ONEOK PARTNERS 2008 ANNUAL REPORT | OKS

Building.

ONEOK Partners is a publicly traded master limited partnership engaged in natural gas gathering and processing, natural gas pipelines, natural gas liquids gathering and fractionation, and natural gas liquids pipelines. Our sole general partner is a subsidiary of ONEOK, an energy company founded in 1906 that's involved in natural gas distribution and energy services, and owns 47.7 percent of the partnership.

Financial Highlights

Year Ended December 31	2008	2007	2006
Consolidated financial information (millions of dollars)			
Net margin	$ 1,140.7	$ 895.9	$ 843.5
Operating income	$ 644.8	$ 446.8	$ 511.2
Net income	$ 625.6	$ 407.7	$ 445.2
Total assets	$ 7,254.3	$ 6,112.1	$ 4,921.7
Total debt to capitalization	54%	55%	48%
Capital expenditures (millions of dollars)			
Growth	$ 1,172.0	$ 650.3	$ 134.7
Maintenance	$ 81.9	$ 59.6	$ 67.0
Total capital expenditures	$ 1,253.9	$ 709.9	$ 201.7
Common unit data			
Common units outstanding at year-end	54,426,087	46,397,214	46,397,214
Class B units outstanding at year-end	36,494,126	36,494,126	36,494,126
Total units outstanding at year-end	90,920,213	82,891,340	82,891,340
Data per limited partner unit			
Net income	$ 6.01	$ 4.21	$ 5.01
Distributions declared	$ 4.26	$ 4.025	$ 3.78
Book value at year-end	$ 31.15	$ 25.78	$ 25.75
Market price range			
High	$ 64.01	$ 72.42	$ 65.91
Low	$ 39.25	$ 58.20	$ 42.74
Year-end	$ 45.55	$ 61.25	$ 63.34

To Our Unitholders

Just two years ago in this same space, three words were used to describe 2006: *What a year!* We had doubled our asset base, broadened and diversified our revenue streams, strengthened our balance sheet and announced a massive internal growth program.

For a variety of reasons, those same three words describe 2008.

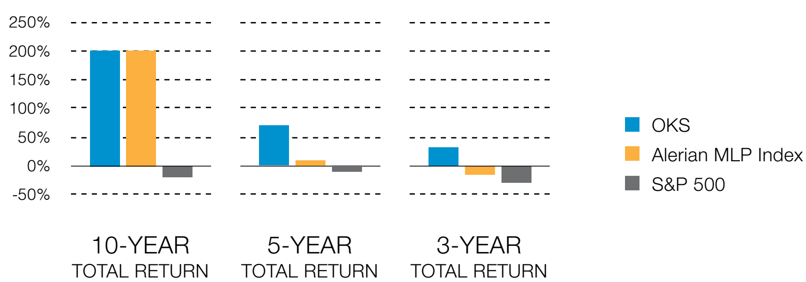
First, we achieved record-setting performance by several measures, with all four of our segments reporting improvements. Operating income was $644.8 million, up 44 percent from 2007. Distributable cash flow was $636.8 million, an increase of 37 percent over the previous year. Cash flow, as measured by earnings before interest, taxes, depreciation and amortization (EBITDA), rose 31 percent to $863.3 million.

Second, while accomplishing this exceptional financial performance, we completed the largest portion of our $2 billion growth program. We're closing in on the finish line, with our capital commitments under this growth program declining to approximately $355 million in 2009, versus $1.2 billion last year.

Third, a global recession became evident by early fall as landmark financial institutions faltered, capital markets tightened, commodity prices fell dramatically from historic levels and the recession spread across diverse sectors of the economy.

The stock market suffered its worst year since the 1930s; ONEOK Partners' unit price declined but outperformed its peer group and continued to provide exceptional value for the long-term investor. ONEOK Partners is ready for the challenges and the opportunities ahead.

Total Returns



Building Our Future

Our gratitude goes to all the employees who contributed to this record-level performance and joined in the successful execution of our internal growth program. These new assets will complement and strengthen our businesses well into the future. Almost two-thirds of the entire $2 billion growth program is devoted to our growing natural gas liquids (NGL) businesses. Here's a snapshot of some of those NGL projects:

- **Overland Pass Pipeline**, the largest pipeline we've ever built, began flowing raw natural gas liquids last fall from Wyoming to our expanded fractionation and storage facilities at Bushton, Kansas. This 760-mile, $575 million pipeline can flow up to 110,000 barrels per day (bpd). Its capacity can be increased to approximately 255,000 bpd with additional pump facilities.

- We also invested approximately $239 million to upgrade and expand our **Mid-Continent infrastructure** to accommodate these additional NGL barrels. This included increasing our Bushton, Kansas, fractionation capacity to 150,000 bpd, upgrading our storage facilities to accommodate additional NGL volumes, building a new NGL pipeline between Bushton and Medford, Oklahoma, the location of our largest fractionator, and expanding the existing NGL pipeline between Bushton and Conway, Kansas, a major market center.
- The 125-mile **Denver-Julesberg Lateral** from Colorado to Overland Pass is under construction, with completion scheduled in the first quarter 2009. And the 150-mile **Piceance Lateral**, also in Colorado, is scheduled for service this fall.
- The **Arbuckle Pipeline** will go into service during the second quarter. This 440-mile, 160,000-bpd system originates in southern Oklahoma, traverses the Barnett Shale natural gas play in northern Texas and continues south to our fractionation and storage facilities at Mont Belvieu, on the Texas Gulf Coast. Arbuckle will also transport NGLs from southern Oklahoma's Woodford Shale natural gas play where we connected a couple of new natural gas processing plants to our existing NGL gathering system last September. Arbuckle Pipeline's capacity can be expanded to 210,000 bpd with additional pump facilities.
- These assets provide our premier NGL business with greater capability, flexibility and future growth potential. The Wyoming and Colorado supplies also will benefit the **North System**, our Bushton-to-Chicago NGL and refined petroleum products system acquired in late 2007.

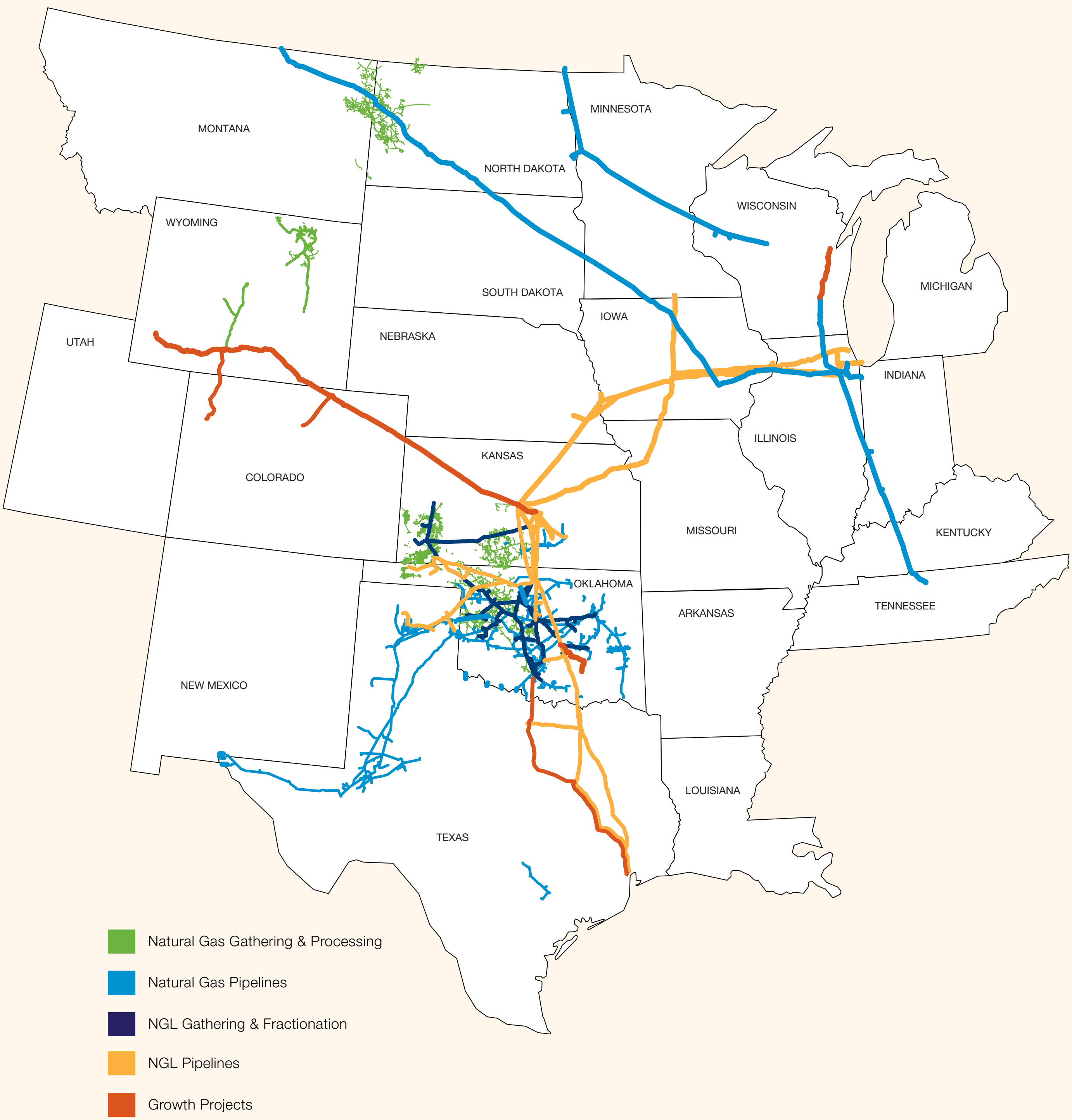
We also made investments in our natural gas businesses, which included:

- The 119-mile **Guardian Pipeline Expansion and Extension** went into service in February and supplies natural gas to two Wisconsin utilities. This $277 million to $305 million project ties into our Chicago-sourced Guardian Pipeline at a point near Milwaukee and runs up the eastern side of Wisconsin to Green Bay. Fully subscribed with two 15-year contracts, it has additional interconnect opportunities along its route.
- During 2008, we invested $146 million in our natural gas gathering and processing business, whose six basins in the Rocky Mountain and the Mid-Continent regions provide great supply diversity. In early 2009, we expect to complete the $40 million to $45 million expansion of our **Grasslands** processing and fractionating facilities in the Williston Basin of North Dakota. Also, expansion of the **Fort Union Gas Gathering** system, in the Powder River Basin of Wyoming, was completed last summer. We have a 37 percent equity interest in Fort Union.

We know that our long-term success comes not from the times but from day-in and day-out consistency, determination and commitment demonstrated by our dedicated employees.

John W. Gibson
Chairman and Chief Executive Officer

ONEOK Partners Assets



Performance Highlights

Our four business segments produced exceptional results:

- Natural Gas Gathering and Processing reported operating income of $247.1 million, up 32 percent over 2007. Favorable commodity prices through most of 2008, combined with our record number of new well connections and higher processed volumes, contributed to this performance.
- Natural Gas Pipelines achieved operating income of $133.2 million, reflecting a 19 percent increase over the previous year. Contributors to this performance included increased transportation and storage margins, driven mainly by higher natural gas prices on retained fuel, and new and renegotiated contracts.
- Natural Gas Liquids Gathering and Fractionation reported operating income of $204.4 million, an 83 percent increase over 2007 results. This segment achieved record gathering volumes of 271,000 bpd and record fractionation volumes of 373,000 bpd. The 2008 financial performance reflected our ability to capture the significantly wider NGL product price differentials between Conway and Mont Belvieu through asset optimization, and our increased gathering and fractionation volumes.
- Natural Gas Liquids Pipelines reported operating income of $60.6 million, an increase of 53 percent over the previous year, primarily driven by owning the North System for a full year. This fee-based segment will continue to grow as our projects come on line.

Challenges and Opportunities

As we move through the current environment, we are encountering challenges … and opportunities as well. Chief among the challenges is downward pressure on natural gas, crude oil and natural gas liquids prices.

Lower commodity prices will impact our businesses involving natural gas gathering and processing, and NGL gathering and fractionation. However, approximately 60 percent of the partnership's earnings are fee based. And going forward, earnings from the partnership's internal growth projects will bring additional fee-based income.

On a larger scale, lower commodity prices will reduce drilling activity across the country. To mitigate our exposure, the partnership has geographically diverse assets and provides non-discretionary services to producers. Our natural gas gathering and processing business operates in six different supply basins in the Mid-Continent and the Rockies, which reduces the effect of any basin-specific pullback in drilling or production. Also, our NGL businesses have gained much greater supply and volume diversity, which continues to expand as we complete our internal growth program.

This commodity price environment, combined with the tight capital markets, presents challenges … and opportunities. We are beginning to see merger-and-acquisition prospects at lower and more reasonable price levels, which were nonexistent less than a year ago. Armed with a healthy balance sheet and a disciplined approach, we will be looking for opportunities to grow through strategic acquisitions.

Financially Speaking

ONEOK Partners and its general partner, ONEOK, are conservative, financially strong companies whose interests are clearly aligned. As the sole general partner, ONEOK operates and manages the partnership.

In March 2008, we sold ONEOK 5.4 million common units in a private placement that provided approximately $303.2 million to the partnership. ONEOK also paid us $9.4 million to maintain its 2 percent general partner interest. With this transaction, ONEOK increased its ownership in the partnership to 47.7 percent.

We also completed a public offering of 2.5 million common units. The partnership used the money from these activities to repay the debt outstanding under its $1 billion revolving credit facility and for capital expenditures and general purposes.

ONEOK Partners, like its general partner, is an investment-grade company, which enables us to access capital at more reasonable rates. In the first quarter of this year, we issued $500 million of 10-year senior notes. We used the net proceeds to repay indebtedness outstanding under our revolving credit agreement.

Since April 2006, when ONEOK became our sole general partner and major owner, ONEOK Partners has increased the distribution to unitholders 11 times – a total increase of 35 percent. This past January, and during uncertain times, we maintained the quarterly distribution at $1.08 per unit, with a current annualized payout of $4.32. Our total debt-to-capitalization ratio at year-end was 54 percent, which provides us with financial flexibility – a quality particularly valuable in the current environment.

Continuous Improvement

This is an exciting, challenging and promising time. Exciting – because our $2 billion internal growth program is wrapping up and successfully working, providing incremental earnings. Challenging – because of the recession and the pressure it bears on many of us across virtually every economic sector. Promising – because we realize that the world is, in fact, always changing, and we know that we will emerge from these times, as we have in the past, a stronger company.

More important, we know that our long-term success comes not from the times but from day-in and day-out consistency, determination and commitment demonstrated by our dedicated employees, who continue to make ONEOK Partners a success story for everyone involved.

We encourage you to read *An Essay on Responsibility* that begins on page 20 of this report. The article reflects our culture for continuous improvement in everything we do – on the job and after working hours. From all of us, thank you for your continued investment and support of ONEOK Partners.

John W. Gibson

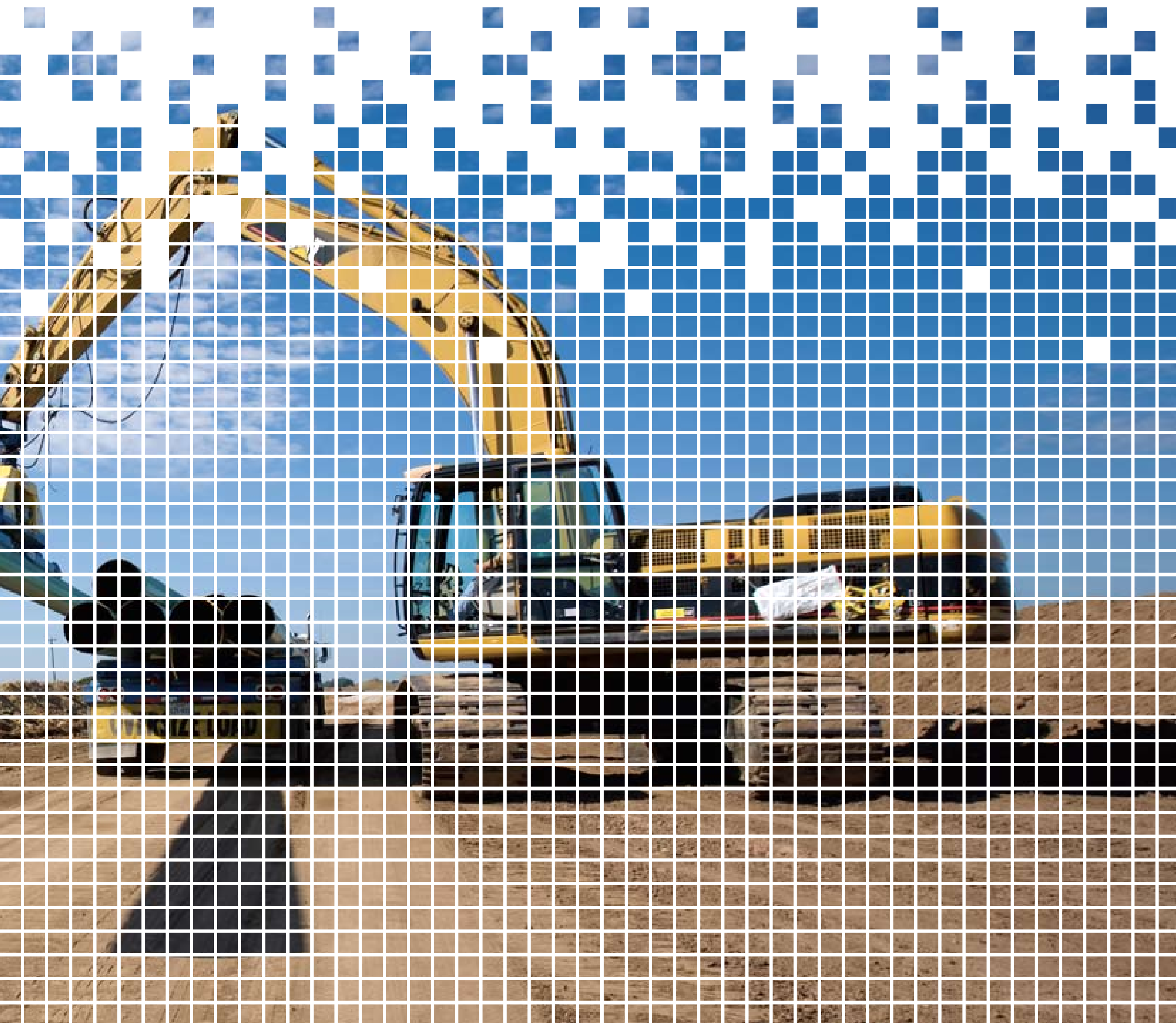
John W. Gibson
Chairman and Chief Executive Officer

March 10, 2009

Building on our capabilities in natural gas.

Our expanding natural gas businesses deliver essential services to our producers and customers in a variety of basins and markets.

Pierce H. Norton II
Executive Vice President, Natural Gas



Natural Gas

Gathering and Processing

> Diversity of basins, contracts and producers provides us with a solid foundation to effectively manage our business in a challenging price environment.

Robert F. Martinovich
President, Natural Gas Gathering & Processing

Our natural gas gathering and processing segment turned in an exceptionally strong performance in 2008 as it connected a record number of new wells, increased processed volumes and improved operating income by 32 percent over the previous year.

In 2008, processed volumes increased year-over-year in both the mature Mid-Continent and expanding Rocky Mountain regions via heavy drilling activity, offsetting normal production declines. We connected more than 475 wells, representing a 35 percent increase over 2007.

This segment benefited from unusually high commodity prices through the first nine months of 2008. However, its growth in processed volumes accounted for approximately 10 percent of the improvement in margin.

Our $40 million to $45 million expansion of the Grasslands processing facility, in the Williston Basin of North Dakota, will increase the plant's natural gas processing capacity by 60 percent and NGL fractionation capacity by 50 percent.

In Wyoming's Powder River Basin, the second phase of an expansion of the jointly owned Fort Union Gas Gathering system was completed last July. Combined with a prior expansion in late 2007, this latest improvement doubles the gathering system's original capacity to 1.3 billion cubic feet per day. ONEOK Partners has a 37 percent stake in Fort Union Gas Gathering.

Equity earnings from investments increased to $32.8 million in 2008 – a 24 percent improvement – primarily reflecting increased gathering revenues realized from our interest in Fort Union Gas Gathering.

a record number of wells connected

serving hundreds of producers in 6 basins

Among our partnership's four business segments, gathering and processing has the largest exposure to commodity prices. We have significantly reduced commodity-price sensitivity while increasing our fee-based revenues.

Approximately 60 percent of our gathering and processing business by volume is fee based. Percent-of-proceeds contracts, in which we share commodity-price exposure with the producer, account for another 30 percent. The remaining 10 percent involves keep-whole agreements, 90 percent of which can be converted to fee-based terms under certain commodity-pricing conditions.

In an effort to further mitigate risk, during the year we may financially hedge up to 75 percent of the expected production of NGLs, natural gas and condensate.

While unprecedented commodity prices benefited this segment in 2008, the current commodity-market environment is expected to reduce this segment's operating income in 2009. However, despite an expected decline in drilling activity, we expect our gathering and processing volumes to be only slightly below 2008 levels.

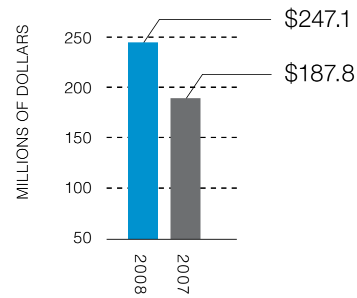
We serve hundreds of producers, from small to large, in six different basins. No single producer accounts for more than 10 percent of our business by volume. We have more than 2,000 contracts with producers that have an average term of two years.

This diversity of basins, contracts and producers, coupled with these essential and non-discretionary services, strengthens our ability to succeed. Going forward, we are committed to meeting our producers' needs in ways that ensure lasting win-win relationships.

Planned capital expenditures this year are $119 million, compared with $146 million in 2008.

Performance Scorecard

OPERATING INCOME



Increase includes $58.4 million in higher realized prices from sales of NGLs, natural gas and condensate; $11.9 million from improved contract terms; and $7.0 million in higher volumes processed and sold. Estimated loss from operational disruptions caused by Hurricane Ike was $1.8 million. The 2007 results included an $8.6 million benefit from a contract settlement. Operating costs in 2008 increased $2.8 million from the previous year.

Natural Gas

Pipelines

Our wholly owned natural gas pipelines and storage facilities provide strong cash flows and stable income. Completion of the Guardian Pipeline Expansion and Extension will provide incremental earnings this year.

W. Kent Shortridge
President, Natural Gas Pipelines

Our natural gas pipelines segment turned in an excellent performance in 2008, increasing its operating income by 19 percent, while also completing a major pipeline expansion and extension project that will provide additional throughput and earnings in 2009.

This predominantly fee-based segment provides strong cash flow, stable income and sustainable growth. During 2008, our natural gas pipelines segment recorded improved transportation margins, due in part to higher natural gas prices and new and renegotiated contracts.

Equity earnings increased by 7 percent, primarily because of Northern Border Pipeline's sale of its Bison Pipeline project. We hold a 50 percent interest in Northern Border Pipeline.

The Guardian Pipeline Expansion and Extension – the segment's largest project in 2008 – was completed near year-end, initiated operations in January and was in full service the following month. The $277 million to $305 million extension has the capacity to provide 537 million cubic feet per day of natural gas to eastern Wisconsin.

The 119-mile extension, which originates near Milwaukee and extends up to Green Bay, is anchored by 15-year contracts with two Wisconsin utilities.

Our assets include 6,900 miles of interstate and intrastate pipelines, with a peak capacity of 5.8 billion cubic feet per day and a working storage capacity of 51.6 billion cubic feet. Midwestern Gas Transmission, Guardian Pipeline and Viking Gas Transmission – our owned and operated interstate pipelines – are 90 percent subscribed under demand-based rates.

The segment's intrastate pipelines, located in the Mid-Continent, are 80 percent subscribed under demand-based rates; its storage facilities are fully subscribed.

Our pipelines are connected to multiple supply basins and quality end-use markets, primarily natural gas and electric utilities. Additional natural gas pipeline throughput opportunities are anticipated within our operating areas.

Planned 2009 capital expenditures in our natural gas pipelines business are $62 million, compared with $267 million in 2008. This year's planned activities include approximately $38 million for expansions, extensions and interconnections of interstate natural gas pipelines, along with storage development and expansion.

major pipeline expansion completed

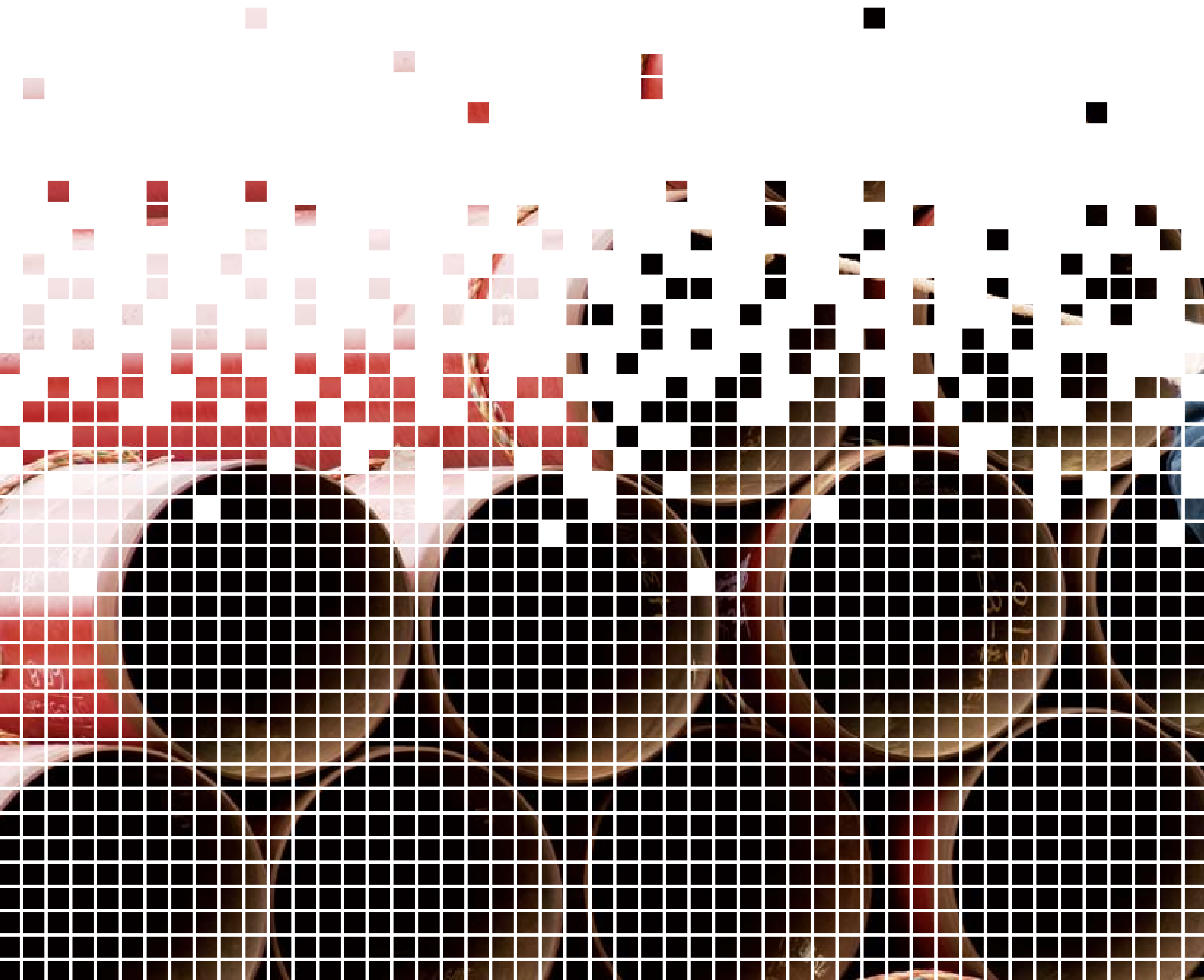
Performance Scorecard

OPERATING INCOME

Increase includes $6.3 million in improved transportation margins, primarily from higher natural gas price impact on retained fuel; $5.4 million in improved storage margins, primarily from new and renegotiated contracts and the higher natural gas price impact on retained fuel; and $3.8 million due to increased natural gas sales from inventory. Operating costs decreased $6.7 million from the previous year.

Equity earnings from investments increased $4.2 million, primarily as a result of the partnership's share – $8.3 million – from the sale of Bison Pipeline.

Building new assets and adding supply in natural gas liquids.



Our NGL businesses have grown volumes significantly, while expanding and diversifying their operating footprint – providing our customers with essential services.

Terry K. Spencer
Executive Vice President, Natural Gas Liquids

Natural Gas Liquids

Gathering and Fractionation

{ Our expanded and upgraded gathering, fractionation, storage and delivery capabilities – combined with our new NGL pipelines – create additional opportunities for success. }

Sheridan C. Swords
President, Natural Gas Liquids
Gathering & Fractionation

The partnership's natural gas liquids gathering and fractionation segment established a series of performance records in 2008 including:

- Operating income – up 83 percent
- Gathering volumes – up 9 percent, to 271,000 bpd
- Fractionation volumes – up 5 percent, to 373,000 bpd

The increase in gathered and fractionated volumes realized in 2008 accounted for more than one-fourth of this business segment's 2008 margin improvement. We expect gathering and fractionation volumes to continue to grow in 2009 as Arbuckle Pipeline comes on line and the first full-year impact of Overland Pass Pipeline – coupled with the partial-year impact of the D-J and Piceance Lateral pipelines – is realized, despite predicted periodic, reduced ethane production.

Throughout 2008, we captured exceptionally high NGL product price differentials between the Conway, Kansas, and Mont Belvieu, Texas, market centers, which accounted for more than 60 percent of the segment's margin improvement. Increases in volumes, storage measurement gains and improved storage margins also contributed to this segment's exceptional performance.

Over a three-year period prior to 2008, the average price difference for a gallon of ethane between the two market centers was 5 cents per gallon. This ethane differential rose to as high as 45 cents during 2008 and averaged 15 cents per gallon for the year.

We expect a return to more normal NGL price differentials between Conway and Mont Belvieu this year. Our broad footprint, premier assets and supply diversity provide us with exceptional flexibility to succeed in a challenging environment. Slightly more than 50 percent of NGL products go to the petrochemical sector, 30 percent to refineries, and 20 percent is used for residential and commercial heating.

We provide non-discretionary, fee-based services to NGL producers and are connected to more than 90 percent of the natural gas processing facilities in the Mid-Continent. In the past several years, we have added 21 natural gas processing plants to our NGL systems.

In September, we completed a 78-mile pipeline extension that links our NGL gathering system in southern Oklahoma's Woodford Shale natural gas play to two new processing plants capable of producing 25,000 barrels of NGLs per day.

In October, we completed improvements at our Bushton, Kansas, facilities in time to accommodate the initial flow of barrels on Overland Pass Pipeline, whose capacity is 110,000 bpd. Bushton's fractionation capacity was increased to 150,000 bpd; its storage facility was upgraded to handle additional NGL products; and a new NGL pipeline between Bushton and Medford, Oklahoma, was completed.

During the second quarter 2009, Arbuckle Pipeline will begin delivering new NGL supplies from southern Oklahoma and northern Texas to our Mont Belvieu facilities.

In addition to Bushton, Mont Belvieu and Medford, we also provide fractionation and storage at Hutchinson, Kansas, and have an equity interest in similar assets at Conway. Our total net fractionation capacity is 550,000 bpd.

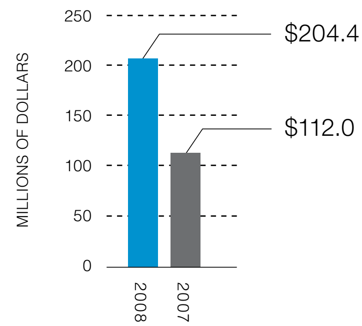
As a part of the partnership's $2 billion internal growth program, some $246 million has been invested since 2006 in our NGL gathering and fractionation business.

Our NGL gathering and fractionation segment's planned capital expenditures for 2009 are $71 million, compared with $170 million in 2008.

continued volume growth

Performance Scorecard

OPERATING INCOME



Increase includes $70.8 million in improved optimization margins from wider price differentials in NGL products between the Conway and Mont Belvieu market centers; $32.1 million due to increased gathering and fractionation volumes; $8.4 million in operational measurement gains, primarily at NGL storage caverns; and $3.6 million from higher storage margins. Estimated loss from operational disruptions caused by Hurricane Ike was $3.8 million. Operating costs increased $19.1 million from the previous year, primarily due to expansion and maintenance of fractionation facilities.

Natural Gas Liquids

Pipelines

> Overland Pass, Piceance, Denver-Julesberg, Arbuckle – these are more than names. They represent our vision, which is hard at work.

Roger G. Thorpe
President, Natural Gas Liquids Pipelines

These are exciting and gratifying times as this rapidly growing business segment nears the finish line on more than a billion dollars of pipeline construction – bringing new supplies of raw NGLs from some of the nation's most prolific basins to our infrastructure in the Mid-Continent and Texas Gulf Coast.

These NGL pipelines provide incremental, fee-based earnings and serve as the foundation for future growth as we gather and fractionate raw NGLs from new sources in Wyoming, Colorado, Oklahoma and Texas, and distribute higher-value NGL finished products to the nation's primary NGL market centers in Conway, Kansas, and Mont Belvieu, Texas, as well as Chicago. We have dedicated supply commitments for these pipelines, with the potential to add even more.

Last fall, the partnership completed $239 million of improvements and expansions to our Mid-Continent region fractionation and distribution capabilities to accommodate deliveries from these new NGL pipelines.

In 2008, our NGL pipelines segment improved its operating income by 53 percent over the previous year, primarily because of incremental margins from the North System – the $300 million NGL and refined petroleum products pipeline system we acquired in late 2007 – increased throughput on that system, and completion of Overland Pass Pipeline, which began flowing last fall.

Overland Pass Pipeline, which originates in Opal, Wyoming, and terminates at Conway, Kansas, is the largest capital project we have ever undertaken. Throughput on this $575 million pipeline ramped up to 60,000 bpd this past January and is expected to be at 140,000 bpd by the end of the third quarter 2009.

Overland Pass Pipeline's 110,000 barrels-per-day capacity can be increased to 255,000 bpd to meet future demand. Overland Pass Pipeline Company is a joint venture with Williams, whose NGL production from two of its natural gas processing plants in western Wyoming is dedicated to this pipeline.

In the fourth quarter 2008, we began construction on the 125-mile D-J Lateral Pipeline, which will transport raw natural gas liquids from the Denver-Julesberg Basin in Colorado to Overland Pass Pipeline. Completion of this $70 million to $80 million pipeline, with a capacity of 55,000 bpd, is scheduled for the first quarter of this year. Flow is expected to reach 33,000 bpd by the second quarter of 2009.

completed largest pipeline project in our history

Last October, we received regulatory approvals to begin building the 150-mile Piceance Lateral Pipeline, which will connect Overland Pass Pipeline to the Piceance Basin in western Colorado. This pipeline, estimated to cost from $110 million to $140 million, is scheduled for operation in the third quarter of this year. It has a capacity to transport 100,000 bpd of raw NGLs and is expected to initially flow 37,000 bpd.

We will begin shipping new raw NGL supplies from southern Oklahoma and northern Texas to our fractionation and storage facilities at Mont Belvieu, along the Texas Gulf Coast, by mid-2009 when the Arbuckle Pipeline is completed. This 440-mile pipeline, which will possibly cost 10 to 15 percent more than the previously announced range of $340 million to $360 million, originates in southern Oklahoma.

From its strategic origination point in Oklahoma, Arbuckle Pipeline travels south through the Barnett Shale of northern Texas and continues to the Texas Gulf Coast. This pipeline's capacity is 160,000 bpd and can be increased to 210,000 bpd, with sufficient supply commitments to fill the pipeline's expanded capacity in the next three to five years. Initial flow is expected to be in excess of 60,000 bpd.

Our new pipelines expand the footprint, capability and flexibility of our NGL businesses, positioning them for future growth and long-term success.

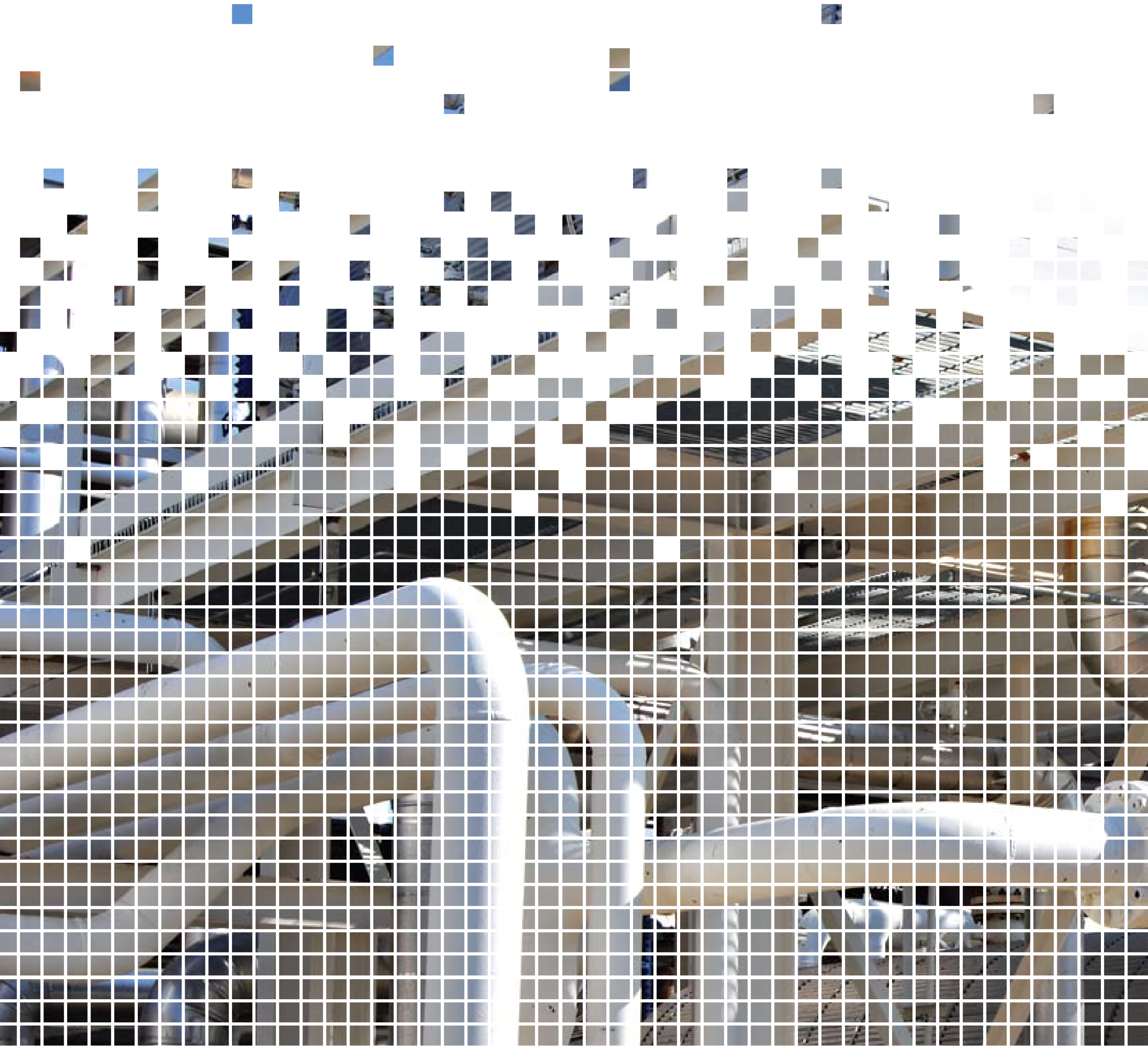
Planned capital expenditures for 2009 in the NGL pipelines segment are $173 million, compared with $671 million in 2008.

Performance Scorecard

OPERATING INCOME

Increase includes $44.3 million of incremental margins from the North System's first full year of operation; $4.3 million from increased volumes on other NGL pipelines; and $2.6 million of incremental margins from the fourth-quarter start-up of Overland Pass Pipeline. Estimated loss from operational disruptions caused by Hurricane Ike was $2.2 million. Operating costs increased $26.1 million, related primarily to the first full-year operation of the North System.

Building on a legacy of corporate social responsibility.



An Essay on Responsibility

At ONEOK Partners, corporate social responsibility is interwoven into everything we do – from daily operations to community enrichment.

We are, and always have been, committed to operating our assets safely, efficiently and environmentally responsibly.

More than 50 employees from across the company serve on a leadership team focused on operations and compliance, emergency response and preparedness, the environment, and safety and health.

We have one overarching vision: development of a best-in-class environmental, safety and health program that benefits all of our stakeholders – employees, customers, communities and investors.

This is a top-down and bottom-up effort – everyone is signed on companywide. This year we added two safety-performance measures to the measures we use to determine short-term incentive compensation, and our results in this area will impact all employees.

National Recognition

Several of our operational activities drew national recognition in 2008:

- The Environmental Protection Agency named us Natural Gas STAR Gathering and Processing Partner of the Year in connection with our voluntary reduction of methane emissions – one of three greenhouse gases – from line loss.
- The Occupational Safety and Health Administration recognized three consecutive years of “excellence in health and safety” at our Mont Belvieu, Texas, NGL fractionation facility.

Giving Back

We have a long and rich history of giving back to communities by supporting education, helping families in need and enhancing the quality of life in our communities.

From large gifts by the ONEOK Foundation to energy-assistance programs to generous donations of time and money by our employees, we are making a positive difference.

Since its inception in 1997, the ONEOK Foundation has provided a dollar-for-dollar match of employee contributions to annual United Way campaigns, making our collective contribution to United Way more than $18 million.

Last fall, our Tulsa employees, with support from the ONEOK Foundation, contributed more than a million dollars to support the local United Way, which met its goal in the midst of an economic recession.

“ONEOK employees connect with their heart,” says Mark Graham, president and chief executive officer of the Tulsa Area United Way. “ONEOK takes a wonderful and completely integrated approach to supporting the community. It sets the leadership tone.”

These kinds of remarks warm our hearts – and make us want to do more.

One of the primary focus areas of the ONEOK Foundation’s charitable programs has always been education at all levels to ensure that we have the talent necessary to be successful today and in the future.

The ONEOK Foundation's educational endowments include:

- Oklahoma State University: a $1 million contribution – which, when matched by the state and other organizations, multiplied to $4 million – to fund the ONEOK Chair in Finance in the university's Spears School of Business
- The University of Oklahoma: a $1 million Larry W. Brummett/ONEOK Chair in Rock Mechanics in the Mewbourne College of Earth and Energy; and a $1 million ONEOK Natural Gas Engineering and Management program endowment in the Mewbourne School of Petroleum and Geological Engineering
- The University of Tulsa: a $1 million Professorship in Business Ethics in the College of Business

Our employees are also involved in the communities where they live and work, contributing their time, effort and talents to nonprofit organizations.

Volunteers With Energy (VWE) is a companywide organization of employee volunteers who improve quality of life by helping others through volunteer participation in community and civic activities. Employees, retirees and family members have volunteered for events such as Special Olympics, community food drives, Habitat for Humanity and Big Brothers Big Sisters. Last year, 10,230 volunteer hours were invested in our communities.

VWE was organized in response to the growing need for volunteers for nonprofit agencies. Membership is open to all employees and retirees, as well as family members. Since its inception in January 2003, VWE has received more than 300 requests from charitable organizations for volunteer assistance with various events and activities, reaffirming that the organization is indeed addressing a critical need in the communities we serve.

safe,
efficient and
environmentally
responsible

Board of Directors

From left to right:

Curtis L. Dinan
Senior Vice President,
Chief Financial Officer
and Treasurer
ONEOK, Inc. and
Executive Vice President,
Chief Financial Officer
and Treasurer
ONEOK Partners, L.P.
Tulsa, Oklahoma

Gil J. Van Lunsen
Retired Managing Partner
KPMG LLP
Durango, Colorado

Gary N. Petersen
President
Endres Processing LLC
Rosemount, Minnesota

James C. Kneale
President and
Chief Operating Officer
ONEOK, Inc. and
ONEOK Partners, L.P.
Tulsa, Oklahoma

John W. Gibson
Chief Executive Officer
ONEOK, Inc.
Chairman and
Chief Executive Officer
ONEOK Partners, L.P.
Tulsa, Oklahoma

Gerald B. Smith
Chairman of the Board and
Chief Executive Officer
Smith, Graham & Company
Investment Advisors, L.P.
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Officers

John W. Gibson, 56
Chairman and
Chief Executive Officer

James C. Kneale, 57
President and
Chief Operating Officer

Curtis L. Dinan, 41
Executive Vice President, Chief
Financial Officer and Treasurer

John R. Barker, 62
Executive Vice President,
General Counsel and Secretary

Caron A. Lawhorn, 48
Senior Vice President and
Chief Accounting Officer

NATURAL GAS

Pierce H. Norton II, 49
Executive Vice President,
Natural Gas

Robert F. Martinovich, 51
President, Natural Gas Gathering
& Processing

W. Kent Shortridge, 42
President, Natural Gas Pipelines

Michel E. Nelson, 61
Senior Vice President,
Natural Gas Pipelines Operations

NATURAL GAS LIQUIDS

Terry K. Spencer, 49
Executive Vice President,
Natural Gas Liquids

Sheridan C. Swords, 40
President, Natural Gas Liquids
Gathering & Fractionation

Roger G. Thorpe, 41
President, Natural Gas Liquids
Pipelines

Wesley J. Christensen, 55
Senior Vice President, Natural Gas
Liquids Operations

Form 10-K

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, 2008.
OR
___ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from __________ to __________.

Commission file number **1-12202**

ONEOK PARTNERS, L.P.

(Exact name of registrant as specified in its charter)

Delaware	**93-1120873**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
100 West Fifth Street, Tulsa, OK	**74103**
(Address of principal executive offices)	(Zip Code)

Registrant's telephone number, including area code **(918) 588-7000**

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

Common units	**New York Stock Exchange**
(Title of Each Class)	(Name of Each Exchange on which Registered)

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

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

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

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

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Registration S-K (§ 229.405) 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. (Check one)
Large accelerated filer X Accelerated filer __ 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.

Aggregate market value of the common units held by non-affiliates based on the closing trade price on June 30, 2008, was $3.0 billion.

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date.

Class	Outstanding at February 18, 2009
Common units	54,426,087 units
Class B units	36,494,126 units

DOCUMENTS INCORPORATED BY REFERENCE: None.

ONEOK PARTNERS, L.P.
2008 ANNUAL REPORT ON FORM 10-K

As used in this Annual Report on Form 10-K, "we," "our," "us" or the "Partnership" refers to ONEOK Partners, L.P., its subsidiary, ONEOK Partners Intermediate Limited Partnership and its subsidiaries, unless the context indicates otherwise.

GLOSSARY

The abbreviations, acronyms and industry terminology used in this Annual Report on Form 10-K are defined as follows:

AFUDC..Allowance for funds used during construction
APB Opinion ....Accounting Principles Board Opinion
ARB ....Accounting Research Bulletin
Bbl ....Barrels, 1 barrel is equivalent to 42 United States gallons
Bbl/d ....Barrels per day
BBtu/d...Billion British thermal units per day
Bcf ....Billion cubic feet
Bcf/d ....Billion cubic feet per day
Bighorn Gas Gathering ....Bighorn Gas Gathering, L.L.C.
Black Mesa Pipeline ....Black Mesa Pipeline, Inc.
Btu ....British thermal units, a measure of the amount of heat required to raise the temperature of one pound of water one degree Fahrenheit
Bushton Plant..Bushton Gas Processing Plant
EBITDA..Earnings before interest, taxes, depreciation and amortization
EITF..Emerging Issues Task Force
EPA...United States Environmental Protection Agency
Exchange Act..Securities Exchange Act of 1934, as amended
FASB ....Financial Accounting Standards Board
FERC ....Federal Energy Regulatory Commission
FIN..FASB Interpretation
Fort Union Gas Gathering...Fort Union Gas Gathering, L.L.C.
GAAP ....Generally Accepted Accounting Principles in the United States
Guardian Pipeline ....Guardian Pipeline, L.L.C.
Heartland ....Heartland Pipeline Company
Intermediate Partnership ....ONEOK Partners Intermediate Limited Partnership, a wholly owned subsidiary of ONEOK Partners, L.P.
IRS ....Internal Revenue Service
KCC ....Kansas Corporation Commission
KDHE ....Kansas Department of Health and Environment
LIBOR ....London Interbank Offered Rate
Lost Creek Gathering Company ....Lost Creek Gathering Company, L.L.C.
MBbl...Thousand barrels
MBbl/d..Thousand barrels per day
Midwestern Gas Transmission....................................Midwestern Gas Transmission Company
MMBbl ....Million barrels
MMBtu ....Million British thermal units
MMBtu/d ....Million British thermal units per day
MMcf...Million cubic feet
MMcf/d ....Million cubic feet per day
Moody's...Moody's Investors Service, Inc.
NBP Services ....NBP Services, LLC, a subsidiary of ONEOK, Inc.
NGL(s)..Natural gas liquid(s)
Northern Border Pipeline..Northern Border Pipeline Company
NYMEX...New York Mercantile Exchange
NYSE...New York Stock Exchange
OBPI ....ONEOK Bushton Processing Inc.
OCC ....Oklahoma Corporation Commission
OkTex Pipeline ....OkTex Pipeline Company, L.L.C.
ONEOK ....ONEOK, Inc.
ONEOK NB..ONEOK NB Company, a wholly owned subsidiary of ONEOK, Inc.
ONEOK Partners GP ....ONEOK Partners GP, L.L.C., a wholly owned subsidiary of ONEOK and our sole general partner
OPIS ....Oil Price Information Service
Overland Pass Pipeline Company ....Overland Pass Pipeline Company LLC

Partnership Agreement	Third Amended and Restated Agreement of Limited Partnership of ONEOK Partners, L.P., as amended
RRC	Texas Railroad Commission
S&P	Standard & Poor's Rating Group
SEC	Securities and Exchange Commission
Statement	Statement of Financial Accounting Standards
TC PipeLines	TC PipeLines Intermediate Limited Partnership, a subsidiary of TC PipeLines, LP
TransCanada	TransCanada Corporation
Viking Gas Transmission	Viking Gas Transmission Company

The statements in this Annual Report on Form 10-K that are not historical information, including statements concerning plans and objectives of management for future operations, economic performance or related assumptions, are forward-looking statements. Forward-looking statements may include words such as "anticipate," "estimate," "expect," "project," "intend," "plan," "believe," "should," "goal," "forecast," "could," "may," "continue," "might," "potential," "scheduled" and other words and terms of similar meaning. Although we believe that our expectations regarding future events are based on reasonable assumptions, we can give no assurance that such expectations or assumptions will be achieved. Important factors that could cause actual results to differ materially from those in the forward-looking statements are described under Part I, Item 1A, Risk Factors, and Part II, Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operation, and "Forward-Looking Statements," in this Annual Report on Form 10-K for the year ended December 31, 2008.

PART I

ITEM 1. BUSINESS

GENERAL

ONEOK Partners, L.P. is a publicly traded Delaware master limited partnership that was formed in 1993. Our common units are listed on the NYSE under the trading symbol "OKS." We are one of the largest publicly traded master limited partnerships and a leader in the gathering, processing, storage and transportation of natural gas in the United States. In addition, we own one of the nation's premier natural gas liquids systems, connecting NGL supply in the Mid-Continent and Rocky Mountain regions with key market centers. We also own a 50 percent equity interest in a leading transporter of natural gas imported from Canada into the United States.

DESCRIPTION OF BUSINESS SEGMENTS

Our operations are divided into four strategic business segments based on similarities in economic characteristics, products and services, types of customers, methods of distribution and regulatory environment, as follows:

- our Natural Gas Gathering and Processing segment primarily gathers and processes unprocessed natural gas;
- our Natural Gas Pipelines segment primarily owns and operates regulated interstate and intrastate natural gas transmission pipelines and natural gas storage facilities;
- our Natural Gas Liquids Gathering and Fractionation segment primarily gathers, treats and fractionates NGLs and stores and markets NGL products; and
- our Natural Gas Liquids Pipelines segment primarily owns and operates FERC-regulated interstate natural gas liquids gathering and distribution pipelines.

For financial and statistical information regarding our business segments, see below in the "Segment Financial Information" section, Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operation and Note L of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.

Partnership Structure

We are managed under the direction of the Board of Directors of our sole general partner, ONEOK Partners GP, which consists of six members. Three of our Board members qualify as independent under the listing standards of the NYSE and also serve as the Audit Committee of ONEOK Partners GP. ONEOK Partners GP is a wholly owned subsidiary of ONEOK. ONEOK owns a 47.7 percent aggregate equity interest in us.

Business Strategy

Our primary business strategy is to deliver consistent growth and sustainable earnings while focusing on safe, reliable, environmentally sound and legally compliant operations for our customers, employees, contractors and the public through the following:

- developing and executing internally generated growth projects;
- executing strategic acquisitions that utilize our core competencies; and
- managing our balance sheet over the long term to maintain our credit ratings at or above their current investment-grade levels.

Outlook for 2009

We expect continued deteriorating economic conditions in 2009, with downward pressures, relative to 2008, on commodity prices for natural gas, NGLs and crude oil. We anticipate that lower commodity prices will result in reduced drilling activity and economic conditions will result in reduced petrochemical demand. We also expect continued volatility and disruption in the financial markets, which could result in an increased cost of capital. We expect depressed commodity prices and tighter capital markets to also result in the sale or consolidation of underperforming assets in the industry, which may present opportunities for us.

We intend to pursue growth in our natural gas businesses through well-connects and contract renegotiations and through expansions and extensions of our existing systems and plants. For our natural gas liquids businesses, we intend to continue to focus on adding new supply connections, optimizing existing assets, as well as completing our growth projects currently under construction. Capital expenditures in 2009 are expected to be significantly lower than in 2008 when we spent approximately $1.3 billion. We plan to spend approximately $425 million on capital expenditures in 2009, of which approximately $355 million is for growth projects. We also plan to pursue strategic acquisitions related to gathering, processing, fractionating, storing, transporting and marketing natural gas and NGLs.

SIGNIFICANT DEVELOPMENTS IN 2008

Capital Projects - The following projects were placed in-service during 2008:

- January - Midwestern Gas Transmission's eastern extension pipeline;
- July - final phase of Fort Union Gas Gathering expansion project;
- September - Woodford Shale natural gas liquids pipeline extension;
- October - Bushton fractionation expansion;
- November - Overland Pass Pipeline from Opal, Wyoming to Conway, Kansas; and
- December - partial operations of the Guardian Pipeline extension with interruptible service from Ixonia, Wisconsin, to Green Bay, Wisconsin.

Equity Issuance - In March 2008, we completed a public offering of 2.5 million common units at $58.10 per common unit, generating net proceeds of approximately $140.4 million after deducting underwriting discounts but before offering expenses. In addition, we sold 5.4 million common units to ONEOK in a private placement, generating proceeds of approximately $303.2 million. In conjunction with the public offering of common units and the private placement, ONEOK Partners GP contributed $9.4 million in order to maintain its 2 percent general partner interest in us.

In April 2008, we sold an additional 128,873 common units at $58.10 per common unit to the underwriters of the public offering upon the partial exercise of their option to purchase additional common units to cover over-allotments. We received net proceeds of approximately $7.2 million from the sale of the common units after deducting underwriting discounts but before offering expenses. In conjunction with the partial exercise by the underwriters, ONEOK Partners GP contributed $0.2 million in order to maintain its 2 percent general partner interest in us. As a result of these transactions, ONEOK now holds a 47.7 percent aggregate equity interest in us.

SEGMENT FINANCIAL INFORMATION

Operating Income - The following table sets forth (i) operating income and (ii) operating income including the impact of equity earnings from investments by segment, as a percentage of our consolidated total, excluding any gain or (loss) on sale of assets, for the periods indicated.

	Operating Income			Operating Income and Equity Earnings from Investments		
	Years Ended December 31,			Years Ended December 31,		
	2008	**2007**	**2006**	**2008**	**2007**	**2006**
Natural Gas Gathering and Processing	**38%**	42%	46%	**38%**	40%	41%
Natural Gas Pipelines	**21%**	25%	31%	**27%**	33%	40%
Natural Gas Liquids Gathering and Fractionation	**32%**	25%	22%	**27%**	21%	18%
Natural Gas Liquids Pipelines	**9%**	9%	7%	**8%**	8%	6%
Other and Eliminations	*	(1%)	(6%)	*	(2%)	(5%)
Total	**100%**	100%	100%	**100%**	100%	100%

* Represents a value of less than 1 percent.

Customers and Total Assets - See Note L of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K for discussion of revenues from external customers under "Customers" and disclosure of total assets by segment within the "Operating Segment Information" table.

Intersegment Revenues - The following table sets forth the percentage of intersegment revenues to total revenue, by segment, for the periods indicated.

	Years Ended December 31,		
Intersegment Revenues	**2008**	**2007**	**2006**
Natural Gas Gathering and Processing	**39%**	35%	35%
Natural Gas Pipelines	*	*	*
Natural Gas Liquids Gathering and Fractionation	*	*	*
Natural Gas Liquids Pipelines	**60%**	83%	100%

* Represents a value of less than 1 percent.

See Note L of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K for additional information about intersegment revenues.

NARRATIVE DESCRIPTION OF BUSINESS

Natural Gas Gathering and Processing

Business Strategy - We focus on safe, environmentally sound and legally compliant operations for our employees, contractors, customers and the public. We pursue growth through additional well connections, system expansions and strategic acquisitions. We seek to restructure expiring contracts to mitigate commodity price exposure. We also seek to provide reliable, efficient and consistent operations through optimization of our natural gas gathering and processing operations while managing costs.

Description of Business - Our operations include gathering of unprocessed natural gas produced from crude oil and natural gas wells. We gather unprocessed natural gas in the Mid-Continent region, which includes the Anadarko Basin of Oklahoma and the Hugoton and Central Kansas Uplift Basins of Kansas. We also gather unprocessed natural gas in two producing basins in the Rocky Mountain region: the Williston Basin, which spans portions of Montana, North Dakota and the Canadian province of Saskatchewan, and the Powder River Basin of Wyoming.

Our gathering and processing operations are non-discretionary services required by our customers to move their unprocessed natural gas from the producing regions to end users for consumption. In the Mid-Continent and Rocky Mountain regions, unprocessed natural gas is compressed and transported through pipelines to processing facilities where volumes are aggregated, treated and processed to remove water vapor, solids and other contaminants, and to extract NGLs in order to provide marketable natural gas, commonly referred to as residue gas. The residue gas, which consists primarily of methane, is compressed and delivered to natural gas pipelines for transportation to end users. When the NGLs are separated from the unprocessed natural gas at the processing plants, the NGLs are generally in the form of a mixed, unfractionated NGL stream. This unfractionated NGL stream is generally shipped to fractionators where, through the application of heat and pressure, the unfractionated NGL stream is separated into marketable purity products, such as ethane/propane mix, propane, iso-butane, normal butane and natural gasoline (collectively, NGL products). Our natural gas and NGL products are sold to affiliates and a diverse customer base.

Our natural gas processing operations utilize straddle and field gas processing plants to extract NGLs from unprocessed natural gas and remove water vapor and other contaminants from the unprocessed natural gas stream. A straddle gas processing plant is situated on a pipeline system and relies on the pipeline's natural gas throughput volume, which subjects the plant to increased supply risk as it is dependent upon the throughput of a single pipeline rather than several supply sources. Field gas processing plants process natural gas gathered from multiple producing wells.

Our Natural Gas Gathering and Processing segment gathers and processes unprocessed natural gas. We generally gather and process gas under the following types of contracts.

- Percent-of-Proceeds (POP) - Under a POP contract, we retain a percentage of the NGLs and/or a percentage of the residue gas as payment for gathering, compressing and processing the producer's unprocessed natural gas. The producer may take its share of the NGLs and residue gas in-kind or receive its share of proceeds from our sale of the commodities. POP contracts expose us to both natural gas and NGL commodity price risk but economically align us with the producer because we both benefit from higher commodity prices. For 2008, this type of contract represented approximately 34 percent of contracted volumes. There are a variety of factors that directly affect our POP margins, including:
    - the percentages of products retained that represent our equity NGL, condensate and residue gas sales volumes;
    - transportation and fractionation costs incurred on the NGLs; and

  - the natural gas, crude oil and NGL prices received for our retained products.
- Fee - Under a fee contract, we are paid a fee for the services provided that is based on Btus gathered, compressed and/or processed. The wellhead volume and fees received for the services provided are the main components of the margin for this type of contract. The producer typically takes its NGLs and residue gas in-kind. This type of contract primarily exposes us to volumetric risk with minimal commodity price risk. Our POP and keep-whole contracts also typically include fee provisions. For 2008, this type of contract represented approximately 58 percent of contracted volumes.
- Keep-Whole - Under a keep-whole processing contract, we extract NGLs from the unprocessed natural gas and return to the producer volumes of residue gas containing the same amount of Btus as the unprocessed natural gas that was delivered to us. We retain the NGLs as our fee for processing. Accordingly, we must purchase and return to the producer sufficient volumes of residue gas to replace the Btus that were removed as NGLs through the gathering and processing operation, commonly referred to as "shrink." Under index-based purchase agreements, we purchase unprocessed natural gas at the wellhead to replace the natural gas that we consume in processing, and we typically bear the full cost of the plant fuel and shrink, with the excess residue gas being sold monthly at index-based prices. By using this contract type, the producer is kept whole on a Btu basis. This type of contract exposes us to the keep-whole spread, or gross processing spread, which is the relative difference in the economic value between NGLs and natural gas on a Btu basis. For 2008, this type of contract represented approximately 8 percent of contracted volumes, with approximately 89 percent of that contracted volume containing language that effectively converts these contracts into fee contracts when the gross processing spread is negative. The main factors that affect our keep-whole margins include:
  - shrink;
  - plant fuel consumed;
  - transportation and fractionation costs incurred on the NGLs;
  - gross processing spread; and
  - the natural gas, crude oil and NGL prices received for products sold.

Revenues of this segment are derived primarily from POP and fee contracts. We use derivative instruments to mitigate our sensitivity to fluctuations in the price of natural gas, condensate and NGLs.

Unconsolidated Affiliates - Our Natural Gas Gathering and Processing segment has the following unconsolidated affiliates:
- 49 percent ownership interest in Bighorn Gas Gathering, which operates a major coalbed methane gathering system serving a broad production area in northeast Wyoming;
- 37 percent ownership interest in Fort Union Gas Gathering, which gathers coalbed methane gas produced in the Powder River Basin and delivers natural gas into the interstate pipeline grid;
- 35 percent ownership interest in Lost Creek Gathering Company, which gathers natural gas produced from conventional wells in the Wind River Basin of central Wyoming and delivers natural gas into the interstate pipeline grid; and
- 10 percent ownership interest in Venice Energy Services Co., LLC, a gas processing complex near Venice, Louisiana.

See Note M of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K for additional discussion of unconsolidated affiliates.

Market Conditions and Seasonality - Supply - Natural gas supply is affected by rig availability, operating capability and producer drilling activity, which is sensitive to commodity prices, exploration success, available capital and regulatory control. Relatively high natural gas and crude oil prices resulted in increased drilling for most of 2008 in the Mid-Continent and Rocky Mountain regions, which are our primary supply regions. Significant price declines and reduced drilling activity beginning in the fourth quarter of 2008 are now creating less favorable near-term supply projections.

In the Mid-Continent region, our gathering and processing assets in the Anadarko Basin of Oklahoma and the Hugoton and Central Kansas Uplift Basins of Kansas are well established. However, we anticipate continuing volumetric declines in certain fields that supply our gathering and processing operations.

In the Williston Basin, we connected more wells in 2008 than in prior years as a result of increased drilling activity. While transportation and refining capacity constraints for crude oil continue to moderately impact natural gas production in the Williston Basin, the recent reduction in commodity prices has decreased drilling activity.

Demand - Demand for gathering and processing services is typically aligned with the supply of natural gas, which generally flows from a producing area at a relatively steady but gradually declining pace over time unless new reserves are added. Our plant operations can be adjusted to respond to market conditions, such as demand for ethane. By changing operating parameters at certain plants, we can produce more of the specific commodity that has the most favorable price or price spread.

Commodity Prices - Crude oil, natural gas and NGL prices are volatile due to market conditions. Storage injection and withdrawal rates, as well as available storage capacity, can also have an impact on commodity prices. We are exposed to commodity price risk, primarily NGLs, as a result of receiving commodities in exchange for our services. To a lesser extent, exposures arise from the relative price differential between NGLs and natural gas, or the gross processing spread, with respect to our keep-whole processing contracts. We are also exposed to the risk of price fluctuations and the cost of intervening transportation at various market locations, and the demand for our products by the petrochemical industry and other consumers.

Seasonality - Some of this segment's products are subject to weather-related seasonal demand. Cold temperatures typically increase demand for natural gas and propane, which are used to heat homes and businesses. Warm temperatures typically drive demand for natural gas used for gas-fired electric generation used to cool residential and commercial properties. Demand for iso-butane and natural gasoline, which are primarily used by the refining industry as blending stocks for motor fuel, may also be subject to some variability when automotive travel is higher. During periods of peak demand for a certain commodity, prices for that product typically increase, which influences processing decisions.

Competition - The gathering and processing business remains relatively fragmented despite significant consolidation in the industry. We compete for natural gas supplies with major integrated exploration and production companies, pipeline companies and their affiliated marketing companies, national and local natural gas gatherers and processors, and marketers in the Mid-Continent and Rocky Mountain regions. The factors that typically affect our ability to compete for natural gas supplies are:

- producer drilling activity;
- the petrochemical industry's level of capacity utilization and its specific feedstock requirements;
- fees charged under our contracts;
- pressures maintained on our gathering systems;
- location of our gathering systems relative to our competitors;
- location of our gathering systems relative to drilling activity;
- efficiency and reliability of our operations; and
- delivery capabilities that exist in each system and plant location.

We are responding to these industry conditions by making capital investments to improve plant processing flexibility and reduce operating costs, evaluating consolidation opportunities to maximize earnings, selling assets in non-core operating areas and renegotiating unprofitable contracts. The principal goal of the contract renegotiation effort is to eliminate unprofitable contracts and improve margins, primarily during periods when the gross processing spread is negative.

Government Regulation - The FERC has traditionally maintained that a processing plant is not a facility for the transportation or sale for resale of natural gas in interstate commerce and, therefore, is not subject to jurisdiction under the Natural Gas Act. Although the FERC has made no specific declaration as to the jurisdictional status of our natural gas processing operations or facilities, our natural gas processing plants are primarily involved in removing NGLs and, therefore, we believe, are exempt from FERC jurisdiction. The Natural Gas Act also exempts natural gas gathering facilities from the jurisdiction of the FERC. Interstate transmission facilities remain subject to FERC jurisdiction. The FERC has historically distinguished between these two types of facilities, either interstate or intrastate, on a fact-specific basis. We believe our gathering facilities and operations meet the criteria used by the FERC for non-jurisdictional gathering facility status. We can transport residue gas from our plants to interstate pipelines in accordance with Section 311(a) of the Natural Gas Policy Act.

Oklahoma and Kansas also have statutes regulating, to various degrees, the gathering of natural gas in those states. In each state, regulation is applied on a case-by-case basis if a complaint is filed against the gatherer with the appropriate state regulatory agency.

Additionally, the operations of our assets are regulated by various state and federal government agencies. See further discussion in the "Environmental and Safety Matters" section.

Natural Gas Pipelines

Business Strategy - We focus on safe, environmentally sound and legally compliant operations for our employees, contractors, customers and the public. We seek to maintain a competitive cost structure and increase throughput and growth of our existing natural gas pipelines and storage assets through extensions and expansions supported by long-term transportation and reservation contracts.

Description of Business - Our Natural Gas Pipelines segment primarily owns and operates regulated natural gas transmission pipelines, natural gas storage facilities, and non-processable natural gas gathering facilities. We also provide interstate natural gas transportation and storage service in accordance with Section 311(a) of the Natural Gas Policy Act.

Our interstate natural gas pipeline assets transport natural gas through FERC-regulated interstate natural gas pipelines in Montana, North Dakota, South Dakota, Minnesota, Wisconsin, Iowa, Illinois, Indiana, Kentucky, Tennessee, Oklahoma, Texas and New Mexico. Our interstate pipelines include:

- Midwestern Gas Transmission, which is a bi-directional system that interconnects with Tennessee Gas Transmission Company near Portland, Tennessee, and with several interstate pipelines near Joliet, Illinois;
- Viking Gas Transmission, which transports natural gas from an interconnection with TransCanada near Emerson, Manitoba, to an interconnection with ANR Pipeline Company near Marshfield, Wisconsin;
- Guardian Pipeline interconnects with several pipelines in Joliet, Illinois, and with local distribution companies in Wisconsin; and
- OkTex Pipeline, which has interconnects in Oklahoma, New Mexico and Texas.

Our intrastate natural gas pipeline assets in Oklahoma have access to the major natural gas producing areas and transport natural gas throughout the state. We also have access to the major natural gas producing area in south central Kansas. In Texas, our intrastate natural gas pipelines are connected to the major natural gas producing areas in the Texas panhandle and the Permian Basin and transport natural gas to the Waha Hub, where other pipelines may be accessed for transportation east to the Houston Ship Channel market, north into the Mid-Continent market and west to the California market.

We own storage capacity in underground natural gas storage facilities in Oklahoma, Kansas and Texas.

Our transportation contracts for our regulated natural gas activities are based upon rates stated in our tariffs. Tariffs specify the maximum rates customers can be charged, which can be discounted to meet competition if necessary, and the general terms and conditions for pipeline transportation service, which are established at FERC or appropriate state jurisdictional agency proceedings known as rate cases. In Texas and Kansas, natural gas storage service is a fee business that may be regulated by the state in which the facility operates and by the FERC for certain types of services. In Oklahoma, natural gas gathering and natural gas storage operations are not subject to rate regulation and have market-based rate authority from the FERC for certain types of services.

Our Natural Gas Pipelines segment’s revenues are typically derived from fee services from the following types of contracts.

- Firm Service - Customers can reserve a fixed quantity of pipeline or storage capacity for the term of their contract. Under this type of contract, the customer pays a fixed fee for a specified quantity regardless of their actual usage. The customer then typically pays incremental fees, known as commodity charges, that are based upon the actual volume of natural gas they transport or store, and/or we may retain a specified volume of natural gas in-kind for fuel. Under the firm-service contract, the customer is generally guaranteed access to the capacity they reserve.
- Interruptible Service - Customers with interruptible service transportation and storage agreements may utilize available capacity after firm-service requests are satisfied or on an as-available basis. Interruptible service customers are typically assessed fees, such as a commodity charge, based on their actual usage, and/or we may retain a specified volume of natural gas in-kind for fuel. Under the interruptible service contract, the customer is not guaranteed use of our pipelines and storage facilities unless excess capacity is available.

Unconsolidated Affiliates - Our Natural Gas Pipelines segment has the following unconsolidated affiliates:

- 50 percent interest in Northern Border Pipeline, which transports natural gas from the Montana-Saskatchewan border near Port Morgan, Montana, to a terminus near North Hayden, Indiana; and
- 48 percent ownership interest in Sycamore Gas System, which is a gathering system with compression located in south central Oklahoma.

See Note M of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K for additional discussion of unconsolidated affiliates.

Market Conditions and Seasonality - Supply - The supply of natural gas for Viking Gas Transmission and Northern Border Pipeline originates in Canada. Significant factors that can impact the supply of Canadian natural gas transported by our pipelines are the Canadian natural gas available for export, Canadian storage capacity and demand for Canadian natural gas in other U.S. consumer markets. Guardian Pipeline and Midwestern Gas Transmission access supply from the major producing regions of the Mid-Continent, Rocky Mountain, Canada and Gulf Coast. The supply of natural gas to our Mid-Continent pipelines and storage assets currently depends on the pace of natural gas drilling activity by producers and the decline rate of existing production in the major natural gas production areas in the Rocky Mountain and Mid-Continent regions, including the Anadarko Basin, Hugoton Basin, Central Kansas Uplift Basin, Permian Basin, Williston Basin and Powder River Basin. United States natural gas drilling rig counts increased in 2008, compared with 2007, but rig counts began to decline towards the end of 2008 and continuing into 2009.

Demand - Demand for pipeline transportation service and natural gas storage is directly related to demand for natural gas in the markets that the natural gas pipelines and storage facilities serve, and is affected by weather, the economy, and natural gas and NGL price volatility. The effect of weather on our natural gas pipelines operations is discussed below under "Seasonality." The strength of the economy directly impacts manufacturing and industrial companies that rely on natural gas. Commodity price volatility can influence producers' decisions related to the production of natural gas, the level of NGLs processed from natural gas and natural gas storage injection and withdrawal activity.

Commodity Prices - We are exposed to market risk when existing contracts expire and are subject to renegotiation with customers that have competitive alternatives and analyze the market price spread or basis differential between receipt and delivery points along the pipeline to determine their expected gross margin. The anticipated margin and its variability are important determinants of the transportation rate customers are willing to pay. Natural gas storage revenue is impacted by the differential between forward pricing of natural gas physical contracts and the price of natural gas on the spot market. Our fuel costs and the value of the retained fuel in-kind are also impacted by changes in the price of natural gas.

Seasonality - Demand for natural gas is seasonal. Weather conditions throughout the United States can significantly impact regional natural gas supply and demand. High temperatures can increase demand for gas-fired electric generation to cool residential and commercial properties. Cold temperatures can lead to greater demand for our transportation services due to increased demand for natural gas to heat residential and commercial properties. Low precipitation levels can impact the demand for natural gas that is used to fuel irrigation activity in the Mid-Continent region.

To the extent that pipeline capacity is contracted under firm-service transportation agreements, revenue, which is generated primarily from demand charges, is not significantly impacted by seasonal throughput variations. However, when transportation agreements expire, seasonal demand can impact negotiations of firm-service transportation capacity.

Natural gas storage is necessary to balance the relatively steady natural gas supply with the seasonal demand of residential, commercial and electric power generation users. The majority of our storage capacity is contracted under term agreements. A small portion of our storage capacity is retained for operational purposes and seasonal market activity.

Competition - Our natural gas pipelines compete directly with other intrastate and interstate pipeline companies and other storage facilities for natural gas. Our natural gas assets primarily serve local distribution companies, large industrial companies, municipalities, irrigation customers, power generation facilities and marketing companies. Competition among pipelines and natural gas storage facilities is based primarily on fees for services, quality of services provided, current and forward natural gas prices, and proximity to natural gas supply areas and markets. Competition for natural gas transportation services continues to increase as the FERC and state regulatory bodies continue to encourage more competition in the natural gas markets. We believe that we compete effectively with our pipelines and storage assets due to their strategic locations connecting supply areas to market centers and other pipelines.

Government Regulation - Our interstate natural gas pipelines are regulated under the Natural Gas Act and Natural Gas Policy Act, which give the FERC jurisdiction to regulate virtually all aspects of this business segment, such as transportation of natural gas, rates and charges for services, construction of new facilities, depreciation and amortization policies, acquisition and disposition of facilities, and initiation and discontinuation of services.

Likewise, our intrastate natural gas pipelines in Oklahoma, Kansas and Texas are regulated by the OCC, KCC and RRC, respectively. While we have flexibility in establishing natural gas transportation rates with customers, there is a maximum rate that we can charge our customers in Oklahoma and Kansas. In Kansas and Texas, natural gas storage may be regulated by the state and by the FERC for certain types of services. In Oklahoma, natural gas gathering and storage are not subject to rate regulation and have market-based rate authority for certain types of services.

Additionally, the operations of our assets are regulated by various state and federal government agencies. See further discussion in the "Environmental and Safety Matters" section.

Natural Gas Liquids Gathering and Fractionation

Business Strategy - We focus on safe, environmentally sound and legally compliant operations for our employees, contractors, customers and the public. We seek to maximize our value by increasing facility utilization and efficiently managing the operating costs of our natural gas liquids assets, which consist of facilities that gather, fractionate and treat NGLs and store NGL products in the Mid-Continent and Gulf Coast regions.

Description of Business - Our natural gas liquids gathering and fractionation assets consist of facilities that gather, fractionate and treat NGLs and store NGL products primarily in Oklahoma, Kansas and Texas, as well as store and fractionate NGLs and NGL products in Mont Belvieu, Texas. Most of the pipeline-connected natural gas processing plants in Oklahoma, Kansas and the Texas panhandle, which extract NGLs from unprocessed natural gas, are connected to our gathering systems.

Most natural gas produced at the wellhead contains a mixture of NGL components such as ethane, propane, iso-butane, normal butane and natural gasoline. Natural gas processing plants remove the NGLs from the natural gas stream to realize the higher economic value of the NGLs and to meet natural gas pipeline quality specifications, which limit NGLs in the natural gas stream due to liquid and Btu content. The NGLs that are separated from the natural gas stream at the natural gas processing plants remain in a mixed, unfractionated form until they are gathered, primarily by pipeline, and delivered to fractionators.

Our natural gas liquids gathering and fractionation operations are non-discretionary services required by our customers to convert their mixed, unfractionated NGLs into marketable purity products. A fractionator, through the application of heat and pressure, separates the unfractionated NGL stream into marketable purity products, such as ethane, ethane/propane mix, propane, iso-butane, normal butane and natural gasoline (collectively, NGL products). These NGL products are then stored or distributed to our customers, such as petrochemical manufacturers, heating fuel users, refineries and propane distributors. Our fractionation and storage facilities are connected to the key natural gas liquids market centers in Conway, Kansas, and Mont Belvieu, Texas, by FERC-regulated interstate natural gas liquids pipelines, which are part of our Natural Gas Liquids Pipelines segment. We also purchase NGLs and condensate from third parties as well as from our Natural Gas Gathering and Processing segment.

Revenues for our Natural Gas Liquids Gathering and Fractionation segment are primarily derived from exchange services, optimization, isomerization and storage.

- Our exchange services business collects fees to gather, fractionate and treat unfractionated NGLs, thereby converting them into NGL products that are stored and shipped to a market center or customer-designated location.
- Our optimization business utilizes our assets, contract portfolio and market knowledge to capture locational and seasonal price differentials. We move NGL products between Conway, Kansas, and Mont Belvieu, Texas, in order to capture the locational price differentials between the two market centers. Our NGL storage facilities are also utilized to capture seasonal price variances.
- Our isomerization business captures the price differential when normal butane is converted into the more valuable iso-butane at an isomerization unit in Conway, Kansas. Iso-butane is used in the refining industry to increase the octane of motor gasoline.
- Our storage business collects fees to store NGLs at our Mid-Continent and Mont Belvieu facilities.

Market Conditions and Seasonality - Supply - Supply for our Natural Gas Liquids Gathering and Fractionation segment depends on the pace of crude oil and natural gas drilling activity by producers, the decline rate of existing production, and the liquid content of the natural gas that is produced and processed. Our Mont Belvieu fractionation operation receives NGLs from a variety of processors and pipelines located in the Gulf Coast, west and central Texas, and Rocky Mountain regions.

Our natural gas liquids gathering pipelines are also affected by operational or market-driven changes that impact the output of natural gas processing plants to which they are connected. The differential between the composite price of NGL products and the price of natural gas, particularly the differential between the price of ethane and the price of natural gas, may influence processing plant NGL output. Historically, the forward price of ethane, compared with the forward price of natural gas, provides minimal or no processing spread. However, when the physical transactions occur, the price of ethane to natural gas has generally provided a positive processing spread. For the majority of 2008, ethane prices remained above natural gas prices on a relative basis, which resulted in ethane recovery from processing plants that deliver NGLs to our natural gas liquids gathering pipelines. Similar to the pricing environments we experienced in September and December of 2008, we expect ethane prices in 2009, at times, to be below natural gas prices, with some processing plants connected to our natural gas liquids gathering pipelines reducing ethane production.

Demand - Demand for NGLs and the ability of natural gas processors to successfully and economically sustain their operations impacts the volume of unfractionated NGLs produced by natural gas processing plants, thereby affecting the demand for NGL gathering and fractionation services. Natural gas and propane are subject to weather-related seasonal demand. Other NGL products are affected by economic conditions and the demand associated with the various industries that utilize the commodity, such as butanes and natural gasoline, which are used by the refining industry as blending stocks for motor fuel. Ethane/propane mix is used by the petrochemical industry to produce chemical products, such as plastic, rubber and synthetic fiber.

Commodity Prices - In recent years, crude oil, natural gas and NGL prices have been volatile due to market conditions. We are exposed to market risk associated with adverse changes in the price of NGLs, the basis differential between the Mid-Continent and Gulf Coast regions, and the relative price differential between natural gas, NGLs and individual NGL products, which impact our NGL purchases, sales, exchange and storage revenue. When natural gas prices are higher relative to NGL prices, NGL production may decline, which could negatively impact our exchange services revenue. When the basis differential between the Mid-Continent and Gulf Coast regions is narrow, optimization opportunity and margins may decline. NGL storage revenue may be impacted by price volatility and forward pricing of NGL physical contracts versus the price of NGLs on the spot market.

Seasonality - Some NGL products produced by our natural gas liquids facilities are subject to weather-related seasonal demand, such as propane, which is primarily used to heat residential properties during the winter heating season. Demand for normal butane, iso-butane and natural gasoline, which are primarily used by the refining industry as blending stocks for motor fuel, may also be subject to some variability when automotive travel is higher.

Competition - Our gathering and fractionation business competes with other fractionators, storage providers and gatherers for NGL supplies in the Rocky Mountain, Mid-Continent and Gulf Coast regions. The factors that typically affect our ability to compete for NGL supplies are:

- producer drilling activity;
- the petrochemical industry's level of capacity utilization and feedstock requirements;
- fees charged under our contracts;
- pressures maintained on our gathering systems;
- location of our gathering systems relative to our competitors;
- location of our gathering systems relative to drilling activity;
- efficiency and reliability of our operations; and
- delivery capabilities that exist in each system, plant and storage location.

We are responding to these industry conditions by making capital investments to access new supplies, increase gathering and fractionation capacity, increase storage capabilities and reduce operating costs so that we may effectively compete.

Government Regulation - Revenues generated by our pipelines in both Oklahoma and Kansas are not regulated by the FERC or those states' respective corporation commissions. However, the operations of our assets are regulated by various state and federal government agencies. See further discussion in the "Environmental and Safety Matters" section.

Natural Gas Liquids Pipelines

Business Strategy - We focus on safe, environmentally sound and legally compliant operations for our employees, contractors, customers and the public. We seek to increase throughput and to continue to provide cost-effective transportation of NGLs between the Rocky Mountain, Mid-Continent and Gulf Coast regions and the Midwest markets near Chicago, Illinois. We pursue growth of our interstate natural gas liquids pipelines by making capital investments to expand our access to new supplies and increase our pipeline capacity.

Description of Business - Our Natural Gas Liquids Pipelines segment primarily owns and operates FERC-regulated natural gas liquids gathering and distribution pipelines and associated above- and below-ground storage facilities. Our natural gas liquids gathering pipelines deliver unfractionated NGLs gathered in Oklahoma, Kansas, the Texas panhandle and the Rocky Mountain region to our Natural Gas Liquids Gathering and Fractionation segment's Mid-Continent fractionation facilities in Oklahoma and Kansas. Our natural gas liquids distribution pipelines deliver unfractionated NGLs and NGL products to the natural gas liquids market hubs in Conway, Kansas, and Mont Belvieu, Texas. Through our acquisition of the natural gas liquids assets from Kinder Morgan Energy Partners, L.P. (Kinder Morgan), we acquired terminal and storage facilities, as well as natural gas liquids and refined petroleum products pipelines that connect our Mid-Continent assets with Midwest markets, including Chicago, Illinois. We operate FERC-regulated natural gas liquids gathering and distribution pipelines in

Oklahoma, Kansas, Nebraska, Missouri, Iowa, Illinois, Indiana, Texas, Wyoming and Colorado. We have product terminal and storage facilities in Missouri, Nebraska, Iowa and Illinois.

Revenues for this segment are primarily derived from transporting product under our FERC-regulated tariffs. Tariffs specify the rates we can charge our customers and the general terms and conditions for NGL transportation service on our pipelines. Our tariffs include specifications regarding the receipt and delivery of NGLs at points along the pipeline systems. We generally charge tariff rates under a FERC-approved indexing methodology, which allows charging rates up to a prescribed ceiling that changes annually based on the year-to-year change in the Producer Price Index for finished goods. The FERC also permits interstate natural gas liquids pipelines to support rates by using a cost-of-service methodology, competitive market price or an agreement with a pipeline's non-affiliated shipper.

Our storage services are primarily offered through FERC-regulated tariffs and are generally used for operational purposes and to store our customers' NGL products. Under some of our FERC-regulated tariffs, customers are allotted earned storage capacity based upon their utilization of transport services. When a customer exceeds its earned storage capacity, we charge the customer an excess storage fee. In some of our product storage agreements, we charge some customers storage lease fees to reserve a specific storage capacity, and we charge some customers based on the quantity of capacity utilized.

Unconsolidated Affiliates - Our Natural Gas Liquids Pipelines segment has the following unconsolidated affiliates:

- 50 percent ownership interest in Chisholm Pipeline Company, which operates an interstate natural gas liquids pipeline system extending approximately 184 miles from origin points in Oklahoma and Kansas; and
- 50 percent ownership interest in Heartland, which operates a terminal and pipeline system that transports refined petroleum products in Kansas, Nebraska and Iowa.

See Note M of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K for additional discussion of unconsolidated affiliates.

Market Conditions and Seasonality - Supply - The supply for our Natural Gas Liquids Pipelines segment depends on the pace of crude oil and natural gas drilling activity by producers, the decline rate of existing production and the liquid content of the natural gas that is produced and processed. The unfractionated NGLs that we transport and store are primarily gathered from natural gas processing plants in Oklahoma, Kansas, the Texas panhandle and the Rocky Mountain region. The supply of NGLs gathered are affected by operational or market-driven changes that impact the NGL output of natural gas processing plants to which we are connected. The differential between the composite price of NGL products and the price of natural gas, particularly the differential between the price of ethane and the price of natural gas, may influence processing plant output. Historically, the forward price of ethane, compared with the forward price of natural gas, provides minimal or no processing spread. However, as the prices settle, the price of ethane to natural gas has generally provided a positive processing spread. For the majority of 2008, ethane prices remained above natural gas prices on a relative basis, which resulted in ethane recovery from processing plants that deliver NGLs to our natural gas liquids gathering pipelines. Similar to the pricing environments we experienced in September and December of 2008, we expect ethane prices in 2009, at times, to be below natural gas prices, with some processing plants connected to our natural gas liquids gathering pipelines reducing ethane production.

Demand - Demand for NGLs and the ability of natural gas processors to successfully and economically sustain their operations impacts the volume of unfractionated NGLs produced by natural gas processing plants, which affects the demand for our NGL gathering and distribution services. Propane is subject to weather-related seasonal demand. Other products are affected by economic conditions and the demand associated with the various industries that utilize the commodity, such as butanes and natural gasoline, which are used by the refining industry as blending stocks for motor fuel. Ethane/propane mix is used by the petrochemical industry to produce chemical products, such as plastic, rubber and synthetic fiber.

Commodity Prices - In recent years, crude oil, natural gas and NGL prices have been volatile due to market conditions. We are exposed to market risk associated with adverse changes in the price of NGLs, the basis differential between the Mid-Continent, Chicago, Illinois, and Gulf Coast regions, and the relative price differential between natural gas, unfractionated NGLs and individual NGL products, which impact the distribution of NGL products. When natural gas prices are higher relative to NGL prices, NGL production may decline, which could negatively impact the revenues of our gathering and distribution activities. When the basis differential between the Mid-Continent, Chicago, Illinois, and Gulf Coast regions is narrow, NGL shipments may decline, resulting in a reduction of transportation revenues.

Seasonality - Some NGLs gathered and distributed by our natural gas liquids pipeline facilities are subject to weather-related seasonal demand, such as propane, which is primarily used to heat residential properties during the winter heating season and for agricultural purposes such as grain drying in the fall. Demand for normal butane, iso-butane and natural gasoline, which are primarily used by the refining industry as blending stocks for motor fuel, may also be subject to some variability when automotive travel is higher.

Competition - Our natural gas liquids pipelines compete directly with other intrastate and interstate pipeline companies and other storage facilities for NGLs. Competition among pipeline companies and NGL storage facilities is based primarily on fees for services, quality of services provided, current and forward NGL prices and proximity to natural gas liquids supply areas and markets. We believe that we compete effectively with our pipelines and storage assets due to their strategic locations connecting supply areas to market centers.

Government Regulation - Our interstate natural gas liquids pipelines are regulated by the FERC, which regulates virtually all aspects of this business segment, such as transportation of NGLs and refined products, fees for services, depreciation and amortization policies, and initiation and discontinuation of services. The KCC regulates intrastate transportation of NGLs and refined products in Kansas.

Additionally, the operations of our assets are regulated by various state and federal government agencies. See further discussion in the "Environmental and Safety Matters" section.

Other

Description of Business - Our Other segment includes Black Mesa Pipeline, a 273-mile pipeline designed to transport crushed coal suspended in water that originates at a coal mine in Kayenta, Arizona, and terminates at the Mohave Generating Station (Mohave) in Laughlin, Nevada. Operations for Mohave ceased on December 31, 2005. Also on December 31, 2005, Black Mesa Pipeline's transportation contract with the coal supplier of Mohave expired, and our coal slurry pipeline operations were shut down. In the second quarter of 2008, we started the decommissioning of Black Mesa Pipeline. The duration of the decommissioning process will depend on, among other factors, the arrangements we make with land owners as to the transfer, abandonment or removal of property on their lands. We do not expect the decommissioning to have a material impact on our consolidated financial statements.

ENVIRONMENTAL AND SAFETY MATTERS

Information about our environmental matters is included in Note J of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.

Pipeline Safety - We are subject to United States Department of Transportation regulations, including integrity management regulations. The Pipeline Safety Improvement Act requires pipeline companies to perform integrity assessments on pipeline segments that pass through densely populated areas or near specifically designated high consequence areas. To our knowledge, we are in compliance with all material requirements associated with the various pipeline safety regulations.

Air and Water Emissions - The federal Clean Air Act, the federal Clean Water Act and analogous state laws impose restrictions and controls regarding the discharge of pollutants into the air and water in the United States. Under the Clean Air Act, a federally enforceable operating permit is required for sources of significant air emissions. We may be required to incur certain capital expenditures for air pollution-control equipment in connection with obtaining or maintaining permits and approvals for sources of air emissions. The Clean Water Act imposes substantial potential liability for the removal of pollutants discharged to waters of the United States and remediation of waters affected by such discharge. To our knowledge, we are in compliance with all material requirements associated with the various regulations.

The United States Congress is actively considering legislation to reduce emissions of greenhouse gases, including carbon dioxide and methane. In addition, state and regional initiatives to regulate greenhouse gas emissions are underway. We are monitoring federal and state legislation to assess the potential impact on our operations. Our most recent calculation of direct greenhouse gas emissions is estimated to be less than 6 million metric tons of carbon dioxide equivalents on an annual basis. We will continue efforts to quantify our direct greenhouse gas emissions and will report such emissions as required by any mandatory reporting rule, including the rules anticipated to be issued by the EPA in mid-2009.

Superfund - The Comprehensive Environmental Response, Compensation and Liability Act, also known as CERCLA or Superfund, imposes liability, without regard to fault or the legality of the original act, on certain classes of persons who contributed to the release of a hazardous substance into the environment. These persons include the owner or operator of a facility where the release occurred and companies that disposed or arranged for the disposal of the hazardous substances found at the facility. Under CERCLA, these persons may be liable for the costs of cleaning up the hazardous substances released into the environment, damages to natural resources and the costs of certain health studies.

Chemical Site Security - The United States Department of Homeland Security (Homeland Security) released an interim rule in April 2007 that requires companies to provide reports on sites where certain chemicals, including many hydrocarbon products, are stored. We completed the Homeland Security assessments, and our facilities were subsequently assigned one of four risked-based tiers ranging from high (Tier 1) to low (Tier 4) risk, or not tiered at all due to low risk. A majority of our facilities were not tiered. We are currently waiting for Homeland Security's analysis to determine if any of the tiered facilities will require Site Security Plans and possible physical security enhancements.

Climate Change - Our environmental and climate change strategy focuses on taking steps to minimize the impact of our operations on the environment. These strategies include: (i) developing and maintaining an accurate greenhouse gas emissions inventory, according to rules anticipated to be issued by the EPA in mid-2009, (ii) improving the efficiency of our various pipelines, natural gas processing facilities and natural gas liquids fractionation facilities, (iii) following developing technologies for emissions control, (iv) following developing technologies to capture carbon dioxide to keep it from reaching the atmosphere, and (v) analyzing options for future energy investment.

We participate in the EPA's Natural Gas STAR Program to voluntarily reduce methane emissions. We were honored in 2008 as the "Natural Gas STAR Gathering and Processing Partner of the Year" for our efforts to positively address environmental issues through voluntary implementation of emission-reduction opportunities. In addition, we continue to focus on maintaining low rates of lost-and-unaccounted-for methane gas through expanded implementation of best practices to limit the release of methane gas during pipeline and facility maintenance and operations. Our most recent calculation of our annual lost-and-unaccounted-for natural gas, for all of our business operations, is less than 1 percent of total throughput.

EMPLOYEES

We do not directly employ any of the persons responsible for managing, operating or providing us with services related to our day-to-day business affairs. We have a service agreement with ONEOK, ONEOK Partners GP and NBP Services (the Services Agreement) under which our operations and the operations of ONEOK and its affiliates can combine or share certain common services in order to operate more efficiently and cost effectively. Under the Services Agreement, ONEOK provides us an equivalent type and amount of services that it provides to its other affiliates, including those services required to be provided pursuant to our Partnership Agreement. ONEOK Partners GP operates our interstate natural gas pipeline assets according to each pipeline's operating agreement. ONEOK Partners GP may purchase services from ONEOK and its affiliates pursuant to the terms of the Services Agreement. As of January 31, 2009, we utilized the services of 1,232 people in addition to the other resources provided by ONEOK and its affiliates.

AVAILABLE INFORMATION

We make available on our Web site copies of our Annual Report on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K, amendments to those reports filed or furnished to the SEC pursuant to Section 13(a) or 15(d) of the Exchange Act and reports of holdings of our securities filed by our officers and directors under Section 16 of the Exchange Act as soon as reasonably practicable after filing such material electronically or otherwise furnishing it to the SEC. Copies of our Code of Business Conduct, Governance Guidelines, Partnership Agreement and the written charter of our Audit Committee are also available on our Web site, and we will make available, free of charge, copies of these documents upon request. However, our Web site and any contents thereof are not incorporated by reference into this document.

ITEM 1A. RISK FACTORS

Our investors should consider the following risks that could affect us and our business. Although we have tried to discuss key factors, our investors need to be aware that other risks may prove to be important in the future. New risks may emerge at any time, and we cannot predict such risks or estimate the extent to which they may affect our financial performance. Investors should carefully consider the following discussion of risks and the other information included or incorporated by reference in this Annual Report on Form 10-K, including "Forward-Looking Statements," which are included in Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operation.

RISKS INHERENT IN OUR BUSINESS

Current levels of market volatility are unprecedented.

The capital and credit markets have been experiencing volatility and disruption. During the fourth quarter of 2008, the volatility and disruption reached unprecedented levels. In many cases, the capital markets have exerted downward pressure on equity prices and reduced the credit capacity for companies. Our ability to grow could be constrained if we do not have regular access to the capital and credit markets. If current levels of market disruption and volatility continue or worsen, our access to capital and credit markets could be disrupted, making growth through acquisitions and development projects difficult or impractical to pursue until such time as markets stabilize.

Our operating results may be adversely affected by unfavorable economic and market conditions.

Economic conditions worldwide have from time to time contributed to slowdowns in the oil and gas industry, as well as in the specific segments and markets in which we operate, resulting in reduced demand and increased price competition for our products and services. Our operating results in one or more geographic regions may also be affected by uncertain or changing economic conditions within that region. Volatility in commodity prices might have an impact on many of our customers, which, in turn, could have a negative impact on their ability to meet their obligations to us. If global economic and market conditions (including volatility in commodity markets), or economic conditions in the United States or other key markets, remain uncertain or persist, spread or deteriorate further, we may experience material impacts on our business, financial condition and results of operations.

The recent downturn in the credit markets has increased the cost of borrowing and has made financing difficult to obtain, each of which may have a material adverse effect on our results of operations and business.

Recent events in the financial markets have had an adverse impact on the credit markets. As a result, credit has become more expensive and difficult to obtain. Some lenders are imposing more stringent restrictions on the terms of credit and there may be a general reduction in the amount of credit available in the markets in which we conduct business. The negative impact of the tightening of the credit markets or a further tightening may have a material adverse effect on us resulting from, but not limited to, an inability to obtain credit necessary to expand facilities or finance the acquisition of assets on favorable terms, if at all, increased financing costs or financing with increasingly restrictive covenants.

The volatility of natural gas, crude oil and NGL prices could adversely affect our cash flow.

A significant portion of our revenues are derived from the sale of commodities received as payment for our natural gas gathering and processing services, for transportation and storage of natural gas and NGLs, and for the fractionation of NGLs. As a result, we are sensitive to commodity price fluctuations. Commodity prices have been volatile and are likely to continue to be so in the future. Recent significant and steep commodity price declines and compressions in commodity price differentials have had and could continue to have material negative impacts on our financial results. The prices we receive for our commodities are subject to wide fluctuations in response to a variety of factors beyond our control, including the following:

- overall domestic and global economic conditions;
- relatively minor changes in the supply of, and demand for, domestic and foreign energy;
- market uncertainty;
- the availability and cost of transportation capacity;
- the level of consumer product demand;
- geopolitical conditions impacting supply and demand for natural gas and crude oil;
- weather conditions;
- domestic and foreign governmental regulations and taxes;
- the price and availability of alternative fuels;
- speculation in the commodity futures markets;
- the price of natural gas, crude oil, NGL and liquefied natural gas imports; and
- the effect of worldwide energy conservation measures.

These external factors and the volatile nature of the energy markets make it difficult to reliably estimate future prices of commodities and the impact commodity price fluctuations have on our customers and their need for our services. As commodity prices decline, we are paid less for our commodities, thereby reducing our cash flow. In addition, production and related volumes could also decline.

We may not be able to generate sufficient cash from operations to allow us to pay quarterly distributions at current levels following establishment of cash reserves and payment of fees and expenses, including payments to our affiliates.

The amount of cash we can distribute to our unitholders principally depends upon the cash we generate from our operations. Because the cash we generate from operations will fluctuate from quarter to quarter, we may not be able to maintain future quarterly distributions at the current level. Our ability to pay quarterly distributions depends primarily on cash flow, including cash flow from financial reserves and working capital borrowings, and not solely on profitability, which is affected by non-cash items. As a result, we may pay cash distributions during periods when we record net losses and may be unable to pay cash distributions during periods when we record net income.

We do not fully hedge against price changes in commodities. This could result in decreased revenues, increased costs and lower margins, adversely affecting our results of operations.

Our businesses are exposed to market risk and the impact of market fluctuations in natural gas, NGLs and crude oil prices. Market risk refers to the risk of loss arising from adverse changes in commodity energy prices. Our primary exposures arise from commodity prices with respect to our processing agreements, the differentials between NGL and natural gas prices with respect to our natural gas and NGL transportation, fractionation and exchange agreements, the differential between the individual NGL products and the differentials in natural gas and NGLs in storage utilized by our operations. To manage the risk from market fluctuations in natural gas, NGL and condensate prices, we use commodity derivative instruments such as futures contracts, swaps and options. However, we do not fully hedge against commodity price changes, and we therefore retain some exposure to market risk. Accordingly, any adverse changes to commodity prices could result in decreased revenue and increased costs.

Our use of financial instruments to hedge market risk may result in reduced income.

We utilize financial instruments to mitigate our exposure to interest rate and commodity price fluctuations. Hedging instruments that are used to reduce our exposure to interest rate fluctuations could expose us to risk of financial loss where we have contracted for variable-rate swap instruments to hedge fixed-rate instruments and the variable rate exceeds the fixed rate. In addition, these hedging arrangements may limit the benefit we would otherwise receive if we have contracted for fixed-rate swap agreements to hedge variable-rate instruments and the variable rate falls below the fixed rate. Hedging arrangements that are used to reduce our exposure to commodity price fluctuations may limit the benefit we would otherwise receive if market prices for natural gas and NGLs exceed the stated price in the hedge instrument for these commodities.

Our inability to execute growth and development projects and acquire new assets could reduce cash distributions to our unitholders.

Our primary business objectives are to generate cash flow sufficient to pay quarterly cash distributions to our unitholders and to increase our quarterly cash distributions over time. Our ability to maintain and grow our distributions to unitholders depends on the growth of our existing businesses and strategic acquisitions. Accordingly, if we are unable to implement business development opportunities and finance such activities on economically acceptable terms, our future growth will be limited, which could adversely impact our results of operations and cash flows.

Growing our business by constructing new pipelines and plants or making modifications to our existing facilities subjects us to construction risks and risks that adequate natural gas or NGL supplies will not be available upon completion of the facilities.

One of the ways we intend to grow our business is through the construction of new pipelines and new gathering, processing, storage and fractionation facilities and through modifications to our existing pipelines and existing gathering, processing, storage and fractionation facilities. The construction and modification of pipelines and gathering, processing, storage and fractionation facilities requires the expenditure of significant amounts of capital, which may exceed our estimates, and involves numerous regulatory, environmental, political and legal uncertainties. Construction projects in our industry may increase demand for labor, materials and rights of way, which may, in turn, impact our costs and schedule. If we undertake these projects, we may not be able to complete them on schedule or at the budgeted cost. Additionally, our revenues may not increase immediately upon the expenditure of funds on a particular project. For instance, if we build a new pipeline, the construction will occur over an extended period of time, and we will not receive any material increases in revenues until after completion of the project. We may have only limited natural gas or NGL supplies committed to these facilities prior to their construction. Additionally, we may construct facilities to capture anticipated future growth in production in a region in which anticipated production growth does not materialize. We may also rely on estimates of proved reserves in our decision to construct new pipelines and facilities, which may prove to be inaccurate because there are numerous uncertainties inherent in estimating quantities of proved reserves. As a result, new facilities may not be able to attract enough natural gas or NGLs to achieve our expected investment return, which could adversely affect our results of operations and financial condition.

Acquisitions that appear to be accretive may nevertheless reduce our cash from operations on a per unit basis.

Any acquisition involves potential risks that may include, among other things:

- mistaken assumptions about volumes, revenues and costs, including synergies;

- an inability to successfully integrate the businesses we acquire;
- decrease in our liquidity as a result of our using a significant portion of our available cash or borrowing capacity to finance the acquisition;
- a significant increase in our interest expense or financial leverage if we incur additional debt to finance the acquisition;
- the assumption of unknown liabilities for which we are not indemnified or for which our indemnity is inadequate;
- an inability to hire, train or retain qualified personnel to manage and operate the acquired business and assets;
- limitations on rights to indemnity from the seller;
- mistaken assumptions about the overall costs of equity or debt;
- the diversion of management's and employees' attention from other business concerns;
- unforeseen difficulties operating in new product areas or new geographic areas;
- increased regulatory burdens;
- customer or key employee losses at an acquired business; and
- increased regulatory requirements.

If we consummate any future acquisitions, our capitalization and results of operations may change significantly, and investors will not have the opportunity to evaluate the economic, financial and other relevant information that we will consider in determining the application of these funds and other resources.

We do not own all of the land on which our pipelines and facilities are located, which could disrupt our operations.

We do not own all of the land on which certain of our pipelines and facilities are located, and we are, therefore, subject to the risk of increased costs to maintain necessary land use. We obtain the rights to construct and operate certain of our pipelines and related facilities on land owned by third parties and governmental agencies for a specific period of time. Our loss of these rights, through our inability to renew right-of-way contracts, or increased costs to renew such rights, could have a material adverse effect on our financial condition, results of operations and cash flows.

Our operations are subject to operational hazards and unforeseen interruptions, which could adversely affect our business and for which we may not be adequately insured.

Our operations are subject to all of the risks and hazards typically associated with the operation of natural gas and natural gas liquids gathering and transportation pipelines, storage facilities, and processing and fractionation plants. Operating risks include, but are not limited to, leaks, pipeline ruptures, the breakdown or failure of equipment or processes, and the performance of facilities below expected levels of capacity and efficiency. Other operational hazards and unforeseen interruptions include adverse weather conditions, accidents, the collision of equipment with our pipeline facilities (for example, this may occur if a third party were to perform excavation or construction work near our facilities) and catastrophic events such as explosions, fires, hurricanes, earthquakes, floods or other similar events beyond our control. It is also possible that our infrastructure facilities could be direct targets or indirect casualties of an act of terrorism. A casualty occurrence might result in injury or loss of life, extensive property damage or environmental damage. Liabilities incurred and interruptions to the operation of our pipeline caused by such an event could reduce revenues generated by us and increase expenses, thereby impairing our ability to meet our obligations. Insurance proceeds may not be adequate to cover all liabilities or expenses incurred or revenues lost, and we are not fully insured against all risks inherent to our business. Additionally, in accordance with typical industry practice, we do not have any property insurance on any of our underground pipeline systems that would cover damage to such systems.

As a result of market conditions, premiums and deductibles for certain insurance policies can increase substantially, and in some instances, certain insurance may become unavailable or available only for reduced amounts of coverage. For example, changes in the insurance markets subsequent to the terrorist attacks on September 11, 2001 and the hurricanes in 2005 and 2008 have made it more difficult for us to obtain certain types of coverage. Consequently, we may not be able to renew existing insurance policies or procure other desirable insurance on commercially reasonable terms, if at all. If we were to incur a significant liability for which we were not fully insured, it could have a material adverse effect on our financial position and results of operations. Further, the proceeds of any such insurance may not be paid in a timely manner and may be insufficient if such an event were to occur.

If the level of drilling and production in the Mid-Continent, Rocky Mountain, Texas and Gulf Coast regions substantially declines near our assets, our volumes and revenues could decline.

Our ability to maintain or expand our businesses depends largely on the level of drilling and production in the Mid-Continent, Rocky Mountain, Texas, and Gulf Coast regions. Drilling and production are impacted by factors beyond our control, including:

- demand for natural gas and refinery-grade crude oil;
- producers' desire and ability to obtain necessary permits in a timely and economic manner;
- natural gas field characteristics and production performance;
- surface access and infrastructure issues; and
- capacity constraints on natural gas, crude oil and natural gas liquids pipelines from the producing areas and our facilities.

In addition, drilling and production may be impacted by environmental regulations governing water discharge. If the level of drilling and production in any of these regions substantially declines, our volumes and revenue could be reduced.

If production from the Western Canada Sedimentary Basin remains flat or declines and demand for natural gas from the Western Canada Sedimentary Basin is greater in market areas other than the Midwestern United States, demand for our interstate transportation services could significantly decrease.

We depend on natural gas supply from the Western Canada Sedimentary Basin because our interstate pipelines primarily transport Canadian natural gas from the Western Canada Sedimentary Basin to the Midwestern U.S. market area. If demand for natural gas increases in Canada or other markets not served by our pipelines and production remains flat or declines, demand for transportation service on our interstate natural gas pipelines could decrease significantly, which could adversely impact our results of operations.

Pipeline integrity programs and repairs may impose significant costs and liabilities.

Pursuant to a United States Department of Transportation rule, pipeline operators are required to develop integrity management programs for intrastate and interstate natural gas and natural gas liquids pipelines located near high consequence areas, where a leak or rupture could do the most harm. The rule also requires operators to perform ongoing assessments of pipeline integrity; identify and characterize applicable threats to pipeline segments that could impact a high consequence area; improve data collection, integration and analysis; repair and remediate the pipeline as necessary; and implement preventive and mitigating actions. The results of these testing programs could cause us to incur significant capital and operating expenditures to make repairs or take remediation, preventive or mitigating actions that are determined to be necessary.

Our business is subject to increased regulatory oversight and potential penalties.

The natural gas industry historically has been heavily regulated; therefore, there is no assurance that a more stringent regulatory approach will not be pursued by the FERC and United States Congress, especially in light of previous market power abuse by certain companies engaged in interstate commerce. In response to this issue, the United States Congress, in the Energy Policy Act of 2005 (EPACT), developed requirements intended to ensure that the energy market is not impacted by the exercise of market power or manipulative conduct. The FERC then adopted the Market Manipulation Rules to implement the authority granted under EPACT. These rules are intended to prohibit fraud and manipulation and are subject to broad interpretation. EPACT also gave the FERC increased penalty authority for violations.

Our regulated pipelines' transportation rates are subject to review and possible adjustment by federal and state regulators.

Our regulated pipelines are subject to extensive regulation by the FERC and state regulatory agencies, which regulate most aspects of our pipeline business, including our transportation rates. Under the Natural Gas Act, which is applicable to interstate natural gas pipelines, and the Interstate Commerce Act, which is applicable to crude oil and natural gas liquids pipelines, interstate transportation rates must be just and reasonable and not unduly discriminatory.

Action by the FERC or a state regulatory agency could adversely affect our pipeline business' ability to establish or charge rates that would cover future increases in their costs, or even to continue to collect rates that cover current costs, including a reasonable return. We cannot assure unitholders that our pipeline systems will be able to recover all of their costs through existing or future rates.

Our regulated pipeline companies have recorded certain assets that may not be recoverable from our customers.

Accounting policies for FERC-regulated companies permit certain assets that result from the regulated ratemaking process to be recorded on our balance sheet that could not be recorded under GAAP for nonregulated entities. We consider factors such as regulatory changes and the impact of competition to determine the probability of future recovery of these assets. If we determine future recovery is no longer probable, we would be required to write off the regulatory assets at that time.

Our operations are subject to federal and state laws and regulations relating to the protection of the environment, which may expose us to significant costs and liabilities.

The risk of incurring substantial environmental costs and liabilities is inherent in our business. Our operations are subject to extensive federal, state and local laws and regulations governing the discharge of materials into, or otherwise relating to the protection of, the environment. Examples of these laws include:

- the federal Clean Air Act and analogous state laws that impose obligations related to air emissions;
- the federal Clean Water Act and analogous state laws that regulate discharge of wastewaters from our facilities to state and federal waters;
- the federal Comprehensive Environmental Response, Compensation and Liability Act and analogous state laws that regulate the cleanup of hazardous substances that may have been released at properties currently or previously owned or operated by us or locations to which we have sent waste for disposal; and
- the federal Resource Conservation and Recovery Act and analogous state laws that impose requirements for the handling and discharge of solid and hazardous waste from our facilities.

Various governmental authorities, including the EPA, have the power to enforce compliance with these laws and regulations and the permits issued under them. Violators are subject to administrative, civil and criminal penalties, including civil fines, injunctions or both. Joint and several, strict liability may be incurred without regard to fault under the Comprehensive Environmental Response, Compensation and Liability Act, Resource Conservation and Recovery Act and analogous state laws for the remediation of contaminated areas.

There is an inherent risk of incurring environmental costs and liabilities in our business due to our handling of the products we gather, transport and process, air emissions related to our operations, historical industry operations and waste disposal practices, some of which may be material. Private parties, including the owners of properties through which our pipeline systems pass, may have the right to pursue legal actions to enforce compliance as well as to seek damages for non-compliance with environmental laws and regulations or for personal injury or property damage arising from our operations. Some sites we operate are located near current or former third-party hydrocarbon storage and processing operations, and there is a risk that contamination has migrated from those sites to ours. In addition, increasingly strict laws, regulations and enforcement policies could significantly increase our compliance costs and the cost of any remediation that may become necessary, some of which may be material. Additional information is included under Item 1, Business under "Environmental and Safety Matters" and in Note J of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.

Our insurance may not cover all environmental risks and costs or may not provide sufficient coverage in the event an environmental claim is made against us. Our business may be adversely affected by increased costs due to stricter pollution control requirements or liabilities resulting from non-compliance with required operating or other regulatory permits. New environmental regulations might also adversely affect our products and activities, and federal and state agencies could impose additional safety requirements, all of which could materially affect our profitability.

In the competition for customers, we may have significant levels of uncontracted or discounted transportation and storage capacity on our natural gas and natural gas liquids pipelines and in our storage assets.

Our natural gas and natural gas liquids pipelines and storage assets compete with other pipelines and storage facilities for natural gas and NGL supplies delivered to the markets we serve. As a result of competition, we may have significant levels of uncontracted or discounted capacity on our pipelines and in our storage assets, which could have a material adverse impact on our results of operations.

Terrorist attacks aimed at our facilities could adversely affect our business.

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

We are exposed to the credit risk of our customers or counterparties, and our credit risk management may not be adequate to protect against such risk.

We are subject to the risk of loss resulting from nonpayment and/or nonperformance by our customers and counterparties. Our customers or counterparties may experience deterioration of their financial condition as a result of changing market conditions or financial difficulties that could impact their creditworthiness or ability to pay us for our services. We assess the creditworthiness of our customers and counterparties and obtain security as we deem appropriate. If we fail to adequately assess the creditworthiness of existing or future customers or counterparties, unanticipated deterioration in their creditworthiness and any resulting nonpayment and/or nonperformance could adversely impact our results of operations. In addition, if any of our customers or counterparties file for bankruptcy protection, this could have a material negative impact on our results of operations.

Mergers among our customers and competitors could result in lower volumes being shipped on our pipelines or products stored in or distributed through our terminals, thereby reducing the amount of cash we generate.

Mergers between our existing customers and our competitors could provide strong economic incentives for the combined entities to utilize their existing gathering, processing, fractionation and/or transportation systems instead of ours in those markets where the systems compete. As a result, we could lose some or all of the volumes and associated revenues from these customers, and we could experience difficulty in replacing those lost volumes and revenues. Because most of our operating costs are fixed, a reduction in volumes would result not only in less revenue but also a decline in cash flow of a similar magnitude, which would reduce our ability to pay cash distributions to our unitholders.

A shortage of skilled labor may make it difficult for us to maintain labor productivity, and competitive costs could adversely affect our operations and cash flows available for distribution to our unitholders.

Our operations require skilled and experienced laborers with proficiency in multiple tasks. In recent years, a shortage of workers trained in various skills associated with the midstream energy business has caused us to conduct certain operations without full staff, which decreases our productivity and increases our costs. This shortage of trained workers is the result of experienced workers reaching retirement age, combined with the difficulty of attracting new laborers to the midstream energy industry. This shortage of skilled labor could continue over an extended period. If the shortage of experienced labor continues or worsens, it could have an adverse impact on our labor productivity and costs and our ability to expand production in the event there is an increase in the demand for our products and services, which could adversely affect our operations and cash flows available for distribution to our unitholders.

We may face significant costs to comply with the regulation of greenhouse gas emissions.

Global warming is a significant concern for the energy industry. Various federal and state legislative proposals have been introduced to regulate the emission of greenhouse gases, particularly carbon dioxide and methane, and the United States Supreme Court has ruled that carbon dioxide is a pollutant subject to regulation by the EPA. In addition, there have been international efforts seeking legally binding reductions in emissions of greenhouse gases.

We believe it is likely that future governmental legislation and/or regulation may require us either to limit greenhouse gas emissions from our operations or to purchase allowances for such emissions. However, we cannot predict precisely what form these future regulations will take, the stringency of the regulations or when they will become effective. Several bills have been introduced in the United States Congress that would compel carbon dioxide emission reductions. Previously considered proposals have included, among other things, limitations on the amount of greenhouse gases that can be emitted (so called "caps") together with systems of permitted emissions allowances. This type of system could require us to reduce emissions, even though the technology is not currently available for efficient reduction, or to purchase allowances for such emissions. Emissions also could be taxed independently of limits.

In addition to activities on the federal level, state and regional initiatives could also lead to the regulation of greenhouse gas emissions sooner and/or independent of federal regulation. These regulations could be more stringent than any federal legislation that is adopted.

Future legislation and/or regulation designed to reduce greenhouse gas emissions could make some of our activities uneconomic to maintain or operate and could affect future results of operations, cash flows or financial condition.

We continue to monitor legislative and regulatory developments in this area. Although we expect the regulation of greenhouse gas emissions may have a material impact on our operations and rates, we believe it is premature to attempt to quantify the potential costs of the impacts.

We are subject to physical and financial risks associated with climate change.

There is a growing belief that emissions of greenhouse gases may be linked to global climate change. Climate change creates physical and financial risk. Our customers' energy needs vary with weather conditions, primarily temperature and humidity. For residential customers, heating and cooling represent their largest energy use. To the extent weather conditions are affected by climate change, customers' energy use could increase or decrease depending on the duration and magnitude of any changes. Increased energy use due to weather changes may require us to invest in more pipelines and other infrastructure to serve increased demand. A decrease in energy use due to weather changes may affect our financial condition, through decreased revenues. Extreme weather conditions in general require more system backup, adding to costs, and can contribute to increased system stresses, including service interruptions. Weather conditions outside of our service territory could also have an impact on our revenues. Severe weather impacts our service territories primarily through hurricanes, thunderstorms, tornadoes and snow or ice storms. To the extent the frequency of extreme weather events increases, this could increase our cost of providing service. We may not be able to pass on the higher costs to our customers or recover all costs related to mitigating these physical risks. To the extent financial markets view climate change and emissions of greenhouse gases as a financial risk, this could negatively affect our ability to access capital markets or cause us to receive less favorable terms and conditions in future financings.

We may be subject to legislative and regulatory responses to climate change, with which compliance could be difficult and costly.

Legislative and regulatory responses related to climate change create financial risk. Increased public awareness and concern may result in more state, regional and/or federal requirements to reduce or mitigate the emission of greenhouse gases. Numerous states have announced or adopted programs to stabilize and reduce greenhouse gases and federal legislation has been introduced in both houses of the United States Congress. Our pipelines, natural gas processing facilities and natural gas liquids fractionation facilities will potentially be subject to regulation under climate change policies introduced at either the state or federal level within the next few years. We may not be able to pass on the higher costs to our customers or recover all costs related to complying with climate change regulatory requirements, which could have a material adverse effect on our results of operations, cash flows or financial condition.

RISKS INHERENT IN AN INVESTMENT IN US

ONEOK selling substantial amounts of common units could reduce the market price of our common units.

ONEOK and its affiliates own all of the Class B units, 5,900,000 common units and the entire 2 percent general partner interest in us, which together constitutes a 47.7 percent ownership interest in us. The Class B units are eligible to convert into common units on a one-for-one basis at ONEOK's option. ONEOK may, from time to time, sell all or a portion of its common units. Sales of substantial amounts of its common units, or the anticipation of such sales, could lower the market price of our common units and may make it more difficult for us to sell our equity securities in the future at a time and price that we deem appropriate.

ONEOK could withdraw the waiver of its right to receive, on its Class B units, 110 percent of the distributions paid with respect to our common units.

At a special meeting of the holders of our common units, adjourned to May 10, 2007, the proposed amendments to our Partnership Agreement were not approved by the required two-thirds affirmative vote of our outstanding units, excluding the common units and Class B limited partner units held by ONEOK and its affiliates. As a result, effective April 7, 2007, ONEOK, as the sole holder of our Class B limited partner units, became entitled to receive increased quarterly distributions on its Class B units equal to 110 percent of the distributions paid with respect to our common units.

On June 21, 2007, ONEOK waived its right to receive the increased quarterly distributions on the Class B units for the period of April 7, 2007, through December 31, 2007, and continuing thereafter until ONEOK gives us no less than 90 days advance notice that it has withdrawn its waiver. ONEOK could withdraw such waiver and begin receiving such increased distributions, effective with respect to any distribution on the Class B units declared or paid on or after 90 days following delivery of the notice.

If our unitholders vote to remove ONEOK or its affiliates as our general partner, quarterly distributions and distributions payable to ONEOK upon liquidation of the Class B units would increase.

Since the proposed amendments to our Partnership Agreement were not approved by the requisite number of our common unitholders, if our common unitholders vote at any time to remove ONEOK or its affiliates as our general partner, quarterly distributions payable on the Class B limited partner units would increase to 123.5 percent of the distributions payable with respect to the common units, and distributions payable upon liquidation of the Class B limited partner units would increase to 123.5 percent of the distributions payable with respect to the common units.

Our unitholders have limited voting rights and are not entitled to elect our general partner's directors, which could lower the trading price of our common units. In addition, 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 have no right to elect our general partner or its directors on an annual or other continuing basis. The Board of Directors of our general partner, including the independent directors, is chosen by the owners of the general partner and not by the unitholders.

Furthermore, if unitholders are dissatisfied with the performance of our general partner, it may be difficult to remove ONEOK Partners GP or its officers or directors. ONEOK Partners GP may not be removed except upon the vote of the holders of at least 66-2/3 percent of our outstanding units voting together as a single class (excluding units held by ONEOK Partners GP and its affiliates). As a result of this provision, the trading price of our common units may be lower than other forms of equity ownership because of the absence or reduction of a takeover premium in the trading price.

We do not operate all of our assets nor do we directly employ any of the persons responsible for providing us with administrative, operating and management services. This reliance on others to operate our assets and to provide other services could adversely affect our business and operating results.

We rely on ONEOK, ONEOK Services Company and ONEOK Partners GP to provide us with administrative, operating and management services. We have a limited ability to control our operations and the associated costs of such operations. The success of these operations depends on a number of factors that are outside our control, including the competence and financial resources of the provider. ONEOK, ONEOK Services Company and ONEOK Partners GP may outsource some or all of these services to third parties, and a failure to perform by these third-party providers could lead to delays in or interruptions of these services. Should ONEOK, ONEOK Services Company and ONEOK Partners GP not perform their respective contractual obligations, we may have to contract elsewhere for these services, which may cost more than we are currently paying. In addition, we may not be able to obtain the same level or kind of service or retain or receive the services in a timely manner, which may impact our ability to perform under our contracts and negatively affect our business and operating results. Our reliance on ONEOK, ONEOK Services Company, ONEOK Partners GP and third-party providers with which they contract, together with our limited ability to control certain costs, could harm our business and results of operations.

Our Partnership Agreement limits our general partner's fiduciary duties to our unitholders and restricts the remedies available to unitholders for actions taken by our general partner that might otherwise constitute breaches of fiduciary duty.

Our Partnership Agreement contains provisions that reduce the standards to which our general partner would otherwise be held by state fiduciary duty law. For example, our Partnership Agreement:

- permits our general partner to make a number of decisions in its individual capacity, as opposed to in its capacity as our general partner. This entitles our general partner to consider only the interests and factors that it desires, and it has no duty or obligation to give any consideration to any interest of, or factors affecting, us, our affiliates or any limited partner. Examples include the exercise of its limited call right, its voting rights with respect to the units it owns, its registration rights and its determination (through its Board of Directors) whether or not to consent to any merger or consolidation of us;
- provides that our general partner will not have any liability to us or our unitholders for decisions made in its capacity as general partner so long as it acted in "good faith," meaning it believed the decision was in our best interests;
- provides that our general partner is entitled to make other decisions in "good faith" if it reasonably believes that the decision is in, or not inconsistent with, our best interests;
- provides generally that affiliated transactions and resolutions of conflicts of interest not approved by the Audit Committee and not involving a vote of unitholders must be on terms no less favorable to us than those generally being provided to or available from unrelated third parties or be "fair and reasonable" to us, as determined by our general partner in "good faith," and that, in determining whether a transaction or resolution is "fair and reasonable," our general partner may consider the totality of the relationships between the parties involved, including other transactions that may be particularly advantageous or beneficial to us; and

- provides that our general partner and its affiliates, officers and directors will not be liable for monetary damages to us or our limited partners for any acts or omissions so long as such person acted in "good faith" and in a manner believed to be in, or not opposed to, the best interest of us and, with respect to any criminal proceeding, had no reasonable cause to believe its conduct was unlawful.

By purchasing a common unit, a common unitholder will be bound by the provisions in our Partnership Agreement, including the provisions discussed above.

The Board of Directors of our general partner, our general partner and its affiliates have conflicts of interest and limited fiduciary duties, which may permit them to favor their own interests.

ONEOK owns 100 percent of our general partner interest and a 47.7 percent aggregate equity interest in us. Our Partnership Agreement limits any fiduciary duties owed by our general partner and ONEOK to those duties that are specifically stated in our Partnership Agreement. Although ONEOK, through the Board of Directors of our general partner, has an obligation to manage us in a manner that is in, or not inconsistent with, our best interests, the Board of Directors of ONEOK has a fiduciary duty to manage our general partner in a manner beneficial to ONEOK. One management member of the Board of Directors of our general partner is also the only management member of ONEOK's Board of Directors. Conflicts of interest may arise between our general partner and its affiliates and between us and our unitholders. In resolving these conflicts, our general partner may determine that the transaction is "fair and reasonable" to us, without the agreement of any other party, including the Audit Committee. In that regard, our general partner may favor its own interests and the interests of its affiliates over the interests of our unitholders, as long as it does not take action that conflicts with our Partnership Agreement. These conflicts include, among others, the following situations:

- our general partner, which is owned by ONEOK, and the Board of Directors of our general partner are allowed to take into account the interests of parties other than us in resolving conflicts of interest, which has the effect of limiting their fiduciary duties to our unitholders;
- our Partnership Agreement limits the liability and reduces the fiduciary duties of the members of the Board of Directors of our general partner and also restricts the remedies available to our unitholders for actions that, without the limitations, might constitute breaches of fiduciary duty;
- the Board of Directors of our general partner determines the amount and timing of our cash reserves, asset purchases and sales, capital expenditures, borrowings and issuances of additional partnership securities, each of which can affect the amount of cash that is distributed to our unitholders;
- the Board of Directors of our general partner approves the amount and timing of any capital expenditures and determines whether they are maintenance capital expenditures or growth capital expenditures, which can affect the amount of cash that is distributed to our unitholders;
- the Board of Directors of our general partner may cause us to borrow funds in order to permit the payment of cash distributions, even if the purpose or effect of the borrowing is to make incentive distributions;
- the Board of Directors of our general partner and its Audit Committee determine which costs incurred by the Board of Directors, our general partner and its affiliates are reimbursable by us;
- our Partnership Agreement does not restrict the members of the Board of Directors of our general partner from causing us to pay the Board of Directors, our general partner or its affiliates for any services rendered to us or entering into additional contractual arrangements with any of these entities on our behalf;
- our general partner may exercise its limited right to call and purchase common units, which right may be assigned or transferred to, among others, us or affiliates of the general partner, if the general partner and its affiliates own 80 percent or more of the common units; and
- the Board of Directors and Audit Committee of our general partner decide whether to retain separate counsel, accountants or others to perform services for us.

Our general partner and its affiliates may compete directly with us and have no obligation to present business opportunities to us.

ONEOK and its affiliates are not prohibited from owning assets or engaging in businesses that compete directly or indirectly with us. ONEOK may acquire, construct or dispose of additional midstream or other assets in the future without any obligation to offer us the opportunity to purchase or construct any of those assets. In addition, under our Partnership Agreement, the doctrine of corporate opportunity, or any analogous doctrine, will not apply to ONEOK and its affiliates. As a result, neither ONEOK nor any of its affiliates has any obligation to present business opportunities to us.

The control of our general partner may be transferred to a third party without unitholder consent.

Our general partner may transfer all, or any part of, its general partner interest to a third party without the consent of the unitholders. The members, shareholders or unitholders, as the case may be, of our new general partner may then be in a position to replace all or a portion of the directors of our general partner with their own choices and to possibly control the decisions made by the Board of Directors of our general partner.

Any reduction in our credit ratings could materially and adversely affect our business, financial condition, liquidity and results of operations.

Our senior unsecured long-term debt has been assigned an investment-grade rating by Moody's of "Baa2" (Stable) and by S&P of "BBB" (Stable). We cannot provide assurance that any of our current ratings will remain in effect for any given period of time or that a rating will not be lowered or withdrawn entirely by a rating agency if, in its judgment, circumstances in the future so warrant. Specifically, if Moody's or S&P were to downgrade our long-term rating, particularly below investment grade, our borrowing costs would increase, which would adversely affect our financial results, and our potential pool of investors and funding sources could decrease. If Moody's or S&P were to downgrade our long-term ratings below investment grade, we would, under certain circumstances, be required to offer to repurchase certain of our senior notes. Ratings from credit agencies are not recommendations to buy, sell or hold our securities. Each rating should be evaluated independently of any other rating.

Increases in interest rates may cause the market price of our common units to decline.

An increase in interest rates may cause a corresponding decline in demand for equity investments in general, and in particular for yield-based equity investments such as our common units. Any such increase in interest rates or reduction in demand for our common units resulting from other more attractive investment opportunities may cause the trading price of our common units to decline.

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 of reserves for commitments and contingencies, including capital and operating costs and debt-service requirements, all of which are significant. The value of our units and other limited partner interests may decrease in 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.

A downgrade of our credit rating may require us to offer to repurchase certain of our senior notes or may impair our ability to access capital.

We could be required to offer to repurchase certain of our senior notes due 2010 and 2011 at par value, plus any accrued and unpaid interest, if Moody's or S&P rate those senior notes below investment grade (Baa3 for Moody's and BBB- for S&P). Further, the indenture governing our senior notes due 2010 and 2011 includes an event of default upon acceleration of other indebtedness of $25 million or more and the indenture governing our senior notes due 2012, 2016, 2036 and 2037 includes an event of default upon the acceleration of other indebtedness of $100 million or more that would be triggered by such an offer to repurchase. Such an event of default would entitle the trustee or the holders of 25 percent in aggregate principal amount of the outstanding senior notes due 2010, 2011, 2012, 2016, 2036 and 2037 to declare those notes immediately due and payable in full. We may not have sufficient cash on hand to repurchase and repay any accelerated senior notes, which may cause us to borrow money under our credit facilities or seek alternative financing sources to finance the repayments and repurchases. We could also face difficulties accessing capital or our borrowing costs could increase, impacting our ability to obtain financing for acquisitions or capital expenditures, to refinance indebtedness and to fulfill our debt obligations.

Our indebtedness could impair our financial condition and our ability to fulfill our other obligations.

As of December 31, 2008, we had total indebtedness of approximately $3.5 billion. Our indebtedness could have significant consequences. For example, it could:

- make it more difficult for us to satisfy our obligations with respect to our notes and our other indebtedness, which could in turn result in an event of default on such other indebtedness or our notes;
- impair our ability to obtain additional financing in the future for working capital, capital expenditures, acquisitions or general business purposes;

- diminish our ability to withstand a downturn in our business or the economy;
- require us to dedicate a substantial portion of our cash flow from operations to debt service payments, reducing the availability of cash for working capital, capital expenditures, acquisitions, distributions to partners, and general purposes;
- limit our flexibility in planning for, or reacting to, changes in our business and the industry in which we operate; and
- place us at a competitive disadvantage compared with our competitors that have proportionately less debt.

We are not prohibited under the indentures governing our senior notes from incurring additional indebtedness, but our debt agreements do subject us to certain operational limitations summarized in the next paragraph. Our incurrence of significant additional indebtedness would exacerbate the negative consequences mentioned above and could adversely affect our ability to repay our notes and other indebtedness.

Our debt agreements contain provisions that restrict our ability to finance future operations or capital needs or to expand or pursue our business activities. For example, certain of these agreements contain provisions that, among other things, limit our ability to make loans or investments, make material changes to the nature of our business, merge, consolidate or engage in asset sales, or grant liens or make negative pledges. Certain of these agreements also require us to maintain certain financial ratios, which limits the amount of additional indebtedness we can incur. These restrictions could result in higher costs of borrowing and impair our ability to generate additional cash. Future financing agreements we may enter into may contain similar or more restrictive covenants.

If we are unable to meet our debt-service obligations, we could be forced to restructure or refinance our indebtedness, seek additional equity capital or sell assets. We may be unable to obtain financing or sell assets on satisfactory terms, or at all.

We and the Intermediate Partnership have a holding company structure in which our subsidiaries conduct our operations and own our operating assets.

We and the Intermediate Partnership are holding companies, and our subsidiaries conduct all of our operations and own all of our operating assets. Neither we nor the Intermediate Partnership have significant assets other than the partnership interests and the equity in our subsidiaries and other investments. As a result, our ability to make quarterly distributions and required payments on our indebtedness depends on the performance of our subsidiaries and their ability to distribute funds to us. The ability of our subsidiaries to make distributions to us may be restricted by, among other things, credit facilities, applicable state partnership laws, and other laws and regulations, including FERC policies. If we are unable to obtain the funds necessary to make quarterly distributions or required payments on our indebtedness, we may be required to adopt one or more alternatives, such as refinancing the indebtedness or seeking alternative financing sources to fund the quarterly distributions and indebtedness payments.

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

Our general partner, without the approval of our unitholders, may cause us to issue an unlimited number of additional units,. The issuance by us 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 distribution paid on each unit may decrease;
- the relative voting strength of each previously outstanding unit may be diminished; and
- the market price of the common units may decline.

Notwithstanding the foregoing, the issuance of equity securities ranking senior to the common units requires approval of a majority of the outstanding common units.

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

If at any time our general partner and its affiliates own 80 percent or more 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, unitholders may be required to sell their common units at an undesirable time or price and may not receive any return on their investment. Unitholders may also incur a tax liability upon the sale of their units. Our general partner is not obligated to obtain a fairness opinion regarding the value of the common units to be repurchased by it upon exercise of the limited call right. There is no restriction in our Partnership Agreement that prevents our general partner from issuing additional common units and exercising its call right. If our general partner exercised its limited call right, the effect would be to take us private and, if the units were subsequently deregistered, we would no longer be subject to the reporting requirements of the Exchange Act.

Our Partnership Agreement restricts the voting rights of unitholders owning 20 percent or more of our common units.

Our Partnership Agreement restricts unitholders' voting rights by providing that any units held by a person or entity that owns 20 percent or more of our common units then outstanding, other than our general partner and its affiliates, 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 or direction of management.

Unitholders may not have limited liability if a court finds that unitholder action constitutes control of our business. Unitholders may also have liability to repay distributions.

As a limited partner in a limited partnership organized under Delaware law, unitholders could be held liable for our obligations to the same extent as a general partner if they participate in the "control" of our business. Our general partner generally has unlimited liability for our obligations, such as our debts and environmental liabilities, except for our contractual obligations that are expressly made without recourse to our general partner. In addition, the Delaware Revised Uniform Limited Partnership Act provides that, under some circumstances, a unitholder may be liable to us for the amount of a distribution for a period of three years from the date of the distribution. The limitations on the liability of holders of limited partner interests for the obligations of a limited partnership have not been clearly established in some of the states in which we do business.

TAX RISKS

Our tax treatment depends on our status as a partnership for federal income tax purposes. Additionally, other than our corporate subsidiaries, we are only subject to entity-level taxation in the state of Texas. If the IRS were to treat us as a corporation or if we were to become subject to a material amount of entity-level taxation for state tax purposes, then our cash available for distribution to our common unitholders would be substantially reduced.

The anticipated after-tax economic benefit of an investment in our 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 matter.

If we were treated as a corporation for federal income tax purposes, we would pay federal income tax on our taxable income at the corporate tax rate, which is currently a maximum of 35 percent, and we likely would pay state taxes as well. Distributions to our unitholders would generally be taxed again as corporate distributions, and no income, gains, losses or deductions would flow through to our unitholders. Because a tax would be imposed upon us as a corporation, the cash available for distributions to our common unitholders would be substantially reduced. Therefore, treatment of us as a corporation would result in a material reduction in the after-tax return to our common unitholders, likely causing a substantial reduction in the value of our common units.

Because of widespread state budget deficits and other reasons, several states are evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise or other forms of taxation. For example, beginning in 2008, we were required to pay the revised Texas franchise tax at a maximum effective rate of 0.7 percent of our gross revenue that is apportioned to Texas. Imposition of such tax on us by Texas, or any other state, reduces the cash available for distribution to our common unitholders.

The tax treatment of our structure could be subject to potential legislative, judicial or administrative changes and differing interpretations, possibly on a retroactive basis.

The federal income tax treatment of us and common unitholders depends in some instances on determinations of fact and interpretations of complex provisions of federal income tax law. The federal income tax rules are constantly under review by persons involved in the legislative process, the IRS and the United States Treasury Department (Treasury), frequently resulting in revised interpretations of established concepts, statutory changes, revisions to Treasury regulations and other modifications and interpretations. The IRS pays close attention to the proper application of tax laws to partnerships. The present federal income tax treatment of us and/or an investment in our common units may be modified by administrative, legislative or judicial interpretation at any time. For example, in response to certain recent developments, members of the United States Congress are considering substantive changes to the definition of qualifying income under the Internal Revenue Code Section 7704(d) and the treatment of certain types of income earned from profits interests in the partnerships. Any modification to the federal income tax laws and interpretations thereof may or may not be applied retroactively and could make it more difficult or impossible for us to meet the exception to be treated for federal income tax purposes as a partnership that is not taxable as a corporation (referred to as the "Qualifying Income Exception"), affect or cause us to change our business activities, affect the tax consequences for common unitholders of an investment in us, change the character or treatment of portions of our income and adversely affect an investment in our common units. We are unable to predict whether any of these or other changes or proposals will ultimately be enacted. Any such changes could negatively impact the value of an investment in our common units and the amount of cash available for distribution to our unitholders.

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

We have not requested any 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 federal income tax positions we take. It may be necessary to resort to administrative or court proceedings to sustain some or all of the positions we take. A court may not agree with some or all of the positions we take. Any contest with the IRS may adversely impact the taxable income reported to our unitholders and the income taxes they are required to pay. As a result, any such contest with the IRS may materially and adversely impact the market for our common units and the price at which they trade. In addition, the costs of any such contest with the IRS will result in a reduction in cash available to pay distributions to our unitholders and our general partner and thus will be borne indirectly by our unitholders and our general partner.

A unitholder will be required to pay taxes on the unitholder's share of our taxable income even if the unitholder does not receive any cash distributions from us.

A unitholder will be required to pay federal income taxes and, in some cases, state and local income taxes on the unitholder's share of our taxable income, whether or not the unitholder receives cash distributions from us. A unitholder may not receive cash distributions from us equal to the unitholder's share of our taxable income or even equal to the actual tax liability that results from the unitholder's share of our taxable income.

Unitholders may have negative tax consequences if we default on our debt or sell assets.

If we default on any of our debt, the lenders will have the right to sue us for non-payment. Such an action could cause negative tax consequences for unitholders through the realization of taxable income by unitholders without a corresponding cash distribution. Likewise, if we were to dispose of assets and realize a taxable gain while there is substantial debt outstanding and proceeds of the sale were applied to the debt, unitholders could have increased taxable income without a corresponding cash distribution.

The taxable gain or loss on the disposition of our common units could be different than expected.

A unitholder will recognize a gain or loss on the sale of common units equal to the difference between the amount realized and the unitholder's tax basis in those common units. A unitholder's amount realized will be measured by the sum of the cash and the fair market value of other property received plus the unitholder's share of our nonrecourse liabilities. Because the amount realized includes a unitholder's share of our nonrecourse liabilities, the gain recognized on the sale of common units could result in a tax liability in excess of any cash received from the sale. Prior distributions to a unitholder in excess of the total net taxable income allocated to a unitholder for a common unit, which decreased the tax basis in that common unit, will, in effect, become taxable income to a unitholder if the common unit is sold at a price greater than the tax basis in that common unit, even if the price received is less than the original cost. A substantial portion of the amount realized, whether or not representing a gain, may be ordinary income to a unitholder. Should the IRS successfully contest some positions we take, unitholders could recognize more gain on the sale of units than would be the case under those positions, without the benefit of decreased income in prior years.

Tax-exempt entities and non-U.S. 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 and non-U.S. persons, raises issues unique to them. For example, virtually all of our income allocated to unitholders who are organizations exempt from federal income tax, including individual retirement accounts and other retirement plans, may be taxable to them as "unrelated business taxable income." Distributions to non-U.S. persons may be subject to U.S. withholding taxes. Non-U.S. persons will be required to file U.S. federal income tax returns and pay tax on their share of our taxable income.

We will treat each purchaser of 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 the common units.

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

We may be required to change the allocation of items of income, gain, loss and deduction among our unitholders.

We prorate our items of income, gain, loss and deduction between transferors and transferees of our common units each month based upon the ownership of our units as of the close of business on the last day of the preceding month, instead of on the basis of the date a particular unit is transferred. The use of this proration method may not be permitted under existing Treasury regulations. If the IRS were to challenge this method or new Treasury regulations were issued, we may be required to change the allocation of items of income, gain, loss and deduction among our unitholders.

Unitholders will be subject to state and local taxes and return filing requirements as a result of investing in our common units.

In addition to federal income taxes, unitholders will 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 we do business or own property. Unitholders will be required to file state and local income tax returns and pay state and local income taxes in some or all of these various jurisdictions and may be subject to penalties for failure to comply with those requirements. We may own property or conduct business in other states or foreign countries in the future. It is each unitholder's responsibility to file all United States federal, state and local tax returns and foreign tax returns, as applicable.

Some of the states in which we do business or own property may require us to, 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 greater or less than a particular unitholder's income tax liability to the state, generally does not relieve the non-resident 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.

The sale or exchange of 50 percent or more of the total interest in our capital and profits within a 12-month period will result in the termination of our Partnership for federal income tax purposes.

We will be considered to have terminated for federal income tax purposes if there is a sale or exchange of 50 percent or more of the total interests in our capital and profits within a 12-month period. Our termination would, among other things, result in the closing of our taxable year for all unitholders, which may result in us filing two tax returns for one fiscal year.

Our termination could also result in a deferral of depreciation deductions allowable in computing taxable income. Our termination currently would not affect our classification as a partnership for federal income tax purposes, instead, we would be treated as a new partnership, we must make new tax elections, and we could be subject to penalties if we were unable to determine that the termination had occurred.

We have adopted certain valuation methodologies that may result in a shift of income, gain, loss and deduction between the general partner and the unitholders. The IRS may challenge this treatment, which could adversely affect the value of our common units.

When we issue additional units or engage in certain other transactions, we determine the fair market value of our assets and allocate any unrealized gain or loss attributable to our assets to the capital accounts of our unitholders and our general partner. Our methodology may be viewed as understating the value of our assets. In that case, there may be a shift of income, gain, loss and deduction between certain unitholders and the general partner, which may be unfavorable to such unitholders. Moreover, under our current valuation methods, subsequent purchasers of common units may have a greater portion of their Internal Revenue Code Section 743(b) adjustment allocated to our tangible assets and a lesser portion allocated to our intangible assets. The IRS may challenge our valuation methods, or our allocation of the Section 743(b) adjustment attributable to our tangible and intangible assets, and allocations of income, gain, loss and deduction between the general partner and certain of our unitholders.

A successful IRS challenge to these methods or allocations could adversely affect the amount of taxable income or loss being allocated to our unitholders. It also could affect the amount of gain from our unitholders' sale of common units and could have a negative impact on the value of the common units or result in audit adjustments to our unitholders' tax returns without the benefit of additional deductions.

A unitholder whose units are loaned to a "short seller" to cover a short sale of units may be considered as having disposed of those units. If so, the unitholder would no longer be treated for tax purposes as a partner with respect to those units during the period of the loan and may recognize gain or loss from the disposition.

Because a unitholder whose units are loaned to a "short seller" to cover a short sale of units may be considered as having disposed of the loaned units, the unitholder may no longer be treated for tax purposes as a partner with respect to those units during the period of the loan to the short seller and the unitholder may recognize gain or loss from such disposition. Moreover, during the period of the loan to the short seller, any of our income, gain, loss or deduction with respect to those units may not be reportable by the unitholder, and any cash distributions received by the unitholder as to those units could be fully taxable as ordinary income. Unitholders desiring to assure their status as partners and avoid the risk of gain recognition from a loan to a short seller are urged to modify any applicable brokerage account agreements to prohibit their brokers from borrowing their units.

ITEM 1B. UNRESOLVED STAFF COMMENTS

Not applicable.

ITEM 2. PROPERTIES

Natural Gas Gathering and Processing

Property - Our Natural Gas Gathering and Processing segment owns the following assets:
- approximately 10,100 miles and 4,500 miles of natural gas gathering pipelines in the Mid-Continent and Rocky Mountain regions, respectively;
- nine active natural gas processing plants, with approximately 645 MMcf/d of processing capacity in the Mid-Continent region, and four active natural gas processing plants, with approximately 80 MMcf/d of processing capacity in the Rocky Mountain region; and
- approximately 18 MBbl/d of natural gas liquids fractionation capacity at various natural gas processing plants in the Mid-Continent and Rocky Mountain regions.

On January 1, 2007, the Bushton Plant was temporarily idled as a result of a decline in natural gas volumes available for natural gas processing at this straddle plant. Volumes declined due to natural field declines and as a result of contract terminations, as advances in technology made it more cost efficient to process natural gas at other facilities. We have contracted for all of the capacity of the plant from ONEOK.

Utilization - The utilization rate for our natural gas processing plants was approximately 71 percent for 2008.

Natural Gas Pipelines

Property - Our Natural Gas Pipelines segment owns the following assets:
- approximately 1,320 miles of FERC-regulated interstate natural gas pipelines with approximately 2.5 Bcf/d of peak transportation capacity;
- approximately 5,560 miles of intrastate natural gas gathering and state-regulated intrastate transmission pipelines with peak transportation capacity of approximately 3.3 Bcf/d; and
- approximately 51.6 Bcf of total active working natural gas storage capacity.

Our storage includes five underground natural gas storage facilities in Oklahoma, three underground natural gas storage facilities in Kansas and three underground natural gas storage facilities in Texas. One of our natural gas storage facilities outside of Hutchinson, Kansas, has been idle since 2001, following natural gas explosions and eruptions of natural gas geysers. We began injecting brine into the facility in the first quarter of 2007 in order to ensure the long-term integrity of the idled facility. We expect to complete the injection process by the end of 2011. Monitoring of the facility and review of the data for the geoengineering studies are ongoing, in compliance with a KDHE order while we evaluate the alternatives for the facility. Following the testing of the gathered data, we expect that the facility will be returned to storage service, although most likely for a product other than natural gas. The return to service will require KDHE approval. It is possible, however, that testing could reveal that it is not safe to return the facility to service or that the KDHE will not grant the required permits to resume service.

Utilization - During 2008, our natural gas pipelines were approximately 86 percent subscribed, and our storage facilities were fully subscribed.

Natural Gas Liquids Gathering and Fractionation

Property - Our Natural Gas Liquids Gathering and Fractionation segment owns the following assets:

- approximately 2,011 miles of natural gas liquids gathering pipelines with peak capacity of approximately 247 MBbl/d;
- approximately 163 miles of natural gas liquids distribution pipelines with peak transportation capacity of approximately 66 MBbl/d;
- two natural gas liquids fractionators with operating capacity of approximately 260 MBbl/d;
- 80 percent ownership interest in one natural gas liquids fractionator with operating capacity of approximately 160 MBbl/d;
- interest in one natural gas liquids fractionator with proportional operating capacity of approximately 11 MBbl/d;
- one 9 MBbl/d isomerization unit; and
- six NGL storage facilities in Oklahoma, Kansas and Texas with operating storage capacity of approximately 23.2 MMBbl.

In addition, we lease four NGL storage facilities in Oklahoma, Kansas and Texas with operating storage capacity of approximately 3.2 MMBbl. We also own and lease assets through an affiliate at the Bushton facility in Kansas, which includes 150 MBbl/d of fractionation capacity.

During 2007 and 2008, we added new natural gas liquids fractionation facilities at the Bushton location, in conjunction with other changes that were made to the NGL fractionation capabilities of the existing plant. Although the Bushton Plant remains idled, we currently have 150 MBbl/d of active NGL fractionation capacity as a result of combining the previously existing fractionation equipment with the new fractionation facilities. We resumed fractionating NGLs at the facilities in the second half of 2008.

Utilization - The utilization rate for our natural gas liquids gathering pipelines was approximately 73 percent for 2008. Our average contracted storage volume was approximately 74 percent of storage capacity for 2008. The utilization rate for our natural gas liquids fractionators was approximately 87 percent for 2008. Our fractionation utilization rate reflects approximate proportional capacity associated with ownership interests noted above and partial service for our Bushton facility, which was placed in service during the second half of 2008.

Natural Gas Liquids Pipelines

Property - Our Natural Gas Liquids Pipelines segment owns the following assets:

- approximately 1,480 miles of FERC-regulated natural gas liquids gathering pipelines with peak capacity of approximately 203 MBbl/d;
- approximately 3,480 miles of FERC-regulated natural gas liquids and refined petroleum products distribution pipelines with peak transportation capacity of 691 MBbl/d;
- eight NGL product terminals in Missouri, Nebraska, Iowa and Illinois; and
- above- and below-ground storage facilities in Iowa, Illinois, Nebraska and Kansas with 978 MBbl operating capacity.

Utilization - The utilization rate for our FERC-regulated natural gas liquids gathering pipelines was approximately 55 percent for 2008. Utilization rate for our natural gas liquids distribution pipelines was approximately 49 percent for 2008. We calculated utilization on our assets using a weighted-average approach, adjusting for the in-service dates of our assets placed in service during 2008.

Other

Our Other segment includes Black Mesa Pipeline, which we started decommissioning in the second quarter of 2008.

ITEM 3. LEGAL PROCEEDINGS

Will Price, et al. v. Gas Pipelines, et al. (f/k/a Quinque Operating Company, et al. v. Gas Pipelines, et al.), 26th Judicial District, District Court of Stevens County, Kansas, Civil Department, Case No. 99C30 ("Price I"). Plaintiffs brought suit on May 28, 1999, against Mid-Continent Market Center, L.L.C., ONEOK Field Services Company, L.L.C., ONEOK WesTex Transmission, L.L.C. and ONEOK Hydrocarbon, L.P. (formerly Koch Hydrocarbon, LP), as well as approximately 225 other defendants. Plaintiffs sought class certification for its claims for monetary damages that the defendants had underpaid gas producers and royalty owners throughout the United States by intentionally understating both the volume and the heating content of purchased gas. After extensive briefing and a hearing, the Court refused to certify the class sought by plaintiffs. Plaintiffs then filed an amended petition limiting the purported class to gas producers and royalty owners in Kansas, Colorado and Wyoming and limiting the claim to undermeasurement of volumes. Oral argument on the plaintiffs' motion to certify this suit as a class action was conducted on April 1, 2005. The Court has not yet ruled on the class certification issue.

Will Price and Stixon Petroleum, et al. v. Gas Pipelines, et al., 26th Judicial District, District Court of Stevens County, Kansas, Civil Department, Case No. 03C232 ("Price II"). This action was filed by the plaintiffs on May 12, 2003, after the Court had denied class status in Price I. Plaintiffs are seeking monetary damages based upon a claim that 21 groups of defendants, including Mid-Continent Market Center, L.L.C., ONEOK Field Services Company, L.L.C., ONEOK WesTex Transmission, L.L.C. and ONEOK Hydrocarbon, L.P. (formerly Koch Hydrocarbon, LP), intentionally underpaid gas producers and royalty owners by understating the heating content of purchased gas in Kansas, Colorado and Wyoming. Price II has been consolidated with Price I for the determination of whether either or both cases may properly be certified as class actions. Oral argument on the plaintiffs' motion to certify this suit as a class action was conducted on April 1, 2005. The Court has not yet ruled on the class certification issue.

Mont Belvieu Emissions, Texas Commission on Environmental Quality - We are in discussions with the Texas Commission on Environmental Quality (TCEQ) staff regarding air emissions from a heat exchanger at our Mont Belvieu fractionator, which may have exceeded the emissions allowed under our air permit. We discovered the possibility of excessive air emissions in May 2008. The TCEQ has not issued a notice of enforcement relating to the emissions under this permit. Although no assurances can be given, we do not believe that any penalties associated with any alleged violations will have a material adverse effect on our financial position, results of operations, or net cash flows.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

Not applicable.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

MARKET INFORMATION AND HOLDERS

Our equity consists of a 2 percent general partner interest and a 98 percent limited partner interest. Our limited partner interests are represented by our common units, which are listed on the NYSE under the trading symbol "OKS," and our Class B limited partner units. The following table sets forth the high and low closing prices of our common units for the periods indicated.

	Year Ended December 31, 2008		Year Ended December 31, 2007	
	High	**Low**	**High**	**Low**
First Quarter	**$ 63.89**	**$ 54.58**	$ 67.80	$ 62.62
Second Quarter	**$ 64.01**	**$ 55.90**	$ 72.42	$ 66.82
Third Quarter	**$ 60.05**	**$ 50.32**	$ 70.70	$ 58.20
Fourth Quarter	**$ 55.88**	**$ 39.25**	$ 65.41	$ 59.00

At February 18, 2009, there were 834 holders of record of our 54,426,087 outstanding common units. ONEOK and its affiliates own all of the Class B units, 5,900,000 common units and the entire 2 percent general partner interest in us, which together constitutes a 47.7 percent ownership interest in us.

CASH DISTRIBUTIONS

The following table sets forth the quarterly cash distribution declared and paid on each of our common and Class B units during the periods indicated.

	Years Ended December 31,	
	2008	**2007**
First Quarter	**$ 1.025**	$ 0.980
Second Quarter	**$ 1.040**	$ 0.990
Third Quarter	**$ 1.060**	$ 1.000
Fourth Quarter	**$ 1.080**	$ 1.010

In January 2009, we declared a cash distribution of $1.08 per unit ($4.32 per unit on an annualized basis) for the fourth quarter of 2008, which was paid on February 13, 2009, to unitholders of record as of January 30, 2009.

CASH DISTRIBUTION POLICY

Under our Partnership Agreement, we make distributions to our partners with respect to each calendar quarter in an amount equal to 100 percent of available cash within 45 days following the end of each quarter. Available cash generally consists of cash receipts less adjustments for cash disbursements and net changes to reserves. Available cash will generally be distributed to our general partner and limited partners according to their partnership percentages of 2 percent and 98 percent, respectively. Our general partner's percentage interest in quarterly distributions is increased after certain specified target levels are met. Under the incentive distribution provisions, our general partner receives:

- 15 percent of amounts distributed in excess of $0.605 per unit;
- 25 percent of amounts distributed in excess of $0.715 per unit; and
- 50 percent of amounts distributed in excess of $0.935 per unit.

We paid cash distributions to our general and limited partners of $453.0 million for 2008 and $384.6 million for 2007, which included an incentive distribution to our general partner of $69.9 million for 2008 and $47.1 million for 2007. Additional information about our cash distributions is included in Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operation under "Liquidity and Capital Resources," and Item 13, Certain Relationships and Related Transactions, and Director Independence.

ISSUANCE OF CLASS B UNITS

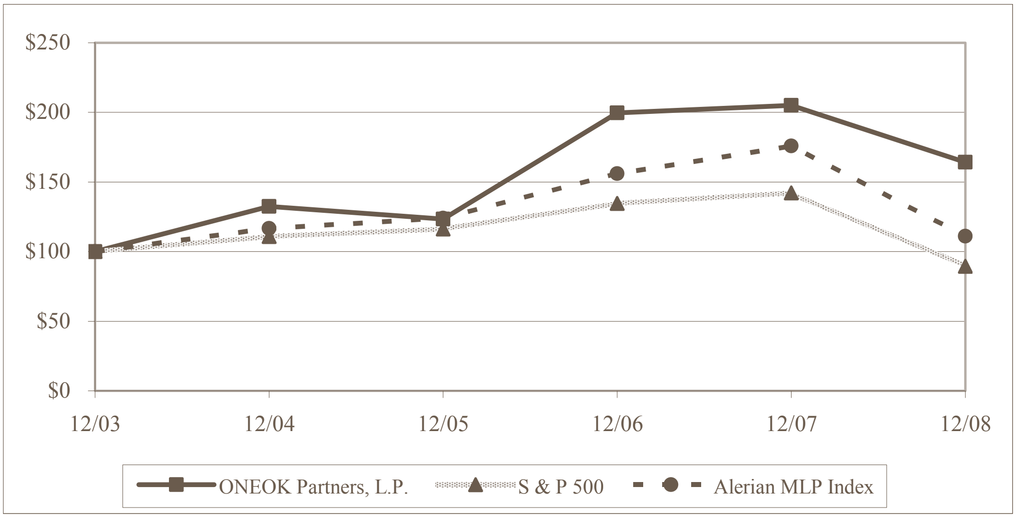
In April 2006, we issued approximately 36.5 million Class B units to ONEOK as part of the acquisition of the ONEOK Energy Assets. See discussion of the ONEOK Energy Assets acquisition in Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operation under "Significant Acquisitions and Divestitures." The units issued to ONEOK were the newly created Class B limited partner units. The Class B limited partner units are no longer subordinated to distributions on our common units and generally have the same voting rights as our common units. See Note B of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K for additional information.

The Class B units were not registered in reliance on the exemption from registration with the SEC as set forth in Section 4(2) of the Securities Act of 1933, as amended, as a transaction not involving any public offering.

PERFORMANCE GRAPH

The following performance graph compares the performance of our common units with the S&P 500 Index and the Alerian MLP Index during the period beginning on December 31, 2003, and ending on December 31, 2008. The graph assumes a $100 investment in our common units and in each of the indices at the beginning of the period and a reinvestment of distributions/dividends paid on such investments throughout the period.

Value of $100 Investment Assuming Reinvestment of Distributions/Dividends
At December 31, 2003, and at the End of Every Year Through December 31, 2008
Among ONEOK Partners LP, the S&P 500 Index and the Alerian MLP Index



	Cumulative Total Return					
	Years Ending December 31,					
	2003	2004	2005	2006	2007	2008
ONEOK Partners, L.P.	$ 100.00	$ 132.53	$ 123.45	$ 199.73	$ 205.01	**$ 164.26**
S&P 500 Index	$ 100.00	$ 110.88	$ 116.32	$ 134.69	$ 142.09	**$ 89.52**
Alerian MLP Index (a)	$ 100.00	$ 116.67	$ 124.04	$ 156.07	$ 175.88	**$ 111.12**

(a) - The Alerian MLP Index measures the composite performance of the 50 most prominent energy master limited partnerships.

ITEM 6. SELECTED FINANCIAL DATA

The following table sets forth our selected financial data for each of the periods indicated.

	Years Ended December 31,				
	2008	2007	2006	2005	2004
	(In thousands of dollars, except per unit data)				
Revenues	**$ 7,720,206**	$ 5,831,558	$ 4,738,248	$ 703,944	$ 590,383
Income from continuing operations	**$ 625,616**	$ 407,747	$ 445,186	$ 146,507	$ 140,921
Net income	**$ 625,616**	$ 407,747	$ 445,186	$ 147,013	$ 144,720
Total assets	**$ 7,254,272**	$ 6,112,065	$ 4,921,717	$ 2,527,766	$ 2,514,690
Long-term debt, including current maturities	**$ 2,601,440**	$ 2,617,326	$ 2,031,529	$ 1,123,971	$ 1,139,358
Per unit income from continuing operations	**$ 6.01**	$ 4.21	$ 5.01	$ 2.92	$ 2.81
Per unit net income	**$ 6.01**	$ 4.21	$ 5.01	$ 2.93	$ 2.89
Distributions per common unit (a)	**$ 4.205**	$ 3.98	$ 3.60	$ 3.20	$ 3.20

(a) - Class B unitholders received the same distribution as common unitholders.

Financial data for 2008, 2007 and 2006 is not directly comparable with 2005 and 2004 due to the significance of the April 2006 ONEOK Transactions. See discussion of acquisitions and dispositions beginning on page 37 under "Significant Acquisitions and Divestitures" in Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operation.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATION

The following discussion and analysis should be read in conjunction with our audited consolidated financial statements and the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.

EXECUTIVE SUMMARY

The following discussion highlights some of our achievements this past year. Please refer to the "Liquidity and Capital Resources," "Capital Projects," and "Financial Results and Operating Information" sections of Management's Discussion and Analysis of Financial Condition and Results of Operation and our Consolidated Financial Statements for additional information.

Equity Issuance - In March 2008, we completed a public offering of 2.5 million common units at $58.10 per common unit, generating net proceeds of approximately $140.4 million after deducting underwriting discounts but before offering expenses. In addition, we sold 5.4 million common units to ONEOK in a private placement, generating proceeds of approximately $303.2 million. In conjunction with the public offering of common units and the private placement, ONEOK Partners GP contributed $9.4 million in order to maintain its 2 percent general partner interest in us.

In April 2008, we sold an additional 128,873 common units at $58.10 per common unit to the underwriters of the public offering upon the partial exercise of their option to purchase additional common units to cover over-allotments. We received net proceeds of approximately $7.2 million from the sale of the common units after deducting underwriting discounts but before offering expenses. In conjunction with the partial exercise by the underwriters, ONEOK Partners GP contributed $0.2 million in order to maintain its 2 percent general partner interest in us. As a result of these transactions, ONEOK now holds a 47.7 percent aggregate equity interest in us.

We used a portion of the proceeds from the sale of common units and the general partner contributions to repay borrowings under our amended and restated revolving credit agreement dated March 30, 2007 (Partnership Credit Agreement).

Cash Distributions - During 2008, we paid cash distributions totaling $4.205 per unit, an increase of approximately 6 percent over the $3.98 per unit paid during 2007. On January 13, 2009, we declared a cash distribution of $1.08 per unit ($4.32 per unit on an annualized basis), an increase of approximately 5 percent over the $1.025 declared in January 2008.

Capital Projects - The following projects were placed in-service during 2008:

- January - Midwestern Gas Transmission's eastern extension pipeline;
- July - final phase of Fort Union Gas Gathering expansion project;
- September - Woodford Shale natural gas liquids pipeline extension;
- October - Bushton fractionation expansion;

- November - Overland Pass Pipeline from Opal, Wyoming to Conway, Kansas; and
- December - partial operations of the Guardian Pipeline extension with interruptible service from Ixonia, Wisconsin, to Green Bay, Wisconsin.

Operating Results - Net income per unit increased to $6.01 in 2008, compared with $4.21 in 2007. The increase in net income per unit in 2008 is primarily due to the following:
- wider NGL product price differentials, increased NGL gathering and fractionation volumes and certain operational measurement gains, primarily at NGL storage caverns, in our Natural Gas Liquids Gathering and Fractionation segment;
- higher realized commodity prices, improved contractual terms and higher volumes sold and processed in our Natural Gas Gathering and Processing segment;
- incremental operating income in our Natural Gas Liquids Pipelines segment from the assets acquired from Kinder Morgan in October 2007; and
- increased transportation and storage margins as a result of the impact of higher natural gas prices on retained fuel and new and renegotiated storage contracts in our Natural Gas Pipelines segment.

During September 2008, our Natural Gas Gathering and Processing segment, Natural Gas Liquids Gathering and Fractionation segment, and Natural Gas Liquids Pipelines segment experienced disruptions related to Hurricane Ike. Without these disruptions, we estimate our net margin of $1.1 billion for 2008 would have been approximately $7.8 million higher.

Outlook for 2009

We expect continued deteriorating economic conditions in 2009, with downward pressures, relative to 2008, on commodity prices for natural gas, NGLs and crude oil. We anticipate that lower commodity prices will result in reduced drilling activity and economic conditions will reduce petrochemical demand. We also expect continued volatility and disruption in the financial markets, which could result in increased cost of capital. We expect depressed commodity prices and tighter capital markets to also result in the sale or consolidation of underperforming assets in the industry, which may present opportunities for us.

We intend to pursue growth in our natural gas businesses through well-connects and contract renegotiations and through expansions and extensions of our existing systems and plants. For our natural gas liquids businesses, we intend to continue to focus on adding new supply connections, optimizing existing assets, as well as completing our growth projects currently under construction. Capital expenditures in 2009 are expected to be significantly lower than in 2008 when we spent approximately $1.3 billion. We plan to spend approximately $425 million on capital expenditures in 2009, of which approximately $355 million is for growth projects. We also plan to pursue strategic acquisitions.

SIGNIFICANT ACQUISITIONS AND DIVESTITURES

Acquisition of NGL Pipeline - In October 2007, we completed the acquisition of an interstate natural gas liquids and refined petroleum products pipeline system and related assets from a subsidiary of Kinder Morgan for approximately $300 million, before working capital adjustments. The system extends from Bushton and Conway, Kansas, to Chicago, Illinois, and transports, stores and delivers a full range of NGL products and refined petroleum products. The FERC-regulated system spans 1,624 miles and has a capacity to transport up to 134 MBbl/d. The transaction also included approximately 978 MBbl of owned storage capacity, eight NGL terminals and a 50 percent ownership of Heartland. ConocoPhillips owns the other 50 percent of Heartland and is the managing partner of Heartland, which consists primarily of one refined petroleum products terminal and pipelines with access to two other refined petroleum product terminals. Our investment in Heartland is accounted for under the equity method of accounting. Financing for this transaction came from a portion of the proceeds of our September 2007 issuance of $600 million 6.85 percent Senior Notes due 2037 (the 2037 Notes). See Note I of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K for a discussion of the 2037 Notes. The working capital settlement was finalized in April 2008, with no material adjustments. These assets are included in our Natural Gas Liquids Pipelines segment.

Overland Pass Pipeline Company - See "Capital Projects" for discussion of Overland Pass Pipeline Company.

The ONEOK Transactions - In April 2006, we completed the acquisition of and consolidated certain companies comprising ONEOK's former gathering and processing, natural gas liquids, and pipelines and storage segments (collectively, the ONEOK Energy Assets) in a series of transactions (collectively, the ONEOK Transactions). This acquisition is accounted for in our Natural Gas Gathering and Processing, Natural Gas Pipelines, Natural Gas Liquids Gathering and Fractionation, and Natural Gas Liquids Pipelines segments.

Acquisition of ONEOK Energy Assets - We acquired the ONEOK Energy Assets for approximately $3 billion, including $1.35 billion in cash, before adjustments, and approximately 36.5 million Class B limited partner units. The Class B limited partner units and the related general partner interest contribution were valued at approximately $1.65 billion. After this acquisition, ONEOK owned approximately 37.0 million of our common units, which, when combined with its general partner interest, increased its total interest in us to approximately 45.7 percent at the date of acquisition. We used $1.05 billion drawn under a $1.1 billion, 364-day credit agreement, coupled with the proceeds from the sale of a 20 percent partnership interest in Northern Border Pipeline, to finance the cash portion of the transaction. The assets were recorded at historical cost rather than at fair value since these transactions were between affiliates under common control. These assets and their related operations are included in our consolidated financial statements retroactive to January 1, 2006.

Equity Issuance - In connection with the ONEOK Transactions, we amended our Partnership Agreement to provide for the issuance of Class B limited partner units and issued approximately 36.5 million Class B limited partner units to ONEOK. The Class B limited partner units were issued on April 6, 2006. For more information regarding the Class B units, refer to discussion of the ONEOK Transactions in Note B of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.

Purchase and Sale of General Partner Interest - In connection with the ONEOK Transactions, in April 2006, ONEOK acquired ONEOK NB, formerly known as Northwest Border Pipeline Company, an affiliate of TransCanada that held a 0.35 percent general partner interest in us. As a result, ONEOK now owns our entire 2 percent general partner interest and controls us.

Disposition of 20 Percent Partnership Interest in Northern Border Pipeline - In connection with the ONEOK Transactions, in April 2006, we completed the sale of a 20 percent partnership interest in Northern Border Pipeline to TC PipeLines for approximately $297 million to help finance the acquisition of the ONEOK Energy Assets. We recorded a gain on the sale of approximately $113.9 million in the second quarter of 2006. We and TC PipeLines each now own a 50 percent interest in Northern Border Pipeline, and an affiliate of TransCanada became the operator of the pipeline in April 2007. Effective January 1, 2006, our interest in Northern Border Pipeline is accounted for as an investment under the equity method in our Natural Gas Pipelines segment.

Acquisition of Guardian Pipeline Interests - In April 2006, we acquired the 66-2/3 percent interest in Guardian Pipeline not previously owned by us for approximately $77 million, increasing our ownership interest to 100 percent. We used borrowings from our credit facility to fund the acquisition of the additional interest in Guardian Pipeline. Guardian Pipeline is consolidated in our consolidated financial statements and reported in our Natural Gas Pipelines segment as of January 1, 2006.

CAPITAL PROJECTS

Woodford Shale Natural Gas Liquids Pipeline Extension - The 78-mile natural gas liquids gathering pipeline connecting two natural gas processing plants, operated by Devon Energy Corporation and Antero Resources Corporation, was placed into service in September 2008. The cost of the project was approximately $36 million, excluding AFUDC. These two plants have the capacity to produce approximately 25 MBbl/d of unfractionated NGLs. The natural gas liquids production is gathered by our existing Mid-Continent natural gas liquids gathering pipelines. Upon completion of the Arbuckle Pipeline project, the Woodford Shale natural gas liquids production is expected to be transported through the Arbuckle Pipeline to our Mont Belvieu, Texas, fractionation facility. This project is in our Natural Gas Liquids Gathering and Fractionation segment.

Overland Pass Pipeline Company - In May 2006, we entered into an agreement with a subsidiary of The Williams Companies, Inc. (Williams) to form a joint venture called Overland Pass Pipeline Company. In November 2008, Overland Pass Pipeline Company completed construction of a 760-mile natural gas liquids pipeline from Opal, Wyoming, to the Mid-Continent natural gas liquids market center in Conway, Kansas. The Overland Pass Pipeline is designed to transport approximately 110 MBbl/d of unfractionated NGLs and can be increased to approximately 255 MBbl/d with additional pump facilities. During 2006, we paid $11.6 million to Williams for the acquisition of our interest in the joint venture and for reimbursement of initial capital expenditures. Initially, as the 99 percent owner of the joint venture, we managed the construction project and advanced all costs associated with construction. We are currently operating the pipeline. On or before November 17, 2010, Williams will have the option to increase its ownership up to 50 percent, with the purchase price being determined in accordance with the joint venture’s operating agreement. If Williams exercises its option to increase its ownership to the full 50 percent, Williams would have the option to become operator. The pipeline project cost was approximately $575 million, excluding AFUDC.

As part of a long-term agreement, Williams dedicated its NGL production from two of its natural gas processing plants in Wyoming, estimated to be approximately 60 MBbl/d, to the Overland Pass Pipeline. We will provide downstream fractionation, storage and transportation services to Williams. We have also reached agreements with certain producers for supply commitments of up to an additional 80 MBbl/d, and we are negotiating agreements with other producers for supply commitments that could add an additional 60 MBbl/d of supply to this pipeline within the next three to five years.

We also invested approximately $239 million, excluding AFUDC, to expand our existing fractionation and storage capabilities and to increase the capacity of our natural gas liquids distribution pipelines. Part of this expansion included adding new fractionation facilities at our Bushton location, which increased the total fractionation capacity at the Bushton facility from 80 MBbl/d to 150 MBbl/d. The addition of the new facilities and the upgrade to the existing fractionator was completed in October 2008. Additionally, portions of our natural gas liquids distribution pipeline upgrades were completed in the second and third quarters of 2008. Overland Pass Pipeline Company is included in our Natural Gas Liquids Pipelines segment, while the associated expansions are included in our Natural Gas Liquids Gathering and Fractionation segment and Natural Gas Liquids Pipelines segment.

Piceance Lateral Pipeline - In March 2007, we announced that Overland Pass Pipeline Company also plans to construct a 150-mile lateral pipeline with capacity to transport as much as 100 MBbl/d of unfractionated NGLs from the Piceance Basin in Colorado to the Overland Pass Pipeline. Williams announced that it intends to construct a new natural gas processing plant in the Piceance Basin and will dedicate its NGL production from that plant and an existing plant, with estimated volumes totaling approximately 30 MBbl/d, to be transported by the lateral pipeline. We continue to negotiate with other producers for supply commitments. In October 2008, this project received the approval of various state and federal regulatory authorities, allowing construction to commence. Construction began during the fourth quarter of 2008 and is expected to be completed during the third quarter of 2009. The project is currently estimated to cost in the range of $110 million to $140 million, excluding AFUDC. This project is in our Natural Gas Liquids Pipelines segment.

D-J Basin Lateral Pipeline - In September 2008, we announced plans to construct a 125-mile natural gas liquids lateral pipeline from the Denver-Julesburg Basin in northeastern Colorado to the Overland Pass Pipeline, with capacity to transport as much as 55 MBbl/d of unfractionated NGLs. The project is currently estimated to cost in the range of $70 million to $80 million, excluding AFUDC. We have supply commitments for up to 33 MBbl/d of unfractionated NGLs with potential for an additional 10 MBbl/d of supply from new drilling and plant upgrades in the next two years. The pipeline is currently under construction and is expected to be fully completed during the first quarter of 2009. This project is in our Natural Gas Liquids Pipelines segment.

Arbuckle Natural Gas Liquids Pipeline - In March 2007, we announced plans to build the 440-mile Arbuckle Pipeline, a natural gas liquids pipeline from southern Oklahoma through northern Texas and continuing on to the Texas Gulf Coast. The Arbuckle Pipeline will have the capacity to transport 160 MBbl/d of unfractionated NGLs, expandable to 210 MBbl/d with additional pump facilities, and will connect our existing Mid-Continent infrastructure with our fractionation facility in Mont Belvieu, Texas, and other Gulf Coast region fractionators. We have supply commitments from producers that we expect will be sufficient to fill the 210 MBbl/d capacity level over the next three to five years. Construction on the pipeline has been under way since the third quarter of 2008. Much of the Oklahoma and north Texas portions are either complete or nearing completion. However, right-of-way acquisition has been challenging, time consuming and expensive, which could affect the completion schedule and final cost of the project. Many of Arbuckle Pipeline's remaining right-of-way tracts are being acquired through a condemnation process, which adds to the cost and time to construct the pipeline. The demand for surface easements has increased dramatically in Texas and Oklahoma in the last 12 to 18 months because of increased oil and natural gas exploration and production activities, as well as pipeline construction. Because of the delays associated with right-of-way acquisition, we anticipate construction on the south end of the project will be more difficult and expensive due to wet low-lying areas and potential for spring rains. Accordingly, we expect the project to be operational in the second quarter of 2009. Based on the increased costs and delays associated with right-of-way acquisition and potential weather impacts, our project costs could increase 10 percent to 15 percent above the range of $340 million to $360 million, excluding AFUDC, as previously reported. This project is in our Natural Gas Liquids Pipelines segment.

Williston Basin Gas Processing Plant Expansion - In March 2007, we announced the expansion of our Grasslands natural gas processing facility in North Dakota, currently estimated to cost in the range of $40 million to $45 million, excluding AFUDC. Our estimated project costs increased from $30 million, primarily as a result of higher contract labor and equipment costs. The Grasslands facility is our largest natural gas processing plant in the Williston Basin. The expansion increases processing capacity to approximately 100 MMcf/d from its current capacity of 63 MMcf/d and increases fractionation capacity to approximately 12 MBbl/d from 8 MBbl/d. The construction on the expansion project is expected to be complete in the first quarter of 2009. This project is in our Natural Gas Gathering and Processing segment.

Fort Union Gas Gathering Expansion - In January 2007, Fort Union Gas Gathering announced plans to double its existing gathering pipeline capacity by adding 148 miles of new gathering lines, resulting in approximately 649 MMcf/d of additional capacity in the Powder River basin of Wyoming. The expansion occurred in two phases and cost approximately $121 million, excluding AFUDC, which was primarily financed within the Fort Union Gas Gathering partnership. Any cost overruns are covered through escalation clauses to preserve the original economics of the project. Phase I, with more than 200 MMcf/d capacity, was placed in service during the fourth quarter of 2007. Phase II, with approximately 450 MMcf/d capacity, was completed in July 2008. The additional capacity has been fully subscribed for 10 years. We own approximately 37 percent of Fort Union Gas Gathering. This investment is in our Natural Gas Gathering and Processing segment and is accounted for under the equity method of accounting.

Guardian Pipeline Expansion and Extension - In December 2007, Guardian Pipeline received and accepted the certificate of public convenience and necessity issued by the FERC for its expansion and extension project. The certificate authorizes us to construct, install and operate approximately 119 miles of a 20-inch and 30-inch natural gas transportation pipeline, with capacity to transport 537 MMcf/d of natural gas north from Ixonia, Wisconsin, to the Green Bay, Wisconsin area. The project is supported by 15-year shipper commitments with We Energies and Wisconsin Public Service Corporation, and the capacity has been fully subscribed. The project is currently estimated to cost in the range of $277 million to $305 million, excluding AFUDC. Our estimated project costs increased from our initial estimate of $241 million in 2006, which excluded AFUDC, primarily due to weather delays, equipment delivery delays, construction in environmentally sensitive areas, rocky terrain and escalating costs associated with crop damage and condemnation costs. We received the notice to proceed from the FERC in May 2008. On December 22, 2008, the FERC issued a letter order granting Guardian Pipeline’s request for an extension of time for a phased in-service. On December 29, 2008, the FERC issued a letter order granting Guardian Pipeline’s request to commence service. On December 31, 2008, the pipeline and seven meter stations were placed into service with the ability to transport natural gas on a limited basis. Construction on one compressor station is complete, and construction on a second compressor station is near completion. The project is expected to be fully in service in the first quarter of 2009. This project is in our Natural Gas Pipelines segment.

IMPACT OF NEW ACCOUNTING STANDARDS

Information about the impact of the following new accounting standards is included in Note A of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K:

- Statement 157, “Fair Value Measurements,” and related FASB Staff Position (FSP) 157-2, “Effective Date of FASB Statement No. 157,” and FSP 157-3, “Determining the Fair Value of a Financial Asset When the Market for That Asset Is Not Active;”
- Statement 159, “The Fair Value Option for Financial Assets and Financial Liabilities;”
- FSP FIN 39-1, “Amendment of FASB Interpretation No. 39;”
- Statement 141R, “Business Combinations;”
- Statement 160, “Noncontrolling Interests in Consolidated Financial Statements - an amendment of ARB No. 51;”
- EITF 08-6, “Equity Method Investment Accounting Considerations;”
- Statement 161, “Disclosures about Derivative Instruments and Hedging Activities - an amendment to FASB Statement No. 133;” and
- EITF 07-4, “Application of the Two-Class Method under FASB Statement No. 128 to Master Limited Partnerships.”

CRITICAL ACCOUNTING ESTIMATES

The preparation of our consolidated financial statements and related disclosures in accordance with GAAP requires us to make estimates and assumptions with respect to values or conditions that cannot be known with certainty that affect the reported amount of assets and liabilities, and the disclosure of contingent assets and liabilities at the date of the consolidated financial statements. These estimates and assumptions also affect the reported amounts of revenue and expenses during the reporting period. Although we believe these estimates and assumptions are reasonable, actual results could differ from our estimates.

The following is a summary of our most critical accounting estimates, which are defined as those policies most important to the portrayal of our financial condition and results of operations and requiring our management’s most difficult, subjective or complex judgment, particularly because of the need to make estimates concerning the impact of inherently uncertain matters. We have discussed the development and selection of our critical accounting policies and estimates with the Audit Committee of our Board of Directors.

Impairment of Long-Lived Assets, Goodwill and Intangible Assets - We assess our long-lived assets for impairment based on Statement 144, "Accounting for the Impairment or Disposal of Long-Lived Assets." A long-lived asset is tested for impairment whenever events or changes in circumstances indicate that its carrying amount may exceed its fair value. Fair values are based on the sum of the undiscounted future cash flows expected to result from the use and eventual disposition of the assets.

We assess our goodwill for impairment at least annually, based on Statement 142, "Goodwill and Other Intangible Assets." There were no impairment charges resulting from our July 1, 2008, impairment test. As a result of recent events in the financial markets and current economic conditions, we performed a review and determined that interim testing of goodwill as of December 31, 2008, was not necessary. As part of our impairment test, an initial assessment is made by comparing the fair value of a reporting unit with its book value, including goodwill. If the fair value is less than the book value, an impairment is indicated, and we must perform a second test to measure the amount of the impairment. In the second test, we calculate the implied fair value of the goodwill by deducting the fair value of all tangible and intangible net assets of the reporting unit from the fair value determined in step one of the assessment. If the carrying value of the goodwill exceeds the implied fair value of the goodwill, we will record an impairment charge.

We use two generally accepted valuation approaches, an income approach and a market approach, to estimate the fair value of a reporting unit. Under the income approach, we use anticipated cash flows over a three-year period plus a terminal value and discount these amounts to their present-value using appropriate rates of return. Under the market approach, we apply multiples to forecasted EBITDA amounts. The multiples used are consistent with historical asset transactions, and the EBITDA amounts are based on average EBITDA for a reporting unit over a three-year forecasted period. At December 31, 2008, we had $396.7 million of goodwill recorded on our Consolidated Balance Sheet as shown below.

	(Thousands of dollars)
Natural Gas Gathering and Processing	$ **90,037**
Natural Gas Pipelines	**131,115**
Natural Gas Liquids Gathering and Fractionation	**175,566**
Total goodwill	$ **396,718**

Intangible assets with a finite useful life are amortized over their estimated useful life, while intangible assets with an indefinite useful life are not amortized. All intangible assets are subject to impairment testing. As shown below, we had $279.8 million of intangible assets recorded on our Consolidated Balance Sheet as of December 31, 2008.

	(Thousands of dollars)
Natural Gas Liquids Gathering and Fractionation	$ **266,451**
Natural Gas Liquids Pipelines	**13,367**
Total intangible assets	$ **279,818**

Our impairment tests require the use of assumptions and estimates. If actual results are not consistent with our assumptions and estimates or our assumptions and estimates change due to new information, we may be exposed to an impairment charge.

During 2006, we reassessed our coal slurry pipeline operation and concluded that the likelihood of Black Mesa Pipeline resuming operations was significantly reduced, and a goodwill and asset impairment of $8.4 million and $3.6 million, respectively, was recorded as depreciation and amortization. The reduction to our net income after income taxes was $10.6 million. Additional information about Black Mesa Pipeline is included above in Item 1 under "Description of Business Segments - Other."

Our total unamortized excess cost over underlying fair value of net assets accounted for under the equity method was $185.6 million as of December 31, 2008 and 2007. These amounts were recorded in investment in unconsolidated affiliates on our accompanying Consolidated Balance Sheets. For the investments we account for under the equity method, the premium or excess cost over underlying fair value of net assets is referred to as equity method goodwill and under Statement 142 is not subject to amortization but rather to impairment testing pursuant to APB Opinion No. 18, "The Equity Method of Accounting for Investments in Common Stock." The impairment test under APB Opinion No. 18 considers whether the fair value of the equity investment as a whole, not the underlying net assets, has declined and whether that decline is other than temporary. Therefore, we periodically reevaluate the amount at which we carry the excess of cost over fair value of net assets accounted for under the equity method to determine whether current events or circumstances warrant adjustments to our carrying value in accordance with APB Opinion No. 18. See Note M of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K for additional discussion of unconsolidated affiliates.

Derivatives and Risk Management - We utilize financial instruments to reduce our market risk exposure to interest rate and commodity price fluctuations and to achieve more predictable cash flows. We account for derivative instruments utilized in connection with these activities and services in accordance with Statement 133, "Accounting for Derivative Instruments and Hedging Activities," as amended.

Under Statement 133, entities are required to record derivative instruments at fair value, with the exception of normal purchases and normal sales that are expected to result in physical delivery. See Note C of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K for additional fair value discussion. Market value changes result in a change in the fair value of our derivative instruments. The accounting for changes in the fair value of a derivative instrument depends on whether it has been designated and qualifies as part of a hedging relationship and, if so, the nature of the risk being hedged and how we will determine if the hedging instrument is effective. If the derivative instrument does not qualify or is not designated as part of a hedging relationship, then we account for changes in fair value of the derivative in earnings as changes occur. Commodity price volatility may have a significant impact on the gain or loss in a given period. For more information on fair value sensitivity and a discussion of the market risk of pricing changes, see Item 7A, Quantitative and Qualitative Disclosures about Market Risk.

To reduce our exposure to fluctuations in natural gas, NGLs and condensate prices, we periodically enter into futures, forwards, options or swap transactions in order to hedge anticipated purchases and sales of natural gas, NGLs and condensate and fuel requirements. Interest-rate swaps are also used to manage interest rate risk. Under certain conditions, we designate these derivative instruments as a hedge of exposure to changes in fair values or cash flow. For hedges of exposure to changes in cash flow, the effective portion of the gain or loss on the derivative instrument is reported initially as a component of accumulated other comprehensive income (loss) and subsequently recorded to earnings when the forecasted transaction affects earnings. Any ineffectiveness of designated hedges is reported in earnings during the period the ineffectiveness occurs. For hedges of exposure to changes in fair value, the gain or loss on the derivative instrument is recognized in earnings during the period of change together with the offsetting gain or loss on the hedged item attributable to the risk being hedged.

Upon election, many of our purchase and sale agreements that otherwise would be required to follow derivative accounting qualify as normal purchases and normal sales under Statement 133 and are therefore exempt from fair value accounting treatment.

See Note D of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K for additional discussion of derivatives and risk management activities.

Contingencies - Our accounting for contingencies covers a variety of business activities, including contingencies for legal and environmental exposures. We accrue these contingencies when our assessments indicate that it is probable that a liability has been incurred or an asset will not be recovered, and an amount can be reasonably estimated in accordance with Statement 5, "Accounting for Contingencies." We base our estimates on currently available facts and our estimates of the ultimate outcome or resolution. Accruals for estimated losses from environmental remediation obligations generally are recognized no later than completion of the remediation feasibility study. Recoveries of environmental remediation costs from other parties are recorded as assets when their receipt is deemed probable. Actual results may differ from our estimates resulting in an impact, positive or negative, on earnings. See Note J of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K for additional discussion of contingencies.

FINANCIAL RESULTS AND OPERATING INFORMATION

Consolidated Operations

Selected Financial Results - The following table sets forth certain selected financial results for the periods indicated.

Financial Results	Years Ended December 31, 2008	2007	2006	Variances 2008 vs. 2007 Increase (Decrease)		Variances 2007 vs. 2006 Increase (Decrease)	
	(Millions of dollars)						
Revenues	**$ 7,720.2**	$ 5,831.6	$ 4,738.2	**$ 1,888.6**	**32%**	$ 1,093.4	23%
Cost of sales and fuel	**6,579.5**	4,935.7	3,894.7	**1,643.8**	**33%**	1,041.0	27%
Net margin	**1,140.7**	895.9	843.5	**244.8**	**27%**	52.4	6%
Operating costs	**371.8**	337.4	325.8	**34.4**	**10%**	11.6	4%
Depreciation and amortization	**124.8**	113.7	122.0	**11.1**	**10%**	(8.3)	(7%)
Gain (loss) on sale of assets	**0.7**	2.0	115.5	**(1.3)**	**(65%)**	(113.5)	(98%)
Operating income	**$ 644.8**	$ 446.8	$ 511.2	**$ 198.0**	**44%**	$ (64.4)	(13%)
Equity earnings from investments	**$ 101.4**	$ 89.9	$ 95.9	**$ 11.5**	**13%**	$ (6.0)	(6%)
Allowance for equity funds used during construction	**$ 50.9**	$ 12.5	$ 2.2	**$ 38.4**	*****	$ 10.3	*
Other income (expense)	**$ (7.7)**	$ 6.7	$ (0.6)	**$ (14.4)**	*****	$ 7.3	*
Interest expense	**$ (151.1)**	$ (138.9)	$ (133.5)	**$ 12.2**	**9%**	$ 5.4	4%
Minority interests in income of consolidated subsidiaries	**$ (0.4)**	$ (0.4)	$ (2.4)	**$ -**	**0%**	$ (2.0)	(83%)
Capital expenditures	**$ 1,253.9**	$ 709.9	$ 201.7	**$ 544.0**	**77%**	$ 508.2	*

* Percentage change is greater than 100 percent.

2008 vs. 2007 - Net margin increased primarily due to the following:

- wider NGL product price differentials, increased NGL gathering and fractionation volumes and certain operational measurement gains, primarily at NGL storage caverns, in our Natural Gas Liquids Gathering and Fractionation segment;
- higher realized commodity prices, improved contractual terms and higher volumes sold and processed in our Natural Gas Gathering and Processing segment;
- incremental net margin in our Natural Gas Liquids Pipelines segment from the assets acquired from Kinder Morgan in October 2007; and
- increased transportation and storage margins as a result of the impact of higher natural gas prices on retained fuel and new and renegotiated storage contracts in our Natural Gas Pipelines segment.

Operating costs increased primarily due to incremental operating expenses associated with the assets acquired from Kinder Morgan, outside services primarily associated with scheduled maintenance expenses at our Medford and Mont Belvieu fractionators, and chemical costs. Operating costs also increased due to costs associated with the startup of our newly expanded Bushton fractionator and Overland Pass Pipeline.

Depreciation and amortization increased primarily due to depreciation expense associated with our completed capital projects and the assets acquired from Kinder Morgan.

Equity earnings from investments increased primarily due to higher gathering revenues in our various investments as well as a gain on the sale of Bison Pipeline LLC by Northern Border Pipeline, partially offset by reduced throughput on Northern Border Pipeline. We own a 50 percent equity interest in Northern Border Pipeline.

Allowance for equity funds used during construction and capital expenditures increased due to increased spending for our capital projects, which are discussed beginning on page 38.

Other income (expense) fluctuated primarily due to investment gains (losses).

Interest expense increased primarily due to increased borrowings to fund our capital projects.

2007 vs. 2006 - Net margin increased primarily due to the following:

- performance of our Natural Gas Liquids Gathering and Fractionation segment and Natural Gas Liquids Pipelines segment, which benefited primarily from new supply connections that increased volumes gathered, transported, fractionated and sold;
- higher product price differentials and higher isomerization price differentials in our Natural Gas Liquids Gathering and Fractionation segment;
- incremental net margin related to the acquired assets from Kinder Morgan in October 2007 in our Natural Gas Liquids Pipelines segment; and
- increased storage margins in our Natural Gas Pipelines segment; partially offset by
- decreased natural gas transportation margins in our Natural Gas Pipelines segment, primarily resulting from lower throughput and higher fuel costs; and
- lower natural gas volumes processed as a result of contract terminations in late 2006 in our Natural Gas Gathering and Processing segment.

Operating costs increased primarily due to higher employee-related costs and the incremental operating expenses associated with our acquired assets from Kinder Morgan, partially offset by lower litigation costs.

Depreciation and amortization decreased primarily due to a goodwill and asset impairment charge of $12.0 million recorded in the second quarter of 2006 related to Black Mesa Pipeline, which is included in our Other segment.

Gain on sale of assets decreased primarily due to the $113.9 million gain on sale of a 20 percent partnership interest in Northern Border Pipeline recorded in the second quarter of 2006 in our Natural Gas Pipelines segment.

Equity earnings from investments primarily include earnings from our interest in Northern Border Pipeline. The decrease in equity earnings from investments for 2007 was primarily due to the decrease in our share of Northern Border Pipeline's earnings from 70 percent in the first quarter of 2006 to 50 percent beginning in the second quarter of 2006. See page 38 for discussion of the disposition of the 20 percent partnership interest in Northern Border Pipeline.

Allowance for equity funds used during construction and capital expenditures increased due to our capital projects.

Other income (expense) fluctuated primarily due to expenses incurred in 2006 related to costs associated with transitioning operations from Omaha, Nebraska.

Minority interest in income of consolidated subsidiaries decreased primarily due to our acquisition of the remaining interest in Guardian Pipeline. Minority interest in income of consolidated subsidiaries for 2006 included the 66-2/3 percent interest in Guardian Pipeline that we did not own until April 2006. We owned 100 percent of Guardian Pipeline beginning in April 2006, resulting in no minority interest in income of consolidated subsidiaries related to Guardian Pipeline after March 31, 2006.

More information regarding our results of operations is provided in the following discussion of operating results for each of our segments.

Natural Gas Gathering and Processing

Selected Financial Results and Operating Information - The following tables set forth certain selected financial results and operating information for our Natural Gas Gathering and Processing segment for the periods indicated.

	Years Ended December 31,			Variances 2008 vs. 2007		Variances 2007 vs. 2006	
Financial Results	**2008**	**2007**	**2006**	**Increase (Decrease)**		**Increase (Decrease)**	
			(Millions of dollars)				
NGL and condensate sales	**$ 851.7**	$ 673.8	$ 646.5	**$ 177.9**	**26%**	$ 27.3	4%
Residue gas sales	**750.4**	636.8	706.3	**113.6**	**18%**	(69.5)	(10%)
Gathering, compression, dehydration and processing fees and other revenue	**154.1**	148.1	123.2	**6.0**	**4%**	24.9	20%
Cost of sales and fuel	**1,321.0**	1,092.2	1,105.3	**228.8**	**21%**	(13.1)	(1%)
Net margin	**435.2**	366.5	370.7	**68.7**	**19%**	(4.2)	(1%)
Operating costs	**138.2**	135.4	147.5	**2.8**	**2%**	(12.1)	(8%)
Depreciation and amortization	**49.9**	45.1	43.0	**4.8**	**11%**	2.1	5%
Gain (loss) on sale of assets	**-**	1.8	0.4	**(1.8)**	**(100%)**	1.4	*
Operating income	**$ 247.1**	$ 187.8	$ 180.6	**$ 59.3**	**32%**	$ 7.2	4%
Equity earnings from investments	**$ 32.8**	$ 26.4	$ 22.6	**$ 6.4**	**24%**	$ 3.8	17%
Capital expenditures	**$ 146.2**	$ 83.8	$ 81.0	**$ 62.4**	**74%**	$ 2.8	3%

* Percentage change is greater than 100 percent.

	Years Ended December 31,		
Operating Information (a)	**2008**	**2007**	**2006**
Natural gas gathered *(BBtu/d)*	**1,164**	1,171	1,168
Natural gas processed *(BBtu/d)*	**641**	621	988
NGL sales *(MBbl/d)*	**39**	38	42
Residue gas sales *(BBtu/d)*	**279**	281	302
Realized composite NGL sales price *($/gallon)*	**$ 1.27**	$ 1.06	$ 0.93
Realized condensate sales price *($/Bbl)*	**$ 89.30**	$ 67.35	$ 57.84
Realized residue gas sales price *($/MMBtu)*	**$ 7.34**	$ 6.21	$ 6.31
Realized gross processing spread *($/MMBtu)*	**$ 7.47**	$ 5.21	$ 5.05

(a) - Includes volumes for consolidated entities only.

	Years Ended December 31,		
Operating Information (a)	**2008**	**2007**	**2006**
Percent of proceeds			
Wellhead purchases *(MMBtu/d)*	**67,718**	83,993	121,199
NGL sales *(Bbl/d)*	**6,223**	5,959	7,364
Residue gas sales *(MMBtu/d)*	**39,724**	34,010	28,855
Condensate sales *(Bbl/d)*	**928**	719	1,103
Percentage of total net margin	**62%**	56%	55%
Fee-based			
Wellhead volumes *(MMBtu/d)*	**1,164,273**	1,170,502	1,168,478
Average rate *($/MMBtu)*	**$ 0.26**	$ 0.25	$ 0.25
Percentage of total net margin	**23%**	30%	29%
Keep-whole			
NGL shrink *(MMBtu/d)*	**21,354**	23,636	37,029
Plant fuel *(MMBtu/d)*	**2,288**	2,846	4,959
Condensate shrink *(MMBtu/d)*	**1,825**	2,490	3,328
Condensate sales *(Bbl/d)*	**369**	504	683
Percentage of total net margin	**15%**	14%	16%

(a) - Includes volumes for consolidated entities only.

2008 vs. 2007 - Net margin increased primarily due to the following:

- an increase of $58.4 million due to higher realized commodity prices;
- an increase of $11.9 million due to improved contractual terms;
- an increase of $7.0 million due to higher volumes sold and processed; partially offset by
- a decrease of $8.6 million due to a one-time favorable contract settlement that occurred in the fourth quarter of 2007.

During September 2008, the disruption in the Gulf Coast area related to Hurricane Ike limited our ability to process and deliver natural gas and NGL volumes from our Mid-Continent processing plants. Without this volume reduction, we estimate net margin would have been approximately $1.8 million higher. During the fourth quarter of 2008, we experienced operational interruptions at our Grasslands plant that we estimate reduced our net margin by approximately $2.7 million and weather-related interruptions are estimated to have reduced our net margin by approximately $2.1 million.

Operating costs increased primarily due to increased costs for chemicals and maintenance parts, and a favorable legal settlement received in June 2007, which reduced legal costs for 2007. These increases were partially offset by decreased equipment lease costs in 2008 associated with the Bushton Plant.

Depreciation and amortization increased primarily as a result of depreciation expense associated with our completed capital projects.

Equity earnings from investments increased primarily due to higher gathering revenues in our Fort Union Gas Gathering investment as a result of capacity expansions.

Capital expenditures increased due to our increased growth activities, primarily in the Rocky Mountain region.

2007 vs. 2006 - Net margin decreased primarily due to the following:

- a decrease of $25.8 million from lower volumes processed as a result of contract terminations at the Bushton Plant in late 2006;
- a decrease of $5.6 million primarily due to lower processed volumes associated with winter storms and summer flooding in the Mid-Continent region and reduced processing capacity due to a temporary shutdown to install additional processing and fractionation capacity at our Grasslands plant located in the Williston Basin; partially offset by
- an increase of $13.0 million in fee margins primarily from improved contractual terms and increased volumes in our gathering business;
- an increase of $8.6 million due to a one-time favorable contract settlement that occurred in the fourth quarter of 2007; and
- an increase of $5.5 million due to higher realized NGL and natural gas prices.

Operating costs decreased primarily due to lower litigation costs and reduced operating expenses associated with the temporarily idled Bushton Plant, partially offset by higher employee-related costs.

Depreciation and amortization and capital expenditures increased primarily due to our capital projects.

Equity earnings from investments increased primarily due to earnings related to our interest in an investment in Venice Energy Services Co., LLC, which operated on a limited basis in 2006 due to hurricane damage.

Commodity Price Risk - Our Natural Gas Gathering and Processing segment is exposed to commodity price risk, primarily from NGLs, as a result of receiving commodities in exchange for our services. A small percentage of our services, based on volume, is provided through keep-whole arrangements. See discussion regarding our commodity price risk beginning on page 60 under "Commodity Price Risk" in Item 7A, Quantitative and Qualitative Disclosures about Market Risk.

Natural Gas Pipelines

Selected Financial Results and Operating Information - The following tables set forth certain selected financial results and operating information for our Natural Gas Pipelines segment for the periods indicated.

	Years Ended December 31,			Variances 2008 vs. 2007		Variances 2007 vs. 2006	
Financial Results	**2008**	**2007**	**2006**	**Increase (Decrease)**		**Increase (Decrease)**	
			(Millions of dollars)				
Transportation revenues	**$ 240.0**	$ 225.4	$ 232.1	**$ 14.6**	**6%**	$ (6.7)	(3%)
Storage revenues	**63.7**	54.8	49.5	**8.9**	**16%**	5.3	11%
Gas sales and other revenues	**38.4**	21.8	35.4	**16.6**	**76%**	(13.6)	(38%)
Cost of sales	**84.7**	60.9	70.2	**23.8**	**39%**	(9.3)	(13%)
Net margin	**257.4**	241.1	246.8	**16.3**	**7%**	(5.7)	(2%)
Operating costs	**89.9**	96.6	91.5	**(6.7)**	**(7%)**	5.1	6%
Depreciation and amortization	**34.3**	32.4	32.8	**1.9**	**6%**	(0.4)	(1%)
Gain (loss) on sale of assets	**-**	0.1	114.9	**(0.1)**	**(100%)**	(114.8)	(100%)
Operating income	**$ 133.2**	$ 112.2	$ 237.4	**$ 21.0**	**19%**	$ (125.2)	(53%)
Equity earnings from investments	**$ 66.7**	$ 62.5	$ 72.8	**$ 4.2**	**7%**	$ (10.3)	(14%)
Allowance for equity funds used during construction	**$ 14.0**	$ 3.6	$ 0.9	**$ 10.4**	*****	$ 2.7	*
Capital expenditures	**$ 267.0**	$ 138.9	$ 48.6	**$ 128.1**	**92%**	$ 90.3	*

* Percentage change is greater than 100 percent.

	Years Ended December 31,		
Operating Information (a)	**2008**	**2007**	**2006**
Natural gas transported *(MMcf/d)*	**3,665**	3,579	3,634
Average natural gas price Mid-Continent region (*$/MMBtu*)	**$ 7.17**	$ 6.05	$ 6.04

(a) - Includes volumes for consolidated entities only.

2008 vs. 2007 - Net margin increased due to the following:

- an increase of $6.3 million due to higher natural gas transportation margins, primarily as a result of the impact of higher natural gas prices on retained fuel;
- an increase of $5.4 million due to higher natural gas storage margins, primarily related to new and renegotiated natural gas storage contracts and the impact of higher natural gas prices on retained fuel; and
- an increase of $3.8 million due to increased operational natural gas inventory sales.

Operating costs decreased primarily due to lower general taxes and lower general operating costs, which includes decreased employee-related costs.

Depreciation and amortization increased primarily as a result of depreciation expense associated with our completed capital projects.

Equity earnings from investments increased primarily due to an $8.3 million gain on the sale of Bison Pipeline LLC by Northern Border Pipeline, partially offset by reduced throughput on Northern Border Pipeline. We own a 50 percent equity interest in Northern Border Pipeline.

Allowance for equity funds used during construction and capital expenditures increased primarily due to increased spending for our capital projects, which are discussed beginning on page 38.

2007 vs. 2006 - Net margin decreased due to the following:

- a decrease of $7.1 million from natural gas transportation margins, as a result of lower throughput and higher fuel costs;
- a decrease of $2.8 million primarily due to the expiration of reimbursements associated with an intrastate natural gas transportation construction project in Oklahoma; and
- a decrease of $0.9 million due to a reduction in operational natural gas inventory sales; partially offset by
- an increase of $5.4 million from natural gas storage margins as a result of new and renegotiated contracts.

Operating costs increased primarily due to higher employee-related costs.

During the second quarter of 2006, we sold a 20 percent partnership interest in Northern Border Pipeline and recorded a gain on sale of approximately $113.9 million.

Equity earnings from investments primarily include earnings from our interest in Northern Border Pipeline. The decrease in equity earnings from investments is primarily due to the decrease in our share of Northern Border Pipeline's earnings from 70 percent in the first quarter of 2006 to 50 percent beginning in the second quarter of 2006. See page 38 for discussion of the disposition of the 20 percent partnership interest in Northern Border Pipeline.

Allowance for equity funds used during construction and capital expenditures increased primarily due to our capital projects.

Natural Gas Liquids Gathering and Fractionation

Selected Financial Results and Operating Information - The following tables set forth certain selected financial results and operating information for our Natural Gas Liquids Gathering and Fractionation segment for the periods indicated.

	Years Ended December 31,			Variances 2008 vs. 2007		Variances 2007 vs. 2006	
Financial Results	**2008**	**2007**	**2006**	**Increase (Decrease)**		**Increase (Decrease)**	
			(Millions of dollars)				
NGL and condensate sales	**$ 5,944.0**	$ 4,314.8	$ 3,299.3	**$ 1,629.2**	**38%**	$ 1,015.5	31%
Storage and fractionation revenues	**325.7**	272.5	193.7	**53.2**	**20%**	78.8	41%
Cost of sales and fuel	**5,952.0**	4,381.5	3,326.0	**1,570.5**	**36%**	1,055.5	32%
Net margin	**317.7**	205.8	167.0	**111.9**	**54%**	38.8	23%
Operating costs	**89.8**	70.7	57.5	**19.1**	**27%**	13.2	23%
Depreciation and amortization	**23.5**	23.1	20.7	**0.4**	**2%**	2.4	12%
Operating income	**$ 204.4**	$ 112.0	$ 88.8	**$ 92.4**	**83%**	$ 23.2	26%
Capital expenditures	**$ 169.5**	$ 123.6	$ 21.8	$ 45.9	**37%**	$ 101.8	*

* Percentage change is greater than 100 percent.

	Years Ended December 31,		
Operating Information	**2008**	**2007**	**2006**
NGLs gathered *(MBbl/d)*	**271**	248	226
NGL sales *(MBbl/d)*	**283**	231	207
NGLs fractionated *(MBbl/d)*	**389**	356	313
Conway-to-Mont Belvieu OPIS average price differential			
Ethane *($/gallon)*	**$ 0.15**	$ 0.06	$ 0.05

2008 vs. 2007 - Net margin increased due to the following:

- an increase of $70.8 million due to wider product price differentials between Conway, Kansas, and Mont Belvieu, Texas;
- an increase of $32.1 million due to higher exchange margins, primarily driven by increased gathering and fractionation volumes;
- an increase of $8.4 million from certain operational measurement gains, primarily at NGL storage caverns; and
- an increase of $3.6 million due to higher storage margins in our Mid-Continent storage business.

During September 2008, Hurricane Ike caused disruptions to our gathering and fractionation operations in the Mid-Continent and Gulf Coast regions. Without this disruption, we estimate net margin would have been approximately $3.8 million higher.

Operating costs increased primarily due to costs associated with the startup of our newly expanded Bushton fractionator, maintenance projects at our Medford fractionator, increased lease costs for our Bushton facility and expenses related to a planned maintenance shutdown at our Mont Belvieu fractionator.

Capital expenditures increased primarily due to our growth activities and the associated expansion of the Bushton facility. See discussion of our capital projects beginning on page 38.

2007 vs. 2006 - Net margin increased due to the following:

- an increase of $17.8 million due to higher exchange net margin primarily driven by increased volumes due to new supply connections, improved natural gas processing economics and increased fractionation volumes at our Mont Belvieu fractionator;
- an increase of $13.5 million due to higher product price differentials and higher isomerization price differentials; and
- an increase of $7.6 million due to new storage contracts entered into in the second quarter of 2007 and our acquisition of the Mont Belvieu storage assets in the fourth quarter of 2006.

Operating costs increased due to higher regulatory compliance costs at our storage facilities, employee-related costs and general taxes, as well as the acquisition of the Mont Belvieu storage assets in the fourth quarter of 2006.

Capital expenditures increased primarily due to our growth activities and the associated expansion of the Bushton facility.

Natural Gas Liquids Pipelines

Selected Financial Results and Operating Information - The following tables set forth certain selected financial results and operating information for our Natural Gas Liquids Pipelines segment for the periods indicated.

	Years Ended December 31,			Variances 2008 vs. 2007		Variances 2007 vs. 2006	
Financial Results	**2008**	**2007**	**2006**	**Increase (Decrease)**		**Increase (Decrease)**	
				(Millions of dollars)			
Transportation and gathering revenues	**$ 148.9**	$ 90.4	$ 66.4	**$ 58.5**	**65%**	$ 24.0	36%
Storage revenues	**4.8**	0.8	-	**4.0**	*****	0.8	100%
NGL sales and other revenues	**3.4**	0.6	0.1	**2.8**	*****	0.5	*
Cost of sales and fuel	**24.3**	10.2	6.1	**14.1**	*****	4.1	67%
Net margin	**132.8**	81.6	60.4	**51.2**	**63%**	21.2	35%
Operating costs	**55.1**	29.0	19.3	**26.1**	**90%**	9.7	50%
Depreciation and amortization	**17.1**	13.1	12.0	**4.0**	**31%**	1.1	9%
Operating income	**$ 60.6**	$ 39.5	$ 29.1	**$ 21.1**	**53%**	$ 10.4	36%
Equity earnings from investments	**$ 2.0**	$ 1.0	$ 0.4	**$ 1.0**	**100%**	$ 0.6	*
Allowance for equity funds used during construction	**$ 36.9**	$ 8.9	$ 1.3	**$ 28.0**	*****	$ 7.6	*
Capital expenditures	**$ 670.9**	$ 363.5	$ 49.3	**$ 307.4**	**85%**	$ 314.2	*

* Percentage change is greater than 100 percent.

	Years Ended December 31,		
Operating Information	**2008**	**2007**	**2006**
NGLs transported *(MBbl/d)*	**333**	299	200
NGLs gathered *(MBbl/d)*	**76**	61	40

2008 vs. 2007 - Net margin increased primarily as a result of:

- an increase of $44.3 million in incremental margin from the assets acquired from Kinder Morgan in October 2007, including $10.3 million due to increased throughput during the fourth quarter of 2008, compared with the fourth quarter of 2007;
- an increase of $4.3 million due to increased throughput from new supply connections, increased production volumes from existing supply connections to our natural gas liquids gathering pipelines, and increased throughput on our natural gas liquids distribution pipelines; and
- an increase of $2.6 million in incremental margin from Overland Pass Pipeline, which began operating during the fourth quarter of 2008.

During September 2008, the disruption in the Gulf Coast area related to Hurricane Ike reduced transportation and gathering volumes on our pipeline assets between the Mid-Continent fractionation facilities and the natural gas liquids market hubs in Conway, Kansas, and Mont Belvieu, Texas. Without this volume reduction, we estimate net margin would have been approximately $2.2 million higher.

Operating costs increased primarily due to $20.6 million in incremental operating expenses associated with the assets acquired from Kinder Morgan, as well as higher employee-related costs and outside services, and costs associated with the startup of Overland Pass Pipeline operations.

Depreciation and amortization increased primarily due to the assets acquired from Kinder Morgan and the startup of Overland Pass Pipeline operations.

Allowance for equity funds used during construction and capital expenditures increased primarily due to our growth activities. See discussion of our capital projects beginning on page 38.

2007 vs. 2006 - Net margin increased due to the following:
- an increase of $11.5 million due to incremental margin from our acquired assets from Kinder Morgan in October 2007; and
- an increase of $9.5 million primarily due to increased throughput from new supply connections and increased production volume from existing supply connections to our natural gas liquids gathering pipelines.

Operating costs increased primarily due to $5.8 million in incremental operating expenses associated with our acquired assets from Kinder Morgan, as well as higher employee-related costs.

Depreciation and amortization increased primarily due to incremental operating expenses associated with our acquired assets from Kinder Morgan.

Allowance for equity funds used during construction and capital expenditures increased primarily due to our growth activities.

Other

In the second quarter of 2008, we started the decommissioning of Black Mesa Pipeline. We do not expect the decommissioning to have a material impact on our consolidated financial statements.

Contingencies

Legal Proceedings - We are a party to various litigation matters and claims that are in the normal course of our operations. While the results of litigation and claims cannot be predicted with certainty, we believe the final outcome of such matters will not have a material adverse effect on our consolidated results of operations, financial position or liquidity.

FERC Matter – As a result of a transaction that was brought to the attention of one of our affiliates by a third party, we conducted an internal review of transactions that may have violated FERC natural gas capacity release rules or related rules and determined that there were transactions that should be disclosed to the FERC. We notified the FERC of this review and filed a report with the FERC regarding these transactions in March 2008. We cooperated fully with the FERC in its investigation of this matter and have taken steps to better ensure that current and future transactions comply with applicable FERC regulations by implementing a compliance plan dealing with capacity release. We, along with ONEOK, entered into a global settlement with the FERC to resolve this matter and other FERC enforcement matters, which was approved by the FERC on January 15, 2009. The global settlement provides for a total civil penalty of $4.5 million and approximately $2.2 million in disgorgement of profits and interest. We are responsible for $1.7 million in civil penalties, which is recorded as a liability on our Consolidated Balance Sheet as of December 31, 2008, and the disgorgement of profits and interests are the responsibility of ONEOK. We made the required payments in January 2009.

LIQUIDITY AND CAPITAL RESOURCES

General - Our principal sources of liquidity include cash generated from operating activities, bank credit facilities, debt issuances and the sale of common units. We fund our operating expenses, debt service and cash distributions to our limited partners and general partner primarily with operating cash flow. We have no material guarantees or other similar commitments to unaffiliated parties.

During 2008 and continuing into 2009, the capital markets experienced volatility and disruption, which could limit our access to those markets or increase the cost of issuing new securities in the future. During this period, we have continued to have access to our Partnership Credit Agreement to fund our short-term liquidity needs. In 2008, we issued common units and received additional contributions from our general partner. See discussion below under "Equity Issuance" for more information. In 2007, we issued $600 million of long-term notes. See discussion below under "Debt Issuance" for more information.

We expect continued deteriorating economic conditions in 2009, with downward pressures, relative to 2008, on commodity prices. We also expect continued volatility and disruption in the financial markets, which could result in increased cost of capital. Our ability to continue to access capital markets for debt and equity financing under reasonable terms depends on our financial condition, credit ratings and market conditions. We anticipate that our cash flow generated from operations, existing capital resources, and ability to obtain financing will enable us to maintain our current level of operations and our planned operations, collateral requirements and capital expenditures.

Capital Structure - The following table sets forth our capitalization structure for the periods indicated.

	Years Ended December 31,	
	2008	**2007**
Long-term debt	**47%**	54%
Equity	**53%**	46%
Debt (including notes payable)	**54%**	55%
Equity	**46%**	45%

Cash Management - We use a centralized cash management program that concentrates the cash assets of our operating subsidiaries in joint accounts for the purpose of providing financial flexibility and lowering the cost of borrowing, transaction costs and bank fees. Our centralized cash management program provides that funds in excess of the daily needs of our operating subsidiaries are concentrated, consolidated or made available for use by other entities within our consolidated group. Our operating subsidiaries participate in this program to the extent they are permitted under FERC regulations. Under the cash management program, depending on whether a participating subsidiary has short-term cash surpluses or cash requirements, the Intermediate Partnership provides cash to the subsidiary or the subsidiary provides cash to the Intermediate Partnership.

Short-term Liquidity - Our principal sources of short-term liquidity consist of cash generated from operating activities and our $1.0 billion Partnership Credit Agreement. We provide for additional liquidity by maintaining an amount of excess borrowing capacity related to our Partnership Credit Agreement, which can be used for general partnership purposes.

During late 2008, we decided to borrow under our Partnership Credit Agreement to fund our anticipated working capital requirements for the remainder of 2008 and into 2009.

The total amount of short-term borrowings authorized by our general partner's Board of Directors is $1.5 billion. At December 31, 2008, we had $870 million of borrowings outstanding and $130 million available under our Partnership Credit Agreement and available cash and cash equivalents of approximately $177.6 million. As of December 31, 2008, we could have issued $772.6 million of additional short- and long-term debt under the most restrictive provisions contained in our Partnership Credit Agreement.

We have an outstanding $25 million letter of credit issued by Royal Bank of Canada, which is used for counterparty credit support.

We also have a $15 million Senior Unsecured Letter of Credit Facility and Reimbursement Agreement with Wells Fargo Bank, N.A., of which $12 million is currently being used, and an agreement with Royal Bank of Canada, pursuant to which a $12 million letter of credit was issued. Both agreements are used to support various permits required by the KDHE for our ongoing business in Kansas.

Under our Partnership Credit Agreement, we are required to comply with certain financial, operational and legal covenants. Among other things, these requirements include maintaining a ratio of indebtedness to adjusted EBITDA (EBITDA plus minority interest in income of consolidated subsidiaries, distributions received from investments and EBITDA related to any approved capital projects less equity earnings from investments and the equity portion of AFUDC) of no more than 5 to 1. If we consummate one or more acquisitions in which the aggregate purchase price is $25 million or more, the allowable ratio of indebtedness to adjusted EBITDA will be increased to 5.5 to 1 for the three calendar quarters following the acquisition.

Upon breach of any covenant in our Partnership Credit Agreement, amounts outstanding under such agreement may become immediately due and payable. At December 31, 2008, our ratio of indebtedness to adjusted EBITDA was 4.1 to 1, and we were in compliance with all covenants under our Partnership Credit Agreement.

The average interest rate on our short-term debt outstanding at December 31, 2008, was 4.22 percent, compared with a weighted average of 3.94 percent for the year ended December 31, 2008. Based on the forward LIBOR curve, we expect the interest rate on our short-term borrowing to decrease in 2009, compared with 2008.

Long-term Financing - In addition to our principal sources of short-term liquidity discussed above, options available to us to meet our longer-term cash requirements include the issuance of common units or long-term notes. Other options to obtain financing include, but are not limited to, issuance of convertible debt securities and asset securitization and sale/leaseback of facilities.

We are subject, however, to changes in the equity and debt markets, and there can be no assurance we will be able or willing to access the public or private markets for the issuance of common units or long-term debt. We may choose to meet our cash requirements by utilizing some combination of cash flows from operations, borrowings under existing credit facilities, altering the timing of controllable expenditures, restricting future acquisitions and capital projects, or pursuing other debt or equity financing alternatives, which may include issuing common units to ONEOK in a private placement transaction. Some of these alternatives could involve higher costs or negatively affect our credit ratings, among other factors. Based on our investment-grade credit ratings, general financial condition and market expectations regarding our future earnings and projected cash flows, we believe that we will be able to meet our cash requirements and maintain our investment-grade credit ratings.

Debt Issuance - In September 2007, we completed an underwritten public offering of $600 million aggregate principal amount of 6.85 percent Senior Notes due 2037 (the 2037 Notes). The 2037 Notes were issued under our existing shelf registration statement filed with the SEC.

We may redeem the 2037 Notes, in whole or in part, at any time prior to their maturity at a redemption price equal to the principal amount of the 2037 Notes, plus accrued and unpaid interest and a make-whole premium. The redemption price will never be less than 100 percent of the principal amount of the 2037 Notes plus accrued and unpaid interest. The 2037 Notes are senior unsecured obligations, ranking equally in right of payment with all of our existing and future unsecured senior indebtedness, and effectively junior to all of the existing debt and other liabilities of our non-guarantor subsidiaries. The 2037 Notes are non-recourse to our general partner.

Debt Covenants - The indenture governing the 2037 Notes does not limit the aggregate principal amount of debt securities that may be issued and provides that debt securities may be issued from time to time in one or more additional series. The indenture contains covenants including, among other provisions, limitations on our ability to place liens on our property or assets and sell and lease back our property.

Our $250 million and $225 million senior notes, due 2010 and 2011, respectively, contain provisions that require us to offer to repurchase the senior notes at par value if our Moody's or S&P credit rating falls below investment grade (Baa3 for Moody's or BBB- for S&P) and the investment-grade rating is not reinstated within a period of 40 days. Further, the indentures governing our senior notes due 2010 and 2011 include an event of default upon acceleration of other indebtedness of $25 million or more and the indentures governing our senior notes due 2012, 2016, 2036 and 2037 include an event of default upon the acceleration of other indebtedness of $100 million or more that would be triggered by such an offer to repurchase. Such an event of default would entitle the trustee or the holders of 25 percent in aggregate principal amount of the outstanding senior notes due 2010, 2011, 2012, 2016, 2036 and 2037 to declare those notes immediately due and payable in full.

Equity Issuance - In March 2008, we completed a public offering of 2.5 million common units at $58.10 per common unit, generating net proceeds of approximately $140.4 million after deducting underwriting discounts but before offering expenses. In addition, we sold 5.4 million common units to ONEOK in a private placement, generating proceeds of approximately $303.2 million. In conjunction with the public offering of common units and the private placement, ONEOK Partners GP contributed $9.4 million in order to maintain its 2 percent general partner interest in us.

In April 2008, we sold an additional 128,873 common units at $58.10 per common unit to the underwriters of the public offering upon the partial exercise of their option to purchase additional common units to cover over-allotments. We received net proceeds of approximately $7.2 million from the sale of the common units after deducting underwriting discounts but before offering expenses. In conjunction with the partial exercise by the underwriters, ONEOK Partners GP contributed $0.2 million in order to maintain its 2 percent general partner interest in us. As a result of these transactions, ONEOK now holds a 47.7 percent aggregate equity interest in us.

We used a portion of the proceeds from the sale of common units and the general partner contributions to repay borrowings under our Partnership Credit Agreement.

Capital Expenditures - Our capital expenditures are typically financed through operating cash flows, short- and long-term debt and the issuance of equity. For 2008, our capital expenditures were also financed through the issuance of common units. Capital expenditures were $1,253.9 million and $709.9 million for 2008 and 2007, respectively, exclusive of acquisitions. The increase in capital expenditures for 2008, compared with 2007, is driven primarily by our internal capital projects, which are discussed beginning on page 38. We expect to continue to finance future capital expenditures with a combination of operating cash flows, short- and long-term debt, and the issuance of common units.

We classify expenditures that are expected to generate additional revenue or significant operating efficiencies as growth capital expenditures. Maintenance capital expenditures are those required to maintain existing operations and do not generate additional revenues.

The following tables set forth our growth and maintenance capital expenditures for 2008, 2007 and 2006.

Growth Capital Expenditures	**2008**	**2007**	**2006**
		(Millions of dollars)	
Natural Gas Gathering and Processing	**$ 123.0**	$ 64.8	$ 59.4
Natural Gas Pipelines	**241.0**	123.6	28.5
Natural Gas Liquids Gathering and Fractionation	**143.8**	102.4	7.0
Natural Gas Liquids Pipelines	**664.2**	359.5	39.8
Total growth capital expenditures	**$ 1,172.0**	$ 650.3	$ 134.7

Maintenance Capital Expenditures	**2008**	**2007**	**2006**
		(Millions of dollars)	
Natural Gas Gathering and Processing	**$ 23.2**	$ 19.0	$ 21.6
Natural Gas Pipelines	**26.0**	15.3	20.1
Natural Gas Liquids Gathering and Fractionation	**25.7**	21.2	14.7
Natural Gas Liquids Pipelines	**6.7**	4.0	9.5
Other	**0.3**	0.1	1.1
Total maintenance capital expenditures	**$ 81.9**	$ 59.6	$ 67.0

The following table summarizes our 2009 projected growth and maintenance capital expenditures, excluding AFUDC.

2009 Projected Capital Expenditures	**Growth**	**Maintenance**	**Total**
		(Millions of dollars)	
Natural Gas Gathering and Processing	$ 98	$ 21	$ 119
Natural Gas Pipelines	38	24	62
Natural Gas Liquids Gathering and Fractionation	56	15	71
Natural Gas Liquids Pipelines	163	10	173
Total projected capital expenditures	$ 355	$ 70	$ 425

Projected 2009 capital expenditures are significantly less than 2008 capital expenditures due to the completion of the Overland Pass Pipeline and related projects and the Guardian Pipeline expansion and extension. Additional information about our growth capital expenditures is included under "Capital Projects" on page 38. We anticipate spending a total of $300 million to $500 million per year on growth capital expenditures for the years 2010 through 2015.

Investment in Northern Border Pipeline - Northern Border Pipeline anticipates an equity contribution of approximately $85 million that will be required of its partners in 2009, of which our share will be approximately $43 million for our 50 percent equity interest.

Credit Ratings - Our credit ratings as of December 31, 2008, are shown in the table below.

Rating Agency	Rating	Outlook
Moody's	Baa2	Stable
S&P	BBB	Stable

Our credit ratings, which are currently investment grade, may be affected by a material change in our financial ratios or a material event affecting our business. The most common criteria for assessment of our credit ratings are the debt-to-EBITDA ratio, interest coverage, business risk profile and liquidity. We do not anticipate a downgrade in our credit ratings. However, if our credit ratings were downgraded, the interest rates on borrowings under our Partnership Credit Agreement would increase, resulting in an increase in our cost to borrow funds. An adverse rating change alone is not a default under our Partnership Credit Agreement. See additional discussion about our credit ratings under "Debt Covenants."

In the event of a default under our senior notes, we may not have sufficient cash on hand to repurchase and repay any accelerated senior notes, which may cause us to borrow money under our credit facilities or seek alternative financing sources to finance the repurchases and repayment. We could also face difficulties accessing capital or our borrowing costs could increase, impacting our ability to obtain financing for acquisitions or capital expenditures, to refinance indebtedness and to fulfill our debt obligations.

Other than the note repurchase obligations described under "Debt Covenants," we have determined that we do not have significant exposure to rating triggers in various other contracts and equipment leases. Rating triggers are defined as provisions that would create an automatic default or acceleration of indebtedness based on a change in our credit rating.

In the normal course of business, our counterparties provide us with secured and unsecured credit. In the event of a downgrade in our credit rating or a significant change in our counterparties' evaluation of our creditworthiness, we could be asked to provide additional collateral in the form of cash, letters of credit or other negotiable instruments.

Cash Distributions - We distribute 100 percent of our available cash, which generally consists of all cash receipts less adjustments for cash disbursements and net change to reserves, to our general and limited partners. Our income is allocated to our general partner and limited partners according to their partnership percentages of 2 percent and 98 percent, respectively. The effect of any incremental income allocations for incentive distributions to our general partner is calculated after the income allocation for the general partner's partnership interest and before the income allocation to the limited partners.

The following table sets forth cash distributions paid, including our general partner's incentive distribution interests, during the periods indicated.

	Years Ended December 31,		
	2008	2007	2006
	(Millions of dollars)		
Common unitholders	**$ 220.6**	$ 184.7	$ 167.0
Class B unitholders	**153.5**	145.2	70.1
General Partner	**78.9**	54.7	28.4
Total cash distributions paid	**$ 453.0**	$ 384.6	$ 265.5

The following summarizes our quarterly cash distribution activity for 2008:

- In January 2008, we increased our cash distribution to $1.025 per unit for the fourth quarter of 2007. The distribution was paid on February 14, 2008, to unitholders of record as of January 31, 2008;
- In April 2008, we increased our cash distribution to $1.04 per unit for the first quarter of 2008. The distribution was paid on May 15, 2008, to unitholders of record as of April 30, 2008;
- In July 2008, we increased our cash distribution to $1.06 per unit for the second quarter of 2008. The distribution was paid on August 14, 2008, to unitholders of record as of July 31, 2008; and
- In October 2008, we increased our cash distribution to $1.08 per unit for the third quarter of 2008. The distribution was paid on November 14, 2008, to unitholders of record as of October 31, 2008.

In January 2009, we declared a cash distribution of $1.08 per unit ($4.32 per unit on an annualized basis) for the fourth quarter of 2008. The distribution was paid on February 13, 2009, to unitholders of record as of January 30, 2009.

Additional information about our cash distributions is included under Item 5, Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities, and Item 13, Certain Relationships and Related Transactions and Director Independence.

Commodity Prices - We are subject to commodity price volatility. Significant fluctuations in commodity prices may impact our overall liquidity due to the impact commodity price changes have on our cash flows from operating activities, including the impact on working capital for NGLs held in storage, margin requirements and certain energy-related receivables. We believe that our available credit and cash and cash equivalents are adequate to meet liquidity requirements associated with commodity price volatility. See discussion beginning on page 60 under "Commodity Price Risk" in Item 3, Quantitative and Qualitative Disclosures about Market Risk, for information on our hedging activities.

ENVIRONMENTAL LIABILITIES

Information about our environmental liabilities is included in Note J of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.

CASH FLOW ANALYSIS

We use the indirect method to prepare our Consolidated Statements of Cash Flows. Under this method, we reconcile net income to cash flows provided by operating activities by adjusting net income for those items that impact net income but may not result in actual cash receipts or payments during the period. These reconciling items include depreciation and amortization, allowance for equity funds used during construction, gain on sale of assets, minority interests in income of consolidated subsidiaries, and undistributed earnings from equity investments in excess of distributions received.

The following table sets forth the changes in cash flows by operating, investing and financing activities for the periods indicated.

	Years Ended December 31,			Variances 2008 vs. 2007		Variances 2007 vs. 2006	
	2008	2007	2006	Increase (Decrease)		Increase (Decrease)	
	(Millions of dollars)						
Total cash provided by (used in):							
Operating activities	**$ 656.4**	$ 701.5	$ 603.2	**$ (45.1)**	**(6%)**	$ 98.3	16%
Investing activities	**(1,246.5)**	(1,009.1)	(1,322.1)	**(237.4)**	**(24%)**	313.0	24%
Financing activities	**764.5**	289.7	696.9	**474.8**	*****	(407.2)	(58%)
Change in cash and cash equivalents	**174.4**	(17.9)	(22.0)	**192.3**	*****	4.1	19%
Cash and cash equivalents at beginning of period	**3.2**	21.1	43.1	**(17.9)**	**(85%)**	(22.0)	(51%)
Cash and cash equivalents at end of period	**$ 177.6**	$ 3.2	$ 21.1	**$ 174.4**	*****	$ (17.9)	(85%)

* Percentage change is greater than 100 percent.

Operating Cash Flows - Operating cash flows decreased by $45.1 million for 2008, compared with 2007, primarily due to changes in the components of working capital. These changes decreased operating cash flows by $34.6 million, compared with an increase of $180.3 million for 2007, primarily due to decreases in accounts payable and increases in derivative financial instruments, partially offset by decreases in accounts receivable. Decreased working capital for 2008 was partially offset by higher net income.

Operating cash flows increased by $98.3 million for 2007, compared with 2006, primarily as a result of changes in the components of working capital. These changes increased operating cash flows by $180.3 million, compared with an increase of $123.7 million for 2006, primarily due to increases in accounts payable, partially offset by increases in accounts receivable. Operating cash flows also increased due to a decrease in income taxes as a result of our consolidation of the ONEOK Energy Assets, as of January 1, 2006, which were previously owned by a taxable entity.

Investing Cash Flows - Investing cash flows for 2008 include increased capital expenditures of $544.0 million, compared with 2007, due to increased spending for our capital projects.

Investing cash flows for 2007 included the following:

- the acquisition of an interstate natural gas liquids and refined petroleum products pipeline system and related assets from a subsidiary of Kinder Morgan in October 2007 for approximately $300 million, before working capital adjustments; and
- increased capital expenditures of $508.1 million for 2007, compared with 2006, due to increased spending for our capital projects.

Investing cash flows for 2006 included the following:

- the April 2006 purchase of the ONEOK Energy Assets, which included a cash payment of approximately $1.35 billion, before adjustments;
- the acquisition of the 66-2/3 percent interest in Guardian Pipeline not previously owned by us for approximately $77 million;
- payment to Williams of $11.6 million for initial capital expenditures in connection with the Overland Pass Pipeline Company natural gas liquids pipeline joint venture;
- an equity contribution to Northern Border Pipeline of $7.2 million;
- the receipt of approximately $297 million from the sale of a 20 percent partnership interest in Northern Border Pipeline to TC PipeLines;
- capital expenditures of $201.7 million, primarily related to the ONEOK Energy Assets; and
- the impact of the deconsolidation of Northern Border Pipeline and the consolidation of the ONEOK Energy Assets and Guardian Pipeline.

Financing Cash Flows - During 2008, our concurrent public offering and private placement of common units generated proceeds of $450.2 million. In addition, ONEOK Partners GP contributed $9.5 million in order to maintain its 2 percent general partner interest in us. We used a portion of the proceeds and general partner contributions to repay borrowings under our Partnership Credit Agreement.

During 2007, we completed an underwritten public offering of senior notes totaling $598 million in net proceeds, before offering expenses. During 2006, we completed the underwritten public offering of senior notes totaling $1.4 billion in net proceeds, before offering expenses. The use of these proceeds is discussed below.

We had net borrowings of approximately $770.0 million for 2008, compared with $94.0 million for 2007 and net payments of $200.5 million for 2006. The changes between periods occurred for the following reasons.

- During 2008, borrowings under our Partnership Credit Agreement were primarily used to fund our ongoing capital projects. Net borrowings include repayments, which were made with a portion of the proceeds provided by the public offering and private placement discussed above. Additionally, borrowings increased as a result of our decision in late 2008 to borrow under our Partnership Credit Agreement to fund our anticipated working capital requirements for the remainder of 2008 into 2009.
- During 2007, we also used borrowings to fund our ongoing capital projects. The $598 million debt issuance, net of discounts, was used to repay borrowings under our Partnership Credit Agreement and finance the $300 million acquisition of assets, before working capital adjustments, from a subsidiary of Kinder Morgan in October 2007.
- During 2006, we borrowed $1.05 billion under our $1.1 billion 364-day credit facility dated April 6, 2006 (Bridge Facility) to finance a portion of the acquisition of the ONEOK Energy Assets and $77 million under our primary revolving credit agreement, as then in effect, to acquire the 66-2/3 percent interest in Guardian Pipeline. Also, the net proceeds from the senior notes issued in 2006 discussed above were used to repay all of the amounts outstanding under our Bridge Facility and to repay $335 million of short-term debt.

We reported cash flows retained by ONEOK of $177.5 million for 2006, which represented the cash flows generated during the first quarter of 2006 by the ONEOK Energy Assets prior to the ONEOK Transactions. See Note B of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K for discussion of the ONEOK Transactions.

In March 2006, we borrowed $33 million under our primary revolving credit agreement, as then in effect, to redeem all of the outstanding Viking Gas Transmission Series A, B, C and D senior notes and paid a redemption premium of $3.6 million.

Cash distributions to our general and limited partners for 2008 were $453.0 million, compared with $384.6 million for 2007, an increase of $68.4 million, due the additional units outstanding during 2008, as a result of the concurrent public offering and private placement in March and April 2008, as well as increased distributions per unit. Cash distributions to our general and limited partners increased $119.1 million for 2007, compared with 2006, primarily due to the additional units that were issued to complete the ONEOK Transactions, as well as increased distributions per unit. We paid cash distributions of $4.205 per unit for 2008, compared with $3.98 per unit in 2007 and $3.60 per unit in 2006.

CONTRACTUAL OBLIGATIONS AND COMMERCIAL COMMITMENTS

The following table sets forth our contractual obligations related to debt, operating leases and other long-term obligations as of December 31, 2008. For additional discussion of the debt and operating lease agreements, see Notes I and J, respectively, of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.

	Payments Due by Period						
Contractual Obligations	**Total**	**2009**	**2010**	**2011**	**2012**	**2013**	**Thereafter**
ONEOK Partners				*(Thousands of dollars)*			
$1 billion credit agreement	$ 870,000	$ 870,000	$ -	$ -	$ -	$ -	$ -
Senior notes - 8.875%	250,000	-	250,000	-	-	-	-
Senior notes - 7.10%	225,000	-	-	225,000	-	-	-
Senior notes - 5.90%	350,000	-	-	-	350,000	-	-
Senior notes - 6.15%	450,000	-	-	-	-	-	450,000
Senior notes - 6.65%	600,000	-	-	-	-	-	600,000
Senior notes - 6.85%	600,000	-	-	-	-	-	600,000
Guardian Pipeline							
Senior notes - various	121,711	11,931	11,931	11,931	11,062	7,650	67,206
Interest payments on debt	2,686,400	176,700	163,700	140,000	120,200	114,300	1,971,500
Operating leases	86,508	18,362	16,027	15,527	8,755	2,063	25,774
Firm transportation contracts	14,765	11,086	3,679	-	-	-	-
Financial and physical derivatives	48,467	48,467	-	-	-	-	-
Purchase commitments, rights of way and other	35,582	30,914	977	976	977	977	761
Total	$ 6,338,433	$ 1,167,460	$ 446,314	$ 393,434	$ 490,994	$ 124,990	$ 3,715,241

Long-term Debt - Long-term debt as reported on our Consolidated Balance Sheets includes unamortized debt discount.

Interest Payments on Debt - Interest expense is calculated by taking long-term debt and multiplying it by the respective coupon rates.

Operating Leases - Our operating leases include a natural gas processing plant, storage contracts, office space, pipeline equipment, rights-of-way and vehicles. Our Processing and Services Agreement with ONEOK and OBPI sets out the terms by which OBPI provides processing and related services at the Bushton Plant through 2012. In exchange for such services, we pay OBPI for all direct costs and expenses of operating the Bushton Plant, including reimbursement of a portion of OBPI's obligations under equipment leases covering the Bushton Plant.

Firm Transportation Contracts - Firm transportation agreements with our Natural Gas Gathering and Processing segment's joint ventures require minimum monthly payments.

Financial and Physical Derivatives - Financial and physical derivatives represent fixed-price purchase commitments based on market information at December 31, 2008, associated with our Natural Gas Liquids Gathering and Fractionation segment.

Purchase Commitments - Purchase commitments include commitments related to our growth capital expenditures and other rights of way commitments.

FORWARD-LOOKING STATEMENTS

Some of the statements contained and incorporated in this Annual Report on Form 10-K are forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities and Exchange Act of 1934, as amended. The forward-looking statements relate to our anticipated financial performance, management's plans and objectives for our future operations, our business prospects, the outcome of regulatory and legal proceedings, market conditions and other matters. We make these forward-looking statements in reliance on the safe harbor protections provided under the Private Securities Litigation Reform Act of 1995. The following discussion is intended to identify important factors that could cause future outcomes to differ materially from those set forth in the forward-looking statements.

Forward-looking statements include the items identified in the preceding paragraph, the information concerning possible or assumed future results of our operations and other statements contained or incorporated in this Annual Report on Form 10-K identified by words such as “anticipate,” “estimate,” “expect,” “project,” “intend,” “plan,” “believe,” “should,” “goal,” “forecast,” “could,” “may,” “continue,” “might,” “potential,” “scheduled” and other words and terms of similar meaning.

You should not place undue reliance on forward-looking statements. Known and unknown risks, uncertainties and other factors may cause our actual results, performance or achievements to be materially different from any future results, performance or achievements expressed or implied by forward-looking statements. Those factors may affect our operations, markets, products, services and prices. In addition to any assumptions and other factors referred to specifically in connection with the forward-looking statements, factors that could cause our actual results to differ materially from those contemplated in any forward-looking statement include, among others, the following:

- the effects of weather and other natural phenomena on our operations, demand for our services and energy prices;
- competition from other United States and Canadian energy suppliers and transporters as well as alternative forms of energy, including, but not limited to, biofuels such as ethanol and biodiesel;
- the capital intensive nature of our businesses;
- the profitability of assets or businesses acquired or constructed by us;
- our ability to make cost-saving changes in operations;
- risks of marketing, trading and hedging activities, including the risks of changes in energy prices or the financial condition of our counterparties;
- the uncertainty of estimates, including accruals and costs of environmental remediation;
- the timing and extent of changes in energy commodity prices;
- the effects of changes in governmental policies and regulatory actions, including changes with respect to income and other taxes, environmental compliance, climate change initiatives, authorized rates or recovery of gas and gas transportation costs;
- the impact on drilling and production by factors beyond our control, including the demand for natural gas and refinery-grade crude oil; producers’ desire and ability to obtain necessary permits; reserve performance; and capacity constraints on the pipelines that transport crude oil, natural gas and NGLs from producing areas and our facilities;
- difficulties or delays experienced by trucks or pipelines in delivering products to or from our terminals or pipelines;
- changes in demand for the use of natural gas because of market conditions caused by concerns about global warming;
- conflicts of interest between us, our general partner, ONEOK Partners GP, and related parties of ONEOK Partners GP;
- the impact of unforeseen changes in interest rates, equity markets, inflation rates, economic recession and other external factors over which we have no control;
- our indebtedness could make us vulnerable to general adverse economic and industry conditions, limit our ability to borrow additional funds, and/or place us at competitive disadvantages compared to our competitors that have less debt or have other adverse consequences;
- actions by rating agencies concerning the credit ratings of us or our general partner;
- the results of administrative proceedings and litigation, regulatory actions and receipt of expected clearances involving the OCC, KCC, Texas regulatory authorities or any other local, state or federal regulatory body, including the FERC;
- our ability to access capital at competitive rates or on terms acceptable to us;
- risks associated with adequate supply to our gathering, processing, fractionation and pipeline facilities, including production declines that outpace new drilling;
- the risk that material weaknesses or significant deficiencies in our internal control over financial reporting could emerge or that minor problems could become significant;
- the impact and outcome of pending and future litigation;
- the ability to market pipeline capacity on favorable terms, including the effects of:
    - future demand for and prices of natural gas and NGLs;
    - competitive conditions in the overall energy market;
    - availability of supplies of Canadian and United States natural gas; and
    - availability of additional storage capacity;
- performance of contractual obligations by our customers, service providers, contractors and shippers;
- the timely receipt of approval by applicable governmental entities for construction and operation of our pipeline and other projects and required regulatory clearances;
- our ability to acquire all necessary permits, consents and other approvals in a timely manner, to promptly obtain all necessary materials and supplies required for construction, and to construct gathering, processing, storage, fractionation and transportation facilities without labor or contractor problems;

- the mechanical integrity of facilities operated;
- demand for our services in the proximity of our facilities;
- our ability to control operating costs;
- acts of nature, sabotage, terrorism or other similar acts that cause damage to our facilities or our suppliers' or shippers' facilities;
- economic climate and growth in the geographic areas in which we do business;
- the risk of a prolonged slowdown in growth or decline in the U.S. economy or the risk of delay in growth recovery in the U.S. economy, including increasing liquidity risks in U.S. credit markets;
- the impact of recently issued and future accounting pronouncements and other changes in accounting policies;
- the possibility of future terrorist attacks or the possibility or occurrence of an outbreak of, or changes in, hostilities or changes in the political conditions in the Middle East and elsewhere;
- the risk of increased costs for insurance premiums, security or other items as a consequence of terrorist attacks;
- risks associated with pending or possible acquisitions and dispositions, including our ability to finance or integrate any such acquisitions and any regulatory delay or conditions imposed by regulatory bodies in connection with any such acquisitions and dispositions;
- the impact of unsold pipeline capacity being greater or less than expected;
- the ability to recover operating costs and amounts equivalent to income taxes, costs of property, plant and equipment and regulatory assets in our state and FERC-regulated rates;
- the composition and quality of the natural gas and NGLs we gather and process in our plants and transport on our pipelines;
- the efficiency of our plants in processing natural gas and extracting and fractionating NGLs;
- the impact of potential impairment charges;
- the risk inherent in the use of information systems in our respective businesses, implementation of new software and hardware, and the impact on the timeliness of information for financial reporting;
- our ability to control construction costs and completion schedules of our pipelines and other projects; and
- the risk factors listed in the reports we have filed and may file with the SEC, which are incorporated by reference.

These factors are not necessarily all of the important factors that could cause actual results to differ materially from those expressed in any of our forward-looking statements. Other factors could also have material adverse effects on our future results. These and other risks are described in greater detail in Item 1A, Risk Factors, in this Annual Report on Form 10-K. All forward-looking statements attributable to us or persons acting on our behalf are expressly qualified in their entirety by these factors. Other than as required under securities laws, we undertake no obligation to update publicly any forward-looking statement, whether as a result of new information, subsequent events or change in circumstances, expectations or otherwise.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Our exposure to market risk discussed below includes forward-looking statements and represents an estimate of possible changes in future earnings that could occur assuming hypothetical future movements in interest rates or commodity prices. Our views on market risk are not necessarily indicative of actual results that may occur and do not represent the maximum possible gains and losses that may occur since actual gains and losses will differ from those estimated based on actual fluctuations in interest rates or commodity prices and the timing of transactions.

We are exposed to market risk due to interest rate and commodity price volatility. Market risk is the risk of loss arising from adverse changes in market rates and prices. We may use financial instruments, including forwards, swaps, collars and futures, to manage the risks of certain identifiable or anticipated transactions and achieve a more predictable cash flow. Our risk management function follows established policies and procedures to monitor interest rates and natural gas and NGL marketing activities to ensure our hedging activities mitigate market risks. We do not use financial instruments for trading purposes.

In accordance with Statement 133, we record derivative instruments at fair value. We estimate the fair value of derivative instruments using available market information and appropriate valuation techniques in accordance with Statement 157. Changes in derivative instruments' fair value are recognized in earnings unless the instrument qualifies as a hedge under Statement 133 and meets specific hedge accounting criteria. Qualifying derivative instruments' gains and losses may offset the hedged items' related results in earnings for a fair value hedge or be deferred in accumulated other comprehensive income (loss) for a cash flow hedge.

INTEREST RATE RISK

General - We are subject to the risk of interest rate fluctuation in the normal course of business. We manage interest rate risk through the use of fixed-rate debt, floating-rate debt and, at times, interest-rate swaps. Fixed-rate swaps are used to reduce our risk of increased interest costs during periods of rising interest rates. Floating-rate swaps are used to convert the fixed rates of long-term borrowings into short-term variable rates. At December 31, 2008, the interest rate on all of our long-term debt was fixed.

Fair Value Hedges - See Note D of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K for discussion of interest-rate swaps and interest expense savings from terminated swaps.

Total interest expense savings from amortization of terminated swaps for 2008 were $3.7 million, compared with total net swap savings of $2.5 million in 2007. Total swap savings from terminated swaps for 2009 are expected to be $3.7 million.

COMMODITY PRICE RISK

In our Natural Gas Gathering and Processing segment, we are exposed to commodity price risk, primarily NGLs, as a result of receiving commodities in exchange for our services. To a lesser extent, exposures arise from the relative price differential between NGLs and natural gas, or the gross processing spread, with respect to our keep-whole processing contracts. We are also exposed to the risk of price fluctuations and the cost of intervening transportation at various market locations. As part of our hedging strategy, we use commodity fixed-price physical forwards and derivative contracts, including NYMEX-based futures and over-the-counter swaps, to minimize earnings volatility related to natural gas, NGL and condensate price fluctuations.

We reduce our gross processing spread exposure through a combination of physical and financial hedges. We utilize a portion of our POP equity natural gas as an offset, or natural hedge, to an equivalent portion of our keep-whole shrink requirements. This has the effect of converting our gross processing spread risk to NGL commodity price risk, and we then use financial instruments to hedge the sale of NGLs.

The following table sets forth our Natural Gas Gathering and Processing segment's hedging information for the year ending December 31, 2009.

	Year Ending December 31, 2009		
	Volumes Hedged	**Average Price**	**Percentage Hedged**
NGLs *(Bbl/d)* (a)	5,010	$1.18 / gallon	57%
Condensate *(Bbl/d)* (a)	666	$3.23 / gallon	32%
Total sales hedged *(Bbl/d)*	5,676	$1.42 / gallon	52%

(a) - Hedged with fixed-price swaps.

Our commodity price risk is estimated as a hypothetical change in the price of NGLs, crude oil and natural gas at December 31, 2008, excluding the effects of hedging and assuming normal operating conditions. Our condensate sales are based on the price of crude oil. We estimate the following:

- a $0.01 per gallon decrease in the composite price of NGLs would decrease annual net margin by approximately $1.2 million;
- a $1.00 per barrel decrease in the price of crude oil would decrease annual net margin by approximately $1.0 million; and
- a $0.10 per MMBtu decrease in the price of natural gas would decrease annual net margin by approximately $0.6 million.

The above estimates of commodity price risk do not include any effects on demand for our services that might be caused by, or arise in conjunction with, price changes. For example, a change in the gross processing spread may cause a change in the amount of ethane extracted from the natural gas stream, impacting gathering and processing margins, NGL exchange revenues, natural gas deliveries, and NGL volumes shipped and fractionated.

In our Natural Gas Liquids Gathering and Fractionation segment, we are exposed to commodity price risk primarily as a result of NGLs in storage, the relative values of the various NGL products to each other, the relative value of NGLs to natural gas and the relative value of NGL purchases at one location and sales at another location, known as basis risk. We utilize fixed-price physical forward contracts to reduce earnings volatility related to NGL price fluctuations. We have not entered into any financial instruments with respect to our NGL marketing activities.

In our Natural Gas Pipelines segment, we are exposed to commodity price risk because our intrastate and interstate natural gas pipelines collect natural gas from our customers for operations or as part of our fee for services provided. When the amount of natural gas consumed in operations by these pipelines differs from the amount provided by our customers, our pipelines must buy or sell natural gas, or store or use natural gas from inventory, which exposes us to commodity price risk. At December 31, 2008, there were no hedges in place with respect to natural gas price risk from our intrastate and interstate pipeline operations.

See Note D of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K for more information on our hedging activities.

COUNTERPARTY CREDIT RISK

We assess the creditworthiness of our counterparties on an on-going basis and require security, including prepayments and other forms of cash collateral, when appropriate.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of ONEOK Partners GP, L.L.C. as General Partner of ONEOK Partners, L.P. and to the Unitholders:

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of income, partners' equity and comprehensive income and cash flows present fairly, in all material respects, the financial position of ONEOK Partners, L.P. and its subsidiaries (the Partnership) at December 31, 2008 and 2007, and the results of their operations and their cash flows for each of the two years ended December 31, 2008, in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Partnership maintained, in all material respects, effective internal control over financial reporting as of December 31, 2008, based on criteria established in *Internal Control - Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Partnership's management is responsible for these financial statements, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in Management's Report on Internal Control over Financial Reporting appearing under Item 9A in the Partnership's Form 10-K for the year ended December 31, 2008. Our responsibility is to express opinions on these financial statements and on the Partnership's internal control over financial reporting based on our integrated audit. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audit of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

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

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

/s/ PricewaterhouseCoopers LLP

February 24, 2009
Tulsa, Oklahoma

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of ONEOK Partners GP, L.L.C. as General Partner of ONEOK Partners, L.P. and to the Unitholders:

We have audited the accompanying consolidated statement of income, cash flows, and changes in partners' equity and comprehensive income of ONEOK Partners, L.P. and subsidiaries (the Partnership) (formerly Northern Border Partners, L.P.) for the year ended December 31, 2006. The consolidated financial statements are the responsibility of the Partnership's management. Our responsibility is to express an opinion on these consolidated financial statements 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 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 audit provides a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the results of operations and cash flows of ONEOK Partners, L.P. and subsidiaries for the year ended December 31, 2006, in conformity with U.S. generally accepted accounting principles.

/s/ KPMG LLP

Tulsa, Oklahoma
February 28, 2007, except for Note L, as to which the date is February 27, 2008

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ONEOK Partners, L.P. and Subsidiaries
CONSOLIDATED STATEMENTS OF INCOME

	Years Ended December 31,		
	2008	**2007**	**2006**
	(Thousands of dollars, except per unit amounts)		
Revenues	**$ 7,720,206**	$ 5,831,558	$ 4,738,248
Cost of sales and fuel	**6,579,547**	4,935,665	3,894,700
Net Margin	**1,140,659**	895,893	843,548
Operating Expenses			
Operations and maintenance	**337,526**	302,544	294,207
Depreciation and amortization	**124,765**	113,704	122,045
General taxes	**34,271**	34,812	31,567
Total Operating Expenses	**496,562**	451,060	447,819
Gain (Loss) on Sale of Assets	**713**	1,950	115,483
Operating Income	**644,810**	446,783	511,212
Equity earnings from investments (Note M)	**101,432**	89,908	95,883
Allowance for equity funds used during construction	**50,906**	12,538	2,205
Other income	**5,621**	7,502	6,510
Other expense	**(13,321)**	(779)	(7,081)
Interest expense	**(151,056)**	(138,947)	(133,482)
Income before Minority Interests and Income Taxes	**638,392**	417,005	475,247
Minority interests in income of consolidated subsidiaries	**(441)**	(416)	(2,392)
Income taxes (Note K)	**(12,335)**	(8,842)	(27,669)
Net Income	**$ 625,616**	$ 407,747	$ 445,186
Limited partners' interest in net income:			
Net income	**$ 625,616**	$ 407,747	$ 445,186
General partner's interest in net income	**(88,554)**	(58,781)	(75,654)
Limited Partners' Interest in Net Income	**$ 537,062**	$ 348,966	$ 369,532
Limited partners' per unit net income (Note N)	**$ 6.01**	$ 4.21	$ 5.01
Number of Units Used in Computation *(Thousands)*	**89,309**	82,891	73,768

See accompanying Notes to Consolidated Financial Statements.

ONEOK Partners, L.P. and Subsidiaries

CONSOLIDATED BALANCE SHEETS

		December 31, 2008		December 31, 2007
Assets		*(Thousands of dollars)*		
Current Assets				
Cash and cash equivalents	**$**	**177,635**	$	3,213
Accounts receivable, net		**317,182**		577,989
Affiliate receivables		**25,776**		52,479
Gas and natural gas liquids in storage		**190,616**		251,219
Commodity exchanges and imbalances		**55,086**		82,037
Derivative financial instruments (Notes C and D)		**63,780**		-
Other current assets		**28,176**		19,961
Total Current Assets		**858,251**		986,898
Property, Plant and Equipment				
Property, plant and equipment		**5,808,679**		4,436,371
Accumulated depreciation and amortization		**875,279**		776,185
Net Property, Plant and Equipment (Note A)		**4,933,400**		3,660,186
Investments and Other Assets				
Investments in unconsolidated affiliates (Note M)		**755,492**		756,260
Goodwill and intangible assets (Note E)		**676,536**		682,084
Other assets		**30,593**		26,637
Total Investments and Other Assets		**1,462,621**		1,464,981
Total Assets	**$**	**7,254,272**	$	6,112,065
Liabilities and Partners' Equity				
Current Liabilities				
Current maturities of long-term debt (Note I)	**$**	**11,931**	$	11,930
Notes payable		**870,000**		100,000
Accounts payable		**496,763**		742,903
Affiliate payables		**23,333**		18,298
Commodity exchanges and imbalances		**191,165**		252,095
Other current liabilities		**100,832**		136,664
Total Current Liabilities		**1,694,024**		1,261,890
Long-term Debt, excluding current maturities (Note I)		**2,589,509**		2,605,396
Deferred Credits and Other Liabilities		**54,773**		43,799
Commitments and Contingencies (Note J)				
Minority Interests in Consolidated Subsidiaries		**5,941**		5,802
Partners' Equity				
General partner		**77,546**		58,415
Common units: 54,426,087 units and 46,397,214 units issued and outstanding at December 31, 2008 and 2007, respectively		**1,361,058**		814,266
Class B units: 36,494,126 units issued and outstanding at December 31, 2008 and 2007		**1,407,016**		1,340,638
Accumulated other comprehensive income (loss) (Note F)		**64,405**		(18,141)
Total Partners' Equity		**2,910,025**		2,195,178
Total Liabilities and Partners' Equity	**$**	**7,254,272**	$	6,112,065

See accompanying Notes to Consolidated Financial Statements.

ONEOK Partners, L.P. and Subsidiaries

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Years Ended December 31,		
	2008	**2007**	**2006**
	(Thousands of dollars)		
Operating Activities			
Net income	**$ 625,616**	$ 407,747	$ 445,186
Depreciation and amortization	**124,765**	113,704	122,045
Allowance for equity funds used during construction	**(50,906)**	(12,538)	(2,205)
Gain on sale of assets	**(713)**	(1,950)	(115,483)
Minority interests in income of consolidated subsidiaries	**441**	416	2,392
Equity earnings from investments	**(101,432)**	(89,908)	(95,883)
Distributions received from unconsolidated affiliates	**93,261**	103,785	123,427
Changes in assets and liabilities (net of acquisition and disposition effects):			
Accounts receivable	**256,137**	(268,963)	129,323
Affiliate receivables	**26,703**	36,093	(87,175)
Gas and natural gas liquids in storage	**16,003**	(47,973)	24,933
Derivative financial instruments	**(2,538)**	2,154	(2,154)
Accounts payable	**(273,475)**	368,452	(10,960)
Affiliate payables	**5,035**	(7,439)	18,657
Commodity exchanges and imbalances, net	**(33,979)**	41,997	20,129
Accrued interest	**5,669**	9,069	23,445
Other assets and liabilities	**(34,169)**	46,888	7,541
Cash Provided by Operating Activities	**656,418**	701,534	603,218
Investing Activities			
Changes in investments in unconsolidated affiliates	**3,963**	(3,668)	(6,608)
Acquisitions	**2,450**	(299,560)	(1,396,893)
Capital expenditures (less allowance for equity funds used during construction)	**(1,253,853)**	(709,858)	(201,746)
Proceeds from sale of assets	**990**	3,980	297,674
Increase in cash and cash equivalents attributable to previously unconsolidated subsidiaries	**-**	-	7,496
Decrease in cash and cash equivalents attributable to previously consolidated subsidiaries	**-**	-	(22,039)
Cash Used in Investing Activities	**(1,246,450)**	(1,009,106)	(1,322,116)
Financing Activities			
Cash distributions:			
General and limited partners	**(453,021)**	(384,646)	(265,479)
Minority interests	**(302)**	(220)	(343)
Cash flow retained by ONEOK (Note B)	**-**	-	(177,486)
Borrowing (repayment) of notes payable, net	**(100,000)**	94,000	(200,500)
Borrowing of notes payable with maturities over 90 days	**870,000**	-	-
Issuance of long-term debt, net of discounts	**-**	598,146	1,397,327
Long-term debt financing costs	**-**	(5,805)	(12,003)
Issuance of common units, net of discounts	**450,198**	-	-
Contributions from general partner	**9,508**	-	-
Payment of long-term debt	**(11,929)**	(11,931)	(40,978)
Other financing activities	**-**	139	(3,628)
Cash Provided by Financing Activities	**764,454**	289,683	696,910
Change in Cash and Cash Equivalents	**174,422**	(17,889)	(21,988)
Cash and Cash Equivalents at Beginning of Period	**3,213**	21,102	43,090
Cash and Cash Equivalents at End of Period	**$ 177,635**	$ 3,213	$ 21,102
Supplemental Cash Flow Information:			
Cash Paid for Interest	**$ 148,417**	$ 138,606	$ 86,290
Cash Paid for Taxes	**$ 4,722**	$ 1,039	$ 610

See accompanying Notes to Consolidated Financial Statements.

ONEOK Partners, L.P. and Subsidiaries
CONSOLIDATED STATEMENT OF CHANGES IN PARTNERS' EQUITY AND COMPREHENSIVE INCOME

	Common Units	Class B Units	General Partner	Common Units
	(Units)		*(Thousands of dollars)*	
December 31, 2005	46,397,214	-	$ 17,341	$ 750,201
Net income	-	-	75,654	220,428
Other comprehensive income (loss)	-	-	-	-
Total comprehensive income				
Net Income retained by ONEOK (Note B)	-	-	(35,818)	-
Issuance of Class B units and contribution from general partner	-	36,494,126	25,576	-
Distributions paid (Note N)	-	-	(28,380)	(167,030)
December 31, 2006	46,397,214	36,494,126	54,373	803,599
Net income	-	-	58,781	195,329
Other comprehensive income (loss) (Note F)	-	-	-	-
Total comprehensive income				
Other	-	-	(1)	-
Distributions paid (Note N)	-	-	(54,738)	(184,662)
December 31, 2007	46,397,214	36,494,126	58,415	814,266
Net income	**-**	**-**	**88,554**	**317,226**
Other comprehensive income (loss) (Note F)	**-**	**-**	**-**	**-**
Total comprehensive income				
Issuance of common units (Note G)	**8,028,873**	**-**	**-**	**450,198**
Contribution from general partner (Note G)	**-**	**-**	**9,508**	**-**
Distributions paid (Note N)	**-**	**-**	**(78,931)**	**(220,632)**
December 31, 2008	**54,426,087**	**36,494,126**	**$ 77,546**	**$ 1,361,058**

See accompanying Notes to Consolidated Financial Statements.

ONEOK Partners, L.P. and Subsidiaries
CONSOLIDATED STATEMENT OF CHANGES IN PARTNERS' EQUITY AND COMPREHENSIVE INCOME (Continued)

	Class B Units	Accumulated Other Comprehensive Income (Loss)	Total Partners' Equity
		(Thousands of dollars)	
December 31, 2005	$ -	$ (1,953)	$ 765,589
Net income	149,104	-	445,186
Other comprehensive income (loss)	-	367	367
Total comprehensive income			445,553
Net Income retained by ONEOK (Note B)	-	-	(35,818)
Issuance of Class B units and contribution from general partner	1,253,241	-	1,278,817
Distributions paid (Note N)	(70,069)	-	(265,479)
December 31, 2006	1,332,276	(1,586)	2,188,662
Net income	153,637	-	407,747
Other comprehensive income (loss) (Note F)	-	(16,555)	(16,555)
Total comprehensive income			391,192
Other	(29)	-	(30)
Distributions paid (Note N)	(145,246)	-	(384,646)
December 31, 2007	1,340,638	(18,141)	2,195,178
Net income	**219,836**	**-**	**625,616**
Other comprehensive income (loss) (Note F)	**-**	**82,546**	**82,546**
Total comprehensive income			**708,162**
Issuance of common units (Note G)	**-**	**-**	**450,198**
Contribution from general partner (Note G)	**-**	**-**	**9,508**
Distributions paid (Note N)	**(153,458)**	**-**	**(453,021)**
December 31, 2008	**$ 1,407,016**	**$ 64,405**	**$ 2,910,025**

ONEOK PARTNERS, L.P. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

A. SUMMARY OF ACCOUNTING POLICIES

Organization and Nature of Operations - ONEOK Partners, L.P. is a publicly traded Delaware master limited partnership that was formed in 1993. Our equity consists of a 2 percent general partner interest and a 98 percent limited partner interest. Our limited partner interests are represented by our common units, which are listed on the NYSE under the trading symbol "OKS," and our Class B limited partner units. We are managed under the direction of the Board of Directors of our sole general partner, ONEOK Partners GP. ONEOK Partners GP is a wholly owned subsidiary of ONEOK. ONEOK owns a 47.7 percent aggregate equity interest in us.

Our operations include gathering of unprocessed natural gas produced from crude oil and natural gas wells. We gather unprocessed natural gas in the Mid-Continent region, which includes the Anadarko Basin of Oklahoma and the Hugoton and Central Kansas Uplift Basins of Kansas. We also gather unprocessed natural gas in two producing basins in the Rocky Mountain region: the Williston Basin, which spans portions of Montana, North Dakota and the Canadian province of Saskatchewan, and the Powder River Basin of Wyoming.

Our interstate natural gas pipeline assets transport natural gas through FERC-regulated interstate natural gas pipelines in Montana, North Dakota, South Dakota, Minnesota, Wisconsin, Iowa, Illinois, Indiana, Kentucky, Tennessee, Oklahoma, Texas and New Mexico. Our interstate pipelines include Midwestern Gas Transmission, Viking Gas Transmission, Guardian Pipeline and OkTex Pipeline. Midwestern Gas Transmission is a bi-directional system that interconnects with Tennessee Gas Transmission Company near Portland, Tennessee, and with several interstate pipelines near Joliet, Illinois. Viking Gas Transmission transports natural gas from an interconnection with TransCanada near Emerson, Manitoba, to an interconnection with ANR Pipeline Company near Marshfield, Wisconsin. Guardian Pipeline interconnects with several pipelines in Joliet, Illinois, and with local distribution companies in Wisconsin. OkTex Pipeline has interconnects in Oklahoma, New Mexico and Texas.

Our intrastate natural gas pipeline assets in Oklahoma have access to the major natural gas producing areas and transport natural gas throughout the state. We also have access to the major natural gas producing area in south central Kansas. In Texas, our intrastate natural gas pipelines are connected to the major natural gas producing areas in the Texas panhandle and the Permian Basin and transport natural gas to the Waha Hub, where other pipelines may be accessed for transportation east to the Houston Ship Channel market, north into the Mid-Continent market and west to the California market. We own storage capacity in underground natural gas storage facilities in Oklahoma, Kansas and Texas. Our natural gas pipelines primarily serve local distribution companies, large industrial companies, municipalities, irrigation customers, power generation facilities and marketing companies.

Our natural gas liquids gathering and fractionation assets consist of facilities that gather, fractionate and treat NGLs and store NGL purity products primarily in Oklahoma, Kansas and Texas, as well as store and fractionate NGLs and NGL products in Mont Belvieu, Texas. Most of the pipeline-connected natural gas processing plants in Oklahoma, Kansas and the Texas panhandle, which extract NGLs from unprocessed natural gas, are connected to our gathering systems. The natural gas liquids pipelines operations gather these unfractionated NGLs and deliver them to our fractionators. The unfractionated NGLs are then separated into NGL products, through a fractionation process, to realize the greater economic value of the NGL products. The individual NGL products are then stored or distributed to our customers, such as petrochemical manufacturers, heating fuel users, refineries and propane distributors. Our fractionation and storage facilities are connected to the key natural gas liquids market centers in Conway, Kansas, and Mont Belvieu, Texas, by FERC-regulated interstate natural gas liquids pipelines, which are part of our Natural Gas Liquids Pipelines segment. We also purchase NGLs and condensate from third parties, as well as from our Natural Gas Gathering and Processing segment.

We own and operate FERC-regulated natural gas liquids gathering and distribution pipelines and associated above- and below-ground storage facilities. Our natural gas liquids gathering pipelines deliver unfractionated NGLs gathered in Oklahoma, Kansas, the Texas panhandle and the Rocky Mountain region to our Natural Gas Liquids Gathering and Fractionation segment's Mid-Continent fractionation facilities in Oklahoma and Kansas. Our natural gas liquids distribution pipelines deliver unfractionated NGLs and NGL products to the natural gas liquids market hubs in Conway, Kansas, and Mont Belvieu, Texas. Through our acquisition of the natural gas liquids assets from Kinder Morgan Energy Partners, L.P. (Kinder Morgan), we acquired terminal and storage facilities, as well as natural gas liquids and refined petroleum products pipelines that connect our Mid-Continent assets with the Midwest markets, including Chicago, Illinois. We operate FERC-regulated natural gas liquids gathering and distribution pipelines in Oklahoma, Kansas, Nebraska, Missouri, Iowa, Illinois, Indiana, Texas, Wyoming and Colorado. We have product terminal and storage facilities in Missouri, Nebraska, Iowa and Illinois.

Critical Accounting Policies

The following is a summary of our most critical accounting policies, which are defined as those policies most important to the portrayal of our financial condition and results of operations and requiring our management's most difficult, subjective or complex judgment, particularly because of the need to make estimates concerning the impact of inherently uncertain matters. We have discussed the development and selection of our critical accounting policies and estimates with the Audit Committee of our Board of Directors.

Impairment of Long-Lived Assets, Goodwill and Intangible Assets - We assess our long-lived assets for impairment based on Statement 144, "Accounting for the Impairment or Disposal of Long-Lived Assets." A long-lived asset is tested for impairment whenever events or changes in circumstances indicate that its carrying amount may exceed its fair value. Fair values are based on the sum of the undiscounted future cash flows expected to result from the use and eventual disposition of the assets.

We assess our goodwill for impairment at least annually based on Statement 142, "Goodwill and Other Intangible Assets." There were no impairment charges resulting from our July 1, 2008, impairment test. As a result of recent events in the financial markets and current economic conditions, we performed a review and determined that interim testing of goodwill as of December 31, 2008, was not necessary. As part of our impairment test, an initial assessment is made by comparing the fair value of a reporting unit with its book value, including goodwill. If the fair value is less than the book value, an impairment is indicated, and we must perform a second test to measure the amount of the impairment. In the second test, we calculate the implied fair value of the goodwill by deducting the fair value of all tangible and intangible net assets of the reporting unit from the fair value determined in step one of the assessment. If the carrying value of the goodwill exceeds the implied fair value of the goodwill, we will record an impairment charge.

We use two generally accepted valuation approaches, an income approach and a market approach, to estimate the fair value of a reporting unit. Under the income approach, we use anticipated cash flows over a three-year period plus a terminal value and discount these amounts to their present value using appropriate rates of return. Under the market approach, we apply multiples to forecasted EBITDA amounts. The multiples used are consistent with historical asset transactions, and the EBITDA amounts are based on average EBITDA for a reporting unit over a three-year forecasted period. See Note E for more discussion of goodwill.

Intangible assets with a finite useful life are amortized over their estimated useful life, while intangible assets with an indefinite useful life are not amortized. All intangible assets are subject to impairment testing.

Our impairment tests require the use of assumptions and estimates. If actual results are not consistent with our assumptions and estimates or our assumptions and estimates change due to new information, we may be exposed to an impairment charge.

For the investments we account for under the equity method, the premium or excess cost over underlying fair value of net assets is referred to as equity method goodwill and under Statement 142, is not subject to amortization but rather to impairment testing pursuant to APB Opinion No. 18, "The Equity Method of Accounting for Investments in Common Stock." The impairment test under APB Opinion No. 18 considers whether the fair value of the equity investment as a whole, not the underlying net assets, has declined and whether that decline is other than temporary. Therefore, we periodically reevaluate the amount at which we carry the excess of cost over fair value of net assets accounted for under the equity method to determine whether current events or circumstances warrant adjustments to our carrying value in accordance with APB Opinion No. 18.

Derivatives and Risk Management - We utilize financial instruments to reduce our market risk exposure to interest rate and commodity price fluctuations and achieve more predictable cash flows. We account for derivative instruments utilized in connection with these activities and services in accordance with Statement 133, "Accounting for Derivative Instruments and Hedging Activities," as amended.

Under Statement 133, entities are required to record derivative instruments at fair value, with the exception of normal purchases and normal sales that are expected to result in physical delivery. See Note C for additional fair value discussion. Market value changes result in a change in the fair value of our derivative instruments. The accounting for changes in the fair value of a derivative instrument depends on whether it has been designated and qualifies as part of a hedging relationship and, if so, the nature of the risk being hedged and how we will determine if the hedging instrument is effective. If the derivative instrument does not qualify or is not designated as part of a hedging relationship, then we account for changes in fair value of the derivative in earnings as they occur. Commodity price volatility may have a significant impact on the gain or loss in a given period.

To reduce our exposure to fluctuations in natural gas, NGLs and condensate prices, we periodically enter into futures, forwards, options or swap transactions in order to hedge anticipated purchases and sales of natural gas, NGLs and condensate and fuel requirements. Interest-rate swaps are also used to manage interest-rate risk. Under certain conditions, we designate these derivative instruments as a hedge of exposure to changes in fair values or cash flow. For hedges of exposure to changes in cash flow, the effective portion of the gain or loss on the derivative instrument is reported initially as a component of accumulated other comprehensive income (loss) and subsequently recorded to earnings when the forecasted transaction affects earnings. Any ineffectiveness of designated hedges is reported in earnings during the period the ineffectiveness occurs. For hedges of exposure to changes in fair value, the gain or loss on the derivative instrument is recognized in earnings during the period of change together with the offsetting gain or loss on the hedged item attributable to the risk being hedged.

Upon election, many of our purchase and sale agreements that otherwise would be required to follow derivative accounting qualify as normal purchases and normal sales under Statement 133 and are therefore exempt from fair value accounting treatment.

See Note D for more discussion of derivatives and risk management activities.

Contingencies - Our accounting for contingencies covers a variety of business activities, including contingencies for legal and environmental exposures. We accrue these contingencies when our assessments indicate that it is probable that a liability has been incurred or an asset will not be recovered, and an amount can be reasonably estimated in accordance with Statement 5, "Accounting for Contingencies." We base our estimates on currently available facts and our estimates of the ultimate outcome or resolution. Accruals for estimated losses from environmental remediation obligations generally are recognized no later than completion of the remediation feasibility study. Recoveries of environmental remediation costs from other parties are recorded as assets when their receipt is deemed probable. Actual results may differ from our estimates resulting in an impact, positive or negative, on earnings. See Note J for additional discussion of contingencies.

Significant Accounting Policies

Consolidation - Our consolidated financial statements include the assets, liabilities and results of operations for our majority-owned subsidiaries. All significant intercompany balances and transactions have been eliminated in consolidation. We account for our investments that we do not control by the equity method of accounting. Under this method, an investment is carried at its acquisition cost, plus the equity in undistributed earnings or losses since acquisition.

Use of Estimates - The preparation of our consolidated financial statements and related disclosures in accordance with GAAP requires us to make estimates and assumptions with respect to values or conditions that cannot be known with certainty that affect the reported amount of assets and liabilities, and the disclosure of contingent assets and liabilities at the date of the consolidated financial statements. These estimates and assumptions also affect the reported amounts of revenue and expenses during the reporting period. Items that may be estimated include, but are not limited to, the economic useful life of assets, fair value of assets and liabilities, provisions for uncollectible accounts receivable, unbilled revenues and cost of goods sold, expenses for services received but for which no invoice has been received, the results of litigation and various other recorded or disclosed amounts.

We evaluate these estimates on an ongoing basis using historical experience, consultation with experts and other methods we consider reasonable based on the particular circumstances. Nevertheless, actual results may differ significantly from the estimates. Any effects on our financial position or results of operations from revisions to these estimates are recorded in the period when the facts that give rise to the revision become known.

Cash and Cash Equivalents - Cash equivalents consist of highly liquid investments, which are readily convertible into cash and have original maturities of three months or less.

Accounts Receivable, net - Accounts receivable represent valid claims against non-affiliated customers for products sold or services rendered, net of allowances for doubtful accounts. We assess the creditworthiness of our counterparties on an on-going basis and require security, including prepayments and other forms of cash collateral, when appropriate. Outstanding customer receivables are regularly reviewed for possible non-payment indicators and allowances for doubtful accounts are recorded based upon management's estimate of collectibility at each balance sheet date.

Inventory, Natural Gas Imbalances and Commodity Exchanges - Inventory held for sale is valued at the lower of cost or market. The values of current natural gas and NGLs in storage are determined using the lower of weighted-average cost or market method. Noncurrent natural gas and NGLs are classified as property and valued at cost. Materials and supplies are valued at average cost. Natural gas imbalances and NGL exchanges are valued at market or their contractually stipulated rate. Imbalances and NGL exchanges are settled in cash or made up in-kind, subject to the terms of the pipelines' tariffs or by agreement.

Property, Plant and Equipment - The following table sets forth our property, plant and equipment by segment, for the periods presented.

	December 31, 2008	December 31, 2007
	(Thousands of dollars)	
Non-Regulated		
Natural Gas Gathering and Processing	**$ 1,368,223**	$ 1,227,475
Natural Gas Pipelines	**167,625**	162,390
Natural Gas Liquids Gathering and Fractionation	**879,047**	672,047
Other	**50,474**	50,482
Regulated		
Natural Gas Pipelines	**1,460,764**	1,184,112
Natural Gas Liquids Pipelines	**1,882,546**	1,139,865
Property, plant and equipment	**5,808,679**	4,436,371
Accumulated depreciation and amortization	**875,279**	776,185
Net property, plant and equipment	**$ 4,933,400**	$ 3,660,186

Our properties are stated at cost which includes AFUDC. Generally, the cost of regulated property retired or sold, plus removal costs, less salvage, is charged to accumulated depreciation. Gains and losses from sales or transfers of non-regulated properties or an entire operating unit or system of our regulated properties are recognized in income. Maintenance and repairs are charged directly to expense.

The interest portion of AFUDC represents the cost of borrowed funds used to finance construction activities. We capitalize interest expense during the construction or upgrade of qualifying assets. Interest expense capitalized in 2008, 2007 and 2006 was $36.1 million, $13.6 million and $1.2 million, respectively. Capitalized interest is recorded as a reduction to interest expense. The equity portion of AFUDC represents the capitalization of the estimated average cost of equity used during the construction of major projects and is recorded in the cost of our regulated properties and as a credit to the allowance for equity funds used during construction.

Our properties are depreciated using the straight-line method over their estimated useful lives. Generally, we apply composite depreciation rates to functional groups of property having similar economic circumstances. We periodically conduct depreciation studies to assess the economic lives of our assets. For our regulated assets, these deprecation studies are completed as a part of our rate proceedings, and the changes in economic lives, if applicable, are implemented prospectively when the new rates are billed. For our non-regulated assets, if it is determined that the estimated economic life changes, then the changes are made prospectively. Changes in the estimated economic lives of our property, plant and equipment could have a material effect on our financial position or result of operations.

The average depreciation rates for our regulated property are set forth in the following table for the periods indicated.

	Years Ended December 31,		
Regulated Property	**2008**	**2007**	**2006**
Natural Gas Pipelines	**2.4%**	2.4%	2.4%
Natural Gas Liquids Pipelines	**2.0%**	2.5%	2.6%

The average depreciation rate for our Natural Gas Liquids Pipelines segment's regulated property decreased in 2008, compared with 2007, due to placing newly constructed assets with longer economic lives in service.

At December 31, 2008 and 2007, property, plant and equipment on our Consolidated Balance Sheets included construction work in progress of $810.0 million and $859.8 million, respectively, that had not yet been put in service and therefore was not being depreciated. Assets are transferred out of construction work in process when they are substantially complete and ready for their intended use, in accordance with Statement 34, "Capitalization of Interest Cost."

Revenue Recognition - Our operating segments recognize revenue when services are rendered or product is delivered. Our Natural Gas Gathering and Processing segment records revenues when gas is processed in or transported through company facilities. Our Natural Gas Liquids Gathering and Fractionation segment records revenues based upon contracted services and actual volumes exchanged or stored under service agreements in the period services are provided. Revenues for our Natural Gas Pipelines segment and Natural Gas Liquids Pipelines segment are recognized based upon contracted capacity and contracted volumes transported and stored under service agreements in the period services are provided.

Income Taxes - We are not a taxable entity for federal income tax purposes. As such, we do not directly pay federal income tax. Our taxable income or loss, which may vary substantially from the net income or loss reported in our Consolidated Statements of Income, is included in the federal income tax returns of each partner. The aggregate difference in the basis of our net assets for financial and income tax purposes cannot be readily determined, as we do not have access to all information about each partner's tax attributes related to us.

Our corporate subsidiaries are required to pay federal and state income taxes. Income taxes are accounted for using the provisions of Statement 109, "Accounting for Income Taxes." Deferred income taxes are provided for the difference between the financial statement and income tax basis of assets and liabilities and carryforward items based on income tax laws and rates existing at the time the temporary differences are expected to reverse. Except for the companies whose accounting policies conform to Statement 71, "Accounting for the Effects of Certain Types of Regulation," the effect of a change in tax rates on deferred tax assets and liabilities is recognized in income in the period that includes the enactment date of the rate change. For the companies whose accounting policies conform to Statement 71, the effect on deferred tax assets and liabilities of a change in tax rates is recorded as regulatory assets and regulatory liabilities in the period that includes the enactment date.

In June 2006, the FASB issued FIN 48, "Accounting for Uncertainty in Income Taxes - An Interpretation of FASB Statement No. 109," which was effective for our year beginning January 1, 2007. This interpretation was issued to clarify the accounting for uncertainty in income taxes recognized in the financial statements by prescribing a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. FIN 48 requires the recognition of penalties and interest on any unrecognized tax benefits. Our policy is to reflect penalties and interest as part of income tax expense as they become applicable. During 2008 and 2007, we had no tax positions that would require establishment of a reserve under FIN 48.

We file numerous consolidated and separate income tax returns in the United States federal jurisdiction and in many state jurisdictions. We also file returns in Canada. No returns are currently under audit, and no extensions of statute of limitations have been requested or granted.

Regulation - Our intrastate natural gas transmission pipelines are subject to the rate regulation and accounting requirements of the OCC, KCC and RRC. Our interstate natural gas and natural gas liquids pipelines are subject to regulation by the FERC. In Kansas and Texas, natural gas storage may be regulated by the state and the FERC for certain types of services. Accordingly, portions of our Natural Gas Pipelines segment and Natural Gas Liquids Pipelines segment follow the accounting and reporting guidance contained in Statement 71. During the rate-making process, regulatory authorities set the framework for what we can charge customers for our services and establish the manner that our costs are accounted for, including allowing us to defer recognition of certain costs and permitting recovery of the amounts through rates over time as opposed to expensing such costs as incurred. Certain examples of types of regulatory guidance include costs for fuel and losses, acquisition costs, contributions in aid of construction, charges for depreciation, and gains or losses on disposition of assets. This allows us to stabilize rates over time rather than passing such costs on to the customer for immediate recovery. Actions by regulatory authorities could have an effect on the amount recovered from rate payers. Any difference in the amount recoverable and the amount deferred is recorded as income or expense at the time of the regulatory action. If all or a portion of the regulated operations are no longer subject to the provisions of Statement 71, a write-off of regulatory assets and costs not recovered may be required.

At December 31, 2008 and 2007, we recorded regulatory assets of approximately $12.8 million and $6.8 million, respectively, which are currently being recovered or are expected to be recovered from our customers. Regulatory assets are being recovered as a result of approved rate proceedings over varying time periods up to 40 years. These assets are reflected in other assets on our Consolidated Balance Sheets.

Asset Retirement Obligations - Statement 143, "Accounting for Asset Retirement Obligations," applies to legal obligations associated with the retirement of long-lived assets that result from the acquisition, construction, development and/or normal use of the asset. Statement 143 requires that we recognize the fair value of a liability for an asset retirement obligation in the period when it is incurred if a reasonable estimate of the fair value can be made. The fair value of the liability is added to the carrying amount of the associated asset, and this additional carrying amount is depreciated over the life of the asset. The liability is accreted at the end of each period through charges to operating expense. If the obligation is settled for an amount other than the carrying amount of the liability, we will recognize a gain or loss on settlement. The depreciation and amortization expense is immaterial to our consolidated financial statements.

In accordance with long-standing regulatory treatment, we collect through rates the estimated costs of removal on certain regulated properties through depreciation expense, with a corresponding credit to accumulated depreciation and amortization. These removal costs are non-legal obligations as defined by Statement 143. However, these non-legal asset removal obligations are accounted for as a regulatory liability under Statement 71. Historically, the regulatory authorities that have jurisdiction over our regulated operations have not required us to track this amount; rather, these costs are addressed prospectively as depreciation rates and are set in each general rate order. We have made an estimate of our removal cost liability using current rates since the last general rate order in each of our jurisdictions. However, significant uncertainty exists regarding the ultimate determination of this liability pending, among other issues, clarification of regulatory intent. We continue to monitor the regulatory authorities and the liability may be adjusted as more information is obtained.

Other

Fair Value Measurements - In September 2006, the FASB issued Statement 157, “Fair Value Measurements,” which establishes a framework for measuring fair value and requires additional disclosures about fair value measurements. Beginning January 1, 2008, we partially applied Statement 157 as allowed by FASB Staff Position (FSP) 157-2, “Effective Date of FASB Statement No. 157,” which delayed the effective date of Statement 157 for nonrecurring fair value measurements associated with our nonfinancial assets and liabilities. As of January 1, 2008, we have applied the provisions of Statement 157 to our recurring fair value measurements, and the impact was not material. See Note C for disclosures of fair value measurements for our financial instruments. As of January 1, 2009, we have applied the provisions of Statement 157 to our nonrecurring fair value measurements associated with our nonfinancial assets and liabilities, and the impact was not material. FSP 157-3, “Determining the Fair Value of a Financial Asset When the Market for That Asset Is Not Active,” which clarified the application of Statement 157 in inactive markets, was issued in October 2008 and was effective for our September 30, 2008, unaudited consolidated financial statements. FSP 157-3 did not have a material impact on our consolidated financial statements.

In February 2007, the FASB issued Statement 159, “The Fair Value Option for Financial Assets and Financial Liabilities,” which allows companies to elect to measure specified financial assets and liabilities, firm commitments, and nonfinancial warranty and insurance contracts at fair value on a contract-by-contract basis, with changes in fair value recognized in earnings each reporting period. At January 1, 2008, we did not elect the fair value option under Statement 159, and therefore there was no impact on our consolidated financial statements.

Master Netting Arrangement - In April 2007, the FASB issued FSP FIN 39-1, “Amendment of FASB Interpretation No. 39,” which requires entities that offset the fair value amounts recognized for derivative receivables and payables to also offset the fair value amounts recognized for the right to reclaim cash collateral with the same counterparty under a master netting arrangement. We applied the provisions of FIN 39-1 to our consolidated financial statements beginning January 1, 2008, and the impact was not material. At December 31, 2008, we had no cash collateral held or posted under our master netting arrangement.

Business Combinations - In December 2007, the FASB issued Statement 141R, “Business Combinations,” which will require most identifiable assets, liabilities, noncontrolling interest (previously referred to as minority interest) and goodwill acquired in a business combination to be recorded at fair value. Statement 141R was effective for our year beginning January 1, 2009. Because the provisions of Statement 141R are applied prospectively, our 2009 and subsequent consolidated financial statements will not be impacted unless we complete a business combination.

Noncontrolling Interests - In December 2007, the FASB issued Statement 160, “Noncontrolling Interest in Consolidated Financial Statements - an amendment to ARB No. 51,” which requires noncontrolling interest (previously referred to as minority interest) to be reported as a component of equity. Statement 160 was effective for our year beginning January 1, 2009, and requires retroactive adoption of the presentation and disclosure requirements for existing minority interests beginning with our March 31, 2009, Quarterly Report on Form 10-Q. Statement 160 is not expected to have a material impact on our consolidated financial statements; however, certain financial statement presentation changes and additional required disclosures will be made.

Equity Method Investments - In November 2008, the FASB ratified EITF 08-6, “Equity Method Investment Accounting Considerations,” which clarified certain issues that arose following the issuance of Statements 141R and 160 related to the accounting for equity method investments. EITF 08-6 was effective for our year beginning January 1, 2009, and is not expected to have a material impact on our consolidated financial statements.

Derivative Instruments and Hedging Activities Disclosure - In March 2008, the FASB issued Statement 161, "Disclosures about Derivative Instruments and Hedging Activities - an amendment to FASB Statement No. 133," which required enhanced disclosures about how derivative and hedging activities affect our financial position, financial performance and cash flows. Statement 161 was effective for our year beginning January 1, 2009, and will be applied prospectively beginning with our March 31, 2009, Quarterly Report on Form 10-Q.

Net Income Per Unit - The FASB ratified EITF 07-4, "Application of the Two-Class Method under FASB Statement No. 128 to Master Limited Partnerships," in March 2008. EITF 07-4 results in the allocation of undistributed current-period earnings to the unitholders using the two-class method in periods in which earnings exceed distributions. When distributions to participating securities exceed current-period earnings, the excess distributions generate an undistributed loss that would be allocated back to the equity interests based on the contractual terms of the partnership agreement. EITF 07-4 was effective for our year beginning January 1, 2009, and requires retrospective application beginning with our March 31, 2009, Quarterly Report on Form 10-Q. Application of EITF 07-4 will impact our net income-per-unit disclosure but will have no impact on our financial position, results of operations or cash flows.

Reclassifications - Certain amounts in our consolidated financial statements have been reclassified to conform to the 2008 presentation. These reclassifications did not impact previously reported net income or partners' equity.

B. ACQUISITIONS AND DIVESTITURES

Acquisition of NGL Pipeline - In October 2007, we completed the acquisition of an interstate natural gas liquids and refined petroleum products pipeline system and related assets from a subsidiary of Kinder Morgan for approximately $300 million, before working capital adjustments. The system extends from Bushton and Conway, Kansas, to Chicago, Illinois, and transports, stores and delivers a full range of NGL products and refined petroleum products. The FERC-regulated system spans 1,624 miles and has a capacity to transport up to 134 MBbl/d. The transaction also included approximately 978 MBbl of owned storage capacity, eight NGL terminals and a 50 percent ownership of Heartland. ConocoPhillips owns the other 50 percent of Heartland and is the managing partner of Heartland, which consists primarily of a refined petroleum products terminal and pipelines with access to two other refined petroleum product terminals. Our investment in Heartland is accounted for under the equity method of accounting. Financing for this transaction came from a portion of the proceeds of our September 2007 issuance of $600 million 6.85 percent Senior Notes due 2037 (the 2037 Notes). See Note I for a discussion of the 2037 Notes. The working capital settlement was finalized in April 2008, with no material adjustments.

Overland Pass Pipeline Company - In May 2006, we entered into an agreement with a subsidiary of The Williams Companies, Inc. (Williams) to form a joint venture called Overland Pass Pipeline Company. In November 2008, Overland Pass Pipeline Company completed construction of a 760-mile natural gas liquids pipeline from Opal, Wyoming, to the Mid-Continent natural gas liquids market center in Conway, Kansas. The Overland Pass Pipeline is designed to transport approximately 110 MBbl/d of unfractionated NGLs and can be increased to approximately 255 MBbl/d with additional pump facilities. During 2006, we paid $11.6 million to Williams for the acquisition of our interest in the joint venture and for reimbursement of initial capital expenditures. Initially, as the 99 percent owner of the joint venture, we managed the construction project and advanced all costs associated with construction. We are currently operating the pipeline. On or before November 17, 2010, Williams will have the option to increase its ownership up to 50 percent, with the purchase price being determined in accordance with the joint venture's operating agreement. If Williams exercises its option to increase its ownership to the full 50 percent, Williams would have the option to become operator. The pipeline project cost was approximately $575 million, excluding AFUDC.

As part of a long-term agreement, Williams dedicated its NGL production from two of its natural gas processing plants in Wyoming to the Overland Pass Pipeline. We will provide downstream fractionation, storage and transportation services to Williams.

The ONEOK Transactions - In April 2006, we completed the acquisition of and consolidated certain companies comprising ONEOK's former gathering and processing, natural gas liquids, and pipelines and storage segments (collectively, the ONEOK Energy Assets) in a series of transactions (collectively, the ONEOK Transactions). As part of the ONEOK Transactions, ONEOK acquired ONEOK NB, formerly known as Northwest Border Pipeline Company, an affiliate of TransCanada that held a 0.35 percent general partner interest in us, under a Purchase and Sale Agreement between an affiliate of ONEOK and an affiliate of TransCanada. As a result, ONEOK owns our entire 2 percent general partner interest and controls us.

We acquired the ONEOK Energy Assets for approximately $3 billion, including $1.35 billion in cash, before adjustments, and approximately 36.5 million Class B limited partner units. The Class B limited partner units and the related general partner interest contribution were valued at approximately $1.65 billion. After this acquisition, ONEOK owned approximately 37.0 million of our common units, which, when combined with its general partner interest, increased its total interest in us to approximately 45.7 percent at the date of acquisition. We used $1.05 billion drawn under a $1.1 billion, 364-day credit agreement, coupled with the proceeds from the sale of a 20 percent partnership interest in Northern Border Pipeline, to finance the cash portion of the transaction.

In June 2005, the FASB ratified the consensus reached in EITF Issue No. 04-5, "Determining Whether a General Partner, or the General Partners as a Group, Controls a Limited Partnership or Similar Entity When the Limited Partners Have Certain Rights" (EITF 04-5). EITF 04-5 presumes that a general partner controls a limited partnership and therefore should consolidate the partnership in the financial statements of the general partner. Our Partnership Agreement provides for the right to replace the general partner by a vote of 66-2/3 percent of the outstanding units, excluding units held by the general partner and its affiliates. Under the guidance in EITF 04-5, ONEOK is deemed to have control for accounting purposes. ONEOK elected to use the prospective method and began to consolidate our operations in their consolidated financial statements as of January 1, 2006. As ONEOK is deemed to control us under the requirements of EITF 04-5, the ONEOK Transactions were accounted for as a transaction between entities under common control, and these transactions were excluded from the accounting prescribed by Statement 141, "Business Combinations." Accordingly, ONEOK's historical cost basis in the ONEOK Energy Assets was transferred to us in a manner similar to a pooling of interests. The difference between the historical cost basis of the net assets acquired of $2.7 billion and the cash paid was assigned to the value of the Class B limited partner units issued to ONEOK and its general partner interest in us. These assets and their related operations are included in our consolidated financial statements retroactive to January 1, 2006.

Since the ONEOK Transactions were not completed until April 2006, the income and cash flow from the ONEOK Energy Assets for the first quarter of 2006 were retained by ONEOK. In our 2006 Consolidated Statement of Cash Flows, we reported cash flow retained by ONEOK of $177.5 million, which represents the cash flows generated from these companies while they were owned by ONEOK.

The following table shows the impact to our Consolidated Statements of Income for the ONEOK Energy Assets prior to our acquisition.

ONEOK Energy Assets	**Three Months Ended March 31, 2006**
	(Thousands of dollars)
Revenue	$ 1,162,571
Cost of sales and fuel	1,013,851
Net margin	148,720
Operating expenses	
Operations and maintenance	47,530
Depreciation and amortization	19,277
General taxes	4,407
Total operating expenses	71,214
Operating income	77,506
Interest expense	21,281
Other income, net	1,760
Income before income taxes	57,985
Income taxes	22,167
Net income	$ 35,818
Limited partners' interest in net income:	
Net income	$ 35,818
General partner interest in net income	(35,818)
Limited partners' interest in net income	$ -

Prior to the acquisition, the ONEOK Energy Assets were included in the consolidated state and federal income tax returns of ONEOK and, accordingly, current taxes payable were allocated to the ONEOK Energy Assets based on ONEOK's effective tax rate. Income tax liabilities and provisions for income tax expense for the ONEOK Energy Assets were calculated on a stand-alone basis. Our Consolidated Statement of Income for 2006 includes income tax expense recorded for the ONEOK Energy Assets of $22.2 million for the first quarter of 2006. In conjunction with the ONEOK Transactions, all income tax liabilities of the ONEOK Energy Assets at the time of the ONEOK Transactions were retained by ONEOK.

Income from the ONEOK Energy Assets for the first quarter of 2006 also reflects interest expense of $21.3 million, which represents interest charged on long-term debt owed to ONEOK. The interest rate on the debt was calculated periodically based upon ONEOK's weighted-average cost of debt. This debt was retained by ONEOK as part of the ONEOK Transactions.

Under the terms of the ONEOK Transactions, we recorded a $72.6 million purchase price adjustment related to a finalized working capital settlement. The working capital settlement is reflected as an increase to the value of the Class B units and was approved by our Audit Committee.

The units issued to ONEOK were the newly created Class B limited partner units. The Class B limited partner units are no longer subordinated to distributions on our common units and generally have the same voting rights as our common units.

At a special meeting of the holders of our common units held March 29, 2007, the unitholders approved a proposal to permit the conversion of all or a portion of the Class B limited partner units issued in the ONEOK Transactions into common units on a one-for-one basis at the option of the Class B unitholder. The March 29, 2007, special meeting was adjourned to May 10, 2007, to allow unitholders additional time to vote on an additional proposal to approve amendments to our Partnership Agreement, which, had the amendments been approved, would have granted voting rights for units held by our general partner and its affiliates if a vote was held to remove our general partner and would have required fair market value compensation for the general partner interest if the general partner was removed. While a majority of our common unitholders voted in favor of the proposed amendments to our Partnership Agreement at the reconvened meeting of our common unitholders held May 10, 2007, the proposed amendments were not approved by the required two-thirds affirmative vote of our outstanding units, excluding the common units and Class B limited partner units held by ONEOK and its affiliates. As a result, effective April 7, 2007, the Class B limited partner units are entitled to receive increased quarterly distributions equal to 110 percent of the distributions paid with respect to our common units.

On June 21, 2007, ONEOK, as the sole holder of our Class B limited partner units, waived its right to receive the increased quarterly distributions on the Class B units for the period of April 7, 2007, through December 31, 2007, and continuing thereafter until ONEOK gives us no less than 90 days advance notice that it has withdrawn its waiver. Any such withdrawal of the waiver will be effective with respect to any distribution on the Class B units declared or paid on or after the 90 days following delivery of the notice.

In addition, since the proposed amendments to our Partnership Agreement were not approved by our common unitholders, if our common unitholders vote at any time to remove ONEOK or its affiliates as our general partner, quarterly distributions payable on the Class B limited partner units would increase to 123.5 percent of the distributions payable with respect to the common units, and distributions payable upon liquidation of the Class B limited partner units would increase to 123.5 percent of the distributions payable with respect to the common units.

Disposition of 20 Percent Partnership Interest in Northern Border Pipeline - In April 2006, we completed the sale of a 20 percent partnership interest in Northern Border Pipeline to TC PipeLines for approximately $297 million to help finance the acquisition of the ONEOK Energy Assets. We recorded a gain on the sale of approximately $113.9 million in the second quarter of 2006. We and TC PipeLines each now own a 50 percent interest in Northern Border Pipeline, and an affiliate of TransCanada became the operator of the pipeline in April 2007. Under Statement 94, "Consolidation of All Majority Owned Subsidiaries," a majority-owned subsidiary is not consolidated if control is likely to be temporary or if it does not rest with the majority owner. Neither we nor TC PipeLines has control of Northern Border Pipeline, as control is shared equally through Northern Border Pipeline's Management Committee. Our interest in Northern Border Pipeline has been accounted for as an investment under the equity method applied on a retroactive basis to January 1, 2006.

Acquisition of Guardian Pipeline Interests - In April 2006, we acquired the 66-2/3 percent interest in Guardian Pipeline not previously owned by us for approximately $77 million, increasing our ownership interest to 100 percent. We used borrowings from our credit facility to fund the acquisition of the additional interest in Guardian Pipeline. Following the completion of the transaction, we consolidated Guardian Pipeline in our consolidated financial statements. This change was accounted for on a retroactive basis to January 1, 2006.

C. FAIR VALUE MEASUREMENTS

As discussed in Note A, we applied the provisions of Statement 157 as of January 1, 2008, to our recurring fair value measurements.

Determining Fair Value - Statement 157 defines fair value as the price that would be received to sell an asset or transfer a liability in an orderly transaction between market participants at the measurement date. We use the income approach to determine the fair value of our derivative assets and liabilities and consider the markets in which the transactions are executed. While many of the contracts in our portfolio are executed in liquid markets where price transparency exists, some contracts are executed in markets for which market prices may exist but the market may be relatively inactive. This results in limited price transparency that requires management's judgment and assumptions to estimate fair values. For certain transactions, we utilize modeling techniques using NYMEX-settled pricing data and historical correlations of NGL product prices to crude oil. We validate our valuation inputs with third-party information and settlement prices from other sources, where available. In addition, as prescribed by the income approach, we compute the fair value of our derivative portfolio by discounting the projected future cash flows from our derivative assets and liabilities to present value. The interest rate yields used to calculate the present-value discount factors are derived from LIBOR, Eurodollar futures and Treasury swaps. The projected cash flows are then multiplied by the appropriate discount factors to determine the present value or fair value of our derivative instruments. Finally, we consider the credit risk of our counterparties with whom our derivative assets and liabilities are executed. Although we use our best estimates to determine the fair value of the derivative contracts we have executed, the ultimate market prices realized could differ from our estimates, and the differences could be significant.

Fair Value Hierarchy - Statement 157 establishes the fair value hierarchy that prioritizes inputs to valuation techniques based on observable and unobservable data and categorizes the inputs into three levels, with the highest priority given to Level 1 and the lowest priority given to Level 3. The levels are described below.

- Level 1 - Unadjusted quoted prices in active markets for identical assets or liabilities.
- Level 2 - Significant observable pricing inputs other than quoted prices included within Level 1 that are either directly or indirectly observable as of the reporting date. Essentially, this represents inputs that are derived principally from or corroborated by observable market data.
- Level 3 - Generally unobservable inputs, which are developed based on the best information available and may include our own internal data.

Determining the appropriate classification of our fair value measurements within the fair value hierarchy requires management's judgment regarding the degree to which market data is observable or corroborated by observable market data.

Recurring Fair Value Measurements - The following table sets forth our recurring fair value measurements for the period indicated.

	December 31, 2008			
	Level 1	**Level 2**	**Level 3**	**Total**
	(Thousands of dollars)			
Derivatives				
Assets	**$ -**	**$ 26,131**	**$ 37,649**	**$ 63,780**

For derivatives for which fair value is determined based on multiple inputs, Statement 157 requires that the measurement for an individual derivative be categorized within a single level based on the lowest level input that is significant to the fair value measurement in its entirety.

When our fair value measurements based on NYMEX-settled prices are associated with exchange-traded instruments, we classify those derivatives as Level 1. These measurements may include futures for natural gas and crude oil that are valued based on unadjusted quoted prices in active markets. Our Level 2 fair value measurements are based on NYMEX-settled prices that are utilized to determine the fair value of certain non-exchange traded financial instruments, including natural gas and crude oil swaps. For our Level 3 inputs, we utilize modeling techniques using NYMEX-settled pricing data and historical correlations of NGL product prices to crude oil.

The following table sets forth a reconciliation of our Level 3 fair value measurements for the period indicated.

		Derivative Assets (Liabilities)
		(Thousands of dollars)
Net liabilities at January 1, 2008	$	(16,400)
Total realized/unrealized gains (losses):		
Included in earnings (a)		**980**
Included in other comprehensive income (loss)		**58,143**
Terminations prior to maturity		**(5,074)**
Transfers in and/or out of Level 3		-
Net assets at December 31, 2008	**$**	**37,649**
Total gains (losses) for the period included in earnings attributable to the change in unrealized gains (losses) relating to assets and liabilities still held as of December 31, 2008 (a)	**$**	-

(a) - Reported in revenues in our Consolidated Statements of Income.

Our Level 3 fair value measurements changed from a net liability position at January 1, 2008, to a net asset position at December 31, 2008, due to new hedges being put in place during the period as well as changes in commodity prices. Realized/unrealized gains (losses) include the realization of our fair value derivative contracts through maturity. Terminations prior to maturity represent swap contracts terminated prior to maturity that will remain in accumulated other comprehensive income (loss) until the underlying forecasted transaction occurs.

Fair Value of Debt - The following estimated fair values represent the amount at which debt could be exchanged in a current transaction between willing parties. Based on quoted market prices for similar issues with similar terms and remaining maturities, the estimated fair value of the aggregate of all the senior notes outstanding was approximately $2.4 billion and $2.7 billion at December 31, 2008 and 2007, respectively. We presently intend to maintain the current schedule of maturities for the senior notes, which will result in no gains or losses on their respective repayment. The fair value of our borrowings under our amended and restated revolving credit agreement dated March 30, 2007 (Partnership Credit Agreement) approximates the carrying value since the interest rates are periodically adjusted to reflect current market conditions.

D. DERIVATIVE INSTRUMENTS AND HEDGING ACTIVITIES

We utilize financial instruments to reduce our market risk exposure to interest rate and commodity price fluctuations and to achieve more predictable cash flows. We follow established policies and procedures to assess risk and approve, monitor and report our financial instrument activities. We do not use these instruments for trading purposes. See Note A for discussion of our accounting policies for derivatives and risk management.

Cash Flow Hedges - Our Natural Gas Gathering and Processing segment primarily utilizes NYMEX-based futures, collars and over-the-counter swaps, which are designated as cash flow hedges, to hedge our exposure to volatility in the price of natural gas, NGLs and condensate. At December 31, 2008, our Consolidated Balance Sheet reflected an unrealized gain of $68.9 million in accumulated other comprehensive income (loss), with a corresponding offset in derivative financial instrument assets and liabilities, all of which will be recognized over the next 12 months. Net gains and losses related to the ineffective portion of our hedges are reclassified out of accumulated other comprehensive income (loss) to revenues in the period the ineffectiveness occurs. Ineffectiveness related to our cash flow hedges was not material in 2008 or 2007. Ineffectiveness related to these cash flow hedges resulted in a gain of approximately $4.5 million for 2006. In the event that it becomes probable that a forecasted transaction will not occur, we would discontinue cash flow hedge treatment, which would affect earnings. There were no gains or losses during 2008, 2007 or 2006 due to the discontinuance of cash flow hedge treatment.

Fair Value Hedges - In prior years we terminated various interest-rate swap agreements. The net savings from the termination of these swaps is being recognized in interest expense over the terms of the debt instruments originally hedged. Interest expense savings for 2008 from amortization of terminated swaps was $3.7 million, and the remaining amortization of terminated swaps will be recognized over the following periods.

	(Millions of dollars)	
2009	$	3.7
2010	$	3.7
2011	$	0.9

At December 31, 2008, none of the interest on our fixed-rate debt was swapped to floating using interest-rate swaps.

E. GOODWILL AND INTANGIBLE ASSETS

Goodwill

Carrying Amount - The table below shows goodwill recorded on our Consolidated Balance Sheet for the periods indicated.

	December 31,			
		2008		**2007**
	(Thousands of dollars)			
Natural Gas Gathering and Processing	**$**	**90,037**	$	90,037
Natural Gas Pipelines		**131,115**		128,997
Natural Gas Liquids Gathering and Fractionation		**175,566**		175,566
Goodwill	**$**	**396,718**	$	394,600

Equity Method Goodwill - For the investments we account for under the equity method, the premium or excess cost over underlying fair value of net assets is referred to as equity method goodwill. Investment in unconsolidated affiliates on our accompanying Consolidated Balance Sheets includes equity method goodwill of $185.6 million as of December 31, 2008 and 2007.

Impairment Test - We apply the provisions of Statement 142 and perform our annual impairment test on July 1. There were no impairment charges resulting from our July 1, 2008, impairment test. As a result of recent events in the financial markets and current economic conditions, we performed a review and determined that interim testing of goodwill as of December 31, 2008, was not necessary.

Black Mesa - During 2006, we reassessed our coal slurry pipeline operation and concluded that the likelihood of Black Mesa Pipeline resuming operations was significantly reduced, and a goodwill and asset impairment of $8.4 million and $3.6 million, respectively, was recorded as depreciation and amortization. The reduction to our net income after income taxes was $10.6 million.

Intangible Assets

Our intangible assets primarily relate to contracts acquired through acquisition, which are being amortized over an aggregate weighted-average period of 40 years. Amortization expense for intangible assets for both 2008 and 2007 was $7.7 million, and the aggregate amortization expense for each of the next five years is estimated to be approximately $7.7 million. The following tables reflect the gross carrying amount and accumulated amortization of intangible assets for the periods presented.

	December 31, 2008		
	Gross Intangible Assets	**Accumulated Amortization**	**Net Intangible Assets**
		(Thousands of dollars)	
Natural Gas Liquids Gathering and Fractionation	**$ 292,000**	**$ (25,549)**	**$ 266,451**
Natural Gas Liquids Pipelines	**14,650**	**(1,283)**	**13,367**
Intangible Assets	**$ 306,650**	**$ (26,832)**	**$ 279,818**

	December 31, 2007		
	Gross Intangible Assets	Accumulated Amortization	Net Intangible Assets
		(Thousands of dollars)	
Natural Gas Liquids Gathering and Fractionation	$ 292,000	$ (18,249)	$ 273,751
Natural Gas Liquids Pipelines	14,650	(917)	13,733
Intangible Assets	$ 306,650	$ (19,166)	$ 287,484

F. OTHER COMPREHENSIVE INCOME (LOSS)

The table below shows other comprehensive income (loss) for the periods indicated.

	Years Ended December 31,	
	2008	**2007**
	(Thousands of dollars)	
Unrealized gains (losses) on derivatives	**$ 68,159**	$ (16,555)
Less: Realized losses recognized in net income	**(14,387)**	-
Other comprehensive income (loss)	**$ 82,546**	$ (16,555)

The table below shows the balance in accumulated other comprehensive income (loss) for the periods indicated.

	Unrealized Gains (Losses) on Derivatives
	(Thousands of dollars)
December 31, 2006	$ (1,586)
Other comprehensive income (loss)	(16,555)
December 31, 2007	(18,141)
Other comprehensive income (loss)	**82,546**
December 31, 2008	**$ 64,405**

G. PARTNERS' EQUITY

ONEOK - ONEOK and its affiliates own all of the Class B units, 5,900,000 common units and the entire 2 percent general partner interest in us, which together constituted a 47.7 percent ownership interest in us at December 31, 2008.

Equity Issuance - In March 2008, we completed a public offering of 2.5 million common units at $58.10 per common unit, generating net proceeds of approximately $140.4 million after deducting underwriting discounts but before offering expenses. In addition, we sold 5.4 million common units to ONEOK in a private placement, generating proceeds of approximately $303.2 million. In conjunction with the public offering of common units and the private placement, ONEOK Partners GP contributed $9.4 million in order to maintain its 2 percent general partner interest in us.

In April 2008, we sold an additional 128,873 common units at $58.10 per common unit to the underwriters of the public offering upon the partial exercise of their option to purchase additional common units to cover over-allotments. We received net proceeds of approximately $7.2 million from the sale of the common units after deducting underwriting discounts but before offering expenses. In conjunction with the partial exercise by the underwriters, ONEOK Partners GP contributed $0.2 million in order to maintain its 2 percent general partner interest in us.

We used a portion of the proceeds from the sale of common units and the general partner contributions to repay borrowings under our Partnership Credit Agreement.

Cash Distributions - The following summarizes our quarterly cash distribution activity for 2008:

- In January 2008, we declared a cash distribution of $1.025 per unit for the fourth quarter of 2007. The distribution was paid on February 14, 2008, to unitholders of record as of January 31, 2008;
- In April 2008, we declared a cash distribution of $1.04 per unit for the first quarter of 2008. The distribution was paid on May 15, 2008, to unitholders of record as of April 30, 2008;
- In July 2008, we declared a cash distribution of $1.06 per unit for the second quarter of 2008. The distribution was paid on August 14, 2008, to unitholders of record as of July 31, 2008; and
- In October 2008, we declared a cash distribution of $1.08 per unit for the third quarter of 2008. The distribution was paid on November 14, 2008, to unitholders of record as of October 31, 2008.

On January 13, 2009, we declared a cash distribution of $1.08 per unit ($4.32 per unit on an annualized basis) for the fourth quarter of 2008. The distribution was paid on February 13, 2009, to unitholders of record as of January 30, 2009.

Partnership Agreement - Under our Partnership Agreement, in conjunction with the issuance of additional common units, our general partner is required to make equity contributions to us in order to maintain a 2 percent general partner interest.

Under our Partnership Agreement, we make distributions to our partners with respect to each calendar quarter in an amount equal to 100 percent of available cash within 45 days following the end of each quarter. Available cash generally consists of all cash receipts adjusted for cash disbursements and net changes to cash reserves. Available cash will generally be distributed 98 percent to limited partners and 2 percent to our general partner. As an incentive, the general partner's percentage interest in quarterly distributions is increased after certain specified target levels are met. Under the incentive distribution provisions, the general partner receives:

- 15 percent of amounts distributed in excess of $0.605 per common unit;
- 25 percent of amounts distributed in excess of $0.715 per unit; and
- 50 percent of amounts distributed in excess of $0.935 per unit.

Our income is allocated to the general partner and the limited partners in accordance with their respective partnership percentages, after giving effect to any priority income allocations for incentive distributions that are allocated to the general partner. See Note N for additional information about distributions allocated to the general partner.

H. CREDIT FACILITIES

In March 2007, we amended and restated our revolving Partnership Credit Agreement with several banks and other financial institutions and lenders in the following principal ways: (i) revised the pricing, (ii) extended the maturity by one year to March 2012, (iii) eliminated the interest coverage ratio covenant, (iv) increased the permitted ratio of indebtedness to EBITDA to 5 to 1 (from 4.75 to 1), (v) increased the swingline sub-facility commitments from $15 million to $50 million and (vi) changed the permitted amount of subsidiary indebtedness from $35 million to 10 percent of our consolidated indebtedness. The interest rates applicable to extensions of credit under this agreement are based, at our election, on either (i) the higher of prime or one-half of one percent above the Federal Funds Rate, which is the rate that banks charge each other for the overnight borrowing of funds, or (ii) the Eurodollar rate plus a set number of basis points, depending on our current long-term unsecured debt ratings.

In July 2007, we exercised the accordion feature of our Partnership Credit Agreement to increase the commitment amounts by $250 million to a total of $1.0 billion.

Under our Partnership Credit Agreement, we are required to comply with certain financial, operational and legal covenants. Among other things, these requirements include maintaining a ratio of indebtedness to adjusted EBITDA (EBITDA plus minority interest in income of consolidated subsidiaries, distributions received from investments and the equity portion of AFUDC) of no more than 5 to 1. If we consummate one or more acquisitions in which the aggregate purchase price is $25 million or more, the allowable ratio of indebtedness to adjusted EBITDA will be increased to 5.5 to 1 for the three calendar quarters following the acquisition.

Upon breach of any covenant in our Partnership Credit Agreement, amounts outstanding under such agreement may become immediately due and payable. At December 31, 2008, our ratio of indebtedness to adjusted EBITDA was 4.1 to 1, and we were in compliance with all covenants under our Partnership Credit Agreement.

The average interest rate of borrowings under this agreement was 4.22 percent and 5.40 percent at December 31, 2008 and 2007, respectively. We had $870 million and $100 million of borrowings outstanding and $130 million and $900 million available under our Partnership Credit Agreement at December 31, 2008 and 2007, respectively.

We have an outstanding $25 million letter of credit issued by Royal Bank of Canada, which is used for counterparty credit support.

We also have a $15 million Senior Unsecured Letter of Credit Facility and Reimbursement Agreement with Wells Fargo Bank, N.A., of which $12 million is being used, and an agreement with Royal Bank of Canada, pursuant to which a $12 million letter of credit was issued. Both agreements are used to support various permits required by the KDHE for our ongoing business in Kansas.

I. LONG-TERM DEBT

The following table sets forth our long-term debt for the periods indicated. All notes are senior unsecured obligations, ranking equally in right of payment with all of our existing and future unsecured senior indebtedness.

	December 31, 2008	December 31, 2007
	(Thousands of dollars)	
ONEOK Partners		
$250,000 at 8.875% due 2010	**$ 250,000**	$ 250,000
$225,000 at 7.10% due 2011	**225,000**	225,000
$350,000 at 5.90% due 2012	**350,000**	350,000
$450,000 at 6.15% due 2016	**450,000**	450,000
$600,000 at 6.65% due 2036	**600,000**	600,000
$600,000 at 6.85% due 2037	**600,000**	600,000
	2,475,000	2,475,000
Guardian Pipeline		
Average 7.85% due 2022	**121,711**	133,641
Total long-term notes payable	**2,596,711**	2,608,641
Unamortized portion of terminated swaps	**8,414**	12,155
Unamortized debt premium	**(3,685)**	(3,470)
Current maturities	**(11,931)**	(11,930)
Long-term debt	**$ 2,589,509**	$ 2,605,396

The aggregate maturities of long-term debt outstanding for years 2009 through 2013 are shown below.

	ONEOK Partners	Guardian Pipeline	Total
		(Millions of dollars)	
2009	$ -	$ 11.9	$ 11.9
2010	$ 250.0	$ 11.9	$ 261.9
2011	$ 225.0	$ 11.9	$ 236.9
2012	$ 350.0	$ 11.1	$ 361.1
2013	$ -	$ 7.7	$ 7.7

Debt Issuance - In September 2007, we completed an underwritten public offering of $600 million aggregate principal amount of 6.85 percent Senior Notes due 2037 (the 2037 Notes). The 2037 Notes were issued under our existing shelf registration statement filed with the SEC.

We may redeem the 2037 Notes, in whole or in part, at any time prior to their maturity at a redemption price equal to the principal amount of the 2037 Notes, plus accrued and unpaid interest and a make-whole premium. The redemption price will never be less than 100 percent of the principal amount of the 2037 Notes plus accrued and unpaid interest. The 2037 Notes are senior unsecured obligations, ranking equally in right of payment with all of our existing and future unsecured senior indebtedness, and effectively junior to all of the existing debt and other liabilities of our non-guarantor subsidiaries. The 2037 Notes are non-recourse to our general partner.

Debt Covenants - The indenture governing the 2037 Notes does not limit the aggregate principal amount of debt securities that may be issued and provides that debt securities may be issued from time to time in one or more additional series. The indenture contains covenants including, among other provisions, limitations on our ability to place liens on our property or assets and sell and lease back our property.

Our $250 million and $225 million senior notes, due 2010 and 2011, respectively, contain provisions that require us to offer to repurchase the senior notes at par value if our Moody's or S&P credit rating falls below investment grade (Baa3 for Moody's or BBB- for S&P) and the investment grade rating is not reinstated within a period of 40 days. Further, the indentures governing our senior notes due 2010 and 2011 include an event of default upon acceleration of other indebtedness of $25 million or more and the indentures governing our senior notes due 2012, 2016, 2036 and 2037 include an event of default upon the acceleration of other indebtedness of $100 million or more that would be triggered by such an offer to repurchase. Such an event of default would entitle the trustee or the holders of 25 percent in aggregate principal amount of the outstanding senior notes due 2010, 2011, 2012, 2016, 2036 and 2037 to declare those notes immediately due and payable in full.

Debt Guarantee - The notes due 2012, 2016, 2036 and 2037 are fully and unconditionally guaranteed on a senior unsecured basis by the Intermediate Partnership. The guarantee ranks equally in right of payment to all of the Intermediate Partnership's existing and future unsecured senior indebtedness. We have no significant assets or operations other than our investment in our wholly owned subsidiary, the Intermediate Partnership, which is also consolidated. At December 31, 2008, the Intermediate Partnership held partnership interests and the equity in our subsidiaries, as well as a 50 percent interest in Northern Border Pipeline.

The Northern Border Pipeline partnership agreement provides that distributions to Northern Border Pipeline's partners are to be made on a pro rata basis according to each partner's percentage interest. The Northern Border Pipeline Management Committee determines the amount and timing of such distributions. Any changes to, or suspension of, the cash distribution policy of Northern Border Pipeline requires the unanimous approval of the Northern Border Pipeline Management Committee. Cash distributions are equal to 100 percent of distributable cash flow as determined from Northern Border Pipeline's financial statements based upon earnings before interest, taxes, depreciation and amortization less interest expense and maintenance capital expenditures. Loans or other advances from Northern Border Pipeline to its partners or affiliates are prohibited under its credit agreement. The Northern Border Pipeline Management Committee has adopted a cash distribution policy related to financial ratio targets and capital contributions. The cash distribution policy defines minimum equity-to-total-capitalization ratios to be used by the Northern Border Pipeline Management Committee to establish the timing and amount of required capital contributions. In addition, any shortfall due to the inability to refinance maturing debt will be funded by capital contributions. See Notes J and M for discussion of our investment in Northern Border Pipeline.

Guardian Pipeline Senior Notes - These notes were issued under a master shelf agreement with certain financial institutions. Principal payments are due quarterly through 2022. Interest rates on the $121.7 million in notes outstanding at December 31, 2008, range from 7.61 percent to 8.27 percent, with an average rate of 7.85 percent. Guardian Pipeline's senior notes contain financial covenants that require the maintenance of a ratio of (i) EBITDAR (net income plus interest expense, income taxes, operating lease expense and depreciation and amortization) to fixed charges (interest expense plus operating lease expense) of not less than 1.5 to 1 and (ii) total indebtedness to EBITDAR of not greater than 5.75 to 1. Upon any breach of these covenants, all amounts outstanding under the master shelf agreement may become due and payable immediately. At December 31, 2008, Guardian Pipeline's EBITDAR-to-fixed-charges ratio was 4.95 to 1,the ratio of indebtedness to EBITDAR was 3.34 to 1, and Guardian Pipeline was in compliance with its financial covenants.

Other

We amortize premiums, discounts and expenses incurred in connection with the issuance of long-term debt consistent with the terms of the respective debt instrument.

J. COMMITMENTS AND CONTINGENCIES

Operating Leases - Future minimum lease payments under non-cancelable operating leases on a natural gas processing plant, storage contracts, office space, pipeline equipment, rights-of-way and vehicles are shown in the table below.

	(Millions of dollars)
2009	$ 18.4
2010	$ 16.0
2011	$ 15.5
2012	$ 8.8
2013	$ 2.1

Firm Transportation Obligations and Other Commitments - We have firm transportation agreements with Fort Union Gas Gathering and Lost Creek Gathering Company. The Fort Union Gas Gathering agreement expires in November 2009, and the Lost Creek Gathering Company agreement expires in 2010. Under these agreements, we must make specified minimum payments to Fort Union Gas Gathering and Lost Creek Gathering Company each month. We recorded expenses of $11.7 million, $11.9 million and $12.0 million for 2008, 2007 and 2006, respectively, related to these agreements. At December 31, 2008, the estimated aggregate amounts of such required future payments were $11.1 million for 2009 and $3.7 million for 2010.

Investment in Northern Border Pipeline - Northern Border Pipeline anticipates an equity contribution of approximately $85 million that will be required of its partners in 2009, of which our share will be approximately $43 million for our 50 percent equity interest.

Environmental Liabilities - We are subject to multiple environmental, historical and wildlife preservation laws and regulations affecting many aspects of our present and future operations. Regulated activities include those involving air emissions, stormwater, wastewater discharges, handling and disposal of solid and hazardous wastes, hazardous materials transportation, and pipeline and facility construction. These laws and regulations require us to obtain and comply with a wide variety of environmental clearances, registrations, licenses, permits and other approvals. Failure to comply with these laws, regulations, permits and licenses may expose us to fines, penalties and/or interruptions in our operations that could be material to our results of operations. If a leak or spill of hazardous substances or petroleum products occurs from our lines or facilities, in the process of transporting natural gas, NGLs or refined products, or at any facility that we own, operate or otherwise use, we could be held jointly and severally liable for all resulting liabilities, including investigation and clean-up costs, which could materially affect our results of operations and cash flows. In addition, emission controls required under the federal Clean Air Act and other similar federal and state laws could require unexpected capital expenditures at our facilities. We cannot assure that existing environmental regulations will not be revised or that new regulations will not be adopted or become applicable to us. Revised or additional regulations that result in increased compliance costs or additional operating restrictions, particularly if those costs are not fully recoverable from customers, could have a material adverse effect on our business, financial condition and results of operations.

Our expenditures for environmental evaluation, mitigation and remediation to date have not been significant in relation to our results of operations, and there were no material effects upon earnings during 2008, 2007 or 2006 related to compliance with environmental regulations.

Legal Proceedings - We are a party to various litigation matters and claims that are in the normal course of our operations. While the results of litigation and claims cannot be predicted with certainty, we believe the final outcome of such matters will not have a material adverse effect on our consolidated results of operations, financial position or liquidity.

FERC Matter - As a result of a transaction that was brought to the attention of one of our affiliates by a third party, we conducted an internal review of transactions that may have violated FERC natural gas capacity release rules or related rules and determined that there were transactions that should be disclosed to the FERC. We notified the FERC of this review and filed a report with the FERC regarding these transactions in March 2008. We cooperated fully with the FERC in its investigation of this matter and have taken steps to better ensure that current and future transactions comply with applicable FERC regulations by implementing a compliance plan dealing with capacity release. We, along with ONEOK, entered into a global settlement with the FERC to resolve this matter and other FERC enforcement matters, which was approved by the FERC on January 15, 2009. The global settlement provides for a total civil penalty of $4.5 million and approximately $2.2 million in disgorgement of profits and interest. We are responsible for $1.7 million in civil penalties, which is recorded as a liability on our Consolidated Balance Sheet as of December 31, 2008, and the disgorgement of profits and interests are the responsibility of ONEOK. We made the required payments in January 2009.

K. INCOME TAXES

Components of the income tax provision and income taxes paid by our corporate subsidiaries are shown in the table below.

	Years Ended December 31,		
	2008	2007	2006
	(Thousands of dollars)		
Taxes currently payable:			
Federal	**$ 80**	$ 72	$ -
State	**7,240**	4,203	-
Total taxes currently payable	**7,320**	4,275	-
Deferred taxes:			
Federal	**4,785**	3,994	2,163
State	**230**	573	3,339
Total deferred taxes	**5,015**	4,567	5,502
Taxes retained by ONEOK	**-**	-	22,167
Total tax provision	**$ 12,335**	$ 8,842	$ 27,669

Taxes retained by ONEOK represent taxes accrued for the ONEOK Energy Assets during the first quarter of 2006. In conjunction with the ONEOK Transactions, all income tax liabilities of the ONEOK Energy Assets at the time of the ONEOK Transactions were retained by ONEOK. See Note B for additional discussion of the ONEOK Transactions.

The following table is a reconciliation of our provision for income taxes for the periods indicated.

	Years Ended December 31,		
	2008	2007	2006
	(Thousands of dollars)		
Pretax income	**$ 637,951**	$ 416,589	$ 420,849
Federal statutory income tax rate	**35.0%**	35.0%	35.0%
Provision for federal income taxes	**223,283**	145,806	147,297
Partnership earnings not subject to tax	**(216,332)**	(141,884)	(144,928)
State income taxes	**7,470**	4,772	2,990
Other, net	**(2,086)**	148	143
Income tax expense	**$ 12,335**	$ 8,842	$ 5,502

The following table sets forth the tax effects of temporary differences that gave rise to significant portions of the deferred tax assets and liabilities for the periods indicated.

	Years Ended December 31,	
	2008	2007
	(Thousands of dollars)	
Deferred tax assets:		
Net operating losses	**$ 4,226**	$ 4,715
Other	**44**	1,596
Total deferred tax assets	**4,270**	6,311
Deferred tax liabilities:		
Excess of tax over book depreciation and depletion	**9,660**	7,934
Employee benefits	**790**	-
Regulatory assets	**3,733**	2,544
Other	**823**	77
Total deferred tax liabilities	**15,006**	10,555
Net deferred tax assets (liabilities)	**$ (10,736)**	$ (4,244)

At December 31, 2008, we had approximately $4.2 million of tax benefits available related to net operating loss carryforwards, which will expire between the years 2022 and 2027. We believe that it is more likely than not that the tax benefits of the net operating loss carryforwards will be utilized prior to their expiration; therefore, no valuation allowance is necessary.

We had income taxes payable of approximately $7.2 million and $3.1 million at December 31, 2008 and 2007, respectively.

L. SEGMENTS

Segment Descriptions - Our operations are divided into four strategic business segments based on similarities in economic characteristics, products and services, types of customers, methods of distribution and regulatory environment, as follows:

- our Natural Gas Gathering and Processing segment primarily gathers and processes unprocessed natural gas;
- our Natural Gas Pipelines segment primarily operates regulated interstate and intrastate natural gas transmission pipelines and natural gas storage facilities;
- our Natural Gas Liquids Gathering and Fractionation segment primarily gathers, treats and fractionates NGLs and stores and markets NGL products; and
- our Natural Gas Liquids Pipelines segment primarily owns and operates FERC-regulated interstate natural gas liquids gathering and distribution pipelines.

Accounting Policies - The accounting policies of the segments are described in Note A. Intersegment and affiliate sales are recorded on the same basis as sales to unaffiliated customers. Our Natural Gas Gathering and Processing segment sells natural gas to ONEOK and its subsidiaries. A portion of our Natural Gas Pipelines segment's revenues are from subsidiaries of ONEOK that utilize our transportation and storage services. Overhead costs relating to a reportable segment have been allocated for the purpose of calculating operating income.

Customers - The primary customers for our Natural Gas Gathering and Processing segment are major and independent oil and gas production companies. Our Natural Gas Liquids Gathering and Fractionation segment's customers are primarily natural gas gathering and processing companies and petrochemical, refining and NGL marketing companies. Companies served by our Natural Gas Pipelines segment include local distribution companies, power generating companies, natural gas marketing companies and petrochemical companies. Our Natural Gas Liquids Pipelines segment's customers are primarily NGL gathering companies, propane distributors and petrochemical and refining companies.

In 2008, 2007 and 2006, we had no single external customer from which we received 10 percent or more of our consolidated revenues.

Operating Segment Information - The following tables set forth certain selected financial information for our operating segments for the periods indicated. Amounts in prior periods have been restated to conform to our current presentation.

Year Ended December 31, 2008	Natural Gas Gathering and Processing	Natural Gas Pipelines (a)	Natural Gas Liquids Gathering and Fractionation	Natural Gas Liquids Pipelines (b)	Other and Eliminations	Total
			(Thousands of dollars)			
Sales to unaffiliated customers	$ 447,293	$ 223,223	$ 6,241,296	$ 63,460	$ 48	$ 6,975,320
Sales to affiliated customers	627,774	117,112	-	-	-	744,886
Intersegment revenues	681,172	1,788	28,439	93,631	(805,030)	-
Total revenues	$ 1,756,239	$ 342,123	$ 6,269,735	$ 157,091	$ (804,982)	$ 7,720,206
Net margin	$ 435,223	$ 257,362	$ 317,704	$ 132,697	$ (2,327)	$ 1,140,659
Operating costs	138,196	89,878	89,839	55,060	(1,176)	371,797
Depreciation and amortization	49,883	34,279	23,485	17,097	21	124,765
Gain (loss) on sale of assets	4	(17)	33	10	683	713
Operating income	$ 247,148	$ 133,188	$ 204,413	$ 60,550	$ (489)	$ 644,810
Equity earnings from investments	$ 32,825	$ 66,653	$ -	$ 1,954	$ -	$ 101,432
Investments in unconsolidated affiliates	$ 324,709	$ 400,986	$ -	$ 29,797	$ -	$ 755,492
Minority interests in consolidated subsidiaries	$ -	$ 5,797	$ -	$ 129	$ 15	$ 5,941
Total assets	$ 1,613,903	$ 1,477,301	$ 1,717,550	$ 1,903,568	$ 541,950	$ 7,254,272
Capital expenditures	$ 146,249	$ 267,029	$ 169,510	$ 670,926	$ 139	$ 1,253,853

(a) - Our Natural Gas Pipelines segment has regulated and non-regulated operations. Our Natural Gas Pipelines segment's regulated operations had revenues of $282.2 million, net margin of $201.4 million and operating income of $98.2 million.

(b) - All of our Natural Gas Liquids Pipelines segment's operations are regulated.

Year Ended December 31, 2007	Natural Gas Gathering and Processing	Natural Gas Pipelines (a)	Natural Gas Liquids Gathering and Fractionation	Natural Gas Liquids Pipelines (b)	Other and Eliminations	Total
			(Thousands of dollars)			
Sales to unaffiliated customers	$ 433,139	$ 194,170	$ 4,562,178	$ 15,280	$ 27	$ 5,204,794
Sales to affiliated customers	519,755	107,009	-	-	-	626,764
Intersegment revenues	505,756	785	25,115	76,555	(608,211)	-
Total revenues	$ 1,458,650	$ 301,964	$ 4,587,293	$ 91,835	$ (608,184)	$ 5,831,558
Net margin	$ 366,511	$ 241,097	$ 205,764	$ 81,472	$ 1,049	$ 895,893
Operating costs	135,422	96,584	70,693	28,957	5,700	337,356
Depreciation and amortization	45,099	32,380	23,134	13,062	29	113,704
Gain (loss) on sale of assets	1,825	79	39	7	-	1,950
Operating income	$ 187,815	$ 112,212	$ 111,976	$ 39,460	$ (4,680)	$ 446,783
Equity earnings from investments	$ 26,399	$ 62,487	$ -	$ 1,022	$ -	$ 89,908
Investments in unconsolidated affiliates	$ 298,701	$ 426,992	$ -	$ 30,567	$ -	$ 756,260
Minority interests in consolidated subsidiaries	$ -	$ 5,758	$ -	$ 29	$ 15	$ 5,802
Total assets	$ 1,521,514	$ 1,241,507	$ 1,880,602	$ 1,185,513	$ 282,929	$ 6,112,065
Capital expenditures	$ 83,820	$ 138,919	$ 123,555	$ 363,460	$ 104	$ 709,858

(a) - Our Natural Gas Pipelines segment has regulated and non-regulated operations. Our Natural Gas Pipelines segment's regulated operations had revenues of $252.5 million, net margin of $192.2 million and operating income of $82.9 million.

(b) - All of our Natural Gas Liquids Pipelines segment's operations are regulated.

Year Ended December 31, 2006	Natural Gas Gathering and Processing	Natural Gas Pipelines (a)	Natural Gas Liquids Gathering and Fractionation	Natural Gas Liquids Pipelines (b)	Other and Eliminations	Total
			(Thousands of dollars)			
Sales to unaffiliated customers	$ 478,848	$ 195,063	$ 3,467,048	$ -	$ 1,587	$ 4,142,546
Sales to affiliated customers	476,361	121,088	(1,747)	-	-	595,702
Intersegment revenues	520,881	857	27,675	66,496	(615,909)	-
Total revenues	$ 1,476,090	$ 317,008	$ 3,492,976	$ 66,496	$ (614,322)	$ 4,738,248
Net margin	$ 370,761	$ 246,797	$ 166,981	$ 60,447	$ (1,438)	$ 843,548
Operating costs	147,487	91,516	57,511	19,333	9,927	325,774
Depreciation and amortization	43,032	32,841	20,738	12,035	13,399	122,045
Gain (loss) on sale of assets	373	114,890	47	7	166	115,483
Operating income	$ 180,615	$ 237,330	$ 88,779	$ 29,086	$ (24,598)	$ 511,212
Equity earnings from investments	$ 22,616	$ 72,835	$ -	$ 432	$ -	$ 95,883
Investments in unconsolidated affiliates	$ 294,308	$ 445,339	$ -	$ 9,232	$ -	$ 748,879
Minority interests in consolidated subsidiaries	$ -	$ 5,476	$ -	$ 115	$ 15	$ 5,606
Total assets	$ 1,447,238	$ 1,075,811	$ 1,458,818	$ 514,164	$ 425,686	$ 4,921,717
Capital expenditures	$ 80,982	$ 48,598	$ 21,761	$ 49,322	$ 1,083	$ 201,746

(a) - Our Natural Gas Pipelines segment has regulated and non-regulated operations. Our Natural Gas Pipelines segment's regulated operations had revenues of $269.4 million, net margin of $201.4 million and operating income of $211.0 million, including $113.9 million from a gain on sale of assets.

(b) - All of our Natural Gas Liquids Pipelines segment's operations are regulated.

M. UNCONSOLIDATED AFFILIATES

Investments in Unconsolidated Affiliates - The following table sets forth our investments in unconsolidated affiliates for the periods indicated.

	Net Ownership Interest	December 31, 2008	December 31, 2007
		(Thousands of dollars)	
Northern Border Pipeline	50%	**$ 392,601**	$ 418,982
Bighorn Gas Gathering	49%	**97,289**	97,716
Fort Union Gas Gathering	37%	**108,642**	85,197
Lost Creek Gathering Company (a)	35%	**77,773**	75,612
Other	Various	**79,187**	78,753
Investments in unconsolidated affiliates		**$ 755,492** (b)	$ 756,260 (b)

(a) - We are entitled to receive an incentive allocation of earnings from third-party gathering services revenue recognized by Lost Creek Gathering Company. As a result of the incentive, our share of Lost Creek Gathering Company's income exceeds our 35 percent ownership interest.

(b) - Equity method goodwill (Note E) was $185.6 million at December 31, 2008 and 2007.

Equity Earnings from Investments - The following table sets forth our equity earnings from investments for the periods indicated.

	Years Ended December 31, 2008	2007	2006
		(Thousands of dollars)	
Northern Border Pipeline (a)	**$ 65,912**	$ 62,008	$ 72,393
Bighorn Gas Gathering	**8,195**	7,416	8,223
Fort Union Gas Gathering	**14,172**	9,681	9,030
Lost Creek Gathering Company	**5,365**	4,790	5,363
Other	**7,788**	6,013	874
Equity earnings from investments	**$ 101,432**	$ 89,908	$ 95,883

(a) - Beginning January 1, 2006, our interest in Northern Border Pipeline is accounted for as an investment under the equity method (Note B). For the first three months of 2006, we included 70 percent of Northern Border Pipeline's income in equity earnings from investments. After the sale of a 20 percent interest in Northern Border Pipeline in April 2006, we included 50 percent of Northern Border Pipeline's income in equity earnings from investments.

Unconsolidated Affiliates Financial Information - Summarized combined financial information of our unconsolidated affiliates is presented below.

	December 31, 2008	2007
	(Thousands of dollars)	
Balance Sheet		
Current assets	**$ 106,833**	$ 102,805
Property, plant and equipment, net	**$ 1,777,350**	$ 1,724,330
Other noncurrent assets	**$ 27,547**	$ 25,882
Current liabilities	**$ 279,996**	$ 79,593
Long-term debt	**$ 543,894**	$ 717,301
Other noncurrent liabilities	**$ 14,360**	$ 10,278
Accumulated other comprehensive income (loss)	**$ (5,708)**	$ (2,441)
Owners' equity	**$ 1,079,188**	$ 1,048,286

	Years Ended December 31,		
	2008	**2007**	**2006**
	(Thousands of dollars)		
Income Statement			
Operating revenue	**$ 415,552**	$ 404,399	$ 386,448
Operating expenses	**$ 179,380**	$ 172,997	$ 159,452
Net income	**$ 209,915**	$ 184,434	$ 183,732
Distributions paid to us	**$ 118,010**	$ 103,785	$ 123,427

N. NET INCOME PER UNIT

Net income per unit is computed by dividing net income, after deducting the general partner's allocation, by the weighted-average number of outstanding common units. The general partner owns the entire 2 percent interest in us and also owns incentive distribution rights that provide for an increasing proportion of cash distributions from the partnership as the distributions made to limited partners increase above specified levels. For purposes of our calculation of net income per unit, net income is generally allocated to the general partner as follows: (i) an amount based upon the 2 percent general partner interest in net income and (ii) the amount of the general partner's incentive distribution rights based on the total cash distributions declared for the period. The amount of incentive distributions allocated to our general partners totaled $76.0 million, $50.6 million and $31.6 million for 2008, 2007 and 2006, respectively. Distributions paid to our general partner and shown on our Consolidated Statements of Changes in Partners' Equity and Comprehensive Income of $78.9 million in 2008, $54.7 million in 2007, and $28.4 million in 2006, included incentive distributions of $69.9 million, $47.1 million and $23.1 million in 2008, 2007 and 2006, respectively.

Gains resulting from interim capital transactions, as defined in our Partnership Agreement, are generally not subject to distribution; however, our Partnership Agreement provides that if such distributions were made, the incentive distribution rights would not apply.

As discussed in Note B, we completed the ONEOK Transactions during the second quarter of 2006; however, for accounting purposes, the transactions were accounted for retroactive to January 1, 2006. Net income from the ONEOK Energy Assets prior to the April 2006 acquisition was approximately $35.8 million and has been reflected in our earnings for 2006. For purposes of our calculation of 2006 income per unit, these pre-acquisition earnings were allocated to the general partner, as they retained the related cash flow for that period.

O. RELATED-PARTY TRANSACTIONS

Intersegment and affiliate sales are recorded on the same basis as sales to unaffiliated customers. Our Natural Gas Gathering and Processing segment sells natural gas to ONEOK and its subsidiaries. A portion of our Natural Gas Pipelines segment's revenues are from ONEOK and its subsidiaries that utilize both transportation and storage services. Additionally, our Natural Gas Gathering and Processing segment and Natural Gas Liquids Gathering and Fractionation segment purchase a portion of the natural gas used in their operations from ONEOK and its subsidiaries.

As part of the ONEOK Transactions, we have certain contractual rights to the Bushton Plant that is leased by OBPI. Our Processing and Services Agreement with ONEOK and OBPI sets out the terms by which OBPI provides services at the Bushton Plant through 2012. We have contracted for all of the capacity of the Bushton Plant from OBPI. In exchange, we pay OBPI for all direct costs and expenses of the Bushton Plant, including reimbursement of a portion of OBPI's obligations under equipment leases covering the Bushton Plant.

In April 2006, we entered into a Services Agreement with ONEOK, ONEOK Partners GP and NBP Services (the Services Agreement) that replaced the Administrative Services Agreement between us and NBP Services. Under the Services Agreement, our operations and the operations of ONEOK and its affiliates can combine or share certain common services in order to operate more efficiently and cost effectively. Under the Services Agreement, ONEOK provides to us similar services that it provides to its affiliates, including those services required to be provided pursuant to our Partnership Agreement. ONEOK Partners GP operates our interstate natural gas pipeline assets according to each pipeline's operating agreement. ONEOK Partners GP may purchase services from ONEOK and its affiliates pursuant to the terms of the Services Agreement. ONEOK Partners GP has no employees and utilizes the services of ONEOK and ONEOK Services Company to fulfill its responsibilities.

ONEOK and its affiliates provide a variety of services to us under the Services Agreement, including cash management and financial services, employee benefits provided through ONEOK's benefit plans, administrative services, insurance and office space leased in ONEOK's headquarters building and other field locations. Where costs are specifically incurred on behalf of one of our affiliates, the costs are billed directly to us by ONEOK. In other situations, the costs may be allocated to us through a variety of methods, depending upon the nature of the expense and activities. For example, a service that applies equally to all employees is allocated based upon the number of employees. However, an expense benefiting the consolidated company but having no direct basis for allocation is allocated by the modified Distrigas method, a method using a combination of ratios that include gross plant and investment, earnings before interest and taxes and payroll expense. All costs directly charged or allocated to us are included in our Consolidated Statements of Income.

An affiliate of ONEOK enters into all commodity derivative contracts at the direction of and on behalf of our Natural Gas Gathering and Processing segment. We have an indemnification agreement with ONEOK Energy Services Company, L.P. (OES) that indemnifies and holds OES harmless from any liability OES may incur solely as a result of entering into financial hedges on our behalf. See Note D for a discussion of our derivative instruments and hedging activities.

The following table sets forth the transactions with related parties for the periods indicated.

	Years Ended December 31, 2008	2007	2006
	(Thousands of dollars)		
Revenues	**$ 744,886**	$ 626,764	$ 595,702
Expenses			
Cost of sales and fuel	**$ 107,983**	$ 89,792	$ 177,367
Administrative and general expenses	**191,798**	171,741	175,270
Interest expense	**-**	-	21,372
Total expenses	**$ 299,781**	$ 261,533	$ 374,009

In addition, concurrent with our sale of common units to the public, we sold 5.4 million common units to ONEOK in March 2008 in a private placement, generating proceeds of approximately $303.2 million. ONEOK Partners GP also made additional general partner contributions to us in March and April 2008. See Note G for additional information.

P. QUARTERLY FINANCIAL DATA (UNAUDITED)

Year Ended December 31, 2008	**First Quarter**	**Second Quarter**	**Third Quarter**	**Fourth Quarter**
	(Thousands of dollars, except per unit amounts)			
Revenues	**$ 2,059,035**	**$ 2,143,892**	**$ 2,241,107**	**$ 1,276,172**
Net margin	**$ 268,525**	**$ 280,933**	**$ 325,400**	**$ 265,801**
Operating income	**$ 150,532**	**$ 163,739**	**$ 197,526**	**$ 133,013**
Net income	**$ 145,018**	**$ 154,521**	**$ 203,872**	**$ 122,205**
Limited partners' per unit net income	**$ 1.48**	**$ 1.46**	**$ 1.97**	**$ 1.09**

Year Ended December 31, 2007	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(Thousands of dollars, except per unit amounts)			
Revenues	$ 1,168,674	$ 1,375,314	$ 1,410,257	$ 1,877,313
Net margin	$ 205,370	$ 217,570	$ 213,884	$ 259,069
Operating income	$ 104,376	$ 107,558	$ 105,116	$ 129,733
Net income	$ 95,756	$ 94,619	$ 95,916	$ 121,456
Limited partners' per unit net income	$ 1.00	$ 0.97	$ 0.98	$ 1.27

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

We have established disclosure controls and procedures to ensure that information required to be disclosed by us, including our consolidated entities, in the reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported, within the time periods specified in the SEC's rules and forms. Under the supervision and with the participation of senior management, including the Chief Executive Officer ("Principal Executive Officer") and the Chief Financial Officer ("Principal Financial Officer") of ONEOK Partners GP, our general partner, we evaluated our disclosure controls and procedures, as such term is defined under Rule 13a-15(e) promulgated under the Exchange Act. Based on this evaluation, the Principal Executive Officer and the Principal Financial Officer concluded that our disclosure controls and procedures were effective as of December 31, 2008.

Management's Report on Internal Control Over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Under the supervision and with the participation of our management, including our Principal Executive Officer and Principal Financial Officer, we evaluated the effectiveness of our internal control over financial reporting based on the framework in *Internal Control-Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Because of inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate. Based on our evaluation under that framework and applicable SEC rules, our management concluded that our internal control over financial reporting was effective as of December 31, 2008.

Our internal control over financial reporting as of December 31, 2008, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report that is included herein (Item 8).

Changes in Internal Controls Over Financial Reporting

We have made no changes in our internal controls over financial reporting (as defined in Rule 13a-15(f) and 15d-15(f) under the Exchange Act) during the quarter ended December 31, 2008, that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

ITEM 9B. OTHER INFORMATION

Not applicable.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Partnership Board of Directors and Audit Committee

We are managed under the direction of the Board of Directors of our sole general partner, ONEOK Partners GP, which consists of six members designated by ONEOK, the parent corporation of our general partner. We refer to the Board of Directors of ONEOK Partners GP as our Board of Directors. Because we are a limited partnership and meet the definition of a "controlled company" under the listing standards of the NYSE, certain listing standards of the NYSE are not applicable to us. Accordingly, Section 303A.01 of the NYSE Listed Company Manual, which would require that the Board of Directors of our general partner be comprised of a majority of independent directors, and Sections 303A.04 and 303A.05 of the NYSE Listed Company Manual, which would require that the Board of Directors of our general partner maintain a nominating committee and a compensation committee, each consisting entirely of independent directors, are not applicable to us. However, our Board of Directors has affirmatively determined that three members of our Board of Directors, Gary N. Petersen, Gerald B. Smith and Gil J. Van Lunsen, have no material relationship with us and are "independent" under our Governance Guidelines and the listing standards of the NYSE.

Our Board of Directors has appointed an Audit Committee consisting of the three members of our Board of Directors who are independent under our Governance Guidelines and the listing standards of the NYSE. The Audit Committee has oversight responsibility with respect to the integrity of our financial statements, the performance of our internal audit function, the independent auditor's qualifications and independence and our compliance with legal and regulatory requirements. The

Audit Committee directly appoints, retains, evaluates and may terminate our independent auditor. The Audit Committee reviews our annual and quarterly financial statements. The Audit Committee also has the authority to review specific matters that may present a conflict of interest in order to determine if the resolution of such conflict proposed by our Board of Directors is "fair and reasonable" to our unitholders and, in making any such determination, the Audit Committee has the authority to engage advisors to assist it in carrying out its duties. The Audit Committee has all other responsibilities required by the applicable NYSE listing standards and applicable SEC rules. The Board of Directors of our general partner has adopted a written charter for our Audit Committee which is available on and may be printed from our Web site at www.oneokpartners.com and is also available from the corporate secretary of our general partner.

The members of our Board of Directors and Audit Committee are not elected by unitholders. Accordingly, we do not have a procedure by which security holders may recommend nominees to our Board of Directors or Audit Committee. The persons designated as our executive officers serve in that capacity at the discretion of our Board of Directors.

Directors and Executive Officers

The following table sets forth the members of our Board of Directors and Audit Committee and the executive officers of our general partner. There are no family relationships between any of our executive officers or members of the Board of Directors and the Audit Committee. Some of these individuals are also officers of certain of our subsidiaries and affiliates.

Name	Age	Position
John W. Gibson	56	Chairman of the Board and Chief Executive Officer
James C. Kneale	57	President and Chief Operating Officer, Member, Board of Directors
Curtis L. Dinan	41	Executive Vice President, Chief Financial Officer and Treasurer, Member, Board of Directors
John R. Barker	61	Executive Vice President, General Counsel and Secretary
Caron A. Lawhorn	47	Senior Vice President and Chief Accounting Officer
Gary N. Petersen	57	Member, Board of Directors and Audit Committee
Gerald B. Smith	58	Member, Board of Directors and Chairman, Audit Committee
Gil J. Van Lunsen	66	Member, Board of Directors and Audit Committee

John W. Gibson became our chief executive officer effective January 1, 2007, and chairman of our Board of Directors on October 16, 2007. He served as our president and chief operating officer from May through December 2006. From 2005 until May 2006, he was president of ONEOK Energy companies, which included ONEOK's gathering and processing, natural gas liquids, pipelines and storage and energy services business segments, some of which were acquired by us in April 2006. Prior to that, he was president, Energy, from 2000 to 2005 for ONEOK.

James C. Kneale became our president and chief operating officer effective May 15, 2008. He was elected to our Board of Directors on October 1, 2006. He has served as president and chief operating officer of ONEOK since January 1, 2007. He served as our executive vice president and chief financial officer from May through December 2006. From 1999 to 2000, he was vice president, treasurer and chief financial officer and from 2001 to 2004, senior vice president, treasurer and chief financial officer for ONEOK. From 2005 through May 2006, he was executive vice president, finance and administration and chief financial officer for ONEOK.

Curtis L. Dinan became our executive vice president, chief financial officer and treasurer effective May 15, 2008. Mr. Dinan served as senior vice president, chief financial officer and treasurer from January 1, 2007, to May 15, 2008. He was elected to our Board of Directors on October 16, 2007. Mr. Dinan is a member of both the Management and Audit Committees of Northern Border Pipeline. Mr. Dinan is also the senior vice president, chief financial officer and treasurer of ONEOK. Mr. Dinan served as senior vice president and chief accounting officer of ONEOK from August 2004 through December 2006, and served as vice president and chief accounting officer of ONEOK from February 2004 to August 2004. Prior to joining ONEOK in February 2004, Mr. Dinan served as an assurance and business advisory partner at Grant Thornton, LLP from 2002 to 2004.

John R. Barker became our executive vice president, general counsel and secretary in May 2006. Mr. Barker is also senior vice president, general counsel and assistant secretary for ONEOK, having been appointed to that position in 2004. From 1994 to 2004, he was a stockholder, president and director of GableGotwals, a law firm located in Tulsa, Oklahoma, which provides legal services to us and to ONEOK.

Caron A. Lawhorn was named senior vice president and chief accounting officer on January 15, 2008. Ms. Lawhorn is Chair of the Audit Committee of Northern Border Pipeline. Ms. Lawhorn has served as senior vice president and chief accounting officer for ONEOK since January 1, 2007. Prior to her current position, Ms. Lawhorn served ONEOK as senior vice president of financial services and treasurer from January 2005 to January 2007, vice president and controller from August 2004 to January 2005, vice president of audit and risk control from May 2003 to August 2004, and manager of audit services from September 1998 to May 2003.

Gary N. Petersen was appointed to the Audit Committee in 2002. Since 1998, he has provided consulting services related to strategic and financial planning. Additionally, he is president of Endres Processing LLC. From 1977 to 1998, Mr. Petersen was employed by Reliant Energy-Minnegasco, and served as president and chief operating officer of Reliant Energy-Minnegasco from 1991 to 1998. Prior to his employment at Minnegasco he was a senior auditor with Arthur Andersen. He currently serves on the boards of the YMCA of Metropolitan Minneapolis and the Dunwoody College of Technology.

Gerald B. Smith was appointed to the Audit Committee in 1994. He is founder, chairman and chief executive officer of Smith, Graham & Company Investment Advisors, a global investment management firm. He is a member of the board of directors of the Charles Schwab Family of Funds where he serves as chairman of the investment oversight committee. He also serves as lead independent director and deputy chairman of Cooper Industries. He is a former director of the Fund Management Board of Robeco Group, Rorento N.V. (Netherlands).

Gil J. Van Lunsen was appointed to the Audit Committee in March 2005. Prior to his retirement in 2000, Mr. Van Lunsen was a managing partner of KPMG LLP at the firm's Tulsa, Oklahoma office. He began his career with KPMG LLP in 1968. He is currently a director and audit committee chairman of Array Biopharma in Boulder, Colorado.

Director Compensation

Compensation for our non-management directors for the year ended December 31, 2008, consisted of an annual cash retainer of $65,000 and meeting fees of $1,000 for each Audit Committee meeting attended in person or $500 for each Audit Committee meeting attended by telephone. In addition, the chair of our Audit Committee received an additional annual cash fee of $15,000 and each other member of the Audit Committee received an additional cash fee of $10,000. During 2008, the Chair of the Audit Committee received an additional $45,000 and the other two members of the Audit Committee each received an additional $30,000 for their services in determining the fairness of the terms and conditions of the Partnership's sale, in a private placement, of additional common units to ONEOK in March 2008. Non-management directors are reimbursed for their expenses related to their attendance at Board of Director and Audit Committee meetings. A director who is also an officer or employee of ONEOK Partners GP or ONEOK receives no compensation for his or her service as a director.

The following table sets forth the compensation paid to our non-management directors in 2008.

2008 DIRECTOR COMPENSATION

Name	Fees Earned or Paid in Cash ($)	Stock Awards ($)	Option Awards ($)	Non Equity Incentive Plan Compensation ($)	Change in Pension Value and Nonqualified Deferred Compensation Earnings ($)	All Other Compensation ($)	Total ($)
Gary N. Petersen	110,000	-	-	-	-	-	110,000
Gerald B. Smith	130,000	-	-	-	-	-	130,000
Gil J. Van Lunsen	110,000	-	-	-	-	-	110,000

Compensation Committee Interlocks and Insider Participation

We do not have a compensation committee. During 2008, the compensation of our named executive officers was determined by ONEOK's Executive Compensation Committee, which consists of independent members of the ONEOK Board of Directors. No member of ONEOK's Executive Compensation Committee is, or was formerly, an officer, director or employee of ONEOK Partners or any if its subsidiaries.

Governance Matters

Audit Committee Independence - Our Board of Directors has appointed a standing Audit Committee. Our guidelines for determining the independence of members of the Audit Committee are included in our Governance Guidelines and provide that members of the Audit Committee shall at all times qualify as independent under the listing standards of the NYSE and the applicable rules of the SEC and other applicable laws. At least annually, the Board of Directors reviews the relationships of each Audit Committee member with us to affirmatively determine the independence of each member. In February 2009, our Board of Directors affirmatively determined that Messrs. Petersen, Smith, and Van Lunsen meet the standards for independence set forth in the Governance Guidelines and are therefore independent.

Audit Committee Financial Experts - Our Board of Directors annually reviews the financial expertise of the members of our Audit Committee. In February 2009, our Board of Directors determined that Messrs. Petersen, Smith, and Van Lunsen are each "audit committee financial experts," as defined by the rules of the SEC.

Executive Sessions of Board and Audit Committee - Our Board of Directors has documented its governance practices in our Governance Guidelines. The Board of Directors of our general partner holds regular executive sessions in which non-management board members meet without any members of management present. The chairman of our Audit Committee, Mr. Smith, presides at regular sessions of the non-management members of our Board of Directors. Meetings of the non-management board and committee members are scheduled in connection with each in-person meeting of our Board of Directors and Audit Committee.

Service on Other Audit Committees - Mr. Van Lunsen serves on the audit committee of one other public company. The Board of Directors has determined that Mr. Van Lunsen's service on this other audit committee does not impair his ability to effectively serve on our Audit Committee.

Section 16(a) Beneficial Ownership Reporting Compliance - Section 16(a) of the Exchange Act requires executive officers, members of the Board of Directors and persons who own more than 10 percent of our common units to file reports of ownership and changes in ownership with the SEC and the NYSE and to furnish us with copies of all Section 16(a) forms they file. Based solely on our review of the copies of such forms received by us during and with respect to the 2008 fiscal year, or written representations from certain reporting persons that no Form 5s were required for those persons, we believe that during 2008 our reporting persons complied with all applicable filing requirements in a timely manner.

Governance Guidelines - The Board of Directors of our general partner has adopted Governance Guidelines that address several governance matters, including responsibilities of directors, the composition and responsibility of the Audit Committee, the conduct and frequency of board meetings, management succession, director access to management and outside advisors, director orientation and continuing education, and annual self-evaluation of the board. The Board of

Directors of our general partner recognizes that effective governance is an on-going process, and the Board of Directors will review our Governance Guidelines periodically as deemed necessary.

Code of Conduct - The Board of Directors of our general partner has adopted a Code of Business Conduct applicable to the members of our Board of Directors and Audit Committee, our officers and the employees of ONEOK, ONEOK Partners GP, and ONEOK Services Company, who provide services to us. This code sets out our requirements for compliance with legal and ethical standards in the conduct of our business, including general business principles, legal and ethical obligations, compliance policies for specific subjects, obtaining guidance, the reporting of compliance issues and discipline for violations of the code. We intend to promptly post on our Web site any amendments to, or waivers from (including any implicit waiver), any provision of our Code of Business Conduct in accordance with the applicable rules of the SEC and NYSE.

Web Access - We provide access through our Web site at www.oneokpartners.com to current information relating to our governance, including our Audit Committee Charter, our Code of Business Conduct, our Governance Guidelines and other matters impacting our governance principles. You may copy each of these documents from our Web site. You may also contact the office of the secretary of ONEOK Partners GP for printed copies of these documents free of charge. However, our Web site and any contents thereof are not incorporated by reference into this document.

Communications with Directors - Our Board of Directors believes that it is management's role to speak for us. Our Board of Directors also believes that any communications between members of the Board of Directors and interested parties, including unitholders, should be conducted with the knowledge of our chairman, president and chief executive officer. Interested parties, including unitholders, may contact one or more members of our Board of Directors, including non-management directors and non-management directors as a group, by writing to the director or directors in care of our corporate secretary at our principal executive offices. A communication received from an interested party or unitholder will be promptly forwarded to the director or directors to whom the communication is addressed. A copy of the communication will also be provided to our chief executive officer. We will not, however, forward sales or marketing materials or correspondence primarily commercial in nature or not clearly identified as interested party or unitholder correspondence.

ITEM 11. EXECUTIVE COMPENSATION

Compensation Discussion and Analysis

We do not directly employ any of the persons responsible for managing or operating our business. Instead, we are managed by our general partner, ONEOK Partners GP, the executive officers of which are employees of ONEOK. Certain officers of ONEOK Partners GP are deemed to be executive officers of us. We reimburse ONEOK for a portion of the total compensation paid to the executive officers of our general partner as provided by our Services Agreement with ONEOK. Please read "Certain Relationships and Related Person Transactions, and Director Independence-Services Agreement" for a description of the Services Agreement.

We do not have a compensation committee. The compensation of the officers of our general partner, who are deemed to be our officers, is set by the Executive Compensation Committee of the Board of Directors of ONEOK. A discussion of the objectives of, and other matters related to, ONEOK's compensation programs is included in ONEOK's compensation discussion and analysis and other disclosure related to ONEOK executive compensation contained in ONEOK's 2009 Proxy Statement as filed with the SEC (ONEOK 2009 Proxy Statement), a copy of which will be provided on, and may be copied from, ONEOK's Web site at www.oneok.com and is available free of charge from the secretary of ONEOK Partners GP upon request.

Under our Services Agreement with ONEOK, a portion of the compensation expense for our named executive officers is allocated by ONEOK to us. The compensation amounts shown in the following table represent that portion of the named executive officer's total compensation which is allocated to and paid by us under the Services Agreement.

The following table summarizes the compensation allocated to and paid by us in 2008 for our principal executive officer, principal financial officer and the three other most highly compensated executive officers of our general partner, ONEOK Partners GP, which we collectively refer to as the “named executive officers.”

Summary Compensation Table for 2008

Name and Principal Position	Year	Salary ($)	Stock Awards ($)(1)	Option Awards ($)(2)	Non-Equity Incentive Plan Compensation ($)(3)	Change in Pension Value and Nonqualified Deferred Compensation Earnings ($)(4)	All Other Compensation ($)(5)	Total ($)
John W. Gibson	2008	$ 442,365	$ 1,475,021	$ -	$ 457,379	$ 1,085,848	$ 63,181	$ 3,523,794
Chief Executive Officer	2007	$ 295,926	$ 930,262	$ -	$ 536,963	$ 505,584	$ 67,930	$ 2,336,665
	2006	$ 326,250	$ 794,237	$ 2,210	$ 491,250	$ 483,617	$ 43,448	$ 2,141,012
James C. Kneale	2008	$ 321,720	$ 1,151,085	$ -	$ 294,910	$ 598,479	$ 45,531	$ 2,411,725
President and Chief	2007	$ 248,196	$ 849,464	$ 64,309	$ 389,000	$ 420,392	$ 33,201	$ 2,004,562
Operating Officer	2006	$ 158,014	$ 441,904	$ 173,629	$ 227,032	$ 261,635	$ 21,875	$ 1,284,089
Curtis L. Dinan	2008	$ 214,480	$ 255,391	$ -	$ 147,455	$ 44,230	$ 25,094	$ 686,650
Executive Vice President,	2007	$ 143,190	$ 122,707	$ -	$ 181,374	$ 20,826	$ 13,667	$ 481,764
Chief Financial Officer	2006	$ 82,472	$ 108,166	$ -	$ 59,165	$ 11,340	$ 8,475	$ 269,618
and Treasurer								
Pierce H. Norton II	2008	$ 249,687	$ 209,706	$ -	$ 172,119	$ 37,002	$ 28,860	$ 697,374
Executive Vice President -	2007	$ 261,354	$ 199,306	$ -	$ 320,000	$ 39,437	$ 14,233	$ 834,330
Natural Gas	2006	$ 225,000	$ 165,200	$ -	$ 215,000	$ 35,725	$ 13,683	$ 654,608
Terry K. Spencer	2008	$ 249,687	$ 206,874	$ -	$ 179,291	$ 66,818	$ 29,720	$ 732,390
Executive Vice President -	2007	$ 261,354	$ 185,535	$ -	$ 340,000	$ 55,580	$ 14,233	$ 856,702
Natural Gas Liquids	2006	$ 215,000	$ 268,524	$ 536	$ 215,000	$ 42,024	$ 13,924	$ 755,008

(1) The amounts included in the table reflect the expense allocated to and recognized by us in 2006, 2007 and 2008 for restricted stock, restricted stock incentive units and performance units granted under the ONEOK Long-Term Incentive Plan (LTI Plan) and the ONEOK Equity Compensation Plan, the grant date fair value of which was determined in accordance with Financial Accounting Standards No. 123 (revised 2004), “Share-Based Payments,” (FAS Statement 123R). Material assumptions used in the calculation of the value of these equity grants are included in Note N to the ONEOK audited financial statements for the year ended December 31, 2008, included in the ONEOK 2008 Annual Report on Form 10-K filed with the SEC on February 24, 2009.

The fair value of restricted stock and restricted stock incentive units for the purposes of FAS Statement 123R was determined on the date of grant based on the closing stock price of ONEOK common stock on the grant date, adjusted for the current dividend yield. With respect to the performance units granted in 2006, 2007 and 2008, the grant date fair value for the purposes of FAS Statement 123R was determined using a valuation model that considers the market condition (total shareholder return), using assumptions developed from historical information of ONEOK and each of the referenced peer group companies.

The allocated portion of the 2006 FAS Statement 123R value for Mr. Dinan has been adjusted to reflect an increase of $5,651.27.

(2) No options were granted by ONEOK in 2007 or 2008. However, the remaining unamortized expense from restored options granted in 2006 was fully recognized as of May 2007. No options were granted in 2006, except for restored options granted in connection with the exercise of options granted under the LTI Plan. Effective January 1, 2007, the restorative feature of all outstanding ONEOK stock options was eliminated. The 2003 option grant vested on February 20, 2006. The amounts included in the table reflect our allocated portion of the grant date fair value of the 2003 grant and the restored options granted in 2006 as expensed in accordance with FAS Statement 123R. Material assumptions used in the calculation of the value of option grants are included in Note N to the ONEOK audited financial statements for the year ended December 31, 2008, included in the ONEOK 2008 Annual Report on Form 10-K filed with the SEC on February 24, 2009.

(3) Reflects the amounts allocated to and paid by us in 2006, 2007 and 2008 under the ONEOK annual officer incentive plan. The plan provides that ONEOK officers may receive annual cash incentive awards based on the performance and profitability of ONEOK, the performance of particular business units of ONEOK, and individual performance. The corporate and business unit criteria and individual performance criteria are established annually by the ONEOK Executive Compensation Committee of the ONEOK Board of Directors. The Committee also establishes annual target awards for each ONEOK officer. For a discussion of the performance criteria established by the ONEOK Executive Compensation Committee for awards under the ONEOK annual officer incentive plan, see “Components of Compensation - Annual Cash Compensation” in the ONEOK 2009 Proxy Statement.

(4) Reflects the portion of the aggregate current year change in pension values and above market earnings on nonqualified deferred compensation allocated to us for each named executive officer. For a discussion of the Retirement Plan for Employees of ONEOK,

Inc. and Subsidiaries, the ONEOK, Inc. 2005 Supplemental Executive Retirement Plan, and the ONEOK Nonqualified Deferred Compensation Plan, see the ONEOK 2009 Proxy Statement. The present value is based on the earliest age for which an unreduced benefit is available (age 62) and assumptions from the September 30, 2007 and 2006 and December 31, 2008, measurement dates for the ONEOK pension plan.

Due to the fact that in 2008 ONEOK changed its pension plan measurement date, for financial accounting purposes, from September 30 of each year to December 31, the allocated amounts included in the Summary Compensation Table with respect to the Retirement Plan for Employees of ONEOK, Inc. and Subsidiaries and the ONEOK, Inc. 2005 Supplemental Executive Retirement Plan are twelve-fifteenths of the allocated amounts that were earned over the 15-month period ending on December 31, 2008.

The allocated portion of the change in pension value and nonqualified deferred compensation earnings amounts for Messrs. Gibson, Kneale, Dinan, and Norton for 2006 and 2007 have been adjusted to include only the change in the pension value based on the present value using the RP2000 mortality tables projected to 2010 and exclude any ONEOK Nonqualified Deferred Compensation Plan earnings that were not above market earnings. For 2007, the allocated incremental change in net present value for Messrs. Gibson, Kneale, Dinan and Norton were $505,584, $420,392, $20,825 and $39,437, respectively. For 2006, the allocated incremental change in net present value for Messrs. Gibson, Kneale and Norton were $483,616, $261.634 and $35,725, respectively.

In the Summary Compensation Table for Fiscal 2008 above, only our allocated portion of the above-market earnings for 2006 and 2007 are included. For 2006 and 2007, these allocated amounts are $394 and $765 for Mr. Kneale. No other ONEOK named executive officers received above market earnings in 2006 and 2007. No ONEOK named executive officers received above market earnings in 2008. For additional information on the ONEOK Nonqualified Deferred Compensation Plan, see “Long-Term Compensation Plans-Nonqualified Deferred Compensation Plan” in the ONEOK 2009 Proxy Statement.

(5) Reflects the portion allocated to us of the amounts paid as ONEOK’s dollar for dollar match of contributions made by the named executive officer under both the ONEOK, Inc. Nonqualified Deferred Compensation Plan and the Thrift Plan for Employees of ONEOK, Inc. and Subsidiaries, as follows:

Name	Year	Match Under Nonqualified Deferred Compensation Plan (a)	Match Under Thrift Plan (b)
John W. Gibson	2008	$ 55,336	$ 7,400
	2007	$ 30,070	$ 6,444
	2006	$ 33,075	$ 9,900
James C. Kneale	2008	$ 38,124	$ 7,400
	2007	$ 26,347	$ 6,444
	2006	$ 16,455	$ 4,795
Curtis L. Dinan	2008	$ 17,695	$ 7,400
	2007	$ 6,873	$ 6,444
	2006	$ 3,550	$ 4,733
Pierce H. Norton II	2008	$ 18,963	$ 9,897
	2007	$ -	$ 13,500
	2006	$ -	$ 13,200
Terry K. Spencer	2008	$ 19,823	$ 9,897
	2007	$ -	$ 13,500
	2006	$ -	$ 13,200

(a) For additional information on the ONEOK, Inc. Employee Nonqualified Deferred Compensation Plan, see “Long-Term Compensation Plans - Nonqualified Deferred Compensation Plan” in the ONEOK 2009 Proxy.

(b) The Thrift Plan for Employees of ONEOK, Inc. and Subsidiaries is a tax qualified plan that covers all ONEOK employees. Employee contributions are discretionary. Subject to certain limits, ONEOK matches 100 percent of employee contributions to the plan up to a maximum of 6 percent.

In 2008, Messrs. Gibson and Kneale received tax gross ups with respect to income imputed to each of them under the Internal Revenue Code in connection with travel by their spouses on ONEOK’s aircraft, of which $455 and $8, respectively, were allocated to us.

The named executive officers did not receive perquisites or other personal benefits with an aggregate value of $10,000 or more in 2006, 2007 and 2008, except for Mr. Gibson with respect to whom we were allocated $31,006 of a country club membership fee in 2007.

Potential Post-Employment Payments and Payments upon a Change in Control

Payments Made Upon Any Termination - Regardless of the manner in which a named executive officer's employment terminates, he is entitled to receive amounts earned during his term of employment. Such amounts include:

- accrued but unpaid salary;
- amounts contributed under the Thrift Plan for Employees of ONEOK, Inc. and Subsidiaries and the ONEOK, Inc. Employee Nonqualified Deferred Compensation Plan; and
- amounts accrued and vested through the ONEOK retirement plan and supplemental executive retirement plan (SERP).

Payments Made Upon Retirement - In the event of the retirement of a named executive officer, in addition to the items identified above, such named executive officer will be entitled to:

- exercise rights applicable to retirees with respect to each outstanding and vested stock option granted under the ONEOK LTI Plan;
- receive a prorated portion of each outstanding performance unit granted under the ONEOK Equity Compensation Plan upon the completion of the performance period;
- receive a prorated portion of each outstanding restricted stock incentive unit granted under the ONEOK Equity Compensation Plan upon completion of the restricted period; and
- receive ONEOK health and life benefits for the retiree and qualifying dependents.

Payments Made Upon Death or Disability - In the event of the death or disability of a named executive officer, in addition to the benefits listed under the headings "Payments Made Upon Any Termination" and "Payments Made Upon Retirement" above, the named executive officer will receive applicable benefits under ONEOK's disability plan or payments under ONEOK's life insurance plan.

Payments Made Upon a Change in Control - Effective January 2005, ONEOK entered into amended and restated termination agreements with each of our named executive officers. Each termination agreement has an initial two-year term and is automatically extended in one-year increments after the expiration of the initial term unless ONEOK provides notice of non-renewal to the officer, or the officer provides notice of non-renewal to ONEOK, at least 90 days before the January 1 preceding any termination date of the agreement. Effective December 21, 2006, ONEOK entered into an amended and restated termination agreement with Mr. Gibson which provides for an initial term through January 1, 2008, and is thereafter automatically extended until either party gives written notice of its election to terminate the agreement 90 days following the date of the notice. If a "change in control" of ONEOK occurs, the term of each termination agreement will not expire for at least three years after the change in control. Relative to the overall value of the Partnership, we believe the potential benefits payable upon a change in control under these agreements are comparatively minor.

Under the termination agreements, all change in control benefits are "double trigger." Payments and benefits under these agreements are payable if the officer's employment is terminated by ONEOK without "just cause" or by the officer for "good reason" at any time during the three years following a change in control. In general, severance payments and benefits include a lump sum payment in an amount equal to the sum of (1) for Messrs. Gibson and Kneale three times, and for Messrs. Dinan, Norton and Spencer two times, the aggregate of the officer's annual salary as then in effect, plus the greater of either the amount of the officer's short-term incentive payment received in the prior year or the officer's target short-term incentive payment for the then current period, and (2) a prorated portion of the officer's target short-term incentive compensation. Messrs. Gibson and Kneale would also be entitled to continuation of health and welfare benefits for 36 months and accelerated benefits under the ONEOK, Inc. 2005 Supplemental Executive Retirement Plan. Messrs. Dinan, Norton and Spencer would be entitled to continuation of health and welfare benefits for 24 months. In the case of Messrs. Gibson and Kneale, ONEOK will make gross up payments to them to cover any excise taxes due if any portion of their severance payments and other benefits due constitute "excess parachute payments" under applicable tax law. For Messrs. Dinan, Norton and Spencer, severance payments will be reduced if the net after-tax benefit to such named executive officer exceeds the net after-tax benefit if such reduction were not made. ONEOK will make gross up payments to such officers only if the severance payments, as reduced, are subsequently deemed to constitute excess parachute payments.

For the purposes of these agreements, a "change in control" generally means any of the following events:

- an acquisition of ONEOK voting securities by any person that results in the person having beneficial ownership of 20 percent or more of the combined voting power of ONEOK's outstanding voting securities, other than an acquisition directly from ONEOK;
- the current members of the ONEOK Board, and any new director approved by a vote of at least two-thirds of the ONEOK Board, cease for any reason to constitute at least a majority of the ONEOK Board, other than in connection with an actual or threatened proxy contest (collectively, the "Incumbent Board");

- a merger, consolidation or reorganization with ONEOK or in which ONEOK issues securities, unless (a) ONEOK's shareholders immediately before the transaction, as a result of the transaction, own, directly or indirectly, at least 50 percent of the combined voting power of the voting securities of ONEOK resulting from the transaction, (b) the members of the ONEOK Incumbent Board after the execution of the transaction agreement constitute at least a majority of the members of the Board of ONEOK resulting from the transaction, or (c) no person other than persons who, immediately before the transaction owned 30 percent or more of ONEOK's outstanding voting securities, has beneficial ownership of 30 percent or more of the outstanding voting securities of ONEOK resulting from the transaction; or
- ONEOK completes the liquidation or dissolution or the sale or other disposition of all or substantially all of ONEOK's assets.

For the purposes of these agreements, "just cause" means the executive's conviction in a court of law of a felony, or any crime or offense in a court of law of a felony, or any crime or offense involving misuse or misappropriation of money or property; the executive's violation of any covenant, agreement or obligation not to disclose confidential information regarding our business; any violation by the executive of any covenant not to compete with us; any act of dishonesty by the executive which adversely affects our business; any willful or intentional act of the executive which adversely affects our business, or reflects unfavorably on our reputation; the executive's use of alcohol or drugs which interferes with the executive's performance of duties as our employee; or the executive's failure or refusal to perform the specific directives of our Board of Directors or its officers, which directives are consistent with the scope and nature of the executive's duties and responsibilities. The existence and occurrence of all of such causes are to be determined by us, in our sole discretion, provided, that nothing contained in these provisions of these agreements are to be deemed to interfere in any way with our right to terminate the executive's employment at any time without cause.

For the purposes of these agreements, "good reason" means a demotion, loss of title or significant authority or responsibility of the executive with respect to the executive's employment with us from those in effect on the date of a change in control, a reduction of salary of the executive from that received from us immediately prior to the date of a change in control, a reduction in short-term and/or long-term incentive targets from those applicable to the executive immediately prior to the date of a change in control, the relocation of our principal executive offices to a location outside the metropolitan area of Tulsa, Oklahoma, or our requiring a relocation of principal place of employment of the executive, or the failure of a successor corporation to explicitly assume these termination agreements.

Potential Post-Employment Payment Tables - The following tables reflect estimates of our allocated portion of the amount of incremental compensation due to each named executive officer in the event of such executive's termination of employment upon death, disability or retirement, termination of employment without cause or termination of employment without cause or with good reason within three years following a change in control. The amounts shown assume that such termination was effective as of December 31, 2008, and are estimates of the allocated amounts which would be paid out to the executives upon such termination. The actual amounts to be paid out can only be determined at the time of such executive's separation from the Partnership.

In addition to the amounts set forth in the following tables, in the event of termination of employment for any of the reasons set forth in the tables, Messrs. Gibson and Kneale hold outstanding exercisable options with an allocated value of $189,857 and $82,039, respectively, as of December 31, 2008.

John W. Gibson

Benefit		Termination Upon Death, Disability, or Retirement		Termination Without Cause		Qualifying Termination Following a Change in Control
Cash Severance	$	-	$	-	$	3,277,755
Equity						
Restricted Stock/Units	$	1,250,888	$	1,250,888	$	2,936,868
Performance Shares/Units	$	277,598	$	-	$	1,558,172
Total	$	1,528,486	$	1,250,888	$	4,495,040
Other Benefits						
Health & Welfare	$	-	$	-	$	11,379
Tax Gross-Ups	$	-	$	-	$	3,501,021
Total	$	-	$	-	$	3,512,400
Total	$	1,528,486	$	1,250,888	$	11,285,195

James C. Kneale

Benefit		Termination Upon Death, Disability, or Retirement		Termination Without Cause		Qualifying Termination Following a Change in Control
Cash Severance	$	-	$	-	$	2,378,474
Equity						
Restricted Stock/Units	$	1,032,889	$	1,032,889	$	1,174,747
Performance Shares/Units	$	277,598	$	-	$	987,114
Total	$	1,310,487	$	1,032,889	$	2,161,861
Other Benefits						
Health & Welfare	$	-	$	-	$	11,379
Tax Gross-Ups	$	-	$	-	$	2,043,655
Total	$	-	$	-	$	2,055,034
Total	$	1,310,487	$	1,032,889	$	6,595,369

Curtis L. Dinan

Benefit		Termination Upon Death, Disability, or Retirement		Termination Without Cause		Qualifying Termination Following a Change in Control
Cash Severance	$	-	$	-	$	874,068
Equity						
Restricted Stock/Units	$	82,667	$	82,667	$	137,054
Performance Shares/Units	$	63,451	$	-	$	432,372
Total	$	146,118	$	82,667	$	569,426
Other Benefits						
Health & Welfare	$	-	$	-	$	11,047
Tax Gross-Ups	$	-	$	-	$	-
Total	$	-	$	-	$	11,047
Total	$	146,118	$	82,667	$	1,454,541

Pierce H. Norton II

Benefit	Termination Upon Death, Disability, or Retirement		Termination Without Cause		Qualifying Termination Following a Change in Control	
Cash Severance	$	-	$	-	$	751,576
Equity						
Restricted Stock/Units	$	71,201	$	71,201	$	99,527
Performance Shares/Units	$	71,382	$	-	$	257,792
Total	$	142,583	$	71,201	$	357,319
Other Benefits						
Health & Welfare	$	-	$	-	$	11,047
Tax Gross-Ups	$	-	$	-	$	-
Total	$	-	$	-	$	11,047
Total	$	142,583	$	71,201	$	1,119,942

Terry K. Spencer

Benefit	Termination Upon Death, Disability, or Retirement		Termination Without Cause		Qualifying Termination Following a Change in Control	
Cash Severance	$	-	$	-	$	773,988
Equity						
Restricted Stock/Units	$	71,201	$	71,201	$	99,527
Performance Shares/Units	$	71,382	$	-	$	257,792
Total	$	142,583	$	71,201	$	357,319
Other Benefits						
Health & Welfare	$	-	$	-	$	11,047
Tax Gross-Ups	$	-	$	-	$	-
Total	$	-	$	-	$	11,047
Total	$	142,583	$	71,201	$	1,142,354

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

Beneficial Ownership

The following table sets forth the beneficial ownership of our common units and the common stock of ONEOK, the parent company of our general partner, as of February 1, 2009, by each named executive officer, each member of our Board of Directors of our general partner, and all executive officers and members of our Board of Directors as a group. Other than as set forth below, no person is known to us to beneficially own more than five percent of our common units.

Name and Address of Beneficial Owner (1)	Common Units	Percent of Common Units	Class B Units	Percent of Class B Units	Percent of All Units	ONEOK Shares (2)	Percent of ONEOK Shares
John W. Gibson	10,000	*	-	-	*	177,929 (3)	*
James C. Kneale	-	-	-	-	-	248,705 (4)	*
Curtis L. Dinan	2000	-	-	-	-	22,162	*
Pierce H. Norton II	6,778	*	-	-	*	11,819	*
Terry K. Spencer	-	-	-	-	-	18,478 (5)	*
Gary N. Petersen	8,392	*	-	-	*	-	-
Gerald B. Smith	-	-	-	-	-	-	-
Gil J. Van Lunsen	500	*	-	-	*	-	-
All directors and executive officers as a group.	27,670	*	-	-	*	479,093	*
ONEOK, Inc. and affiliates	5,900,000	10.8	36,494,126	100	46.6	-	-

* Less than 1 percent

(1) The business address for each of the beneficial owners is c/o ONEOK Partners, L.P., 100 West Fifth Street, Tulsa, Oklahoma 74103-4298.

(2) Includes shares of ONEOK common stock held by members of the family of the director or executive officer for which the director or executive officer has sole or shared voting or investment power, shares of common stock held in ONEOK's Direct Stock Purchase and Dividend Reinvestment Plan, Thrift Plan for Employees of ONEOK, Inc. and Subsidiaries and shares that the board member or executive officer has the right to acquire within 60 days of February 1, 2009, upon exercise of stock options granted under the LTI Plan.

(3) Includes options for 59,948 shares exercisable within 60 days of February 1, 2009.

(4) Includes options for 59,932 shares exercisable within 60 days of February 1, 2009.

(5) Includes options for 5,500 shares exercisable within 60 days of February 1, 2009.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

Related-Person Transactions

The Board of Directors of our general partner recognizes that transactions between us and related persons (ONEOK and its subsidiaries and affiliates and their and our executive officers, directors, and their immediate family members) can present potential or actual conflicts of interest and create the appearance our decisions are based on considerations other than our best interests and our unitholders. Accordingly, as a general matter, it is our preference to avoid related person transactions. Nevertheless, we recognize that there are situations where related person transactions may be in, or may not be inconsistent with, our and our unitholders' best interests including, but not limited to, situations where we acquire products or services from related persons on an arm's length basis on terms comparable to those provided to unrelated third parties.

In the event we enter into a transaction in which ONEOK or its subsidiaries or affiliates or their or our executive officers (other than an employment relationship), directors, or a members of their immediate family have a direct or indirect material interest, our general partner or any member of the Board of Directors of our general partner may, but are not obligated to, present such transaction to our Audit Committee for review, to determine if the transaction creates a conflict of interest and is otherwise fair to us. We require each executive officer and director of our general partner to annually provide us written disclosure of any transaction between the officer or director and us. The Board of Directors of our general partner reviews this disclosure in connection with its annual review of the independence of our Audit Committee. These procedures are not in writing but are evidenced through the meeting agendas of the Board of Directors of our general partner and our Audit Committee.

The ONEOK Transactions

For a description of the ONEOK Transactions, see Note B of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K at page 76.

Relationship with ONEOK

ONEOK owns our sole general partner, ONEOK Partners GP, and is able to elect members of our Board of Directors and our Audit Committee. Other relationships with ONEOK include the following.

Cash Distributions - ONEOK and its affiliates own all of the Class B units, 5,900,000 common units and the entire 2 percent general partner interest in us, which, together constituted a 47.7 percent ownership interest in us at December 31, 2008. For 2008, we declared total cash distributions to ONEOK of $266.1 million, which included $76.0 million related to its incentive distribution rights. Additional information about our cash distribution policy is included in Item 5, Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities.

Services Agreement - In April 2006, we entered into a Services Agreement with ONEOK, ONEOK Partners GP and NBP Services. Under the Services Agreement, our operations and the operations of ONEOK and its affiliates can combine or share certain common services in order to operate more efficiently and cost effectively. Under the Services Agreement, ONEOK will provide to us at least the type and amount of services that it provides to its affiliates, including those services required to be provided pursuant to our Partnership Agreement.

ONEOK and its affiliates provide a variety of services to us under the Services Agreement, including cash management and financing services, employee benefits provided through ONEOK's benefit plans, administrative services, insurance and office space leased in ONEOK's headquarters building and other field locations. Where costs are specifically incurred on behalf of one of our affiliates, the costs are billed directly to us by ONEOK. In other situations, the costs may be allocated to us through a variety of methods, depending upon the nature of the expense and activities. For example, a service that applies equally to all employees is allocated based upon the number of employees. However, an expense benefiting the consolidated company but which has no direct basis for allocation is allocated by the modified Distrigas method, a method using a combination of ratios that include gross plant and investment, operating income and wages. All costs directly charged or allocated to us are included in our Consolidated Statements of Income.

In 2008, the aggregate amount charged by ONEOK, NBP Services and their affiliates to us for their services was approximately $181.2 million.

Operating and Administrative Services Agreements - ONEOK Partners GP provides certain administrative, operating and management services to us and Midwestern Gas Transmission, Viking Gas Transmission, and Guardian Pipeline through operating agreements. We, along with Midwestern Gas Transmission, Viking Gas Transmission, and Guardian Pipeline are charged for the salaries, benefits and expenses of ONEOK Partners GP incurred in connection with these operating agreements.

Transportation Agreements - OES, a subsidiary of ONEOK, became an affiliate of Northern Border Pipeline in November 2004 in connection with ONEOK's purchase of ONEOK Partners GP. We do not operate Northern Border Pipeline, but we are a 50 percent owner in Northern Border Pipeline which owns the pipeline. In 2008, 1.4 percent of Northern Border Pipeline's design capacity was contracted on a firm basis with OES. Revenue from OES for 2008 was $5.0 million. As of January 31, 2009, 1.4 percent of Northern Border Pipeline's design capacity was contracted on a firm basis with OES for 2009.

Our Natural Gas Gathering and Processing segment sold $627.8 million of natural gas to ONEOK and its subsidiaries during 2008. Of our Natural Gas Pipelines segment's revenues, $117.1 million were from ONEOK and its subsidiaries during 2008 for both transportation and storage services.

Our Natural Gas Gathering and Processing segment and Natural Gas Liquids Gathering and Fractionation segment purchase a portion of the natural gas used in their operations from ONEOK and its subsidiaries. In 2008, the aggregate amount charged by ONEOK and its affiliates to us for their services was approximately $108 million.

Bushton Plant - As part of the ONEOK Transactions, we acquired contractual rights to the Bushton Plant that is leased by OBPI. Our Processing and Services Agreement with ONEOK and OBPI sets out the terms by which OBPI provides services at the Bushton Plant through 2012. We have contracted for all the capacity of the Bushton Plant from OBPI. In exchange for such services, we pay OBPI for all direct costs and expenses of operating the Bushton Plant, including reimbursement of a portion of OBPI's obligations under equipment leases covering the Bushton Plant. In 2008, the aggregate amount charged by ONEOK and its affiliates related to the Bushton Plant was approximately $10.6 million.

Derivative Contracts - An affiliate of ONEOK from time to time enters into commodity derivative contracts on behalf of our Natural Gas Gathering and Processing segment. We have an indemnification agreement with ONEOK Energy Services

Company, L.P. (OES) that indemnifies and holds OES harmless from any liability OES may incur solely as a result of entering into financial hedges on our behalf. See Note D of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K for a discussion of our derivative instruments and hedging activities.

Relationship with TransCanada

As part of the ONEOK Transactions, in April 2006 ONEOK acquired ONEOK NB, formerly known as Northwest Border Pipeline Company, an affiliate of TransCanada that held a 0.35 percent general partner interest in us. In 2006, we declared total cash distributions to TransCanada of $0.7 million, which included $0.5 million related to its incentive distribution rights. Additional information about our cash distribution policy is included in Item 5, Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities.

In addition, ONEOK Partners GP and TransCanada's affiliate entered into a transition services agreement for the transfer of the operator function from ONEOK Partners GP to the affiliate of TransCanada effective April 1, 2007. Northern Border Pipeline agreed to pay ONEOK Partners GP an amount up to $1.0 million per year for years 2007 through 2011, to reimburse ONEOK Partners GP for shared equipment and furnishings acquired by ONEOK Partners GP and used to support Northern Border Pipeline operations.

Conflicts of Interest

Our Board of Directors, whose members are designated by our general partner, ONEOK Partners GP, establishes our business policies.

Our general partner, which is a subsidiary of ONEOK, and its respective affiliates currently engage or may engage in the businesses in which we engage or in which we may engage in the future. As a result, conflicts of interest may arise between our general partner and its affiliates, and us. If such conflicts arise, the members of our Board of Directors generally have a fiduciary duty to resolve such conflicts in a manner that is in our best interest.

TC PipeLines (a 50 percent owner and operator of Northern Border Pipeline) and its affiliates are also engaged in interstate natural gas pipeline transportation in the United States separate from their interest in Northern Border Pipeline. As a result, conflicts also may arise between TransCanada and its affiliates or TC PipeLines and its affiliates, and Northern Border Pipeline. If such conflicts arise, the representatives on the Northern Border Management Committee generally have a fiduciary duty to resolve such conflicts in a manner that is in the best interest of Northern Border Pipeline.

Unless otherwise provided for in a partnership agreement, the laws of Delaware and Texas generally require a general partner of a partnership to adhere to fiduciary duty standards under which it owes its partners the highest duties of "good faith," fairness and loyalty. Similar rules apply to persons serving on our general partner's Board of Directors and the Northern Border Management Committee. Because of the competing interests identified above, our Partnership Agreement and the partnership agreement for Northern Border Pipeline contain provisions that modify certain of these fiduciary duties. For example:

- Our Partnership Agreement states that our general partner, its affiliates and their officers and directors will not be liable for damages to us, our limited partners or their assignees for errors of judgment or for any acts or omissions if the general partner and such other persons acted in "good faith;"
- Our Partnership Agreement allows our general partner and our Board of Directors to take into account the interests of other parties in addition to our interests in resolving conflicts of interest;
- Our Partnership Agreement provides that our general partner will not be in breach of its obligations under our Partnership Agreement or its duties to us or our unitholders if the resolution of a conflict is "fair and reasonable" to us. The latitude given in our Partnership Agreement in connection with resolving conflicts of interest may significantly limit the ability of a unitholder to challenge what might otherwise be a breach of fiduciary duty;
- Our Partnership Agreement provides that a purchaser of common units is deemed to have consented to certain conflicts of interest and actions of our general partner and its affiliates that might otherwise be prohibited and to have agreed that such conflicts of interest and actions do not constitute a breach by the general partner of any duty stated or implied by law or equity;
- The Audit Committee of our general partner will, at the request of the general partner or a member of our Board of Directors, review conflicts of interest that may arise between a general partner and its affiliates (or the member of our Board of Directors designated by it), and the unitholders or us. Any resolution of a conflict approved by the Audit Committee is conclusively deemed "fair and reasonable" to us; and

- The partnership agreement of Northern Border Pipeline relieves us and TC PipeLines, our affiliates, and transferees from any duty to offer business opportunities to Northern Border Pipeline, subject to specified exceptions.

We are required to indemnify the general partner, the members of its Board of Directors, and its affiliates and their respective officers, directors, employees, agents and trustees to the fullest extent permitted by law against liabilities, costs and expenses incurred by any such person who acted in “good faith” and in a manner reasonably believed to be in, or (in the case of a person other than our general partner) not opposed to, our best interests and with respect to any criminal proceedings, had no reasonable cause to believe the conduct was unlawful.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

Audit and Non-Audit Fees

Audit services provided by PricewaterhouseCoopers LLP during the 2008 and 2007 fiscal years included an audit of our consolidated financial statements, an audit of our internal control over financial reporting, audits of the financial statements of certain of our affiliates, review of our quarterly financial statements, review of debt and equity offerings and related consents and comfort letters, and professional services relating to tax compliance, tax planning, or tax advice.

The following table presents fees billed for audit services rendered by PricewaterhouseCoopers LLP for the audit of annual consolidated financial statements for the years ended December 31, 2008 and 2007, and fees billed for other services rendered by PricewaterhouseCoopers LLP during that period.

	2008	2007
Audit fees (1)	**$ 1,320,179**	$ 1,194,070
Audit-related fees	**-**	-
Tax fees (2)	**730,923**	950,342
All other fees (3)	**35,770**	750
Total	**$ 2,086,872**	$ 2,145,162

(1) Audit fees consisted of work performed in the audit of our financial statements and the audit of internal controls over financial reporting, fees for review of the interim unaudited financial statements included in our Quarterly Reports on Form 10-Q filed with the Securities and Exchange Commission, and fees for special procedures related to regulatory filings.
(2) Tax fees consisted of fees for tax compliance, tax planning, or tax services, including preparation of our K-1 statements.
(3) All other fees consisted of fees for professional education seminars.

Audit Committee Policy on Services Provided by Independent Auditor

Consistent with SEC and NYSE policies regarding auditor independence, the Audit Committee has responsibility for appointing, setting compensation, and overseeing the work for the independent auditor. In recognition of this responsibility, the Audit Committee has established a policy with respect to the pre-approval of audit and permissible non-audit services provided by the independent auditor.

Prior to engagement of PricewaterhouseCoopers LLP as our independent auditor for the 2009 audit, a plan was submitted to and approved by the Audit Committee setting forth the services expected to be rendered during 2009 for each of the following four categories for its approval:

(1) audit services comprised of work performed in the audit of our financial statements and to attest and report on management’s assessment of our internal controls over financial reporting, as well as work that only the independent auditor can reasonably be expected to provide, including quarterly review of our unaudited financial statements, comfort letters, statutory audits, attest services, consents and assistance with the review of documents filed with the SEC;
(2) audit related services comprised of assurance and related services that are traditionally performed by the independent auditor, including due diligence related to mergers and acquisitions, employee benefit plan audits and consultation regarding financial accounting and/or reporting standards;
(3) tax services comprised of tax compliance, tax planning, and tax advice; and
(4) all other permissible non-audit services, if any, that the Audit Committee believes are routine and recurring services that would not impair the independence of the auditor.

Audit fees are budgeted and the Audit Committee requires the independent auditor and management to report actual fees versus budgeted fees periodically during the year by category of service.

The Audit Committee may delegate pre-approval authority to one or more of its members. The member to whom such authority is delegated must report, for informational purposes only, any pre-approval decisions to the Audit Committee at its next scheduled meeting.

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

(2) Financial Statement Schedules

All schedules have been omitted because of the absence of conditions under which they are required.

(3) Exhibits

3.0 Not used.

3.1 Northern Border Partners, L.P. Certificate of Limited Partnership dated July 12, 1993, Certificate of Amendment dated February 16, 2001, and Certificate of Amendment dated May 20, 2003 (incorporated by reference to Exhibit 3.1 to Northern Border Partners, L.P.'s Form 10-K for the year ended December 31, 2004, filed on March 14, 2005 (File No. 1-12202)).

3.2 Certificate of Amendment to Certificate of Limited Partnership of Northern Border Partners, L.P. dated May 17, 2006 (incorporated by reference to Exhibit 3.1 to ONEOK Partners, L.P.'s Form 8-K filed on May 23, 2006 (File No. 1-12202)).

3.3 Third Amended and Restated Agreement of Limited Partnership of ONEOK Partners, L.P. dated as of September 15, 2006 (incorporated by reference to Exhibit 3.1 to ONEOK Partners, L.P.'s Form 8-K filed on September 19, 2006 (File No. 1-12202)).

3.4 Certificate of Formation of ONEOK Partners GP, L.L.C., as amended, dated as of May 15, 2006 (incorporated by reference to Exhibit 3.5 to ONEOK Partners, L.P.'s Form 10-Q for the period ended June 30, 2006, filed on August 4, 2006 (File No. 1-12202)).

3.5 Second Amended and Restated Limited Liability Company Agreement of ONEOK Partners GP, L.L.C. effective May 17, 2006 (incorporated by reference to Exhibit 3.6 to ONEOK Partners, L.P.'s Form 10-Q for the period ended June 30, 2006, filed on August 4, 2006 (File No. 1-12202)).

3.6 Northern Border Intermediate Limited Partnership Certificate of Limited Partnership dated July 12, 1993, Certificate of Amendment dated February 16, 2001, and Certificate of Amendment dated May 20, 2003 (incorporated by reference to Exhibit 3.3 to Northern Border Partners, L.P.'s 10-K for the year ended December 31, 2004, filed on March 14, 2005 (File No 1-12202)).

3.7 Certificate of Amendment to Certificate of Limited Partnership of Northern Border Intermediate Limited Partnership dated May 17, 2006 (incorporated by reference to Exhibit 3.3 to ONEOK Partners, L.P.'s Form 8-K filed on May 23, 2006 (File No. 1-12202)).

3.8 Certificate of Amendment to Certificate of Limited Partnership of ONEOK Partners Intermediate Limited Partnership dated September 15, 2006 (incorporated by reference to Exhibit 3.2 to ONEOK Partners, L.P.'s Form 8-K filed on September 19, 2006 (File No. 1-12202)).

3.9 Second Amended and Restated Agreement of Limited Partnership of ONEOK Partners Intermediate Limited Partnership dated as of May 17, 2006 (incorporated by reference to Exhibit 3.4 to ONEOK Partners, L.P.'s Form 8-K filed on May 23, 2006 (File No. 1-12202)).

3.10 Amendment No. 1 to Second Amended and Restated Agreement of Limited Partnership of ONEOK Partners Intermediate Limited Partnership dated as of September 15, 2006 (incorporated by reference to Exhibit 3.3 to ONEOK Partners, L.P.'s Form 8-K filed on September 19, 2006 (File No. 1-12202)).

3.11 Certificate of Formation of ONEOK ILP GP, L.L.C. dated May 12, 2006 (incorporated by reference to Exhibit 4.11 to ONEOK Partners, L.P.'s Form S-3 filed on September 19, 2006 (File No. 333-137419)).

3.12 Limited Liability Company Agreement of ONEOK ILP GP, L.L.C. effective May 12, 2006 (incorporated by reference to Exhibit 4.12 to ONEOK Partners, L.P.'s Form S-3 filed on September 19, 2006 (File No. 333-137419)).

3.13 Amendment No. 1 to Third Amended and Restated Agreement of Limited Partnership of ONEOK Partners, L.P. dated July 20, 2007 (incorporated by reference to Exhibit 3.1 to ONEOK Partners, L.P.'s Form 10-Q filed on August 3, 2007 (File No. 1-12202)).

4.1 Indenture, dated as of June 2, 2000, between Northern Border Partners, L.P., Northern Border Intermediate Limited Partnership and Bank One Trust Company, N.A., Trustee (incorporated by reference to Exhibit 4.1 to Northern Border Partners, L.P.'s Form 10-Q for the quarter ended June 30, 2000, filed on August 11, 2000 (File No. 1-12202)).

4.2 First Supplemental Indenture, dated as of September 14, 2000, between Northern Border Partners, L.P., Northern Border Intermediate Limited Partnership and Bank One Trust Company, N.A. (incorporated by reference to Exhibit 4.2 to Northern Border Partners, L.P.'s Form S-4 Registration Statement filed on September 20, 2000, (Registration No. 333-46212)).

4.3 Indenture, dated as of March 21, 2001, between Northern Border Partners, L.P. and Northern Border Intermediate Limited Partnership and Bank One Trust Company, N.A., Trustee (incorporated by reference to Exhibit 4.3 to Northern Border Partners, L.P.'s Form 10-K for the year ended December 31, 2001, filed on March 29, 2002 (File No. 1-12202)).

4.4 Indenture, dated as of September 25, 2006, between ONEOK Partners, L.P. and Wells Fargo Bank, N.A., as trustee (incorporated by reference to Exhibit 4.1 to ONEOK Partners, L.P.'s Form 8-K filed on September 26, 2006 (File No. 1-12202)).

4.5 First Supplemental Indenture, dated as of September 25, 2006, among ONEOK Partners, L.P., ONEOK Partners Intermediate Limited Partnership and Wells Fargo Bank, N.A. , as trustee, with respect to the 5.90 percent Senior Notes due 2012 (incorporated by reference to Exhibit 4.2 to ONEOK Partners, L.P.'s Form 8-K filed on September 26, 2006 (File No. 1-12202)).

4.6 Second Supplemental Indenture, dated as of September 25, 2006, among ONEOK Partners, L.P., ONEOK Partners Intermediate Limited Partnership and Wells Fargo Bank, N.A. , as trustee, with respect to the 6.15 percent Senior Notes due 2016 (incorporated by reference to Exhibit 4.3 to ONEOK Partners, L.P.'s Form 8-K filed on September 26, 2006 (File No. 1-12202)).

4.7 Third Supplemental Indenture, dated as of September 25, 2006, among ONEOK Partners, L.P., ONEOK Partners Intermediate Limited Partnership and Wells Fargo Bank, N.A. , as trustee, with respect to the 6.65 percent Senior

Notes due 2036 (incorporated by reference to Exhibit 4.4 to ONEOK Partners, L.P.'s Form 8-K filed on September 26, 2006 (File No. 1-12202)).

4.8 Form of Senior Note due 2012 (included in Exhibit 4.5 above).

4.9 Form of Senior Note due 2016 (included in Exhibit 4.6 above).

4.10 Form of Senior Note due 2036 (included in Exhibit 4.7 above).

4.11 Form of Class B unit certificate (incorporated by reference to Exhibit 4.1 to Northern Border Partners, L.P.'s Form 8-K filed on April 12, 2006 (File No. 1-12202)).

4.12 Form of common unit certificate (included in Exhibit 3.3 above).

4.13 Fourth Supplemental Indenture, dated as of September 28, 2007, among ONEOK Partners, L.P., ONEOK Partners Intermediate Limited Partnership and Wells Fargo Bank, N.A., as trustee, with respect to the 6.85 percent Senior Notes due 2037 (incorporated by reference to Exhibit 4.2 to ONEOK Partners, L.P.'s Form 8-K filed on September 28, 2007 (File No. 1-12202)).

4.14 Form of Senior Note due 2037 (included in Exhibit 4.13 above).

10.1 First Amended and Restated General Partnership Agreement of Northern Border Pipeline Company dated April 6, 2006 by and between Northern Border Intermediate Limited Partnership and TC PipeLines Intermediate Limited Partnership (incorporated by reference to Exhibit 3.1 to Northern Border Pipeline Company's Form 8-K filed April 12, 2006 (File No. 333-87753)).

10.2 Not used.

10.3 Services Agreement dated April 6, 2006, by and among ONEOK, Inc., Northern Plains Natural Gas Company, LLC, NBP Services, LLC, Northern Border Partners, L.P. and Northern Border Intermediate Limited Partnership (incorporated by reference to Exhibit 10.3 to Northern Border Partners, L.P.'s Form 8-K filed on April 12, 2006 (File No. 1-12202)).

10.4 Not used.

10.5 Form of Termination Agreement with ONEOK, Inc. dated as of January 5, 2005 (incorporated by reference to Exhibit 99.1 to Northern Border Partners, L.P.'s Form 8-K filed on January 11, 2005 (File No. 1-12202)).

10.6 Amended and Restated Limited Liability Company Agreement of Overland Pass Pipeline Company LLC entered into between ONEOK Overland Pass Holdings, L.L.C. and Williams Field Services Company, LLC dated May 31, 2006 (incorporated by reference to Exhibit 10.6 to ONEOK Partners, L.P.'s Form 10-Q for the period ended June 30, 2006, filed on August 4, 2006 (File No. 1-12202)).

10.7 Processing and Gathering Services Agreement between ONEOK Field Services Company, L.L.C, ONEOK, Inc. and ONEOK Bushton Processing, Inc. dated April 6, 2006 (incorporated by reference to Exhibit 10.7 to ONEOK Partners, L.P.'s Form 10-Q for the period ended June 30, 2006, filed on August 4, 2006 (File No. 1-12202)).

10.8 Not used.

10.9 Not used.

10.10 Amended and Restated Revolving Credit Agreement dated March 30, 2007, among ONEOK Partners, L.P., as Borrower, the lenders from time to time party thereto, SunTrust Bank, as Administrative Agent, Wachovia Bank, National Association, as Syndication Agent, and BMO Capital Markets, Barclays Bank PLC, and Citibank, N.A., as Co-Documentation Agents (incorporated by reference to Exhibit 10.1 to ONEOK Partners, L.P.'s report on Form 10-Q filed on May 2, 2007 (File No. 1-12202)).

10.11 Supplement and Joinder Agreement dated July 31, 2007, among ONEOK Partners, L.P., as Borrower, each of the existing Lenders, SunTrust Bank, as Administrative Agent, and JPMorgan Chase Bank, N.A. (incorporated by reference to Exhibit 10.1 to ONEOK Partners, L.P.'s report on Form 10-Q filed on August 3, 2007 (File No. 1-12202)).

10.12 Underwriting Agreement, dated September 25, 2007, among ONEOK Partners, L.P. and ONEOK Partners Intermediate Limited Partnership and Wachovia Capital Markets LLC, Greenwich Capital Markets, Inc., and UBS Securities LLC, as representatives of the several underwriters named therein (incorporated by reference to Exhibit 1.1 to ONEOK Partners, L.P.'s report on Form 8-K filed on September 28, 2007 (File No. 1-12202)).

10.13 Underwriting Agreement dated March 11, 2008, among ONEOK Partners, L.P. and the underwriters named therein (incorporated by reference to Exhibit 1.1 to ONEOK Partners, L.P.'s report on Form 8-K filed on March 12, 2008).

10.14 Common Unit Purchase Agreement dated March 11, 2008, between ONEOK Partners, L.P. and ONEOK, Inc. (incorporated by reference to Exhibit 1.2 to ONEOK Partners, L.P.'s report on Form 8-K filed on March 12, 2008).

12 Computation of Ratio of Earnings to Fixed Charges for the years ended December 31, 2008, 2007, 2006, 2005 and 2004.

16.1 Letter from KPMG LLP dated May 2, 2007, to the Securities and Exchange Commission regarding change in certifying accountant (incorporated by reference to Exhibit 16.1 to ONEOK Partners, L.P.'s report on Form 8-K filed on May 2, 2007 (File No. 1-12202)).

21 Required information concerning the registrant's subsidiaries.

23.1 Consent of Independent Registered Public Accounting Firm - PricewaterhouseCoopers LLP.

23.2 Consent of Independent Registered Public Accounting Firm - KPMG LLP.

23.3 Consent of Independent Registered Public Accounting Firm - PricewaterhouseCoopers LLP for Exhibit 99.1.

31.1 Certification of John W. Gibson pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

31.2 Certification of Curtis L. Dinan pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

32.1 Certification of John W. Gibson pursuant to 18 U.S.C. Section 1350 as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (furnished only pursuant to Rule 13a-14(b)).

32.2 Certification of Curtis L. Dinan pursuant to 18 U.S.C. Section 1350 as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (furnished only pursuant to Rule 13a-14(b)).

99.1 Audited balance sheet and related notes of ONEOK Partners GP, L.L.C. as of December 31, 2008.

The total amount of securities of the Partnership authorized under any instrument with respect to long-term debt not filed as an exhibit does not exceed 10 percent of the total assets of the Partnership and its subsidiaries on a consolidated basis. The Partnership agrees, upon request of the SEC, to furnish copies of any or all of such instruments to the SEC.

Signatures

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

ONEOK Partners, L.P.
By: ONEOK Partners GP, L.L.C., its General Partner

Date: February 24, 2009

By: /s/ Curtis L. Dinan
Curtis L. Dinan
Executive Vice President,
Chief Financial Officer and Treasurer
(Signing on behalf of the Registrant
and as Principal Financial Officer)

Pursuant to the requirements of the Exchange Act, this report has been signed below by the following persons on behalf of the registrant and in the capacities indicated on this 24th day of February 2009.

/s/ John W. Gibson
John W. Gibson
Chairman of the Board and
Chief Executive Officer

/s/ Caron A. Lawhorn
Caron A. Lawhorn
Senior Vice President and
Chief Accounting Officer

/s/ Curtis L. Dinan
Curtis L. Dinan
Director

/s/ Jim Kneale
Jim Kneale
Director

/s/ Gil J. Van Lunsen
Gil J. Van Lunsen
Director

/s/ Gary N. Petersen
Gary N. Petersen
Director

/s/ Gerald B. Smith
Gerald B. Smith
Director

Glossary

Hedge, Hedging: The use of derivative commodity and interest rate instruments to reduce financial exposure to commodity price and interest rate volatility.

Master Limited Partnership (MLP): A limited partnership business that is publicly traded on an exchange such as the New York Stock Exchange. MLPs have one or more general partners who manage the business and assume its legal debts and obligations.

Natural Gas Liquids (NGL): Liquid hydrocarbons that are extracted and separated from the natural gas stream. NGL products include ethane, propane, isobutane, butane and natural gasoline.

Partnership Units: The ownership interests owned by partners – the investors – in a partnership; similar to owning shares of stock in a corporation.

Risk: Exposure to uncertainty.

Units of Measure:
Mcf = Thousand cubic feet
Bbls = Barrels (42 U.S. gallons)
MMcf = Million cubic feet
MBbls = Thousand barrels
Bcf = Billion cubic feet
MGal = Thousand gallons
MMBtu = Million British thermal units
BBtu = Billion British thermal units

Corporate Information

ONEOK Partners is a publicly traded master limited partnership engaged in natural gas gathering and processing, natural gas pipelines, natural gas liquids gathering and fractionation, and natural gas liquids pipelines.

Its sole general partner, ONEOK Partners GP, L.L.C., is a subsidiary of ONEOK, Inc., a diversified energy company founded in 1906, that's engaged in natural gas distribution and marketing.

ONEOK owns 47.7 percent of the partnership.

Listed on the New York Stock Exchange under the symbol OKS.

Publicly Traded Partnership Attributes
Unitholders own limited partnership common units instead of shares of stock and receive cash distributions rather than dividends. A partnership generally is not a taxable entity and does not pay federal income taxes. All of the income, gains, losses, deductions or credits flow through the partnership to the unitholders on a per-unit basis. Unitholders are required to report their allocated share of these amounts on their income tax returns whether or not cash distributions are made by the partnership to unitholders.

Cash distributions paid by the partnership to a unitholder are generally not taxable, unless the amount of any cash distributed is in excess of the unitholder's adjusted basis in their partnership interest. Unitholders will receive a Schedule K-1 tax package each year related to the cash received.

The partnership provides each unitholder a Schedule K-1 tax package in March of each year that includes the unitholder's allocated share of reportable partnership income, gains, losses, deductions, credits and other partnership information necessary to file federal and/or state tax returns. Any unitholder receiving a duplicate copy of such Schedule K-1 should call 800-371-2188.

Auditors
PricewaterhouseCoopers LLP
Two Warren Place
6120 South Yale Avenue, Suite 1850
Tulsa, OK 74136

Transfer Agent, Registrar and Distribution Paying Agent
Computershare Trust Company, N.A.
P.O. Box 43078
Providence, RI 02940-3078
Phone toll free: 800-519-3111
Web site: http://www.computershare.com

Schedule K-1 Support
ONEOK Partners, L.P.
K-1 Support
P.O. Box 799060
Dallas, TX 75379-9060
800-371-2188

Credit Rating

Standard & Poor's	BBB
Moody's Investors Service	Baa2

Master Limited Partnership Units
Common units for the partnership trade on the New York Stock Exchange under the symbol OKS.

Investor Relations
Dan Harrison, vice president – investor relations and public affairs, by phone at 918-588-7950 or by e-mail at dan.harrison@oneok.com.

Christy Williamson, manager – investor relations, by phone at 918-588-7163 or by e-mail at christy.williamson@oneok.com.

Corporate Web Site
ONEOK Partners business and financial information is available at www.oneokpartners.com.

Sarbanes-Oxley Act Certification
John W. Gibson, chairman and chief executive officer, and Curtis L. Dinan, executive vice president, chief financial officer and treasurer, have each filed with the Securities and Exchange Commission the written certifications required by Section 302 of the Sarbanes-Oxley Act of 2002 and the rules of the Securities and Exchange Commission. These certifications are included as exhibits 31.1 and 31.2 of the ONEOK Partners, L.P. Annual Report on Form 10-K for the year ended December 31, 2008.

New York Stock Exchange Certification
As required by the listing standards of the New York Stock Exchange, on April 3, 2008, John W. Gibson, chairman, president and chief executive officer, submitted to the New York Stock Exchange the Annual CEO Certification that he was not aware of any violation by ONEOK Partners, L.P. of the New York Stock Exchange listing standards. We anticipate filing our 2009 Annual CEO Certification with the New York Stock Exchange no later than March 27, 2009.

The contents of this annual report have been printed on 10 percent post-consumer recycled paper. Please be responsible and do your part to help the environment by recycling.

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