph A., Blount, Jr. [10] President & Chief Operating Officer	2006	$ 97,615	-	-	$ 4,449 (11)	$ 102,064
Kerry W. Mazoch Vice President, Crude Oil Acquisitions	2006	$ 180,000	$ 95,752 (12)	$ 72,000	$ 14,367 (13)	$ 362,119

Karen N. Pape Vice President & Controller (Principal Accounting Officer)	2006	$	150,000	$	77,430	(14)	$	60,000	$	15,032	(15)	$ 302,462

(1) Amounts in this column represent the amounts, before consideration of expected forfeiture rate, that are included in the determination of net income for 2006 under the provisions of SFAS 123(R) for awards under our Stock Appreciation Rights plan. The forfeiture rate that was applied to these amounts at December 31, 2006 was 10%.

(2) Amounts in this column represent the amount that will be paid to the Executive Officer as an award under our Bonus Plan. In each case with an amount shown, the amount is equal to 40% of the named executive officers annual salary. Mr. Sims and Mr. Blount do not participate in the Bonus Plan.

(3) Mr. Sims was named Chief Executive Officer on August 8, 2006. His annual salary is $310,000. The amount shown as his salary is the amount he received from August 8, 2006 through December 31, 2006.

(4) This amount represents the amount paid for term life insurance premiums.

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(5) Mr. Gorman was Chief Executive Officer from January 1, 2006 through August 7, 2006.

(6) Mr. Gorman exercised all vested SARs after his resignation from Genesis. This amount represents the difference between the cash he received upon exercise of his SARs of $91,173 and the liability that had been recorded for SARs granted to him as of January 1, 2006.

(7) Mr. Gorman received a lump sum severance payment of $1,200,000 upon his resignation, $11,510 for his services during the transition to the new executive team, $1,436 of health benefits, and transition assistance from a third party of $10,000. During the period he was employed by us, he received $9,900 of matching contributions to our defined contribution 401(k) plan. We paid $112 for annual term life insurance premiums.

(8) This amount represents the change in the fair value of the outstanding SAR awards to Mr. Benavides between January 1, 2006 and December 31, 2006.

(9) This amount includes $9,900 of matching contributions to our 401(k) plan, $6,600 of profit-sharing contributions to our 401(k) plan and $168 for annual term life insurance premiums.

(10) Mr. Blount was named President and Chief Operating Officer on August 8, 2006. His annual salary is $270,000. The amount shown as his salary is the amount he received from August 8, 2006 through December 31, 2006.

(11) This amount includes $4,393 of matching contributions to our 401(k) plan and $56 for term life insurance premiums.

(12) This amount represents the change in the fair value of the outstanding SAR awards to Mr. Mazoch between January 1, 2006 and December 31, 2006.

(13) This amount includes $8,690 of matching contributions to our 401(k) plan, $5,509 of profit-sharing contributions to our 401(k) plan and $168 for annual term life insurance premiums.

(14) This amount represents the change in the fair value of the outstanding SAR awards to Ms. Pape between January 1, 2006 and December 31, 2006.

(15) This amount includes $8,264 of matching contributions to our 401(k) plan, $6,600 of profit-sharing contributions to our 401(k) plan and $168 for annual term life insurance premiums.

Stock Appreciation Rights Plan

As discussed in the Compensation Discussion and Analysis, we have a Stock Appreciation Rights plan, or SAR for all employees, with the exception of our new senior management team. Under the terms of this plan, all regular, full-time active employees and the members of the Board are eligible to participate in the plan. The plan is administered by the Compensation Committee of the Board, who shall determine, in its full discretion, the number of rights to award, the grant date of the units and the formula for allocating rights to the participants and the strike price of the rights awarded. Each right is equivalent to one common unit. The rights have a term of 10 years from the date of grant. The initial award to a participant will vest one-fourth each year beginning with the first anniversary of the grant date of the award. Subsequent awards to participants will vest on the fourth anniversary of the grant date. If the right has not been exercised at the end of the ten year term and the participant has not terminated employment with us, the right will be deemed exercised as of the date of the right's expiration and a cash payment will be made as described below.

Upon vesting, the participant may exercise his rights to receive a cash payment equal to the difference between the average of the closing market price of our common units for the ten days preceding the date of exercise over the strike price of the right being exercised. The cash payment to the participant will be net of any applicable withholding taxes required by law. If the Committee determines, in its full discretion, that it would cause significant financial harm to the Partnership to make cash payments to participants who have exercised rights under the plan, then the Committee may authorize deferral of the cash payments until a later date.

Termination for any reason other than death, disability or normal retirement (as these terms are defined in the plan) will result in the forfeiture of any non-vested rights. Upon death, disability or normal retirement, all rights will become fully vested. If a participant is terminated for any reason within one year after the effective date of a change in control (as defined in the plan) all rights will become fully vested.

Bonus Plan

As discussed in the Compensation Disclosure and Analysis, we have a Bonus Plan for all employees of our general partner, with the exception of our new senior management team. This non-equity incentive plan provides for our Other Executives to receive bonuses ranging from zero to forty percent based on our achieving certain levels of Available Cash before reserves and bonus expense. The table below shows the minimum and maximum amounts that each of the Executive Officers named in the table could have achieved for 2006. The maximum amounts were achieved and paid to the individuals in March 2007.

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The following tables show the stock appreciation rights and non-equity incentive plan awards granted to the Executive Officers in 2006 and the outstanding stock appreciation rights awards at December 31, 2006 that were issued to our Executive Officers. Information on rights granted to non-employee directors is included in the section entitled Director Compensation.

Grants of Plan-Based Awards in Fiscal Year 2006

Name	Grant Date	Board Approval Date	Estimated Possible Payouts Under Non-Equity Incentive Plan Awards (1) Threshold $	Estimated Possible Payouts Under Non-Equity Incentive Plan Awards (1) Maximum $	All Other Stock Awards: Number of Shares of Stock or Units) (#) (2)	Exercise or Base Price of Option Awards ($/Sh) (3)	Grant Date Fair Value of Stock and Option Awards (4)
Ross A. Benavides	8/29/2006	8/29/2006			1,003	$ 16.95	$ 3,388
	12/29/2006	12/28/2006			5,270	$ 19.57	$ 19,810
		5/27/2003	$ 0	$ 78,000			
Kerry W. Mazoch	8/29/2006	8/29/2006			949	$ 16.95	$ 3,206
	12/29/2006	12/28/2006			4,127	$ 19.57	$ 15,513
		5/27/2003	$ 0	$ 72,000			
Karen N. Pape	8/29/2006	8/29/2006			767	$ 16.95	$ 2,591
	12/29/2006	12/28/2006			4,254	$ 19.57	$ 15,991
		5/27/2003	$ 0	$ 60,000			

(1) Under the terms of our Bonus Plan, the Executive Officers named in this table were eligible to receive cash bonus awards in an amount that ranged from no award to the amounts shown as the Maximum, which represent 40% of their base salary. The amount of the award is based on the amount of Available Cash before bonus expense generated by us for the year. Each of these Executive Officers received the maximum award for 2006.

(2) The amounts in this column represent the SARs granted to the named Executive Officer during 2006.

(3) For the awards granted on August 29, 2006, the exercise price represents the closing market price for our units for that date. For the awards granted on December 29, 2006, the exercise price represents the average of the closing market price of our units for the ten days preceding December 29, 2006. The closing market price for our units on December 29, 2006 was $19.48.

(4) The amounts in this column represent the fair value of the award on December 31, 2006, as calculated in accordance with the provisions of SFAS 123(R).

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Oustanding Equity Awards at 2006 Fiscal Year-End

Name	Number of Securities Underlying Stock Appreciation Rights (#) Exercisable	Number of Securities Underlying Unexercised Stock Appreciation Rights (#) Unexercisable (1)	Stock Appreciation Rights Exercise Price ($)	Stock Appreciation Rights Expiration Date
		Stock Appreciation Rights		
Ross A. Benavides	11,916	3,973	$ 9.26	12/31/2013
	-	3,777	$ 12.48	12/31/2014
	-	4,015	$ 11.17	12/31/2015
	-	1,003	$ 16.95	8/29/2016
	-	5,270	$ 19.57	12/29/2016
Kerry W. Mazoch	11,272	3,758	$ 9.26	12/31/2013
	-	3,573	$ 12.48	12/31/2014
	-	3,798	$ 11.17	12/31/2015
	-	949	$ 16.95	8/29/2016
	-	4,127	$ 19.57	12/29/2016
Karen N. Pape	9,114	3,039	$ 9.26	12/31/2013
	-	2,889	$ 12.48	12/31/2014
	-	3,071	$ 11.17	12/31/2015
	-	767	$ 16.95	8/29/2016
	-	4,254	$ 19.57	12/29/2016

(1) The unexercisable rights of each named executive officer vest on the following dates in the order they are listed: December 31, 2007, January 1, 2009, January 1, 2010, January 1, 2010 and January 1, 2011.

The following table includes the exercises of stock appreciation rights by our Named Executive Officers. Mr. Gorman exercised his vested rights following his resignation in accordance with the provisions of the SAR Plan.

Option Exercises and Stock Vested in Fiscal Year 2006

Name	Stock Appreciation Rights Number of Rights Exercised (#)	Value Realized on Exercise ($)
Mark J. Gorman	11,810	$ 91,173

Director Compensation

The table below reflects compensation for the directors. Mr. Worthey resigned as a director of Genesis in June 2006. Mr. Allen replaced Mr. Worthey on our Board of Directors. Directors who are employees, like Mr. Sims, do not receive compensation for service as a director.

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Director Compensation in Fiscal 2006

Name	Fees Earned or Paid in Cash ($)	Stock Appreciation Rights Awards ($) (1)	Total ($)
Mark C. Allen (2) (3) (4)	$ 15,000	$ 1,645	$ 16,645
Ronald T. Evans (2) (4)	$ 30,000	$ 16,340	$ 46,340
Herbert I. Goodman (4) (5)	$ 36,000	$ 19,611	$ 55,611
Susan O. Rheney (4) (6)	$ 40,000	$ 21,785	$ 61,785
Gareth Roberts (2) (4)	$ 30,000	$ 16,340	$ 46,340
Phil Rykhoek (2) (4)	$ 30,000	$ 14,167	$ 44,167
J. Conley Stone (4) (5)	$ 36,000	$ 19,611	$ 55,611
Mark Worthey (2) (7)	$ 15,000	$ (2,631)	$ 12,369

(1) Amounts in this column represent the amounts, before consideration of expected forfeiture rate, that are included in the determination of net income for 2006 under the provisions of SFAS 123(R) for awards under our Stock Appreciation Rights plan. The forfeiture rate that was applied to these amounts at December 31, 2006 was 10%.

(2) Fees were paid in cash for these directors to Denbury Resources, Inc.

(3) Mr. Allen received an initial award of stock appreciation rights on September 29, 2006 for 2,576 rights with a strike price of $15.77. The award will vest one-fourth annually through September 29, 2010 and will expire September 29, 2016. The closing market price for our units on the grant date of this award was $15.63. The fair value of this award on the grant date was $7,866.

(4) All of the directors received an award of 1,000 stock appreciation rights on December 29, 2006 with a strike price of $19.57. The awards will vest on January 1, 2011 and will expire on December 29, 2016. The closing market price for our units on the grant date of this award was $19.48. The fair value of each award on the grant date was $3,759. This amount represents the expected value of the award to the director at the end of the vesting period, as calculated under the methodology of SFAS 123(R).

(5) In addition to $30,000 received for service on the Board of Directors, Mr. Goodman and Mr. Stone received payments totaling $6,000 for their service on the Audit Committee.

(6) In addition to $30,000 received for service on the Board of Directors, Ms. Rheney received payments totaling $6,000 for her service on the Audit Committee and payments totaling $4,000 for her service as Audit Committee Chairman.

(7) Upon his departure from the Board of Directors, Mr. Worthey exercised 1,288 stock appreciation rights and received $4,240. He forfeited 2,551 unvested stock appreciation rights. The amount included for stock appreciation rights awards in this table for Mr. Worthey represents the difference between the liability at January 1, 2006 for the outstanding awards issued to Mr. Worthey and the cash he received upon exercise of vested awards.

In 2007, compensation for the three independent directors will consist of an annual fee of $40,000. The Audit Committee Chairman will receive an additional annual fee of $4,000. We will continue to pay Denbury a fee of $120,000 annually for providing four of its executives as directors of Genesis. Additionally, non-employee directors will receive a fee for attendance at meetings of $2,000 for each meeting attended in person and $1,000 for meetings attended telephonically. This fee is applicable to meetings of the Board of Directors and committee meetings, however only one meeting fee can be earned per day. Meeting fees for the four executives provided by Denbury as directors will be paid to Denbury.

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The outstanding awards of stock appreciation rights to the directors of the general partner are shown in the table below.

Oustanding Equity Awards at 2006 Fiscal Year-End to Directors

	Stock Appreciation Rights			
Name	Number of Securities Underlying Stock Appreciation Rights (#) Exercisable	Number of Securities Underlying Unexercised Stock Appreciation Rights (#) Unexercisable	Stock Appreciation Rights Exercise Price ($)	Stock Appreciation Rights Expiration Date
Mark C. Allen (1)	-	2,576	$ 15.77	9/29/2016
	-	1,000	$ 19.57	12/29/2016
Ronald T. Evans (2)	1,932	644	$ 9.26	12/31/2013
	-	612	$ 12.48	12/31/2014
	-	651	$ 11.17	12/31/2015
	-	1,000	$ 19.57	12/29/2016
Herbert I. Goodman (2)	2,319	773	$ 9.26	12/31/2013
	-	735	$ 12.48	12/31/2014
	-	781	$ 11.17	12/31/2015
	-	1,000	$ 19.57	12/29/2016
Susan O. Rheney (2)	2,576	859	$ 9.26	12/31/2013
	-	816	$ 12.48	12/31/2014
	-	868	$ 11.17	12/31/2015
	-	1,000	$ 19.57	12/29/2016
Gareth Roberts (2)	1,932	644	$ 9.26	12/31/2013
	-	612	$ 12.48	12/31/2014
	-	651	$ 11.17	12/31/2015
	-	1,000	$ 19.57	12/29/2016
Phil Rykhoek (3)	1,288	1,288	$ 11.00	8/25/2014
	-	612	$ 12.48	12/31/2014
	-	651	$ 11.17	12/31/2015
	-	1,000	$ 19.57	12/29/2016
J. Conley Stone (2)	2,319	773	$ 9.26	12/31/2013
	-	735	$ 12.48	12/31/2014
	-	781	$ 11.17	12/31/2015
	-	1,000	$ 19.57	12/29/2016

(1) Mr. Allen's first award will vest one-fourth annually beginning September 29, 2007 through September 29, 2010. Mr. Allen's second award will vest on January 1, 2011.

(2) The unexercisable rights of this director vest on the following dates in the order they are listed: December 31, 2007, January 1, 2009, January 1, 2010 and January 1, 2011.

(3) The unexercisable portion of Mr. Rykhoek's first award will vest 644 rights on August 25, 2007 and 644 rights on August 25, 2008. Mr. Rykhoek's remaining awards will vest on January 1, 2009, January 1, 2010 and January 1, 2011.

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Compensation Committee Interlocks and Insider Participation

None of the members of the Compensation Committee has at any time been an officer or employee of the Partnership. None of our executive officers serves, or in the past year has served, as a member of the board of directors or compensation committee of any entity that has one or more of its executive officers serving on our Compensation Committee.

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

Beneficial Ownership of Partnership Units

The following table sets forth certain information as of February 26, 2007, regarding the beneficial ownership of our units by beneficial owners of 5% or more of the units, by directors and the executive officers of our general partner and by all directors and executive officers as a group. This information is based on data furnished by the persons named.

		Beneficial Ownership of Common Units	
Title of Class	Name of Beneficial Owner	Number of Units	Percent of Class
Genesis Energy, L.P.	Genesis Energy, Inc.	1,019,441	7.4
Common Unit	Gareth Roberts	10,000	*
	Grant E. Sims (1)	1,000	*
	Ronald T. Evans	1,000	*
	Herbert I. Goodman	2,000	*
	Susan O. Rheney	700	*
	Phil Rykhoek	2,500	*
	J. Conley Stone	2,000	*
	Ross A. Benavides	9,283	*
	Kerry W. Mazoch (2)	8,669	*
	Karen N. Pape	3,386	*
	All directors and executive officers as a group (12 in total)	40,538	*
	Swank Capital, L.L.C., Swank Energy Income Advisors, L.P. and Mr. Jerry V. Swank 3300 Oak Lawn Ave., Suite 650 Dallas, Texas 75219	1,710,754	12.4

* Less than 1%

(1) Common units are held by Mr. Sims' father. Mr. Sims disclaims beneficial ownership of these units.

(2) Includes 584 units which Mr. Mazoch holds with his children.

Except as noted, each unitholder in the above table is believed to have sole voting and investment power with respect to the shares beneficially held, subject to applicable community property laws.

The mailing address for Genesis Energy, Inc. and all officers and directors is 500 Dallas, Suite 2500, Houston, Texas, 77002.

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Beneficial Ownership of General Partner Interest

Genesis Energy, Inc. owns all of our 2% general partner interest and all of our incentive distribution rights, in addition to 7.4% of our units. Genesis Energy, Inc. is a wholly-owned subsidiary of Denbury Resources, Inc. Denbury has advised us that it has not pledged our general partner under any agreements or arrangements.

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

Our General Partner

Our operations are managed by, and our employees are employed by, Genesis Energy, Inc., our general partner. Our general partner does not receive any management fee or other compensation in connection with the management of our business, but is reimbursed for all direct and indirect expenses incurred on our behalf. During 2006, these reimbursements totaled $16.8 million. At December 31, 2006, we owed our general partner $0.9 million related to these services.

Our general partner owns the 2% general partner interest and all incentive distribution rights. Our general partner is entitled to receive incentive distributions if the amount we distribute with respect to any quarter exceeds levels specified in our partnership agreement. Under the quarterly incentive distribution provisions, generally our general partner is entitled to 13.3% of amounts we distribute to our common unitholders in excess of $0.25 per unit, 23.5% of the amounts we distribute to our common unitholders in excess of $0.28 per unit, and 49% of the amounts we distribute to our common unitholders in excess of $0.33 per unit.

Our general partner also owns 1,019,441 limited partner units and has the same rights and is entitled to receive distributions as the other limited partners with respect to those units.

During 2006, our general partner received a total of $1.0 million from us as distributions on its limited partner units and for its general partner interest.

Relationship with Denbury Resources, Inc.

Historically, we have entered into transactions with Denbury and its subsidiaries to acquire assets. We have instituted specific procedures for evaluating and valuing our material transactions with Denbury and its subsidiaries. Before we consider entering into a transaction with Denbury or any of its subsidiaries, we determine whether the proposed transaction (1) would comply with the requirements under our credit facility, (2) would comply with substantive law, and (3) would be fair to us and our limited partners. In addition, our general partner’s board of directors utilizes a Special Conflicts Committee comprised solely of independent directors. That committee:

- evaluates and, where appropriate, negotiates the proposed transaction;
- engages an independent financial advisor and independent legal counsel to assist with its evaluation of the proposed transaction; and
- determines whether to reject or approve and recommend the proposed transaction.

We will only consummate any proposed material acquisition or disposition with Denbury if, following our evaluation of the transaction, the Special Conflicts Committee approves and recommends the proposed transaction and our general partner’s full board approves the transaction.

During 2005, 2004 and 2003, we acquired CO_2 volumetric production payments and related wholesale marketing contracts from Denbury for $14.4 million, $4.7 million and $24.4 million, respectively. Additionally we enter into transactions with Denbury in the ordinary course of our operations. During 2006, these transactions included:

- Purchases of crude oil from Denbury totaling $1.6 million.
- Provision of transportation services for crude oil by truck totaling $0.8 million.
- Provision of crude oil pipeline transportation services totaling $4.2 million.
- Provision of crude oil from and CO_2 transportation to the Brookhaven field and crude oil from the Olive field for $1.2 million.
- Provision of CO_2 transportation services to our wholesale industrial customers by Denbury's pipeline. The fees for this service totaled $4.6 million in 2006.
- Provision of pipeline monitoring services to Denbury for its CO_2 pipelines totaling $65,000 in 2006.
- Provision of services by Denbury officers as directors of our general partner. We paid Denbury $120,000 for these services in 2006.

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At December 31, 2006, we owed Denbury \$0.8 million for provision of CO_2 transportation services. Denbury owed us \$0.6 million for crude oil trucking and pipeline transportation services.

In 2002, we amended our partnership agreement to broaden the right of the common unitholders to remove our general partner. Prior to this amendment, the general partner could only be removed for cause and with approval by holders of two-thirds or more of the outstanding limited partner interests in us. As amended, the partnership agreement provides that, with the approval of at least a majority of our limited partners, the general partner also may be removed without cause. Any limited partner interests held by the general partner and its affiliates would be excluded from such a vote.

The amendment further provides that if it is proposed that the removal is without cause and an affiliate of Denbury is the general partner to be removed and not proposed as a successor, then any action for removal must also provide for Denbury to be granted an option effective upon its removal to purchase our Mississippi pipeline system at a price that is 110 percent of its fair market value at that time. Denbury also has the right to purchase the Mississippi CO_2 pipeline to Brookhaven field at its fair market value at that time. Fair value is to be determined by agreement of two independent appraisers, one chosen by the successor general partner and the other by Denbury or if they are unable to agree, the mid-point of the values determined by them.

Director Independence

Susan O. Rheney, Herbert I. Goodman and J. Conley Stone, all members of our Audit Committee, meet the listing standard requirements of the American Stock Exchange and the SEC rules to be considered independent directors of Genesis. An independent director means a person other than an officer or employee of our general partner, the Partnership or its subsidiaries, or Denbury or its subsidiaries, or any other individual having a relationship that, in the opinion of the Board of Directors, would interfere with the exercise of independent judgment in carrying out the responsibilities of a director. To be considered independent, neither the director nor an immediate family member of the director has had any direct or indirect material relationship with Genesis.

The independent directors meet regularly in executive sessions without the presence of the non-independent directors or members of our management after each of the regularly scheduled quarterly Audit Committee meetings. See additional discussion of director independence at Item 10. Directors, Executive Officers and Corporate Governance - *Management of Genesis Energy, L.P.*

Item 14. Principal Accountant Fees and Services

The following table summarizes the fees for professional services rendered by Deloitte & Touche LLP for the years ended December 31, 2006 and 2005.

	2006	2005
	(in thousands)	
Audit Fees (1)	$ 632	$ 733
Audit-Related Fees (2)	25	41
Tax-Related Fees (3)	88	66
All Other Fees (4)	1	1
Total	$ 746	$ 841

(1) Includes fees for the annual audit and quarterly reviews, SEC registration statements, accounting and financial reporting consultations and research work regarding Generally Accepted Accounting Principles and the audit of the effectiveness of our internal controls over financial reporting.

(2) Includes fees for the audit of our employee benefit plan.
(3) Includes fees for tax return preparation and tax treatment consultations.
(4) Includes fees associated with a license for accounting research software.

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Pre-Approval Policy

The services by Deloitte in 2006 and 2005 were pre-approved in accordance with the pre-approval policy and procedures adopted by the Audit Committee. This policy describes the permitted audit, audit-related, tax and other services (collectively, the “Disclosure Categories”) that the independent auditor may perform. The policy requires that each fiscal year, a description of the services (the “Service List”) expected to be performed by the independent auditor in each of the Disclosure Categories in the following fiscal year be presented to the Audit Committee for approval.

Any requests for audit, audit-related, tax and other services not contemplated on the Service List must be submitted to the Audit Committee for specific pre-approval and cannot commence until such approval has been granted. Normally, pre-approval is provided at regularly scheduled meetings.

In considering the nature of the non-audit services provided by Deloitte in 2006 and 2005, the Audit Committee determined that such services are compatible with the provision of independent audit services. The Audit Committee discussed these services with Deloitte and management of our general partner to determine that they are permitted under the rules and regulations concerning auditor independence promulgated by the SEC to implement the Sarbanes-Oxley Act of 2002, as well as the American Institute of Certified Public Accountants.

Item 15. Exhibits and Financial Statement Schedules

(a)(1) Financial Statements

See “Index to Consolidated Financial Statements and Financial Statement Schedules” set forth on page 81.

(a)(2) Financial Statement Schedules

See “Index to Consolidated Financial Statements and Financial Statement Schedules” set forth on page 81.

(a)(3) Exhibits

3.1	Certificate of Limited Partnership of Genesis Energy, L.P. (“Genesis”) (incorporated by reference to Exhibit 3.1 to Registration Statement, File No. 333-11545
3.2	Fourth Amended and Restated Agreement of Limited Partnership of Genesis (incorporated by reference to Exhibit 4.1 to Form 8-K dated June 15, 2005
3.3	Certificate of Limited Partnership of Genesis Crude Oil, L.P. (“the Operating Partnership”) (incorporated by reference to Exhibit 3.3 to Form 10-K for the year ended December 31, 1996)
3.4	Fourth Amended and Restated Agreement of Limited Partnership of the Operating Partnership (incorporated by reference to Exhibit 4.2 to Form 8-K dated June 15, 2005)
10.1	Purchase & Sale and Contribution & Conveyance Agreement dated December 3, 1996 among Basis Petroleum, Inc., Howell Corporation (“Howell”), certain subsidiaries of Howell, Genesis, the Operating Partnership and Genesis Energy, L.L.C. (incorporated by reference to Exhibit 10.1 to Form 10-K for the year ended December 31, 1996)

10.2		First Amendment to Purchase & Sale and Contribution and Conveyance Agreement (incorporated by reference to Exhibit 10.2 to Form 10-K for the year ended December 31, 1996)
10.3		Credit Agreement dated as of November 15, 2006 among Genesis Crude Oil, L.P., Genesis Energy, L.P., the Lenders Party Hereto, Fortis Capital Corp., and Deutsche Bank Securities Inc. (incorporated by reference to Exhibit 10.1 to Form 8-K dated November 15, 2006)
10.4	+	Letter dated August 3, 2006 to Grant E. Sims regarding Offer to Enter into Employment Agreements (incorporated by reference to Exhibit 10.1 to Form 10-Q for the quarterly period ended September 30, 2006)

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10.5			Pipeline Sale and Purchase Agreement between TEPPCO Crude Pipeline, L.P. and Genesis Crude Oil, L.P. and Genesis Pipeline Texas, L.P. (incorporated by reference to Exhibit 10.1 to Form 8-K dated October 31, 2003)
10.6			Purchase and Sale Agreement between TEPPCO Crude Pipeline, L.P. and Genesis Crude Oil, L.P. (incorporated by reference to Exhibit 10.2 to Form 8-K dated October 31, 2003)
10.7			Production Payment Purchase and Sale Agreement between Denbury Resources, Inc. and Genesis Crude Oil, L.P. (incorporated by reference to Exhibit 10.7 to Form 10-K for the year ended December 31, 2003)
10.8			Carbon Dioxide Transportation Agreement between Denbury Resources, Inc. and Genesis Crude Oil, L.P. (incorporated by reference to Exhibit 10.8 to Form 10-K for the year ended December 31, 2003)
10.9		+	Genesis Stock Appreciation Rights Plan (incorporated by reference to Exhibit 10.9 to Form 10-K for the year ended December 31, 2004)
10.10		+	Form of Stock Appreciation Rights Plan Grant Notice (incorporated by reference to Exhibit 10.10 to Form 10-K for the year ended December 31, 2004)
*	10.12	+	Summary of Genesis Energy, Inc. Bonus Plan
10.13		+	Genesis Energy Amended and Restated Severance Protection Plan (incorporated by reference to Exhibit 10.1 to Form 8-K dated December 12, 2006)
10.14			Second Production Payment Purchase and Sale Agreement between Denbury Onshore, LLC and Genesis Crude Oil, L.P. executed August 26, 2004 (incorporated by reference to Exhibit 99.1 to Form 8-K dated August 26, 2004)
10.15			Second Carbon Dioxide Transportation Agreement between Denbury Onshore, LLC and Genesis Crude Oil, L.P. (incorporated by reference to Exhibit 99.2 to Form 8-K dated August 24, 2004)
10.16			Third Production Payment Purchase and Sale Agreement between Denbury Onshore, LLC and Genesis Crude Oil, L.P. executed October 11, 2005 (incorporated by reference to Exhibit 99.2 to Form 8-K dated October 11, 2005)
10.17			Third Carbon Dioxide Transportation Agreement between Denbury Onshore, LLC and Genesis Crude Oil, L.P. (incorporated by reference to Exhibit 99.3 to Form 8-K dated October 11, 2005)
11.1			Statement Regarding Computation of Per Share Earnings (See Notes 2 and 9 to the Consolidated Financial Statements

*	21.1	Subsidiaries of the Registrant
*	23.1	Consent of Deloitte & Touche LLP
*	31.1	Certification by Chief Executive Officer Pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934
*	31.2	Certification by Chief Financial Officer Pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934
*	32.1	Certification by Chief Executive Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
*	32.2	Certification by Chief Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

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* Filed herewith

\+ A management contract or compensation plan or arrangement.

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SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized on the 15th day of March, 2007.

GENESIS ENERGY, L.P.
(A Delaware Limited Partnership)

By: GENESIS ENERGY, INC.,
as General Partner

By: /s/ GRANT E. SIMS
Grant E. Sims
Chief Executive Officer

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

/s/	GRANT E. SIMS Grant E. Sims	Director and Chief Executive Officer (Principal Executive Officer	March 15, 2007
/s/	ROSS A. BENAVIDES Ross A. Benavides	Chief Financial Officer, General Counsel and Secretary (Principal Financial Officer)	March 15, 2007
/s/	KAREN N. PAPE Karen N. Pape	Vice President and Controller (Principal Accounting Officer)	March 15, 2007
/s/	GARETH ROBERTS Gareth Roberts	Chairman of the Board and Director	March 15, 2007
/s/	MARK C. ALLEN Mark C. Allen	Director	March 15, 2007
/s/	RONALD T. EVANS Ronald T. Evans	Director	March 15, 2007
/s/	HERBERT I. GOODMAN Herbert I. Goodman	Director	March 15, 2007
/s/	SUSAN O. RHENEY Susan O. Rheney	Director	March 15, 2007
/s/	PHIL RYKHOEK Phil Rykhoek	Director	March 15, 2007
/s/	J. CONLEY STONE	Director	March 15, 2007

J. Conley Stone

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GENESIS ENERGY, L.P.
INDEX TO CONSOLIDATED FINANCIAL STATEMENTS
AND FINANCIAL STATEMENT SCHEDULES

All other financial statement schedules are not required under the relevant instructions or are inapplicable and therefore have been omitted.

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of Genesis Energy, Inc. and Unitholders of
Genesis Energy, L.P.
Houston, Texas

We have audited the accompanying consolidated balance sheets of Genesis Energy, L.P. and subsidiaries (the “Partnership”) as of December 31, 2006 and 2005, and the related consolidated statements of operations, partners’ capital, and cash flows for each of the three years in the period ended December 31, 2006. Our audits also included the financial statement schedule listed in the index at Item 15. These financial statements and financial statement schedule are the responsibility of the Partnership’s management. Our responsibility is to express an opinion on the financial statements and financial statement schedule based on our audits.

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

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Genesis Energy, L.P. and subsidiaries at December 31, 2006 and 2005, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2006, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, present fairly, in all material respects, the information set forth therein.

As discussed in Note 14 to the consolidated financial statements, in connection with the required adoption of a new accounting principle in 2006, the Partnership changed its method of accounting for equity-based payments. As discussed in Note 4 to the consolidated financial statements, in connection with the required adoption of a new accounting principle in 2005, the Partnership changed its method of accounting for asset retirement obligations.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of the Partnership’s internal control over financial reporting as of December 31, 2006, based on the criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated March 14, 2007 expressed an unqualified opinion on management’s assessment of the effectiveness of the Partnership’s internal control over financial reporting and an unqualified opinion on the effectiveness of the Partnership’s internal control over financial reporting.

/s/ DELOITTE & TOUCHE LLP
Houston, Texas

March 14, 2007

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GENESIS ENERGY, L.P.
CONSOLIDATED BALANCE SHEETS
(In thousands)

		December 31, 2006		December 31, 2005
ASSETS				
CURRENT ASSETS:				
Cash and cash equivalents	$	2,318	$	3,099
Accounts receivable:				
Trade		88,006		82,119
Related Party		1,100		515
Inventories		5,172		498
Net investment in direct financing leases, net of unearned income - current portion		568		531
Other		2,828		3,687
Total current assets		99,992		90,449
FIXED ASSETS, at cost		70,382		69,708
Less: Accumulated depreciation		(39,066)		(35,939)
Net fixed assets		31,316		33,769
NET INVESTMENT IN DIRECT FINANCING LEASES, net of unearned income		5,373		5,941
CO_2 ASSETS, net of amortization		33,404		37,648
JOINT VENTURES AND OTHER INVESTMENTS		18,226		13,042
OTHER ASSETS, net of amortization		2,776		928
TOTAL ASSETS	$	191,087	$	181,777
LIABILITIES AND PARTNERS' CAPITAL				
CURRENT LIABILITIES:				
Accounts payable:				
Trade	$	85,063	$	82,369
Related party		1,629		2,917
Accrued liabilities		9,220		7,325
Total current liabilities		95,912		92,611
LONG-TERM DEBT		8,000		-
OTHER LONG-TERM LIABILITIES		991		955
COMMITMENTS AND CONTINGENCIES (Note 17)				
MINORITY INTERESTS		522		522
PARTNERS' CAPITAL:				
Common unitholders, 13,784 units issued and outstanding at 2006 and 2005		83,884		85,870
General partner		1,778		1,819

Total partners' capital		85,662		87,689
TOTAL LIABILITIES AND PARTNERS' CAPITAL	$	191,087	$	181,777

The accompanying notes are an integral part of these consolidated financial statements.

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GENESIS ENERGY, L.P.
CONSOLIDATED STATEMENTS OF OPERATIONS
(In thousands, except per unit amounts)

	Year Ended December 31, 2006	2005	2004
REVENUES:			
Crude oil gathering and marketing:			
Unrelated parties (including revenues from buy/sell arrangements of $69,772, $365,067 and $296,329, in 2006, 2005 and 2004, respectively)	$ 872,443	$ 1,037,577	$ 901,689
Related parties	825	972	213
Pipeline transportation, including natural gas sales:			
Unrelated parties	24,999	24,297	15,506
Related parties	4,948	4,591	1,174
CO_2 marketing revenues			
Unrelated parties	13,098	11,302	8,561
Related parties	2,056	-	-
Total revenues	918,369	1,078,739	927,143
COSTS AND EXPENSES:			
Crude oil costs:			
Unrelated parties (including costs from buy/sell arrangements of $68,899, $363,208 and $295,380, in 2006, 2005 and 2004, respectively)	850,106	1,014,249	805,990
Related parties	1,565	4,647	77,998
Field operating costs	14,231	15,992	13,880
Pipeline transportation costs:			
Pipeline operating costs	9,928	9,741	8,137
Natural gas purchases	7,593	9,343	-
CO_2 marketing costs:			
Transportation costs - related party	4,640	3,501	2,694
Other costs	202	148	105
General and administrative	13,573	9,656	11,031
Depreciation and amortization	7,963	6,721	7,298
Net (gain) loss on disposal of surplus assets	(16)	(479)	33
Total costs and expenses	909,785	1,073,519	927,166
OPERATING INCOME (LOSS)	8,584	5,220	(23)
OTHER INCOME (EXPENSE):			
Equity in earnings of joint ventures	1,131	501	-
Interest income	198	71	44
Interest expense	(1,572)	(2,103)	(970)
Income from continuing operations before income taxes and minority interest	8,341	3,689	(949)
Income tax benefit	11	-	-
Minority interest	(1)	-	-
	8,351	3,689	(949)

INCOME (LOSS) FROM CONTINUING OPERATIONS						
Income (loss) from discontinued Texas operations		-		312		(463)
Cumulative effect adjustment of adoption of new accounting principles		30		(586)		-
NET INCOME (LOSS)	$	8,381	$	3,415	$	(1,412)

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GENESIS ENERGY, L.P.
CONSOLIDATED STATEMENTS OF OPERATIONS - CONTINUED
(In thousands, except per unit amounts)

	Year Ended December 31, 2006	2005	2004
NET INCOME (LOSS) PER COMMON UNIT - BASIC AND DILUTED:			
Income (loss) from continuing operations	$ 0.59	$ 0.38	$ (0.10)
Income (loss) from discontinued operations	-	0.03	(0.05)
Cumulative effect adjustment	-	(0.06)	-
NET INCOME (LOSS)	$ 0.59	$ 0.35	$ (0.15)
Weighted average number of common units outstanding	13,784	9,547	9,314

The accompanying notes are an integral part of these consolidated financial statements.

GENESIS ENERGY, L.P.
CONSOLIDATED STATEMENTS OF PARTNERS' CAPITAL
(In thousands)

	Number of Common Units	Partners' Capital Common Unitholders	General Partner	Total
Partners' capital, January 1, 2004	9,314	$ 51,299	$ 1,055	$ 52,354
Net loss	-	(1,384)	(28)	(1,412)
Cash distributions	-	(5,589)	(114)	(5,703)
Partners' capital, December 31, 2004	9,314	44,326	913	45,239
Net income	-	3,347	68	3,415
Cash distributions	-	(5,682)	(116)	(5,798)
Issuance of units	4,470	43,879	954	44,833
Partners' capital, December 31, 2005	13,784	85,870	1,819	87,689
Net income	-	8,214	167	8,381
Cash distributions	-	(10,200)	(208)	(10,408)
Partners' capital, December 31, 2006	13,784	$ 83,884	$ 1,778	$ 85,662

The accompanying notes are an integral part of these consolidated financial statements.

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GENESIS ENERGY, L.P.
CONSOLIDATED STATEMENTS OF CASH FLOWS
(In thousands)

	Year Ended December 31, 2006	2005	2004
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income (loss)	$ 8,381	$ 3,415	$ (1,412)
Adjustments to reconcile net income to net cash provided by operating activities -			
Depreciation	3,719	3,579	4,846
Amortization of CO_2 contracts	4,244	3,142	2,452
Amortization and write-off of credit facility issuance costs	969	373	373
Amortization of unearned income on direct financing leases	(655)	(689)	(36)
Payments received under direct financing leases	1,186	1,185	75
Equity in earnings of investments in joint ventures	(1,131)	(501)	-
Distributions from joint ventures - return on investment	1,565	435	-
(Gain) loss on disposal of assets	(16)	(791)	33
Cumulative effect adjustment	(30)	586	-
Other non-cash charges (credits)	1,903	(54)	1,151
Changes in components of working capital -			
Accounts receivable	(6,472)	(13,313)	(2,589)
Inventories	(4,664)	790	(1,170)
Other current assets	870	132	13,251
Accounts payable	1,359	10,431	7,525
Accrued liabilities	34	770	(14,797)
Net cash provided by operating activities	11,262	9,490	9,702
CASH FLOWS FROM INVESTING ACTIVITIES:			
Additions to property and equipment	(1,260)	(6,106)	(8,322)
Investments in joint ventures and other investments	(6,042)	(13,418)	-
CO_2 contracts acquisition	-	(14,446)	(4,723)
Distributions from joint ventures - return of investment	528	388	-
Proceeds from disposal of assets	67	1,585	112
Other, net	(135)	188	128
Net cash used in investing activities	(6,842)	(31,809)	(12,805)
CASH FLOWS FROM FINANCING ACTIVITIES:			

Bank borrowings (repayments), net		8,000		(15,300)		8,300
Credit facility issuance costs		(2,726)		-		(826)
Other, net		(66)		(400)		541
Issuance of limited and general partner interests, net		-		44,833		-
Minority interest (distributions) contributions		(1)		5		-
Distributions to common unitholders		(10,200)		(5,682)		(5,589)
Distributions to general partner		(208)		(116)		(114)
Net cash (used in) provided by financing activities		(5,201)		23,340		2,312
Net (decrease) increase in cash and cash equivalents		(781)		1,021		(791)
Cash and cash equivalents at beginning of period		3,099		2,078		2,869
Cash and cash equivalents at end of period	$	2,318	$	3,099	$	2,078

The accompanying notes are an integral part of these consolidated financial statements.

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GENESIS ENERGY, L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Organization

We are a publicly traded Delaware limited partnership formed in December 1996. Our operations are conducted through our operating subsidiary, Genesis Crude Oil, L.P., and its subsidiary partnerships and corporations. We are engaged in pipeline transportation of crude oil, and, to a lesser degree, natural gas and carbon dioxide, or CO_2, crude oil gathering and marketing, and we engage in industrial gas activities, including wholesale marketing of CO_2 and processing of syngas through a joint venture. Our assets are located in the United States Gulf Coast area.

Our 2% general partner interest is held by Genesis Energy, Inc., a Delaware corporation and indirect wholly-owned subsidiary of Denbury Resources Inc. Denbury and its subsidiaries are hereafter referred to as Denbury. Our general partner also owns a 7.25% interest in us through limited partner interests.

Our general partner manages our operations and activities and employs our officers and personnel, who devote 100% of their efforts to our management.

2. Summary of Significant Accounting Policies

Basis of Consolidation and Presentation

The accompanying financial statements and related notes present our consolidated financial position as of December 31, 2006 and 2005 and our results of operations, cash flows and changes in partners' capital for the years ended December 31, 2006, 2005 and 2004. All intercompany transactions have been eliminated. The accompanying consolidated financial statements include Genesis Energy, L.P., its operating subsidiary and its subsidiary partnerships. Our general partner owns a 0.01% general partner interest in Genesis Crude Oil, L.P., which is reflected in our financial statements as a minority interest.

In 2005, we acquired a 50% interest in T&P Syngas Supply Company. In 2006, we acquired a 50% interest in Sandhill Group, LLC. These investments are accounted for by the equity method, as we exercise significant influence over their operating and financial policies. See Note 7.

No provision for federal or state income taxes related to our operations is included in the accompanying consolidated financial statements; as such income will be taxable directly to the partners holding partnership interests. The State of Texas enacted a margin tax in May 2006 that we will be required to pay beginning in 2008. The method of calculation for this margin tax is similar to an income tax, requiring us to recognize currently the impact of this new tax on the future tax effects of temporary differences between the financial statement carrying amounts and the tax basis of existing assets and liabilities. See Note 18.

Use of Estimates

The preparation of consolidated financial statements in conformity with accounting principles generally accepted in the United States of America requires us to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities, if any, at the date of the consolidated financial statements and the reported amounts of revenues and expenses during the reporting period. Significant estimates that we make include: (1) estimated useful lives of assets, which impacts depreciation and amortization, (2) accruals related to revenues and expenses, (3) liability and contingency accruals, (4) estimated fair value of assets and liabilities acquired, (5) estimates of future net cash flows from assets for purposes of determining whether impairment of those assets has occurred, and (6) estimates of future asset retirement obligations. Additionally, for purposes of the calculation of the fair value of our outstanding stock appreciation rights, we make estimates regarding the expected life of the rights, expected forfeiture rates of the rights, volatility of our unit price and expected future distribution yield on our units. (See Note 14.) While we believe these estimates are reasonable, actual results could differ from these estimates.

GENESIS ENERGY, L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Cash and Cash Equivalents

Cash and cash equivalents consist of all demand deposits and funds invested in highly liquid instruments with original maturities of three months or less. The Partnership has no requirement for compensating balances or restrictions on cash. Cash and cash equivalents are stated at cost which approximates market value.

Inventories

Crude oil inventories held for sale are valued at the lower of average cost or market. Fuel inventories are carried at the lower of cost or market.

Fixed Assets

Property and equipment are carried at cost. Depreciation of property and equipment is provided using the straight-line method over the respective estimated useful lives of the assets. Asset lives are 5 to 15 years for pipelines and related assets, 3 to 7 years for vehicles and transportation equipment, and 3 to 10 years for buildings, office equipment, furniture and fixtures and other equipment.

Interest is capitalized in connection with the construction of major facilities. The capitalized interest is recorded as part of the asset to which it relates and is amortized over the asset’s estimated useful life.

Long-lived assets are reviewed for impairment. An asset is tested for impairment when events or circumstances indicate that its carrying value may not be recoverable. The carrying value of a long-lived asset is not recoverable if it exceeds the sum of the undiscounted cash flows expected to be generated from the use and ultimate disposal of the asset. If the carrying value is determined to not be recoverable under this method, an impairment charge equal to the amount the carrying value exceeds the fair value is recognized. Fair value is generally determined from estimated discounted future net cash flows.

Maintenance and repair costs are charged to expense as incurred. Costs incurred for major replacements and upgrades are capitalized and depreciated over the remaining useful life of the asset.

Certain volumes of crude oil are classified in fixed assets, as they are necessary to ensure efficient and uninterrupted operations of the gathering businesses. These crude oil volumes are carried at their weighted average cost.

We account for asset retirement obligations by capitalizing the present value of the estimated future obligations as part of the cost of the related long-lived asset and subsequently allocating the capitalized value to expense systematically as with depreciation. Accretion of the discount increases the liability and is recorded to expense. See Note 4 regarding asset retirement obligations.

Direct Financing Leasing Arrangements

We lease three pipelines to Denbury under direct financing leases. These leases to Denbury of pipeline segments will expire in eight to ten years.

When a direct financing lease is consummated, we record the gross finance receivable, unearned income and the estimated residual value of the leased pipelines. Unearned income represents the excess of the gross receivable plus the estimated residual value over the costs of the pipelines. Unearned income is recognized as financing income using the interest method over the term of the transaction and is included in pipeline revenue in the Consolidated Statements of Operations. The pipeline cost is not included in fixed assets. See Note 5.

CO_2 and Other Assets

Our CO_2 assets include three volumetric production payments and long-term contracts to sell the CO_2 volume. The contract values are being amortized on a units-of-production method. See Note 6.

Other assets consist primarily of deferred credit facility fees, deferred charges, deposits and intangibles. We are amortizing the deferred credit facility fees over the period the facility is in effect.

Deferred charges consist of third-party costs related to projects or acquisitions in the preliminary stages. We review these deferred charges at each reporting date and charge costs related to projects that have been cancelled or abandoned to expense.

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GENESIS ENERGY, L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

In accordance with SFAS No. 142, "Goodwill and Other Intangible Assets," we test other intangible assets periodically to determine if impairment has occurred. An impairment loss is recognized for intangibles if the carrying amount of an intangible asset is not recoverable and its carrying amount exceeds its fair value. As of December 31, 2006, no impairment has occurred of intangible assets.

Environmental Liabilities

We provide for the estimated costs of environmental contingencies when liabilities are probable to occur and reasonable estimates can be made. Ongoing environmental compliance costs, including maintenance and monitoring costs, are charged to expense as incurred.

Stock Appreciation Rights Plan

On January 1, 2006, we adopted the provisions of SFAS No. 123(R). In December 2004, the FASB issued SFAS No. 123 (revised December 2004), "Share-Based Payments". The adoption of this statement requires that the compensation cost associated with our stock appreciation rights plan, which upon exercise will result in the payment of cash to the employee, be re-measured each reporting period based on the fair value of the rights. Before the adoption of SFAS 123(R), we accounted for the stock appreciation rights in accordance with FASB Interpretation No. 28, "Accounting for Stock Appreciation Rights and Other Variable Stock Option or Award Plans" which required that the liability under the plan be measured at each balance sheet date based on the market price of our common units on that date. Under SFAS 123(R), the liability is calculated using a fair value method that takes into consideration the expected future value of the rights at their expected exercise dates. See Note 14.

Revenue Recognition

Revenues from gathering and marketing of crude oil and natural gas are recognized when title to the crude oil or natural gas is transferred to the customer. Revenues from transportation of crude oil or natural gas by our pipelines are based on actual volumes at a published tariff. Tariff revenues are recognized either at the point of delivery or at the point of receipt pursuant to the specifications outlined in our regulated tariffs. Pipeline loss allowance revenues are recognized to the extent that pipeline loss allowances charged to shippers exceed pipeline measurement losses for the period based upon the fair market value of the crude oil upon which the allowance is based.

Income from direct financing leases is being recognized ratably over the term of the leases and is included in pipeline revenues.

Revenues from CO_2 marketing activities are recorded when title transfers to the customer at the inlet meter of the customer's facility.

Cost of Sales

Crude oil cost of sales consists of the cost of crude oil and field operating expenses. Pipeline transportation costs consist of pipeline operating expenses and the cost of natural gas. Field and pipeline operating expenses consist primarily of labor costs for drivers and pipeline field personnel, truck rental costs, fuel and maintenance, utilities, insurance and property taxes.

We enter into buy/sell arrangements that are accounted for on a gross basis in our statements of operations as revenues and costs of crude. These transactions are contractual arrangements that establish the terms of the purchase of a particular grade of crude oil at a specified location and the sale of a particular grade of crude oil at a different location at the same or at another specified date. These arrangements are detailed either jointly, in a single contract, or separately, in individual contracts that are entered into concurrently or in contemplation of one another with a single counterparty. Both transactions require physical delivery of the crude oil and the risk and reward of ownership are evidenced by title transfer, assumption of environmental risk, transportation scheduling, credit risk and counterparty nonperformance risk. In accordance with the provision of Emerging Issues Task Force Issue No. 04-13, "Accounting for Purchases and Sales of Inventory with the Same Counterparty," we have reflected the amounts of revenues and purchases for these transactions as a net amount in our consolidated statements of operations beginning with April 2006. Transactions for periods prior to April 2006 are not reflected as a net amount; however the amounts are disclosed parenthetically on the consolidated statements of operations. This change had no effect on operating income, net income or cash flows; however it did reduce both crude oil gathering and marketing revenues and crude oil costs by $187.8 million for the year ended December 31, 2006.

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GENESIS ENERGY, L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Cost of sales for the CO_2 marketing activities consists of a transportation fee charged by Denbury to transport the CO_2 to the customer through Denbury's pipeline and insurance costs. The transportation fee charged by Denbury is adjusted annually for inflation. For the year ended December 31, 2006, the fee averaged $0.174 per Mcf.

Derivative Instruments and Hedging Activities

We minimize our exposure to price risk by limiting our inventory positions. However when we use derivative instruments to hedge exposure to price risk, we account for those derivative transactions in accordance with Statement of Financial Accounting Standards No. 133 "Accounting for Derivative Instruments and Hedging Activities", as amended and interpreted. Derivative transactions, which can include forward contracts and futures positions on the NYMEX, are recorded on the balance sheet as assets and liabilities based on the derivative's fair value. Changes in the fair value of derivative contracts are recognized currently in earnings unless specific hedge accounting criteria are met. We must formally designate the derivative as a hedge and document and assess the effectiveness of derivatives associated with transactions that receive hedge accounting. Accordingly, changes in the fair value of derivatives are included in earnings in the current period for (i) derivatives accounted for as fair value hedges; (ii) derivatives that do not qualify for hedge accounting and (iii) the portion of cash flow hedges that is not highly effective in offsetting changes in cash flows of hedged items. See Note 16.

Net Income Per Common Unit

Basic and diluted net income per common unit is calculated on the weighted average number of outstanding common units, after exclusion of the 2 percent general partner interest from net income. The weighted average number of common units outstanding was 13,784,441, 9,546,529 and 9,313,811 for the years ended December 31, 2006, 2005 and 2004, respectively. Diluted net income per common unit did not differ from basic net income per common unit for any period presented. See Note 9 for a computation of net (loss) income per common unit.

Recent and Proposed Accounting Pronouncements

FASB Interpretation No. 48

In July 2006, the Financial Accounting Standards Board, or FASB, issued FASB Interpretation No. 48, "Accounting for Uncertainty in Income Taxes - an interpretation of FASB Statement No. 109", or FIN 48, which clarifies the accounting and disclosure for uncertainty in tax positions, as defined. FIN 48 seeks to reduce the diversity in practice associated with certain aspects of the recognition and measurement related to accounting for income taxes. This interpretation is effective for fiscal years beginning after December 15, 2006. We do not expect that the adoption of FIN 48 will have a material impact on our results of operations or financial position.

SFAS 157

In September 2006, the FASB issued SFAS No. 157, "Fair Value Measurements", or SFAS 157. SFAS 157 defines fair value, establishes a framework for measuring fair value in accordance with accounting principles generally accepted in the United States, and expands disclosures about fair value measurements. SFAS 157 is effective for fiscal years beginning after November 15, 2007, with earlier adoption encouraged. Any amounts recognized upon adoption as a cumulative effect adjustment will be recorded to the opening balance of retained earnings in the year of adoption. SFAS 157 may impact our balance sheet and statement of operations in many areas including the fair value measurement and allocation of the purchase price in business combinations and fair value measurements for derivative instruments, impairment of assets, and asset retirement obligations. We are currently assessing the impact of SFAS 157 on our consolidated financial statements.

SFAS 159

In February 2007, the FASB issued SFAS No. 159, “The Fair Value Option for Financial Assets and Financial Liabilities”, or SFAS 159. SFAS 159 permits entities to choose to measure many financial assets and financial liabilities at fair value. Unrealized gains and losses on items for which the fair value option has been elected are reported in earnings. SFAS 159 is effective for fiscal years beginning after November 15, 2007. We are currently assessing the impact of SFAS 159 on our consolidated financial statements.

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3. Inventories

Inventories consisted of the following (in thousands).

	December 31, 2006		December 31, 2005	
Crude oil inventories, at lower of cost or market	$	5,081	$	411
Fuel and supplies inventories, at lower of cost or market		91		87
Total inventories	$	5,172	$	498

The increase in crude oil inventories at December 31, 2006 is a result of our contango inventory strategy, and is hedged under a fair value hedges. See Note 16.

4. Fixed Assets and Asset Retirement Obligations

Fixed Assets

Fixed assets consisted of the following (in thousands).

	December 31, 2006		December 31, 2005	
Land and buildings	$	808	$	967
Pipelines and related assets		58,428		57,706
Vehicles and transportation equipment		1,257		1,169
Office equipment, furniture and fixtures		2,616		2,724
Construction in progress		78		-
Other		7,195		7,142
		70,382		69,708
Less - Accumulated depreciation		(39,066)		(35,939)
Net fixed assets	$	31,316	$	33,769

In 2006, 2005 and 2004, $9,000, $35,000 and $76,000 of interest cost, respectively, was capitalized related to the construction of pipelines and related assets.

Depreciation expense was $3,719,000, $3,579,000 and $4,846,000 for the years ended December 31, 2006, 2005, and 2004, respectively. In 2004, depreciation expense included $933,000 of impairment recorded to value an out-of-service segment of our Mississippi System at its estimated salvage value.

Asset Retirement Obligations

In 2003, we recorded a charge of $700,000 for an accrual for the removal of an abandoned offshore pipeline. In 2004, we received permission to abandon the pipeline in place, and reversed the amount of the accrual that had not been spent. Additionally, in 2004, we agreed to remove certain pipeline facilities from land we sold. This obligation was completed in 2005.

On December 31, 2005, we adopted FASB Interpretation No. 47, "Accounting for Conditional Asset Retirement Obligations, an interpretation of FASB Statement No. 143", or FIN 47. FIN 47 clarified that the term "conditional asset retirement obligation", as used in SFAS No. 143, "Accounting for Asset Retirement Obligations", refers to a legal obligation to perform an asset retirement activity in which the timing and/or method of settlement are conditional upon a future event that may or may not be within our control. Although uncertainty about the timing and/or method of settlement may exist and may be conditional upon a future event, the obligation to perform the asset retirement activity is unconditional. Accordingly, we are required to recognize a liability for the fair value of a conditional asset retirement obligation if the fair value of the liability can be reasonably estimated.

Upon adoption of FIN 47, we recorded a fixed asset and a liability for the estimated fair value of the asset retirement obligations at the time we acquired the related assets. This $0.3 million fixed asset is being depreciated over the life of the related assets. The accretion of the discount on the liability and the depreciation through December 31, 2005 were recorded in the statement of operations as a cumulative effect adjustment totaling $0.5 million. Additionally, we reflected our share of the asset retirement obligation recorded in accordance with FIN 47 of our equity method joint venture as a cumulative affect adjustment of $0.1 million.

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A reconciliation of our liability for asset retirement obligations is as follows (in thousands):

Asset retirement obligations as of December 31, 2004	$	146
Additions to asset retirement obligations due to FIN 47		651
Asset retirement liability obligations incurred during 2005		34
Asset retirement obligations settled during 2005		(183)
Revisions to asset retirement obligations		9
Asset retirement obligations as of December 31. 2005		657
Accretion of discount during 2006		51
Asset retirement obligations as of December 31. 2006	$	708

The pro forma impact for the periods ended December 31, 2005 and 2004 of the adoption of FIN 47 if it had been adopted at the beginning of each of those periods is as follows (in thousands):

	Year Ended December 31,			
	2005		2004	
	(Unaudited)			
Income (loss) from continuing operations - as reported	$	3,689	$	(949)
Impact of change in accounting principle		(85)		(67)
Pro forma income (loss) from continuing operations	$	3,604	$	(1,016)
Net income (loss) - as reported	$	3,415	$	(1,412)
Add back cumulative effect adjustment		586		-
Impact of change in accounting principle		(85)		(67)
Pro forma income (loss) from continuing operations	$	3,916	$	(1,479)
Basic and diluted net income (loss) per common unit:				
Income (loss) from continuing operations - as reported	$	0.38	$	(0.10)
Impact of change in accounting principle		(0.01)		(0.01)
Pro forma income (loss) from continuing operations	$	0.37	$	(0.11)
Net income (loss) - as reported	$	0.35	$	(0.15)
Impact of change in accounting principle and add back of cumulative effect adjustment		0.05		(0.01)
Pro forma income (loss) from continuing operations	$	0.40	$	(0.16)

5. Net Investment in Direct Financing Leases

In the fourth quarter of 2004, we constructed two segments of crude oil pipeline and a CO_2 pipeline segment to transport crude oil from and CO_2 to producing fields operated by Denbury. Denbury pays us a minimum payment each month for the right to use these pipeline segments. These arrangements have been accounted for as direct financing leases.

The following table lists the components of the net investment in direct financing leases (in thousands):

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	December 31, 2006	December 31, 2005
Total minimum lease payments to be received	$ 8,225	$ 9,410
Estimated residual values of leased property (unguaranteed)	1,287	1,287
Less unearned income	(3,571)	(4,225)
Net investment in direct financing leases	$ 5,941	$ 6,472

At December 31, 2006, minimum lease payments to be received for each of the five succeeding fiscal years are $1.2 million per year.

6. CO_2 and Other Assets

Carbon Dioxide (CO_2) Assets

CO_2 assets consisted of the following (in thousands).

	December 31, 2006	December 31, 2005
CO_2 volumetric production payments	$ 43,570	$ 43,570
Less - Accumulated amortization	(10,166)	(5,922)
Net CO_2 assets	$ 33,404	$ 37,648

The volumetric production payments entitle us to a maximum daily quantity of CO_2 of 101,375 million cubic feet, or Mcf, per day through December 31, 2009, 91,875 Mcf per day for the calendar years 2010 through 2012 and 73,875 Mcf per day beginning in 2013 until we have received all volumes under the production payments. Under the terms of transportation agreements with Denbury, Denbury will process and deliver this CO_2 to our industrial customers and receive a fee of $0.16 per Mcf, subject to inflationary adjustments. During 2006 this fee averaged $0.1743 per Mcf.

The terms of the contracts with the industrial customers include minimum take-or-pay and maximum delivery volumes. The seven industrial contracts expire at various dates between 2010 and 2016.

The CO_2 assets are being amortized on a units-of-production method. After purchase price adjustments, we had 276.7 Bcf of CO_2 at acquisition, and the total $43.6 million cost is being amortized based on the volume of CO_2 sold each month. For 2006, 2005 and 2004, we recorded amortization of $4,244,000, $3,142,000 and $2,452,000, respectively. We have 210.5 Bcf of CO_2 remaining under the volumetric production payments at December 31, 2006. Based on the historical deliveries of CO_2 to the customers (which have exceeded minimum take-or-pay volumes), we would expect that amortization for the next five years to be approximately $4,169,000 annually.

Other Assets

Other assets consisted of the following (in thousands).

	December 31, 2006	December 31, 2005
Credit facility fees	$ 2,726	$ 1,491
Other deferred costs and deposits	119	28

		2,845		1,519
Less - Accumulated amortization		(69)		(591)
Net other assets	$	2,776	$	928

Amortization expense of credit facility fees for the years ended December 31, 2006, 2005 and 2004 was $394,000, $373,000 and $373,000, respectively. In the fourth quarter of 2006, we also charged to expense $575,000 of unamortized fees related to the facility that we replaced in November 2006. Amortization of credit facility fees for the next five years will be $545,000 for 2007 through 2010 and $477,000 in 2011.

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7. Joint Ventures and Other Investments

T&P Syngas Supply Company

On April 1, 2005, we acquired a 50% interest in T&P Syngas Supply Company, a Delaware general partnership, for $13.4 million in cash from a subsidiary of ChevronTexaco Corporation. Praxair Hydrogen Supply Inc. owns the remaining 50% partnership interest in T&P Syngas. We paid for our interest in T&P Syngas with proceeds from our credit facilities.

T&P Syngas is a partnership that owns a syngas manufacturing facility located in Texas City, Texas. That facility processes natural gas to produce syngas (a combination of carbon monoxide and hydrogen) and high pressure steam. Praxair provides the raw materials to be processed and receives the syngas and steam produced by the facility under a long-term processing agreement. T&P Syngas receives a processing fee for its services. Praxair operates the facility.

We are accounting for our 50% ownership in T&P Syngas under the equity method of accounting. We reflect in our consolidated statements of operations our equity in T&P Syngas' net income, net of the amortization of the excess of our investment over our share of partners' capital of T&P Syngas. We paid $4.0 million more for our interest in T&P Syngas than our share of partners' capital on the balance sheet of T&P Syngas at the date of the acquisition. This excess amount of the purchase price over the equity in T&P Syngas is being amortized using the straight-line method over the remaining useful life of the assets of T&P Syngas of eleven years. Our consolidated statements of operations for the years ended December 31, 2006 and 2005 included $1.5 million and $0.8 million, respectively, as our share of the operating earnings of T&P Syngas, reduced by amortization of the excess purchase price of $0.3 million in each year. Additionally, our consolidated statements of operations for 2005 include our share of the cumulative effect adjustment to record asset retirement obligations of $54,000 of T&P Syngas. We received distributions from T&P Syngas of $2.0 million and $0.8 million during the years ended December 31, 2006 and 2005, respectively. In February 2007, we received a distribution of $0.6 million from T&P with respect to the fourth quarter of 2006. Our net investment in T&P Syngas at December 31, 2006 and 2005 was $12.2 million and $13.0 million, respectively.

The table below reflects summarized financial information for T&P Syngas at December 31, 2006 (in thousands).

		Year Ended December 31, 2006		Nine Months Ended December 31, 2005
Revenues	$	4,911	$	3,073
Operating expenses and depreciation		(1,830)		(1,553)
Other income		17		9
		-		(108)
Net income	$	3,098	$	1,421

		December 31, 2006		December 31, 2005
Current assets	$	1,355	$	1,358
Non-current assets		15,387		16,956

Total assets	$	16,742	$	18,314
Current liabilities	$	156	$	1,016
Non-current liabilties		165		-
Partners' capital		16,421		17,298
Total liabilites and partners' capital	$	16,742	$	18,314

Sandhill Group, LLC

On April 1, 2006, we acquired a 50% interest in Sandhill Group, LLC, for $5 million in cash, from Magna Carta Group, LLC. Magna Carta holds the other 50% interest in Sandhill. Sandhill is a limited liability company that owns a CO_2 processing facility located in Brandon, Mississippi. Sandhill is engaged in the production and distribution of liquid carbon dioxide for use in the food, beverage, chemical and oil industries. The facility acquires CO_2 from us under a long-term supply contract that we acquired in 2005 from Denbury.

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We paid for our interest in Sandhill with cash on hand. The terms of the acquisition include earnout provisions such that we could pay up to an additional $2 million to Magna Carta for our interest in Sandhill, based on the distributable cash generated by Sandhill during the period 2006 through no later than 2012. Should the cumulative distributable cash of Sandhill in the period beginning with 2006 average at least $1.5 million per year, and distributions to the members average at least $1.2 million per year, we will owe Magna Carta $1.0 million at the end of the year when the target is exceeded. If the distributable cash averages $2.0 million per year and distributions average $1.6 million per year in the period beginning with 2006, we will owe Magna Carta an additional $1.0 million.

During 2003, Sandhill was authorized to issue a series of "Issuer Floating Rate Option Notes" in an amount not to exceed $15,000,000. In 2003, Sandhill issued notes in the amount of $5,900,000 which are backed by a letter of credit from a bank and have a maturity date of December 1, 2013. At December 31, 2006, the outstanding balance of these notes was $4.5 million. We provide a guarantee of 50% of the letter of credit to Sandhill's bank; therefore, our guaranty represents $2.25 million. Sandhill makes principal payments totaling $0.6 million annually. We recorded the estimated fair value of this guarantee of $0.1 million as a long-term liability in our consolidated balance sheet, with a corresponding increase to our investment in Sandhill.

We are accounting for our 50% ownership in Sandhill under the equity method of accounting as both partners have substantive participating rights. We reflect in our consolidated statements of operations our equity in Sandhill's net income, net of the amortization of the excess of our investment over our share of partners' capital of Sandhill that is not considered goodwill. We paid $3.8 million more for our interest in Sandhill than our share of partners' capital on the balance sheet of Sandhill at the date of the acquisition. This excess amount of the purchase price over the equity in Sandhill has been allocated to the property and equipment of Sandhill and certain intangible assets based on the fair value of those assets, with the remainder of the excess purchase price of $0.7 million allocated to goodwill. The amount allocated to property and equipment and intangible assets is being amortized using the straight-line method over the remaining useful lives of those assets. We annually test our investment in Sandhill to determine if an impairment of the excess purchase price allocated to goodwill has occurred.

Our consolidated statements of operations for the year ended December 31, 2006 included $141,000 as our share of the operating earnings of Sandhill for the period beginning April 1, 2006, reduced by amortization of the excess purchase price of $208,000. We received distributions from Sandhill of $0.1 million during the nine month period that we have owned our interest. Our net investment in Sandhill was $5.0 million at December 31, 2006.

The table below reflects summarized financial information for Sandhill for the period since we acquired our interest in Sandhill and at December 31, 2006 (in thousands).

		Nine Months Ended December 31, 2006
Revenues	$	8,254
Operating expenses and depreciation		(7,977)
Other income		3
Net income	$	280

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		December 31, 2006
Current assets	$	1,606
Non-current assets		6,592
Total assets	$	8,198
Current liabilities	$	1,463
Non-current liabilties		4,140
Members' interests		2,595
Total liabilites and members' interests	$	8,198

Other Projects

In 2006, we invested $1.0 million in a petroleum coke to ammonia project that is in the development stage. All of our investment may later be redeemed, with a return, or converted to equity after construction financing for the project has been obtained.

The funds we have invested will be used for project development activities, which include the negotiation of off-take agreements for the products and by-products of the plant to be constructed, securing permits and securing financing for the construction phase of the plant.

No events or changes in circumstances have occurred that indicate a significant adverse effect on the fair value of our investment at December 31, 2006, therefore the investment is included in our consolidated balance sheet at cost.

8. Debt

Our credit facility, with a maximum facility amount of $500 million, is with a group of banks led by Fortis Capital Corp. and Deutsche Bank Securities Inc. The initial committed amount under our facility is $125 million, of which a maximum of $50 million may be used for letters of credit. The committed amount represents the amount the banks have committed to fund pursuant to the terms of the credit agreement. The borrowing base under the facility at December 31, 2006 is approximately $82 million, and will be recalculated quarterly and at the time of acquisitions. The borrowing base represents the amount that can be borrowed or utilized for letters of credit from a credit standpoint based on our EBITDA (earnings before interest, taxes, depreciation and amortization), computed in accordance with the provisions of our credit facility. The commitment amount can be increased up to the maximum facility amount for acquisitions or internal growth projects with approval of the lenders. Likewise, the borrowing base may be increased to the extent of pro forma additional EBITDA attributable to acquisitions.

At December 31, 2006, we had $8.0 million borrowed under our credit facility. We had $4.6 million in letters of credit outstanding. Due to the revolving nature of loans under our credit facility, additional borrowings and periodic repayments and re-borrowings may be made until the maturity date of November 15, 2011. The total amount available for borrowings at December 31, 2006 was $69.9 million under our credit facility.

The key terms of the Credit Facility are as follows:

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The interest rate on borrowings may be based on the prime rate or the LIBOR rate, at our option. The interest rate on prime rate loans can range from the prime rate plus 0.50% to the prime rate plus 1.875%. The interest rate for LIBOR-based loans can range from the LIBOR rate plus 1.50% to the LIBOR rate plus 2.875%. The rate is based on our leverage ratio as computed under the credit facility. The rate can fluctuate quarterly.

- Letter of credit fees will range from 1.50% to 2.875% based on our leverage ratio as computed under the credit facility. The rate can fluctuate quarterly. At December 31, 2006, the rate was 1.50%.

- We pay a commitment fee on the unused portion of the $125 million commitment. The commitment fee will range from 0.30% to 0.50% based on our leverage ratio as computed under the credit facility. The rate can fluctuate quarterly. At December 31, 2006, the commitment fee rate was 0.30%.

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- Collateral under the credit facility consists of our accounts receivable, inventory, cash accounts, margin accounts and fixed assets. Our credit facility is non-recourse to our general partner, except to the extent of its pledge of its 0.01% general partner interest in our operating partnership.

Our new credit facility covenants also require us to achieve specific minimum financial metrics. For example, we must maintain a debt service coverage ratio of at least 3.0 to 1.0 and a leverage ratio of no more than 5.5 to 1.0. In general, the debt service coverage ratio calculation compares EBITDA (as adjusted in accordance with the credit facility), to interest expense. At December 31, 2006, the calculation resulted in a ratio of 25.0 to 1.0. The leverage ratio calculation compares our consolidated funded debt (as calculated in accordance with the credit facility) to EBITDA (as adjusted) At December 31, 2006, this calculation resulted in a ratio of 0.5 to 1.0. Our credit facility also requires that we meet or exceed a funded indebtedness to capitalization ratio. Our credit facility includes provisions for the temporary adjustment of the required ratios following acquisitions. If we meet these financial metrics and are not otherwise in default under our credit facility, we may make quarterly distributions; however the amount of such distributions may not exceed the sum of the distributable cash generated by us for the eight most recent quarters, less the sum of the distributions made with respect to those quarters. At December 31, 2006, the excess of distributable cash over distributions under this provision of the credit facility was $17.6 million.

The carrying value of our debt under our credit facility approximates fair value primarily because interest rates fluctuate with prevailing market rates, and the credit spread on outstanding borrowings reflect market.

9. Partners' Capital and Distributions

Partners' Capital

Partner's capital at December 31, 2006 consists of 13,784,441 common units, including 1,019,441 units owned by our general partner, representing a 98% aggregate ownership interest in the Partnership and its subsidiaries, (after giving affect to the general partner interest), and a 2% general partner interest.

During the four years ended December 31, 2006, we issued new common units to the public and our general partner as follows:

Period	Purchaser of Common Units	Units	Gross Unit Price	Proceeds from Sale	GP Contributions	Costs	Net Proceeds
			(in thousands, except per unit amounts)				
December 2005	Public	4,140	$ 10.500	$ 43,470	$ 887	$ 2,889	$ 41,468
December 2005	General Partner	331	$ 9.975	$ 3,298	$ 67	$ -	$ 3,365
November 2003	General Partner	689	$ 7.150	$ 4,925	$ 101	$ 14	$ 5,012

Our general partner owns all of our general partner interest, all of the 0.01% general partner interest in our operating partnership (which is reflected as a minority interest in the consolidated balance sheet at December 31, 2006) and operates our business.

Our partnership agreement authorizes our general partner to cause us to issue additional limited partner interests and other equity securities, the proceeds from which could be used to provide additional funds for acquisitions or other needs.

Distributions

Generally, we will distribute 100% of our available cash (as defined by our partnership agreement) within 45 days after the end of each quarter to unitholders of record and to our general partner. Available cash consists generally of all of our cash receipts less cash disbursements adjusted for net changes to reserves. As discussed in Note 8, our credit facility limits the amount of distributions we may pay in any quarter. At December 31, 2006, our restricted net assets (as defined in Rule 4-03 (e)(3) of Regulation S-X) were $68.2 million.

We paid distributions in 2004, 2005 and 2006 as follows:

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Distribution For	Date Paid or to be Paid	Per Unit Amount	Total Amount (000's)
Fourth quarter 2003	February 2004	$ 0.15	$ 1,426
First quarter 2004	May 2004	$ 0.15	$ 1,426
Second quarter 2004	August 2004	$ 0.15	$ 1,426
Third quarter 2004	November 2004	$ 0.15	$ 1,426
Fourth quarter 2004	February 2005	$ 0.15	$ 1,426
First quarter 2005	May 2005	$ 0.15	$ 1,426
Second quarter 2005	August 2005	$ 0.15	$ 1,426
Third quarter 2005	November 2005	$ 0.16	$ 1,521
Fourth quarter 2005	February 2006	$ 0.17	$ 2,391
First quarter 2006	May 2006	$ 0.18	$ 2,532
Second quarter 2006	August 2006	$ 0.19	$ 2,672
Third quarter 2006	November 2006	$ 0.20	$ 2,813
Fourth quarter 2006	February 2007	$ 0.21	$ 2,954

The total amounts in the table above increased with the distribution for the fourth quarter of 2005 due to the issuance of 4,470,630 new common units in December 2005.

Our general partner is entitled to receive incentive distributions if the amount we distribute with respect to any quarter exceeds levels specified in our partnership agreement. Under the quarterly incentive distribution provisions, the general partner is entitled to receive 13.3% of any distributions to our common unitholders in excess of $0.25 per unit, 23.5% of any distributions to our common unitholders in excess of $0.28 per unit and 49% of any distributions to our common unitholders in excess of $0.33 per unit without duplication. We have not paid any incentive distributions through December 31, 2006.

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Net Income (Loss) Per Common Unit

The following table sets forth the computation of basic net income (loss) per common unit for 2006, 2005, and 2004 (in thousands, except per unit amounts).

	Year Ended December 31,					
	2006		2005		2004	
	(in thousands, except per unit amounts)					
Numerators for basic and diluted net income (loss)per common unit:						
Income (loss) from continuing operations	$	8,351	$	3,689	$	(949)
Less general partner 2% ownership		167		74		(19)
Income (loss) from continuing operations available for common unitholders	$	8,184	$	3,615	$	(930)
Income (loss) from discontinued operations	$	-	$	312	$	(463)
Less general partner 2% ownership		-		6		(9)
Income (loss) from discontinued operations available for common unitholders	$	-	$	306	$	(454)
Income (loss) from cumulative effect adjustment	$	30	$	(586)	$	-
Less general partner 2% ownership		-		(12)		-
Income (loss) from cumulative effect adjustment available for common unitholders	$	30	$	(598)	$	-
Denominator for basic and diluted per common unit -weighted average number of common units outstanding		13,784		9,547		9,314
Basic and diluted net income (loss) per common unit:						
Income (loss) from continuing operations	$	0.59	$	0.38	$	(0.10)
Income (loss) from discontinuted operations		-		0.03		(0.05)
Loss from cumulative effect adjustment		-		(0.06)		-
Net income (loss)	$	0.59	$	0.35	$	(0.15)

10. Business Segment Information

Our operations consist of three operating segments: (1) Pipeline Transportation - interstate and intrastate crude oil, natural gas and CO_2 pipeline transportation; (2) Industrial Gases - the sale of CO_2 acquired under volumetric production payments to industrial customers and our investments in joint ventures in a syngas processing facility and a CO_2 processing facility, and (3) Crude Oil Gathering and Marketing - the purchase and sale of crude oil at various points along the distribution chain. The tables below reflect all periods presented as though the current segment designations had existed, and include only continuing operations data.

We evaluate segment performance based on segment margin. We calculate segment margin as revenues less costs of sales and operations expenses, and we include income from investments in joint ventures. We do not deduct depreciation and amortization. All of our revenues are derived from, and all of our assets are located in the United States. The pipeline transportation segment information includes the revenue, segment margin and assets of the direct financing leases. See Notes 2 and 5.

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	Pipeline Transportation	Industrial Gases [a]	Crude Oil Gathering & Marketing	Total
		(in thousands)		
Year Ended December 31, 2006				
Segment margin excluding depreciation and amortization [b]	$ 12,426	$ 11,443	$ 7,366	$ 31,235
Capital expenditures	$ 971	$ 6,058	$ 356	$ 7,385
Maintenance capital expenditures	$ 611	$ -	$ 356	$ 967
Net fixed and other long-term assets [c]	$ 31,863	$ 51,630	$ 7,602	$ 91,095
Revenues:				
External customers	$ 25,479	$ 15,154	$ 873,268	$ 913,901
Intersegment [d]	4,468	-	-	4,468
Total revenues of reportable segments	$ 29,947	$ 15,154	$ 873,268	$ 918,369
Year Ended December 31, 2005				
Segment margin excluding depreciation and amortization [b]	$ 9,804	$ 8,154	$ 3,661	$ 21,619
Capital expenditures	$ 5,425	$ 27,863	$ 547	$ 33,835
Maintenance capital expenditures	$ 1,256	$ -	$ 287	$ 1,543
Net fixed and other long-term assets [c]	$ 34,725	$ 50,690	$ 5,913	$ 91,328
Revenues:				
External customers	$ 25,613	$ 11,302	$ 1,038,549	$ 1,075,464
Intersegment [d]	3,275	-	-	3,275
Total revenues of reportable segments	$ 28,888	$ 11,302	$ 1,038,549	$ 1,078,739
Year Ended December 31, 2004				
Segment margin excluding depreciation and amortization [b]	$ 8,543	$ 5,762	$ 4,034	$ 18,339
Capital expenditures	$ 8,187	$ 4,723	$ 284	$ 13,194
Maintenance capital expenditures	$ 655	$ -	$ 284	$ 939
Net fixed and other long-term assets [c]	$ 33,347	$ 26,344	$ 6,067	$ 65,758
Revenues:				
External customers	$ 13,212	$ 8,561	$ 901,902	$ 923,675
Intersegment [d]	3,468	-	-	3,468

Total revenues of reportable segments	$ 16,680	$ 8,561	$ 901,902	$ 927,143

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(a) The industrial gases segment includes our CO_2 marketing operations and the income from our investments in T&P Syngas Supply Company and Sandhill Group, LLC.
(b) Segment margin was calculated as revenues less cost of sales and operations expense. It includes our share of the operating income of equity joint ventures. A reconciliation of segment margin to income from continuing operations for each year presented is as follows:

	Year Ended December 31,		
	2006	2005	2004
		(in thousands)	
Segment margin excluding depreciation and amortization	$ 31,235	$ 21,619	$ 18,339
General and administrative expenses	(13,573)	(9,656)	(11,031)
Depreciation, amortization and impairment	(7,963)	(6,721)	(7,298)
Net loss (gain) on disposal of surplus assets	16	479	(33)
Interest expense, net	(1,374)	(2,032)	(926)
Income tax credit	-	-	-
Minority interest	-	-	-
Income (loss) from continuing operations	$ 8,341	$ 3,689	$ (949)

(c) Net fixed and other long-term assets are the measure used by management in evaluating the results of its operations on a segment basis. Current assets are not allocated to segments as the amounts are shared by the segments or are not meaningful in evaluating the success of the segment's operations.

(d) Intersegment sales were conducted on an arm's length basis.

11. Discontinued Operations

In the fourth quarter of 2003, we sold a significant portion of our Texas Pipeline System and the related crude oil gathering and marketing operations to TEPPCO Crude Oil, L.P. Additionally we sold other segments of our Texas Pipeline System that had been idled in 2002 to Blackhawk Pipeline, L.P., an affiliate of Multifuels, Inc. Some remaining segments not sold to these parties were abandoned in place.

We agreed not to compete with TEPPCO in a 40-county area in Texas surrounding the pipeline for a five year period. We retained responsibility for environmental matters related to the operations sold to TEPPCO with respect to the period prior to October 31, 2003, subject to certain conditions. TEPPCO will pay the first $25,000 for any environmental claim up to an aggregate of $100,000. We would be responsible for any environmental claim in excess of these amounts up to an aggregate total of $2 million. TEPPCO has purchased an environmental insurance policy for amounts in excess of our $2 million responsibility and we reimbursed TEPPCO for one-half of the policy premium. Our responsibility to indemnify TEPPCO will cease in 2013.

Under the terms of the sale to Blackhawk, we received no consideration from Blackhawk for the sale. We retained responsibility for any environmental matters related to the pipeline segments acquired by Blackhawk through December 31, 2003, however that responsibility will cease in ten years.

During 2004, we recorded $0.4 million of costs related to these discontinued operations. In 2005, we recognized $0.3 million from the sale of surplus assets from these discontinued operations.

12. Transactions with Related Parties

Sales, purchases and other transactions with affiliated companies, in the opinion of management, are conducted under terms no more or less favorable than then-existing market conditions.

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	Year Ended December 31,		
	2006	2005	2004
		(in thousands)	
Truck transportation services provided to Denbury	$ 825	$ 796	$ 213
Pipeline transportation services provided to Denbury	$ 4,228	$ 3,853	$ 1,111
Payments received under direct financing leases from Denbury	$ 1,186	$ 1,186	$ 76
Pipeline transportation income portion of direct financing lease fees	$ 655	$ 689	$ 36
Pipeline monitoring services provided to Denbury	$ 65	$ 30	$ 22
Directors' fees paid to Denbury	$ 120	$ 120	$ 120
CO_2 transportation services provided by Denbury	$ 4,640	$ 3,501	$ 2,694
Crude oil purchases from Denbury	$ 1,565	$ 4,647	$ 77,998
Crude oil sales to Denbury	$ -	$ 176	$ -
Purchase of CO_2 volumetric production payment from Denbury	$ -	$ 14,363	$ 4,663
Operations, general and administrative services provided by our general partner	$ 16,777	$ 15,145	$ 14,065
Distributions to our general partner on its limited partner units and general partner interest	$ 963	$ 536	$ 527
Sales of CO_2 to Sandhill (for the period since Sandhill became a related party)	$ 2,056	$ -	$ -

Transportation Services

In September 2004, we entered into an agreement with Denbury where we would provide truck transportation services to Denbury to move their crude oil from the wellhead to our Mississippi pipeline. Previously we had purchased Denbury's crude oil and trucked the oil for our own account. Denbury pays us a fee for this trucking service that varies with the distance the crude oil is trucked. These fees are reflected in the statement of operations as gathering and marketing revenues.

In September 2004, Denbury also became a shipper on our Mississippi pipeline. We also earned fees from Denbury under the direct financing lease arrangements for the Olive and Brookhaven crude oil pipelines and the Brookhaven CO_2 pipeline and recorded pipeline transportation income from these arrangements. See Note 5.

We also provide pipeline monitoring services to Denbury. This revenue is included in pipeline revenues in the statement of operations.

Directors' Fees

We paid Denbury for the services of each of four of Denbury's officers who serve as directors of our general partner, the same rate at which our independent directors were paid.

CO_2 Operations and Transportation

We acquired contracts, along with volumetric production payments, from Denbury in 2005 and 2004. Denbury charges us a transportation fee of $0.16 per Mcf (adjusted for inflation) to deliver the CO_2 for us to our customers. See Note 6.

Sales and Purchases of Crude Oil

Denbury began shipping its own crude oil on our Mississippi System in September 2004, so our purchases of crude oil from Denbury (and our related crude oil sales) have declined.

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Operations, General and Administrative Services

We do not directly employ any persons to manage or operate our business. Those functions are provided by our general partner. We reimburse the general partner for all direct and indirect costs of these services.

Amounts due to and from Related Parties

At December 31, 2006 and 2005, we owed Denbury $0.8 million and $1.9 million, respectively, for purchases of crude oil and CO_2 transportation charges. Denbury owed us $0.6 million and $0.5 million for transportation services at December 31, 2006 and 2005, respectively. We owed our general partner $0.9 million and $1.1 million for administrative services at December 31, 2006 and 2005, respectively. At December 31, 2006, Sandhill owed us $0.5 million for purchases of CO_2.

Financing

Our general partner, a wholly owned subsidiary of Denbury, guarantees our obligations under our credit facility. Our general partner's principal assets are its general and limited partnership interests in us. The obligations are not guaranteed by Denbury or any of its other subsidiaries. Our credit facility is non-recourse to our general partner, except to the extent of its pledge of its 0.01% general partner interest in our operating partnership

We guarantee 50% of the obligation of Sandhill to a bank. At December 31, 2006, the total amount of Sandhill's obligation to the bank was $4.5 million; therefore, our guarantee was for $2.25 million. See Note 3.

13. Supplemental Cash Flow Information

Cash received by us for interest during the years ended December 31, 2006, 2005 and 2004 was $192,000, $46,000 and $44,000, respectively. Payments of interest and commitment fees were $1,041,000, $1,468,000 and $674,000, during the years ended December 31, 2006, 2005 and 2004, respectively.

At December 31, 2006 and 2005, we had incurred liabilities for fixed asset additions totaling $81,000 and $14,000, respectively, that had not been paid at the end of the year and, therefore, are not included in the caption "Additions to property and equipment" on the Consolidated Statements of Cash Flows. We had incurred liabilities for other assets totaling $46,000 at December 31, 2006 that had not been paid at the end of the year and, therefore, are not included in the caption "Other, net" under investing activities on the Consolidated Statements of Cash Flows.

14. Employee Benefit Plans

We do not directly employ any of the persons responsible for managing or operating our activities. Employees of our general partner provide those services and are covered by various retirement and other benefit plans.

In order to encourage long-term savings and to provide additional funds for retirement to our employees, our general partner sponsors a profit-sharing and retirement savings plan. Under this plan, our general partner's matching contribution is calculated as an equal match of the first 3% of each employee's annual pretax contribution and 50% of the next 3% of each employee's annual pretax contribution. Our general partner also made a profit-sharing contribution of 3% of each eligible employee's total compensation (subject to IRS limitations). The expenses included in the consolidated statements of operations for costs relating to this plan were $660,000, $620,000, and $635,000 for the years ended December 31, 2006, 2005 and 2004, respectively.

Our general partner also provided certain health care and survivor benefits for its active employees. Our health care benefit programs are self-insured, with a catastrophic insurance policy to limit our costs. Our general partner plans to continue self-insuring these plans in the future. The expenses included in the consolidated statements of operations for these benefits were $1,269,000, $1,773,000, and $1,219,000 in 2006, 2005 and 2004, respectively.

Stock Appreciation Rights Plan

Under the terms of our stock appreciation rights plan, all regular, full-time active employees (with the exception of the new senior management team) and the members of the Board are eligible to participate in the plan. The plan is administered by the Compensation Committee of the Board, who shall determine, in its full discretion, the number of rights to award, the grant date of the units and the formula for allocating rights to the participants and the strike price of the rights awarded. Each right is equivalent to one common unit.

The rights have a term of 10 years from the date of grant. The initial award to a participant will vest one-fourth each year beginning with the first anniversary of the grant date of the award. Subsequent awards to participants will vest on the fourth anniversary of the grant date. If the right has not been exercised at the end of the ten year term and the participant has not terminated his employment with us, the right will be deemed exercised as of the date of the right's expiration and a cash payment will be made as described below.

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Upon vesting, the participant may exercise his rights and receive a cash payment calculated as the difference between the averages of the closing market price of our common units for the ten days preceding the date of exercise over the strike price of the right being exercised. The cash payment to the participant will be net of any applicable withholding taxes required by law. If the Committee determines, in its full discretion, that it would cause significant financial harm to the Partnership to make cash payments to participants who have exercised rights under the plan, then the Committee may authorize deferral of the cash payments until a later date.

Termination for any reason other than death, disability or normal retirement (as these terms are defined in the plan) will result in the forfeiture of any non-vested rights. Upon death, disability or normal retirement, all rights will become fully vested. If a participant is terminated for any reason within one year after the effective date of a change in control (as defined in the plan) all rights will become fully vested.

Prior to January 1, 2006, we had accounted for this plan under the provisions of FASB Interpretation No. 28, “Accounting for Stock Appreciation Rights and Other Variable Stock Option or Award Plans”, which required that the liability under the plan be measured at each balance sheet date based on the market price of our common units on that date. On January 1, 2006, we adopted SFAS No. 123 (revised December 2004), “Share-Based Payments.” The adoption of this statement required that the compensation cost associated with our stock appreciation rights plan, which upon exercise will result in the payment of cash to the employee, be re-measured each reporting period based on the fair value of the rights. Under SFAS 123(R), the liability is calculated using a fair value method that takes into consideration the expected future value of the rights at their expected exercise dates.

We have elected to calculate the fair value of the rights under the plan using the Black-Scholes valuation model. This model requires that we include the expected volatility of the market price for our common units, the current price of our common units, the exercise price of the rights, the expected life of the rights, the current risk free interest rate, and our expected annual distribution yield. This valuation is then applied to the vested rights outstanding and to the non-vested rights based on the percentage of the service period that has elapsed. The valuation is adjusted for expected forfeitures of rights (due to terminations before vesting, or expirations after vesting). The liability amount accrued on the balance sheet is adjusted to this amount at each balance sheet date with the adjustment reflected in the statement of operations.

The estimates that we made upon the adoption of this standard included the following assumptions:

- In determining the expected life of the rights, we used the simplified method allowed by the Securities and Exchange Commission. As our stock appreciation rights plan was not put in place until December 31, 2003, we have very limited experience with employee exercise patterns. The simplified method produces an initial expected life of 6.25 years for those rights we issued that vest 25% per year for four years, and an initial expected life of 7 years for those rights we issued that fully vest at the end of a four-year period.

- The expected volatility of our units was computed using the historical period we believe is representative of future expectations. We determined the period to use as the historical period by considering our distribution history and distribution yield. The expected volatility used in the fair value calculations was approximately 33% and 32% at January 1, 2006 and December 31, 2006, respectively.

- The risk-free interest rate was determined from the current yield for U.S. Treasury zero-coupon bonds with a term similar to the remaining expected life of the rights. At January 1, 2006, the risk-free interest rate ranged from 4.39% to 4.41%. At December 31, 2006, the risk-free interest rate ranged from 4.53% to 4.57%.

- In determining our expected future distribution yield, we considered our history of distribution payments, our expectations for future payments, and the distribution yields of entities similar to us. At January 1, 2006 and December 31, 2006, we used an expected future distribution yield of 6%.

- We estimated the expected forfeitures of non-vested rights and expirations of vested rights. We have very limited experience with employee forfeiture and expiration patterns, as our plan was not initiated until December 31, 2003. We reviewed the history available to us as well as employee turnover patterns in determining the rates to use. We also used different estimates for different groups of employees.

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At December 31, 2005, we had a recorded liability of $0.8 million, computed under the provisions of FASB Interpretation No. 28. We calculated the effect of adoption of SFAS 123(R) at January 1, 2006, and determined that our recorded liability at December 31, 2005 should be reduced by $30,000. This reduction is reflected as income from the cumulative effect of the adoption of a new accounting principle on our statement of operations. We do not believe the effect of adoption of this accounting principle at January 1, 2005 would have been material. The adjustment of the liability to its fair value of $2.4 million at December 31, 2006, resulted in total expense of $1.9 million for the year ended December 31, 2006, with $0.3 million, $0.3 million and $1.3 million included in field operating costs, pipeline operating costs and general and administrative expenses, respectively.

The following table reflects rights activity under our plan as of January 1, 2006, and changes during the year ended December 31, 2006:

Stock Appreciation Rights	Rights	Weighted Average Exercise Price	Weighted Average Contractual Remaining Term (Yrs)	Aggregate Intrinsic Value (in thousands)
Outstanding at January 1, 2006	596,128	$ 10.39		
Granted during 2006	205,520	$ 18.31		
Exercised during 2006	(58,193)	$ 9.58		
Forfeited or expired during 2006	(84,445)	$ 11.10		
Outstanding at December 31, 2006	659,010	$ 12.79	8.3	$ 2,458
Exercisable at December 31, 2006	223,135	$ 10.40	7.4	$ 2,063

The weighted-average fair value at December 31, 2006 of rights granted during 2006 was $4.09 per right. The total intrinsic value of rights exercised during 2006 was $364,000, which was paid in cash to the participants.

At December 31, 2006, there was $1.6 million of total unrecognized compensation cost related to rights that we expect will vest under the plan. This amount was calculated as the fair value at December 31, 2006 multiplied by those rights for which compensation cost has not been recognized, adjusted for estimated forfeitures. This unrecognized cost will be recalculated at each balance sheet date until the rights are exercised, forfeited or expire. For the awards outstanding at December 31, 2006, the remaining cost will be recognized over a weighted average period of one year.

Prior to January 1, 2006, the method of accounting for our stock appreciation rights plan required that the liability under the plan be measured at each balance sheet date based on the market price of our common units on that date. In 2005, we recorded a non-cash credit of $0.5 million in general and administrative expense for the decrease in the value of the outstanding rights due to the decrease in the closing market price for common units between December 31, 2005 and December 31, 2004. In 2004, we recorded non-cash expense of $1,151,000 for the increase in the value of the outstanding rights.

Bonus Plan

In March 2003, the Compensation Committee of the Board of Directors of our general partner approved a Bonus Plan for all employees of the general partner (with the exception of the new senior management team.) The Bonus Plan is designed to enhance the financial performance of the Partnership by rewarding all employees for achieving financial performance objectives. The Bonus Plan is administered by the Compensation Committee. Under this plan, amounts will be allocated for the payment of bonuses to employees each time our operating partnership earns $2.0 million of available cash, subject to certain adjustments. The amount allocated to the bonus pool increases for each $2.0 million earned, such that a bonus pool of $2.3 million will exist if the Partnership earns $18.4 million of available cash. We accrued $1.8 million, $1.2 million and $0.2 million for the bonus pool for 2006, 2005 and 2004, respectively.

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Bonuses will be paid to employees after the end of the year, but only if distributions are made to the common unitholders. The amount in the bonus pool will be allocated to employees based on the group to which they are assigned. Employees in the first group can receive bonuses that range from zero to ten percent of base compensation. The next group includes employees who could earn a total bonus ranging from zero to twenty percent. Certain members are eligible to earn a total bonus ranging from zero to thirty percent. Lastly, our officers, excluding our new senior management team, and other key management are eligible for a total bonus ranging from zero to forty percent. The Bonus Plan will be at the discretion of the Compensation Committee, and our general partner can amend or change the Bonus Plan at any time.

Severance Protection Plan

In June 2005, the Compensation Committee of the Board of Directors of our general partner approved the Genesis Energy Severance Protection Plan, or Severance Plan, for employees of our general partner (with the exception of the new senior management team.) The Severance Plan provides that a participant in the Plan is entitled to receive a severance benefit if his employment is terminated during the period beginning six months prior to a change in control and ending two years after a change in control, for any reason other than (x) termination by our general partner for cause or (y) termination by the participant for other than good reason. Termination by the participant for other than good reason would be triggered by a change in job status, a reduction in pay, or a requirement to relocate more than 25 miles.

A change in control is defined in the Severance Plan. Generally, a change in control is a change in the control of Denbury, a disposition by Denbury of more than 50% of our general partner, or a transaction involving the disposition of substantially all of the assets of Genesis.

The amount of severance is determined separately for three classes of participants. The first class, which includes two Executive Officers of Genesis, would receive a severance benefit equal to three times that participant’s annual salary and bonus amounts. The second class, which includes certain other members of management, would receive a severance benefit equal to two times that participant’s salary and bonus amounts. The third class of participant would receive a severance benefit based on the participant’s salary and bonus amounts and length of service. Participants would also receive certain medical and dental benefits.

15. Major Customers and Credit Risk

Due to the nature of our crude oil operations, a disproportionate percentage of our trade receivables constitute obligations of oil companies. This industry concentration has the potential to impact our overall exposure to credit risk, either positively or negatively, in that our customers could be affected by similar changes in economic, industry or other conditions. However, we believe that the credit risk posed by this industry concentration is offset by the creditworthiness of our customer base. Our portfolio of accounts receivable is comprised in large part of integrated and large independent energy companies with stable payment experience. The credit risk related to contracts which are traded on the NYMEX is limited due to the daily cash settlement procedures and other NYMEX requirements.

We have established various procedures to manage our credit exposure, including initial credit approvals, credit limits, collateral requirements and rights of offset. Letters of credit, prepayments and guarantees are also utilized to limit credit risk to ensure that our established credit criteria are met.

Occidental Energy Marketing, Inc., Shell Oil Company and Calumet Specialty Products Partners, L.P. accounted for 20.3%, 19.1% and 10.9% of total revenues in 2006, respectively. Occidental Energy Marketing, Inc. and Shell Oil Company accounted for 26.5% and 12.5% of total revenues in 2005, respectively. Occidental Energy Marketing, Inc., Marathon Ashland Petroleum LLC and Plains Marketing, L.P. accounted for 20.4%, 12.8% and 10.0% of total revenues in 2004, respectively. The revenues from these five customers in all three years relate primarily to our gathering and marketing operations.

16. Derivatives

Our market risk in the purchase and sale of crude oil contracts is the potential loss that can be caused by a change in the market value of the asset or commitment. In order to hedge our exposure to such market fluctuations, we may enter into various financial contracts, including futures, options and swaps. Historically, any contracts we have used to hedge market risk were less than one year in duration, although we have the flexibility to enter into arrangements with a longer term.

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We may utilize crude oil futures contracts and other financial derivatives to reduce our exposure to unfavorable changes in crude oil prices. Every derivative instrument (including certain derivative instruments embedded in other contracts) must be recorded in the balance sheet as either an asset or liability measured at its fair value. Changes in the derivative's fair value must be recognized currently in earnings unless specific hedge accounting criteria are met. Special accounting for qualifying hedges allows a derivative's gains and losses to offset related results on the hedged item in the income statement. We must formally document, designate and assess the effectiveness of transactions that receive hedge accounting.

We mark to fair value our derivative instruments at each period end, with changes in the fair value of derivatives that are not designated as hedges being recorded as unrealized gains or losses. Such unrealized gains or losses will change, based on prevailing market prices, at each balance sheet date prior to the period in which the transaction actually occurs. The effective portion of unrealized gains or losses on derivative transactions qualifying as cash flow hedges are reflected in other comprehensive income. Derivative transactions qualifying as fair value hedges are evaluated for hedge effectiveness and the resulting hedge ineffectiveness is recorded as a gain or loss in the consolidated statements of operations.

We review our contracts to determine if the contracts meet the definition of derivatives pursuant to SFAS 133. At December 31, 2006, we had futures contracts that were considered free-standing derivatives that are accounted for at fair value. The fair value of these contracts was determined based on the closing price for such contracts on December 31, 2006. We marked these contracts to fair value at December 31, 2006. During the year ended December 31, 2006, we recorded gains of $156,000 related to derivative transactions, which is included in the consolidated statements of operations under the caption "Crude Oil Costs".

At December 31, 2006, we had futures contracts that qualified as derivatives and were formally documented and designated as fair value hedges of inventory. During 2006, we recognized gains, due to hedge ineffectiveness, on the fair value hedge of inventory of approximately $64,000. These gains are included in the caption "Crude Oil Costs" in the consolidated statements of operations. The time value component of the derivative gain or loss excluded from the assessment of hedge effectiveness was not material.

The consolidated balance sheet at December 31, 2006 includes an increase in other current assets of $165,000 as a result of these derivative transactions. The consolidated balance sheet at December 31, 2005 included an increase in other current assets of $6,000 as a result of derivative transactions.

We determined that the remainder of our derivative contracts qualified for the normal purchase and sale exemption and were designated and documented as such at December 31, 2006 and December 31, 2005.

17. Commitments and Contingencies

Commitments and Guarantees

We lease office space for our headquarters office under a long-term lease. The lease extends until October 31, 2008. We lease office space for two field offices under leases that expire in 2007 and 2013. Paccar Leasing Services provide tractors and trailers to us under operating leases that include full-service maintenance. We pay a fixed monthly rental charge for each tractor and trailer and a fee based on mileage for the maintenance services. We lease tanks for use in our pipeline operations. Beginning in 2005, we are reimbursed for the costs of the tank lease by a customer, under a reimbursement agreement covering the period of the tank lease. Additionally, we lease a segment of pipeline. Under the terms of that lease, we make lease payments based on throughput, and we have no minimum volumetric or financial requirements remaining. We also lease service vehicles for our field personnel.

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The future minimum rental payments under all non-cancelable operating leases as of December 31, 2006, were as follows (in thousands).

	Office Space	Tractors and Trailers	Tanks	Service Vehicles	Total
2007	$ 363	$ 1,604	$ 508	$ 249	$ 2,724
2008	299	1,604	-	215	2,118
2009	54	1,604	-	69	1,727
2010	54	1,100	-	20	1,174
2011	53	478	-	-	531
2012 and thereafter	67	207	-	-	274
Total minimum lease obligations	$ 890	$ 6,597	$ 508	$ 553	$ 8,548

Total operating lease expense was as follows (in thousands).

Year ended December 31, 2006	$ 3,258
Year ended December 31, 2005	$ 3,929
Year ended December 31, 2004	$ 3,824

We have guaranteed the payments by our operating partnership to the banks under the terms of our credit facility related to borrowings and letters of credit. To the extent liabilities exist under the letters of credit, such liabilities are included in the consolidated balance sheet. Borrowings at December 31, 2006 were $8.0 million and are reflected in the consolidated balance sheet. We have also guaranteed the payments by our operating partnership under the terms of our operating leases of tractors and trailers. Such obligations are included in future minimum rental payments in the table above.

We guaranteed $1.2 million of residual value related to the leases of trailers from Paccar. We believe the likelihood we would be required to perform or otherwise incur any significant losses associated with this guaranty is remote.

We guaranty 50% of the obligations of Sandhill under a credit facility with a bank. At December 31, 2006, Sandhill owed $4.5 million; therefore our guarantee was $2.25 million. Sandhill makes principal payments for this obligation totaling $0.6 million per year.

In general, we expect to incur expenditures in the future to comply with increasing levels of regulatory safety standards. While the total amount of increased expenditures cannot be accurately estimated at this time, we expect that our annual expenditures for integrity testing, repairs and improvements under regulations requiring assessment of the integrity of crude oil pipelines to average from $1.0 million to $1.5 million.

Pennzoil Litigation

We were named a defendant in a complaint filed on January 11, 2001, in the 125th District Court of Harris County, Texas, Cause No. 2001-01176. Pennzoil-Quaker State Company, or PQS, was seeking from us property damages, loss of use and business interruption suffered as a result of a fire and explosion that occurred at the Pennzoil Quaker State refinery in Shreveport, Louisiana, on January 18, 2000. PQS claimed the fire and explosion were caused, in part, by crude oil we sold to PQS that was contaminated with organic chlorides. In December 2003, our insurance carriers settled this litigation for $12.8 million.

PQS is also a defendant in five consolidated class action/mass tort actions brought by neighbors living in the vicinity of the PQS Shreveport, Louisiana refinery in the First Judicial District Court, Caddo Parish, Louisiana, Cause Nos. 455,647-A, 455,658-B, 455,655-A, 456,574-A, and 458,379-C. PQS has brought third party claims against us for indemnity with respect to the fire and explosion of January 18, 2000. We believe that the demand against us is without merit and intend to vigorously defend ourselves in this matter. We currently believe that this matter will not have a material financial effect on our financial position, results of operations, or cash flows.

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Environmental

In 1992, Howell Crude Oil Company entered into a sublease with Koch Industries, Inc., covering a one acre tract of land located in Santa Rosa County, Florida to operate a crude oil trucking station, known as Jay Station. The sublease provided that Howell would indemnify Koch for environmental contamination on the property under certain circumstances. Howell operated the Jay Station from 1992 until December of 1996 when this operation was sold to us by Howell. We operated the Jay Station as a crude oil trucking station until 2003. Koch has indicated that it has incurred certain investigative and/or other costs, for which Koch alleges some or all should be reimbursed by us, under the indemnification provisions of the sublease for environmental contamination on the site and surrounding areas. Koch has also alleged that we are responsible for future environmental obligations relating to the Jay Station.

Howell was acquired by Anadarko Petroleum Corporation in 2002. In 2005, we entered into a joint defense and cost allocation agreement with Anadarko. Under the terms of the joint allocation agreement, we agreed to reasonably cooperate with each other to address any liabilities or defense costs with respect to the Jay Station. Additionally under the joint allocation agreement, Anadarko will be responsible for sixty percent of the costs related to any liabilities or defense costs incurred with respect to contamination at the Jay Station.

We were formed in 1996 by the sale and contribution of assets from Howell and Basis Petroleum, Inc. Anadarko's liability with respect to the Jay Station is derived largely from contractual obligations entered into upon our formation. We believe that Basis has contractual obligations under the same formation agreements. We intend to seek recovery of Basis' share of potential liabilities and defense costs with respect to Jay Station.

We have developed a plan of remediation for affected soil and groundwater at Jay Station which has been approved by appropriate state regulatory agencies. We have accrued an estimate of our share of liability for this matter in the amount of $0.5 million. The time period over which our liability would be paid is uncertain and could be several years. This liability may decrease if indemnification and/or cost reimbursement is obtained by us for Basis' potential liabilities with respect to this matter. At this time, our estimate of potential obligations does not assume any specific amount contributed on behalf of the Basis obligations, although we believe that Basis is responsible for a significant part of these potential obligations.

We are subject to various environmental laws and regulations. Policies and procedures are in place to monitor compliance and to detect and address any releases of crude oil from our pipelines or other facilities, however no assurance can be made that such environmental releases may not substantially affect our business.

Other Matters

Our facilities and operations may experience damage as a result of an accident or natural disaster. These hazards can cause personal injury or loss of life, severe damage to and destruction of property and equipment, pollution or environmental damage and suspension of operations. We maintain insurance that we consider adequate to cover our operations and properties, in amounts we consider reasonable. Our insurance does not cover every potential risk associated with operating our facilities, including the potential loss of significant revenues. The occurrence of a significant event that is not fully-insured could materially and adversely affect our results of operations. We believe we are adequately insured for public liability and property damage to others and that our coverage is similar to other companies with operations similar to ours. No assurance can be made that we will be able to maintain adequate insurance in the future at premium rates that we consider reasonable.

We are subject to lawsuits in the normal course of business and examination by tax and other regulatory authorities. We do not expect such matters presently pending to have a material adverse effect on our financial position, results of operations or cash flows.

18. Income Taxes

In May 2006, the State of Texas enacted a margin tax that will become effective in 2008. This margin tax will require us to pay a tax of 0.5% on our "margin," as defined in the law, beginning in 2008 based on our 2007 results. The margin to which the tax rate will be applied generally will be calculated as our revenues for federal income tax purposes less the cost of the products sold for federal income tax purposes, in the State of Texas. Under the provisions of Statement of Financial Accounting Standards No. 109, "Accounting for Income Taxes", we are required to record the effects on deferred taxes for a change in tax rates or tax law in the period that includes the enactment date.

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Under FAS 109, taxes based on income like the Texas margin tax 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 the end of the period. 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.

Temporary differences related to our inventory will affect the Texas margin tax, so we have recorded a deferred tax asset in the amount of $11,000. We believe that we will be able to utilize this deferred tax asset at December 31, 2006, and therefore have provided no valuation allowance against this deferred tax asset.

19. Subsequent Events

Distribution

On January 24, 2007, the Board of Directors of the general partner declared a cash distribution of $0.21 per unit for the quarter ended December 31, 2006. The distribution was paid on February 14, 2007, to our general partner and all common unitholders of record as of the close of business on February 5, 2007.

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Schedule I - Condensed Financial Information

Genesis Energy, L.P. (Parent Company Only)

Condensed Statements of Operations

	Years Ended December 31,		
	2006	2005	2004
		(in thousands)	
Equity in earnings (losses) of subsidiary	$ 8,381	$ 3,415	$ (1,412)
Net income (loss)	$ 8,381	$ 3,415	$ (1,412)

Condensed Balance Sheets

	December 31,	
	2006	2005
	(in thousands)	
Assets		
Cash	$ 6	$ 6
Investment in subsidiary	118,338	120,365
Advances to subsidiary	88	88
Total Assets	$ 118,432	$ 120,459
Partners' Capital		
Limited Partners	$ 115,960	$ 117,946
General Partner	2,472	2,513
Total Partners' Capital	$ 118,432	$ 120,459

See accompanying note to condensed financial statements.

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Schedule I - Condensed Financial Information - Continued

Genesis Energy, L.P. (Parent Company Only)

Condensed Statements of Cash Flows

	Years Ended December 31, 2006	2005	2004
		(in thousands)	
Cash Flows from Operating Activities:			
Net income (loss)	$ 8,381	$ 3,415	$ (1,412)
Equity in earnings (losses) of GCO	$ (8,381)	$ (3,415)	$ 1,412
Change in advances to GCO	-	-	4
Net cash provided by operating activities	-	-	4
Cash Flows from Investing Activities:			
Investment in GCO	-	(44,833)	(5,012)
Distributions from GCO - return of investment	10,408	5,798	5,703
Net cash provided by (used in) investing activities	10,408	(39,035)	691
Cash Flows from Financing Activities:			
Issuance of limited and general partner interests, net	-	44,833	5,012
Distributions to limited and general partners	(10,408)	(5,798)	(5,703)
Net cash (used in) provided by financing activities	(10,408)	39,035	(691)
Net increase in cash	-	-	4
Cash at beginning of period	$ 6	$ 6	$ 2
Cash at end of period	$ 6	$ 6	$ 6

Schedule I - Condensed Financial Statements - Continued

Genesis Energy, L.P. (Parent Company Only)

Notes to Condensed Financial Statements

1. Basis of Presentation

As discussed in Note 8 of the Notes to the Consolidated Financial Statements, the terms of the credit facility with Genesis Crude Oil, L.P., or GCO, limit the amount of distributions that GCO and its subsidiaries may pay to Genesis Energy, L.P., or GEL. Such distributions may not exceed the sum of the distributable cash generated by GCO and its subsidiaries for the eight most recent quarters, less the sum of the distributions made with respect to those quarters. This restriction results in the restricted net assets (as defined in Rule 4-03 (e)(3) of Regulation S-X) of GEL's subsidiary exceeding 25% of the consolidated net assets of GEL and its subsidiary.

The parent company only financial statements for GEL summarize the results of operations and cash flows for the years ended December 31, 2006, 2005 and 2004, and the financial position as of December 31, 2006 and 2005. In these statements, GEL's investment in GCO is stated on the equity method basis of accounting. The GEL statements should be read in conjunction with the consolidated financial statements of Genesis Energy, L.P.

2. Contingencies

GEL guarantees the obligations of GCO under our credit facility. See Note 8 to the consolidated financial statements of Genesis Energy, L.P.

GEL guarantees the obligations of GCO under our lease with Paccar Leasing Services. See Note 17 to the consolidated financial statements of Genesis Energy, L.P.

GELP has guaranteed crude oil purchases of GCO. These guarantees, totaling $33.2 million, were provided to counterparties. To the extent liabilities exist under the contracts subject to these guarantees, such liabilities are included in the consolidated financial statements of Genesis Energy, L.P.