DEFINING TOMORROW.

ONEOK PARTNERS 2009 ANNUAL REPORT

- *ONEOK Partners, L.P. (ONEOK Partners) is a publicly traded master limited partnership engaged in the natural gas gathering and processing, natural gas pipelines and natural gas liquids businesses.*
- *Our sole general partner is a subsidiary of ONEOK, Inc. (ONEOK). ONEOK is an energy company founded in 1906 that's involved in natural gas distribution and energy services, and owns 42.8 percent (as of February 2010) of the partnership.*

FINANCIAL HIGHLIGHTS

Year Ended December 31	2009	2008	2007
Consolidated financial information (millions of dollars)			
Net margin	$ 1,119.3	$ 1,140.7	$ 895.9
Operating income	$ 546.6	$ 644.8	$ 446.8
Net income attributable to ONEOK Partners, L.P.	$ 434.4	$ 625.6	$ 407.7
Total assets	$ 7,953.3	$ 7,254.3	$ 6,112.1
Total debt to capitalization	55%	54%	55%
Capital expenditures (millions of dollars)			
Growth	$ 556.4	$ 1,172.0	$ 650.3
Maintenance	$ 59.3	$ 81.9	$ 59.6
Total capital expenditures	$ 615.7	$ 1,253.9	$ 709.9
Common unit data			
Common units outstanding at year-end	59,912,777	54,426,087	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	96,406,903	90,920,213	82,891,340
Data per limited partner unit			
Net income	$ 3.60	$ 6.01	$ 4.21
Distributions declared	$ 4.35	$ 4.26	$ 4.025
Market price range			
High	$ 63.00	$ 64.01	$ 72.42
Low	$ 34.21	$ 39.25	$ 58.20
Year-end	$ 62.30	$ 45.55	$ 61.25

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 and natural gas liquids.

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 42.8 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 tax deferred, unless the amount of any cash distributed is in excess of the unitholder's adjusted basis in their partnership interest. Unitholders will receive a tax package including a Schedule K-1 each year related to the cash received.

The partnership provides each unitholder a 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 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: www.computershare.com

Tax Package 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.

Andrew Ziola, manager – investor relations, by phone at 918-588-7163 or by e-mail at andrew.ziola@oneok.com.

Corporate Web Site
ONEOK Partners business and financial information is available at www.oneokpartners.com.

TO OUR UNITHOLDERS

STRATEGY. ASSETS. PEOPLE.

ONEOK Partners performed well in a challenging year marked by a severe economic recession, low commodity prices and sharply reduced drilling activity.

We emerged from 2009 not only stronger but also better equipped to succeed in 2010 and beyond, thanks to the combination of a sound strategy, good assets and exceptional people.

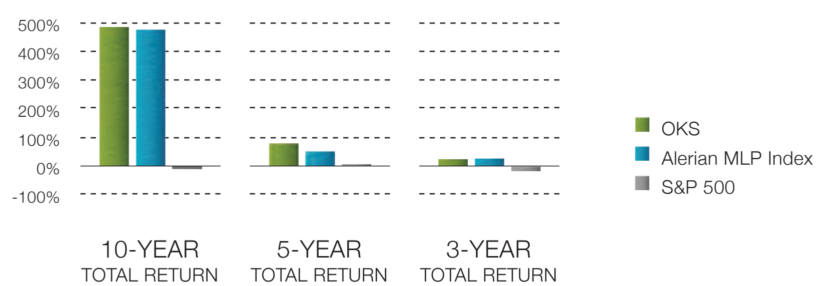
Together, we are *defining tomorrow.*

ONEOK Partners is a supply-driven business, providing quality, non-discretionary services to natural gas and natural gas liquids (NGL) producers and customers from the wellhead to the marketplace. The services we offer throughout the natural gas and natural gas liquids value chains complement each other, creating value for our producers and customers by enabling them to get their products to market.

Our strategy is to grow ONEOK Partners by connecting supply with demand to generate stable cash flow and earnings, which are predominately fee-based.

Our goal is a partnership that is capable of excelling in the good times and performing well in the bad.

TOTAL RETURNS



YEAR IN REVIEW

Operating income in 2009 was $546.6 million, down 15 percent from the record performance of 2008, a year in which robust drilling activity and high commodity prices prevailed before declining in the wake of the financial crisis and the economic recession.

Essentially, 2008 provided a glimpse of our potential; 2009 revealed our strengths and resilience.

During the year, we successfully completed a public offering of 5.5 million common units and sold $500 million of 10-year senior notes. And in February 2010, we completed another equity offering of 5.5 million units. These activities helped fund our growth – which allows us to continue to increase our distributions to unitholders – while enabling us to maintain a balanced capital structure and our investment-grade credit rating.

In the fourth quarter 2009, we increased the quarterly distribution to $1.09 from $1.08 per unit and in January 2010, we again increased it to $1.10 per unit. Our 2010 plan includes a 1-cent-per-quarter increase in unitholder distributions.

Since 2006, when ONEOK became our general partner, we have increased the distribution 13 times – from $3.20 to $4.40 on an annualized basis – representing a 38 percent increase.

These distribution increases reflect the benefits from our $2 billion-plus capital-investment program completed last fall.

At year-end 2009, our common unit price reflected a 37 percent increase from that same time a year earlier.

NEW ASSETS AT WORK

2009 marked the completion of our more than $2 billion capital-investment program that began in 2006. Many of the projects contributed to our strong financial performance in 2009, with additional benefits anticipated in 2010 and beyond, as all will be operating for a full year.

Major project completions in 2009 included the Arbuckle Pipeline, the Denver-Julesberg (D-J) Lateral Pipeline and the Piceance Lateral Pipeline, serving our natural gas liquids segment; the Guardian Pipeline Expansion and Extension in our natural gas pipelines segment; and the Grasslands plant expansion in our natural gas gathering and processing segment.

This capital-investment program was the largest such undertaking in our history. While each project presented unique challenges in terms of cost and completion schedules, all are performing well and providing exceptional returns on our investment.

This growth increased our scope, strength and capabilities. It also set the stage for additional opportunities in the future.

BUSINESS SEGMENT HIGHLIGHTS

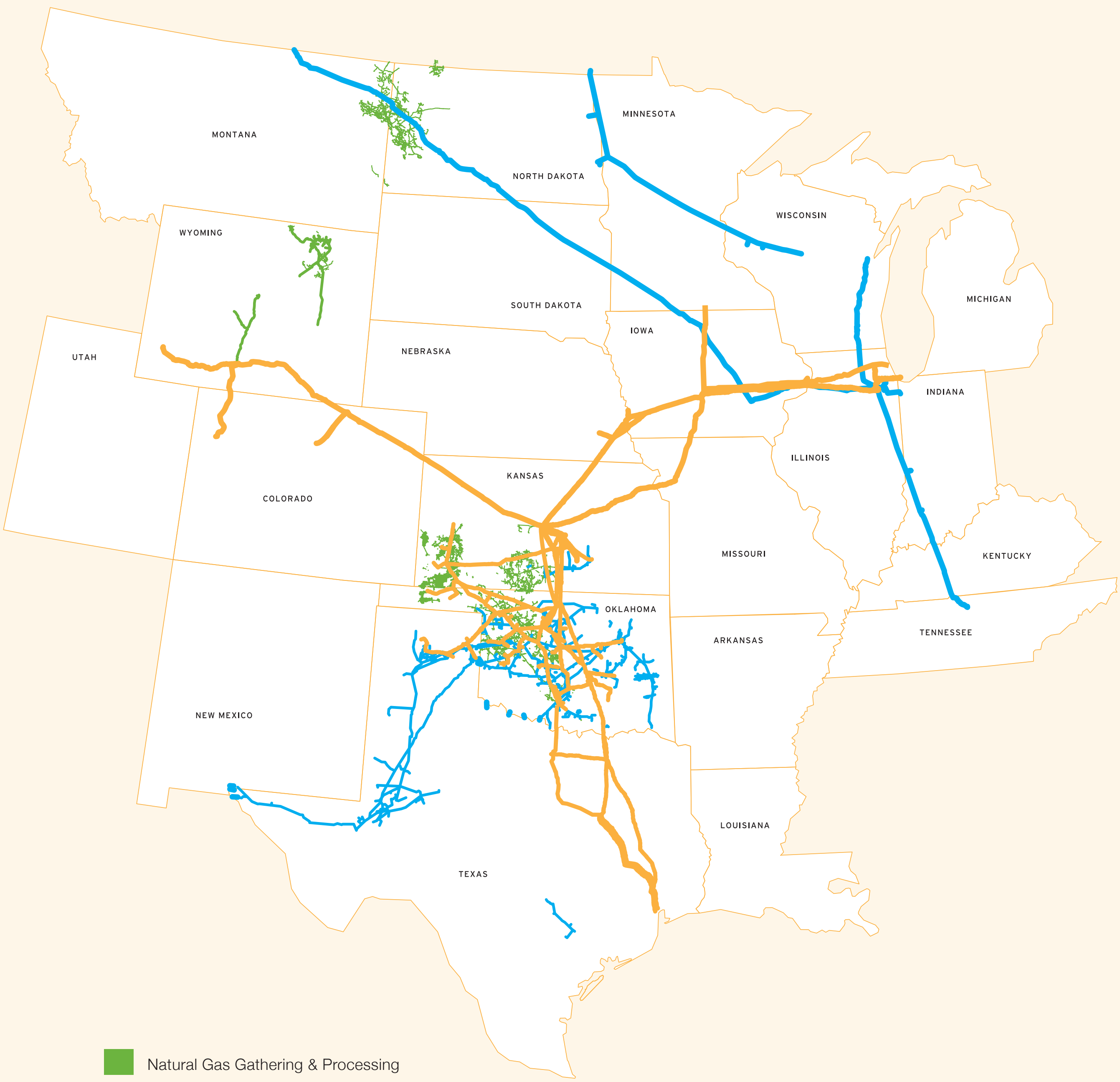
Our **natural gas gathering and processing** segment turned in a solid operating performance in the wake of a challenging industry environment that saw significantly lower drilling activity. Natural gas processed volumes rose slightly and gathered volumes declined only slightly, demonstrating the value of this segment's diversity of supply basins, producers and contracts, as well as its relentless focus on connecting new natural gas supplies to our systems.

For example, while production declined in areas such as the Powder River Basin in Wyoming, it held steady or increased in others, including intensely active shale plays such as the Bakken Shale in the Williston Basin in North Dakota and the Woodford Shale in Oklahoma. The expansion of our Grasslands processing and fractionation capabilities, completed in early 2009, was important in keeping pace with production demands in the Bakken Shale play.

Our **natural gas pipelines** segment achieved its third consecutive year of improved results, benefiting from the completion of the Guardian Pipeline Expansion and Extension, which began serving two Wisconsin utilities in early 2009. The completion of Midwestern Pipeline's new interconnection with the Rockies Express Pipeline also added additional natural gas volumes to our system.

Approximately three-fourths of our internal-growth investments were dedicated to the **natural gas liquids** segment, whose operating footprint and flexibility, and supply access and diversity, as well as its gathering, fractionation and transportation capabilities, were greatly expanded. Collectively, they provide a competitive advantage as we provide quality, non-discretionary services to our NGL producers and customers.

ONEOK PARTNERS ASSETS.



Natural Gas Gathering & Processing

Natural Gas Pipelines

Natural Gas Liquids

In 2009, our NGL gathered volumes increased 43 percent and fractionated volumes rose 24 percent, both setting new record levels. Also, as a result of the internal growth, this segment's fee-based earnings represented 71 percent of its income – a 6 percent increase over 2008.

This NGL volume growth in 2009 reduced the impact of narrower NGL product-price differentials between the Conway, Kansas, and Mont Belvieu, Texas, marketing hubs. Those differentials had been exceptionally high through most of 2008.

The NGL product-price differentials are expected to remain relatively flat in 2010. However, we expect gathered and fractionated NGL volumes to continue growing as the Overland Pass Pipeline accesses additional supplies from two Colorado basins via the Piceance and D-J Lateral Pipelines; and the Arbuckle Pipeline, placed into service last August, accesses supplies from the Woodford Shale in southern Oklahoma and the Barnett Shale in northern Texas.

NGL fractionation capacity remains tight industrywide. We signed an agreement in February 2010 to access additional NGL fractionation services – scheduled to come on line in 2011 – to accommodate continued volume growth across our systems.

OUR PEOPLE ARE THE KEY

The best strategies and assets are worth little without the best people to make them work. I believe our ONEOK Partners team is one of the best – and we're working to make it better. We are committed to attracting, developing and retaining employees who share our passion for creating value for customers and producers.

There is nothing more personally rewarding than to see individuals grow into their jobs and take on greater responsibilities. This process is vital to our continued success and was evident last year when several of our leaders were identified to fill key leadership positions associated with the retirement announcement of James C. Kneale, our president and former chief operating officer, who retired this past January.

Volumes could be written about Jim's contributions during a career that spanned 29 years at our general partner, ONEOK. His constancy of character, high integrity and work ethic are, in a word, unsurpassed. Terry K. Spencer stepped up to the role of chief operating officer last summer and was elected to our board of directors this past December.

During the past year, we named four additional members to the board of directors – Julie H. Edwards, Jim W. Mogg, Shelby E. Odell and Craig F. Strehl. Their depth of industry knowledge, experience and expertise will be called on as we make important decisions. (Our board members appear on page 22.)

I also invite you to read about some of the measures we are taking to ensure that we are the employer and neighbor of choice in all of our locations. (That discussion appears on page 19.)

OUR NEW GROWTH PROGRAM

The completion of our more than $2 billion capital-investment program has led to the identification of additional growth opportunities. Depending on market needs and producer commitments, these investments could average approximately $300 million to $500 million per year between 2010 and 2015 – creating additional value for all of our stakeholders.

We will begin our fifth year of operation as ONEOK Partners this April. That is hard to believe, because the past four years seem to have flown by as we made the partnership better, stronger and more valuable to our customers and producers, and to you, our unitholders.

This past year, we met and overcame some serious challenges. Today, our future appears brighter, commodity prices have improved, and there is more certainty in the financial markets. There will be new challenges – there always are – but we are even better equipped to deal with them.

The financial strength and reputation of ONEOK Partners and our general partner, ONEOK, will serve us well on the exciting road ahead. All of us are committed to making this another rewarding journey. And we appreciate your continued trust and confidence.

John W. Gibson

John W. Gibson
Chairman, President and Chief Executive Officer

March 10, 2010

NATURAL GAS GATHERING AND PROCESSING.

A RELENTLESS FOCUS ON SUPPLY.

Our natural gas gathering and processing business entered 2009 facing low commodity prices, sharply reduced drilling activity and industry uncertainty in the midst of a severe economic recession. Operating in that business environment during the year, we increased processed volumes by 3 percent, limited the decline in gathered volumes to 4 percent and turned in solid operating income results.

We achieved these results through a relentless focus on adding new supplies and by relying on key strengths: a large operating footprint, which accesses supplies from diverse supply basins; a wide range of producers, from small to large; a diverse contract portfolio; hedging skills, which limit exposure to commodity-price changes; and overall financial strength.

BASIN DIVERSITY

Our gathering and processing business operates in five basins, each with distinct characteristics. This diversity serves several purposes, chief among them being that production declines in one basin can be offset by increases in another.

Although volumes declined on some of our gathering systems – most notably Wyoming's Powder River Basin, where the natural gas has no natural gas liquids (NGL) and doesn't require processing – producers remained active in other basins served by this segment.

High drilling activity continued in both the Bakken Shale in North Dakota and the Woodford Shale in southern Oklahoma. A part of the Williston Basin, the Bakken Shale play is driven by crude oil production and also produces natural gas with a high NGL content. The Woodford Shale, a part of the Anadarko Basin, also contains natural gas rich in NGLs. Both of those plays involve horizontal drilling, which improves producers' ability to access large oil and natural gas reserves in tight shale formations.

The expansion of our Grasslands processing facility in the Williston Basin will begin its first full year of operation in 2010. During 2009, we increased that facility's natural gas processing capacity by 59 percent and its NGL fractionation capacity by 50 percent.

THEY KNOW WE ARE IN THIS BUSINESS FOR THE LONG HAUL.

A BALANCED PORTFOLIO

The producers connected to our natural gas gathering systems come in all sizes, increasing our exposure to new drilling and limiting our dependence on the actions of a few producers. No producer makes up more than 15 percent of our business by volume.

These producers know that our performance, reliability, willingness to expand and financial strength – coupled with our reputation for doing what we say we will do – will accommodate their planned growth. And while some producers are weathering a drilling decline, they know we are in this business for the long haul. Those factors, while difficult to measure, matter … and make us the preferred provider of these quality, non-discretionary services that allow producers and customers to get their products to market.

Our contract portfolio continues to ensure that the largest part of our business by volume is fee-based, which stabilizes earnings and reduces risk.

The “contract mix” also provides what we consider to be a prudent level of exposure to commodity price and processing spread changes. We manage this exposure through hedging activities, as well as through conditioning language in some contracts. Our ability to effectively hedge our equity volumes contributed to our operating income performance. We have hedged 75 percent of our expected NGL, condensate and natural gas equity volumes for 2010 and have already hedged a portion of expected equity volumes for 2011.

OPPORTUNITIES AHEAD

In the natural gas gathering and processing segment, we have identified new growth opportunities over the 2010-2015 time frame, including construction of new processing plants and expansions and upgrades of existing plants. Additionally, we anticipate new well-connect expenditures to range from $30 million to $60 million annually. Since 2007, we have made more than 1,000 new well connections.

Most of this growth potential is within our existing footprint and is expected to yield producer and customer commitments, attractive returns and the potential for additional growth. And we prudently examine risks and challenges specific to each potential investment.

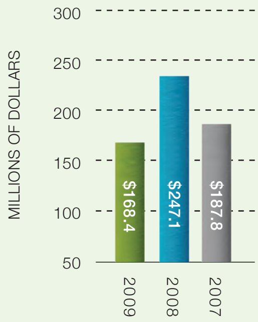
Despite the drilling cutbacks, producers continue to need new gathering, processing and pipeline infrastructure. In the Bakken and Woodford Shale plays, where we have large positions, we expect growth opportunities to continue.

As some of our competitors face difficulties associated with the economic recession, we believe consolidation and acquisition opportunities may occur. We're interested in acquiring assets that provide immediately accretive earnings, fit with our core capabilities and provide excellent growth opportunities – at the right price.

Planned growth capital expenditures for 2010 are $115 million, primarily for system expansions and extensions, increases in processing capability and new well connections.

PERFORMANCE SUMMARY

Natural Gas Gathering and Processing Segment Operating Income



- *$22.3 million increase from higher natural gas volumes processed and sold.*
- *$106 million decrease due to lower realized commodity prices.*
- *Operating costs decreased $3.1 million.*

NATURAL GAS PIPELINES.

STRENGTH IN BALANCING THE NEEDS OF PRODUCERS AND CUSTOMERS.

PROVIDES EXCELLENT CASH FLOW, STABLE EARNINGS AND INCREMENTAL GROWTH THAT IS SUSTAINABLE.

The natural gas pipelines segment increased operating income from its wholly owned pipelines and storage systems once again in 2009, while operating in an environment less favorable than the previous year.

This segment provides excellent cash flow, stable earnings and incremental growth that is sustainable over the long term.

ADDITIONS AND ENHANCEMENTS

The largest contribution to that improved performance came from the Guardian Pipeline Expansion and Extension, which went into full service in February 2009. The 119-mile extension is anchored by 15-year, firm-demand contracts with two Wisconsin utilities and was part of our more than $2 billion internal growth program completed last fall.

During the year, our Midwestern Gas Transmission system completed an interconnection in Illinois with the Rockies Express Pipeline. This additional supply source increases Midwestern's throughput north to a major marketing hub at Chicago and south into Tennessee. This system now has interconnections with 16 major pipelines, including Northern Border Pipeline, which is 50 percent owned by ONEOK Partners.

Last October, our Viking Gas Transmission system completed the expansion of a lateral pipeline to Fargo, North Dakota, to meet the increased demand experienced by a local distribution company. The increased volumes will meet this customer's growing requirements in the Fargo area, as well as two communities in Minnesota.

These three projects demonstrate our commitment and proven ability to meet the growing energy needs of the marketplace.

PERFORMANCE IN PERSPECTIVE

The natural gas pipelines segment’s earnings in 2009 came primarily from pipeline and storage facilities that provide a fixed revenue stream regardless of actual pipeline throughput, as well as from our interruptible transportation and storage services.

The segment’s excellent performance in 2009 was offset partially by lower equity earnings and the effect of lower natural gas prices on retained fuel sales. In 2008, this segment benefited from higher retained fuel sales as a result of high natural gas prices and the sale of Northern Border Pipeline's interest in the Bison Pipeline project.

This segment’s lower equity earnings come primarily from our 50 percent ownership of Northern Border Pipeline, which brings natural gas from western Canada into the United States. In 2009, this pipeline was 69 percent subscribed under demand-based rates.

Our wholly owned interstate natural gas pipelines are nearly fully subscribed under demand-based rates from firm transportation contracts, and our storage facilities are fully subscribed primarily under market-based rates. Our intrastate natural gas pipeline systems are 80 percent subscribed under demand-based rates.

LOOKING FORWARD

In late 2010, Northern Border Pipeline is scheduled to access U.S. Rocky Mountain-sourced natural gas when the Bison Pipeline project goes into service. Accessing this abundant and economically priced natural gas will add substantial incremental firm transportation revenues to Northern Border Pipeline.

We have identified additional potential growth projects for the natural gas pipelines segment in the 2011-2015 time frame. These include new pipeline construction, new market connections and storage- and pipeline-capacity expansions.

This segment's ability to grow is the result of its low operating costs and reputation for reliable delivery of services, diverse supply sources and market connectivity, as well as its long-term relationships with utility customers and the financial strength and reputation of ONEOK Partners and our general partner, ONEOK.

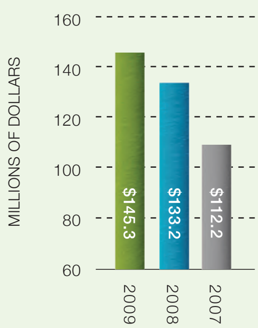
Looking at both ends of the pipeline, in the future we expect to see supply growth from emerging shale plays and demand growth from the economic and environmental advantages of natural gas in commercial and industrial uses.

Planned capital expenditures in 2010 are $31 million, primarily for routine growth and maintenance, as well as increased investments related to pipeline integrity.

REPUTATION FOR RELIABLE DELIVERY OF SERVICES.

PERFORMANCE SUMMARY

Natural Gas Pipelines Segment Operating Income



- *$38.8 million increase in transportation margins, primarily as the result of the completion of the Guardian Pipeline Expansion and Extension and an increase in volumes contracted on Midwestern Gas Transmission as a result of a new interconnection with the Rockies Express Pipeline.*
- *$8.6 million increase in storage margins as a result of contract renegotiations.*
- *$18.6 million net decrease from the effect of lower natural gas prices on retained fuel, offset partially by higher natural gas sales volumes.*
- *Operating costs increased $6.2 million due to higher employee-related costs and higher general taxes resulting from the completed capital projects.*

NATURAL GAS LIQUIDS.

LEADERSHIP WITH A STRATEGIC DIRECTION.

VOLUME GROWTH WAS THE KEY EARNINGS DRIVER IN THIS PREDOMINANTLY FEE-BASED BUSINESS.

Our natural gas liquids segment substantially increased its gathered and fractionated volumes, completed its capital-investment growth program and achieved better-than-anticipated performance in a challenging industry and economic environment. This business primarily gathers, transports, fractionates and stores raw NGLs produced from natural gas processing plants and delivers purity NGL products to market.

Volume growth was the key earnings driver in this predominantly fee-based business. In 2009, gathered NGL volumes increased 43 percent and fractionated volumes increased 24 percent. Since 2006, the year we began our more than $2 billion capital-investment program, gathered and fractionated NGL volumes have each increased by more than 50 percent.

The positive impact of these increased volumes was offset by narrower NGL product-price differentials between the two major NGL market hubs in Conway, Kansas, and Mont Belvieu, Texas. These optimization activities accounted for 17 percent of our NGL margins in 2009, compared with 25 percent in 2008 when exceptionally wide NGL product-price differentials existed.

Petrochemical demand remained steady throughout 2009 as the attractive price of the NGL-based feedstocks competed favorably with crude-oil-derived alternatives. The petrochemical sector consumes approximately half of the industry's NGL purity products, with refineries using approximately 20 percent for motor-fuel blending, and homes and businesses using approximately 30 percent as heating fuel.

FEE-BASED EARNINGS GROWTH

Seventy-one percent of this segment’s 2009 earnings were fee-based – a 6 percent increase from 2008. These fee-based earnings, which include NGL gathering, fractionation, storage and transportation services, help stabilize the segment’s earnings.

We expect NGL volumes and fee-based earnings to continue increasing as additional supplies from prolific supply basins are connected to our pipeline systems, which deliver these raw NGLs to our fractionation and storage facilities.

As a result of our more than $2 billion capital-investment program, we now access additional basins – including some of the most prolific shale plays in the country – in the Rocky Mountains, southern Oklahoma and northern Texas. Since 2006, we also have achieved significant volume growth in the Mid-Continent as a result of 21 new processing plant connections and capacity expansions at existing facilities.

Our NGL infrastructure now stretches from Wyoming to the Texas Gulf Coast and from the Mid-Continent through the Midwest to Chicago. This fully integrated system has excellent supply access and diversity, operational flexibility and delivery options – providing us with distinct competitive advantages in serving our customers.

PROJECT COMPLETIONS

Approximately $1.7 billion of our more than $2 billion capital-investment growth program was in the NGL segment. Its two anchor projects, the Overland Pass Pipeline and the Arbuckle Pipeline, represent more than $1 billion of that investment.

2010 will be the first full year of service for the Arbuckle Pipeline, which was placed into service last August. It connects to our extensive raw NGL Mid-Continent gathering system in southern Oklahoma and traverses the Barnett Shale in northern Texas en route to our fractionation and storage facilities at the Mont Belvieu market hub on the Texas Gulf Coast.

The Piceance Lateral Pipeline and the D-J Lateral Pipeline also will experience their first full year of operation in 2010. These pipelines deliver raw NGLs from two highly active Colorado basins to the Overland Pass Pipeline, which began transporting NGLs from Wyoming in late 2008 to our fractionation and storage facilities at Bushton, Kansas.

We expect NGL volumes to continue to increase in 2010 as these pipelines add additional NGL supplies from the highly active production areas in the Rockies, Mid-Continent and northern Texas.

HOW IT ALL WORKS

Our NGL fractionation, storage and distribution pipeline systems in the Mid-Continent and the Texas Gulf Coast were expanded and improved as a part of our internal growth program to accommodate growing volumes on the Overland Pass Pipeline and the Arbuckle Pipeline and in the Mid-Continent. We access approximately 90 percent of the Mid-Continent natural gas processing plants and a growing share in the Rockies and the Barnett Shale.

The infrastructure improvements included expanding the capacity of our purity products distribution pipeline that connects the Conway, Kansas, and Mont Belvieu, Texas, marketing hubs. This pipeline system allows us to capture NGL product-price differentials between the two hubs.

Our North System delivers NGLs and refined petroleum products up through the Midwest as far as Chicago. The North System, which is connected to our Mid-Continent fractionation, distribution and storage facilities, was acquired in late 2007.

The broadened scale and scope of our NGL assets provide full-service capabilities – and market access – to our NGL producers and customers. These capabilities, coupled with our strengthened ability to capitalize on supply developments, particularly in prolific shale plays, has us well positioned to continue our growth trend.

Supply access and basin diversity are critical to the NGL segment's success. Natural gas producers and processors know that we have the knowledge, experience and capabilities to accommodate their future growth plans.

LOOKING AHEAD

We expect NGL volumes to continue growing this year. For 2009, this segment was distributing an average of 459,000 barrels a day and gathering an average of 372,000 barrels a day on its pipeline systems.

We expect optimization margins – the NGL product-price differentials captured between the two major marketing hubs – to decline slightly during 2010.

While our fractionation capabilities are among the highest in the industry, capacity is tight due to increasing demand. We signed a definitive agreement in February 2010 to contract for 60,000 barrels per day of NGL fractionation services from additional capacity being added by Targa Resources in Mont Belvieu. This expansion, which is scheduled to be in service in mid-2011, will access raw NGL volumes directly from our Arbuckle Pipeline.

The internal growth projects over the past several years presented construction and cost-overrun challenges, including some that fall into the "lessons learned" category, from which we will benefit as new opportunities are developed and captured. Moreover, all of the completed projects are providing attractive returns and strengthen our ability to serve our producers and customers.

The completed projects also helped us identify additional growth opportunities. These include a new fractionator, capacity expansions at existing fractionators, new NGL pipelines and expansions for existing gathering and distribution purity NGL pipelines, additional market connections, storage-capacity expansions and greater truck-and-rail loading capabilities.

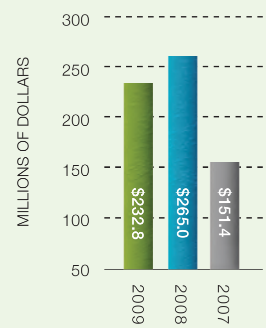
We are involved in discussions with producers and processors regarding this new growth – primarily within our existing NGL footprint. However, we also are examining opportunities beyond it, including in the Marcellus Shale in the Upper Appalachian Basin and the Bakken Shale in North Dakota. Inside and outside the NGL segment's broadened footprint, our growth is predicated on a number of criteria, including long-term producer commitments, attractive returns and the potential for future growth opportunities.

Planned growth capital expenditures for 2010 are $154 million, primarily for asset enhancements and expansions within our existing footprint.

In the third quarter of 2009, the NGL gathering and fractionation segment and the NGL pipelines segment were consolidated into one financial reporting segment. The change more closely reflects the actual operation and management of these integrated segments.

PERFORMANCE SUMMARY

Natural Gas Liquids Segment
Operating Income



- *$68.7 million increase from higher NGL volumes gathered, fractionated and transported, primarily associated with the completion of the Overland Pass Pipeline and related expansion projects and the Arbuckle Pipeline, as well as new NGL supply connections.*
- *$5.0 million increase due to higher storage margins as a result of contract renegotiations.*
- *$41.7 million decrease from narrower NGL product-price differentials.*
- *$4.3 million decrease from prior-year operational measurement gains.*
- *Operating costs in 2009 increased $39.1 million primarily from the operation of the Overland Pass Pipeline, the Arbuckle Pipeline and the recently expanded Bushton fractionator, as well as increased outside-service expenses, incremental general taxes and higher employee-related costs.*

CORPORATE RESPONSIBILITY.

RAISING THE BAR ON ENVIRONMENTAL,
SAFETY AND HEALTH PERFORMANCE.

We made significant progress in 2009 to unify, strengthen and improve our environmental, safety and health (ESH) performance, which is woven into virtually everything we do – from driving safely to and from our jobs each day to serving the nation's energy needs, while operating our facilities in a safe and environmentally responsible manner.

Our goal is clear: measurable and sustainable improvements to protect the environment and the safety and health of our employees, contractors, customers and the communities where we work and live.

Some of our actions include:

- Establishing a companywide ESH Leadership Committee led by executive management and staffed by representatives from diverse disciplines of our company.
- Creating an officer-level position to lead and staff a new ESH group. Hired last spring, the vice president reports directly to ONEOK's chief operating officer.
- Focusing on five key initiatives: improve safety performance; quantify and minimize greenhouse gas emissions; reduce the level of "lost and unaccounted for" natural gas; improve our comprehensive action plans to respond efficiently and effectively to emergencies; and consolidate and improve our ESH policies.
- Ramping up the process of measuring what we do and how well we do it, for both internal and external comparisons.
- Creating and distributing our first corporate responsibility report to key stakeholders.

ACCIDENT REDUCTION

Because of our significant growth, we are identifying best practices to promote consistency while remaining mindful that "one size" does not fit all.

We continue to focus on the prevention of injuries, illnesses and vehicle accidents.

More than 90 percent of all accidents on the job are caused by "unsafe acts," meaning that the person involved either knew the correct behavior but failed to put it into practice or wasn't aware of the behavior required for safe activity.

This year, we are introducing a behavior-based safety program in an effort to reduce unsafe acts. We are also focusing on innovative ways to reduce vehicle accidents. We are emphasizing that all jobs begin and end with getting to and from the work site safely. We'll report back on how we do.

CLIMATE CHANGE

As you are aware, there continues to be a great deal of news – and uncertainty – surrounding climate change. At this time it is not clear if new carbon-emission rules will come from Congress or the Environmental Protection Agency (EPA). This past fall, the EPA declared that greenhouse gases "contribute to air pollution that may endanger public health or welfare." In December, EPA rules made the reporting of greenhouse gas emissions mandatory.

AN ESSENTIAL PART OF LIVING UP TO OUR COMPANY

VALUES AND BELIEFS.

During 2009, we formed an ESH Climate Change Action Team to provide oversight and review of pending climate change and greenhouse gas regulatory and legislative proposals. We also have prepared for the new EPA reporting regulation by improving our ability to accurately measure and track these emissions by business unit and source.

Protection of the environment and conservation of natural resources are a key focus at ONEOK Partners. We are committed to reducing our carbon footprint in sensible and measurable ways that serve all of our stakeholders.

We believe that a strong and effective environmental, safety and health program is an essential part of living up to our company values and beliefs. Moreover, we believe that clean-burning natural gas and natural gas liquids can and should be a part of the solution when it comes to environmental issues.

IMPROVING QUALITY OF LIFE

At ONEOK Partners, we live where we work. We want to be the employer and the neighbor of choice, widely recognized for doing the right things for the right reasons. That means participating in and giving back to these communities in a variety of ways. We believe this, in turn, makes us a stronger company that is better able to attract, develop and retain men and women who share in our dedication to continual improvement – and success.

Established in 1997, the ONEOK Foundation invests in education, health and human services, arts and culture, and community improvements. The foundation is particularly interested in programs that help people gain self-sufficiency.

Our people are widely recognized for getting involved – making their communities better places for young and old alike. Last year, our employees volunteered more than 10,000 hours through our Volunteers With Energy program, whose work projects range from building homes to helping with civic activities.

We have financially contributed to and employees have been involved in Habitat for Humanity construction projects in Texas and Oklahoma. In 2009, our employees built the 200th Tulsa home and the company's fifth. We're scheduled to build our sixth home in the spring of 2010.

Every year, we establish new records in giving to the United Way, which serves a multitude of nonprofit charitable organizations within our communities. The ONEOK Foundation matches employee gifts dollar for dollar. Collectively, employees and the foundation have contributed more than $20 million to the United Way since the foundation was established.

In the spring of 2010, our presence in downtown Tulsa will increase to an unprecedented level with the opening of ONEOK Field, the new home of the Tulsa Drillers minor league baseball team. With this investment, we are reinforcing our strong commitment to Tulsa and the downtown area. We believe the revitalization of downtown Tulsa will help provide the foundation for new development and will bring vibrancy to the city, which we know is key to our ability to attract and retain the employees we need today and in the future.

As millions in our country cope with the effects of the economic recession, giving back to our communities has never been more needed.

BOARD OF DIRECTORS










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

Shelby E. Odell
Retired; Former President, Koch Hydrocarbon and *Former Senior Vice President,* Koch Industries
Ames, Oklahoma

Craig F. Strehl
Chief Operating Officer, LONESTAR Midstream Partners II, L.P.
Fort Worth, Texas

Julie H. Edwards
Former Chief Financial Officer, Southern Union Company; *Former Chief Financial Officer,* Frontier Oil Corporation
Houston, Texas

Gary N. Petersen
President, Endres Processing LLC
Hastings, Minnesota

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

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

Gerald B. Smith
Chairman, Chief Executive Officer and Co-founder, Smith, Graham & Company Investment Advisors
Houston, Texas

Jim W. Mogg
Retired Chairman, DCP Midstream GP, L.L.C.
Hydro, Oklahoma

Terry K. Spencer
Chief Operating Officer, ONEOK Partners, L.P.
Tulsa, Oklahoma

OFFICERS

John W. Gibson, 57
Chairman, President and Chief Executive Officer

Terry K. Spencer, 50
Chief Operating Officer

Curtis L. Dinan, 42
Executive Vice President, Chief Financial Officer and Treasurer

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

Derek S. Reiners, 38
Senior Vice President and Chief Accounting Officer

Caron A. Lawhorn, 48
Senior Vice President, Corporate Planning and Development

NATURAL GAS

Robert S. Mareburger, 48
President

David R. Scharf, 53
President, Gathering & Processing

W. Kent Shortridge, 43
President, Pipelines

Michael E. Nelson, 62
Senior Vice President, Pipeline Operations

NATURAL GAS LIQUIDS

Sheridan C. Swords, 40
President

Michael L. Turner, 36
Vice President, Gathering & Fractionation

Roger G. Thorpe, 42
President, Pipelines

Wesley J. Christensen, 56
Senior Vice President, Operations

Randy L. Jordan, 60
Vice President, Optimization

Ages as of December 31, 2009.

GROWTH INCREASED OUR SCOPE,

STRENGTH

AND CAPABILITIES.

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, 2009.
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 whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes __ No __

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Registration S-K (§ 229.405 of this chapter) 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, a non-accelerated filer, or a smaller reporting company. See definition of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one)
Large accelerated filer X   Accelerated filer __   Non-accelerated filer __   Smaller reporting company __

Indicate by check mark whether the registrant is a shell company (as defined in 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, 2009, was $2.7 billion.

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

Class	Outstanding at February 12, 2010
Common units	65,162,777 units
Class B units	36,494,126 units

DOCUMENTS INCORPORATED BY REFERENCE: None.

ONEOK PARTNERS, L.P.
2009 ANNUAL REPORT

As used in this Annual Report, references to “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 are defined as follows:

AFUDC	Allowance for funds used during construction
Annual Report	Annual Report on Form 10-K for the year ended December 31, 2009
ASU	Accounting Standards Update
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(s)	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
Clean Air Act	Federal Clean Air Act, as amended
Clean Water Act	Federal Water Pollution Control Act, as amended
EBITDA	Earnings before interest, taxes, depreciation and amortization
EBITDAR	Net income plus interest expense, income taxes, depreciation and amortization, and rent expense
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
Fort Union Gas Gathering	Fort Union Gas Gathering, L.L.C.
GAAP	Accounting principles generally accepted in the United States of America
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/d	Million cubic feet per day
Moody’s	Moody’s Investors Service, Inc.
Natural Gas Act	Natural Gas Act of 1938, as amended
Natural Gas Policy Act	Natural Gas Policy Act of 1978, as amended
NBP Services	NBP Services, LLC, a wholly owned subsidiary of ONEOK
NGL products	Marketable natural gas liquid purity products, such as ethane, ethane/propane mix, propane, iso-butane, normal butane and natural gasoline
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

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
Partnership Credit Agreement	The Partnership's $1.0 billion amended and restated revolving credit agreement dated March 30, 2007
POP	Percent of Proceeds
RRC	Texas Railroad Commission
S&P	Standard & Poor's Rating Group
SEC	Securities and Exchange Commission
Securities Act	Securities Act of 1933, as amended
TransCanada	TransCanada Corporation
Viking Gas Transmission	Viking Gas Transmission Company
XBRL	eXtensible Business Reporting Language

The statements in this Annual Report 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," "guidance," "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.

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

Partnership Structure

We are managed under the direction of the Board of Directors of our sole general partner, ONEOK Partners GP, which consists of 10 members. Seven 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. Four of our independent directors serve on the Conflicts Committee.

ONEOK Partners GP is a wholly owned subsidiary of ONEOK. Three of our members that are independent under NYSE listing standards and one management member of the Board of Directors of our general partner are also members of ONEOK's Board of Directors, with the management member being the only management member of ONEOK's Board of Directors. As of December 31, 2009, ONEOK and its subsidiaries owned a 45.1 percent aggregate equity interest in us. As a result of our February 2010 public offering of common units, ONEOK and its subsidiaries own a 42.8 percent aggregate equity interest in us.

Business Strategy

Our primary business strategy is to increase distributable cash flow through consistent earnings growth while focusing on safe, reliable, environmentally responsible and legally compliant operations for our customers, employees, contractors and the public through the following:

- growing fee-based earnings;
- developing and executing internally generated growth projects;
- executing strategic acquisitions; and
- managing our balance sheet to maintain strong credit ratings at or above current investment-grade levels.

Outlook

We expect a moderate economic recovery in 2010, with inflationary pressures beginning in 2011. Although recent volatility in the financial markets could limit our access to financial markets on a timely basis or increase our cost of capital in the future, we anticipate improved credit markets during 2010, compared with 2009; however, inflation risk may increase the cost of capital. We anticipate the consolidation of underperforming assets in the industry, particularly those with high commodity price exposure and/or high levels of debt. Additionally, we anticipate an improving commodity price environment during 2010, compared with 2009.

We intend to pursue growth in our natural gas businesses through well connections and contract renegotiations and through new plant construction, expansions and extensions of our existing systems and plants. For our natural gas liquids business, we intend to continue to focus on adding new supply connections and expanding our existing assets. We plan to spend approximately $362 million on capital expenditures in 2010, of which approximately $278 million is expected to be for growth projects. We may also pursue strategic acquisitions related to gathering, processing, fractionating, storing, transporting or marketing natural gas and NGLs.

SIGNIFICANT DEVELOPMENTS

Capital Projects - The following projects were placed in service during 2009:

- Guardian Pipeline's natural gas pipeline expansion and extension project;
- Williston Basin natural gas processing plant expansion;
- Arbuckle natural gas liquids pipeline;
- D-J Basin lateral natural gas liquids pipeline; and
- Piceance lateral natural gas liquids pipeline.

For further discussion on these projects, see "Capital Projects" beginning on page 37.

Equity Issuances - In July 2009, we completed an underwritten public offering of 5,486,690 common units, including the partial exercise by the underwriters of their over-allotment option, at $45.81 per common unit, generating net proceeds of approximately $241.6 million. In conjunction with the offering, ONEOK Partners GP contributed an aggregate of $5.1 million in order to maintain its 2 percent general partner interest in us. We used the proceeds from the sale of common units and the general partner contributions to repay borrowings under our Partnership Credit Agreement and for general partnership purposes.

In February 2010, we completed an underwritten public offering of 5,500,900 common units, including the partial exercise by the underwriters of their over-allotment option, at $60.75 per common unit, generating net proceeds of approximately $322.6 million. In conjunction with the offering, ONEOK Partners GP contributed $6.8 million in order to maintain its 2 percent general partner interest in us. We used the proceeds from the sale of common units and the general partner contribution to repay borrowings under our Partnership Credit Agreement and for general partnership purposes. As a result of these transactions, ONEOK and its subsidiaries own a 42.8 percent aggregate equity interest in us.

Debt Issuance - In March 2009, we completed an underwritten public offering of $500 million aggregate principal amount of 8.625 percent Senior Notes due 2019. We used the net proceeds of approximately $494.3 million from the offering to repay indebtedness outstanding under our Partnership Credit Agreement.

SEGMENT FINANCIAL INFORMATION

We implemented changes to the structure of our previous reportable business segments during the third quarter of 2009 to better align them with how we manage our businesses. Our financial results are now reported in these three reportable business segments: (i) Natural Gas Gathering and Processing; (ii) Natural Gas Pipelines, both of which remain unchanged; and (iii) Natural Gas Liquids, which consolidates our former natural gas liquids gathering and fractionation segment with our former natural gas liquids pipelines segment, due to the integrated manner in which they are managed. Prior-period amounts have been recast to reflect these segment changes.

Operating Income, Customers and Total Assets - See Note M of the Notes to Consolidated Financial Statements in this Annual Report for operating income by segment and for a discussion of revenues from external customers under "Customers" and disclosure of total assets, by segment, within the "Operating Segment Information" tables.

Intersegment Revenues - The following table sets forth the percentage of sales to other operating segments to total revenues for the periods and segments indicated:

	Years Ended December 31,		
Percentage of Intersegment Revenues to Total Revenues	**2009**	**2008**	**2007**
Natural Gas Gathering and Processing	**33%**	39%	35%
Natural Gas Pipelines	*****	*	*
Natural Gas Liquids	*****	*	*

* Represents a value of less than 1 percent.

See Note M of the Notes to Consolidated Financial Statements in this Annual Report for additional information about intersegment revenues.

NARRATIVE DESCRIPTION OF BUSINESS

Natural Gas Gathering and Processing

Business Strategy - We pursue growth through new well connections, system expansions and extensions, construction of new plants and strategic acquisitions. We seek to restructure expiring contracts to mitigate commodity price exposure and improve profitability. We also seek to provide safe, reliable, efficient and consistent operations of our natural gas gathering and processing assets, while managing costs.

Description of Business - Our Natural Gas Gathering and Processing segment's operations include gathering and processing of natural gas produced from crude oil and natural gas wells. We gather and process 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 and/or process natural gas in two producing basins in the Rocky Mountain region: the Williston Basin, which spans portions of Montana and North Dakota, and the Powder River Basin of Wyoming. The natural gas we gather in the Powder River Basin of Wyoming is coal bed methane, or dry gas, that does not require processing or NGL extraction, in order to be marketable; dry gas is gathered, compressed and delivered into a downstream pipeline or marketed for a fee.

In the Mid-Continent region and the Williston Basin, 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 shipped to fractionators where, through the application of heat and pressure, the unfractionated NGL stream is separated into 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 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.

We generally gather and process gas under the following types of contracts.

- POP - Under a POP contract, we retain a percentage of the NGLs and/or a percentage of the residue gas as payment for gathering, treating, compressing and processing the producer's 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. This type of contract represented approximately 32 percent and 34 percent of contracted volumes for 2009 and 2008, respectively. 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-based 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 our margin for this type of contract. The producer typically takes its NGLs and residue gas in-kind. Our POP and keep-whole contracts also typically include fee provisions, which are a portion of the fees reported in this category. Our fee-based contracts and contract provisions primarily expose us to volumetric risk with minimal commodity price risk and represented approximately 63 percent and 58 percent of contracted volumes for 2009 and 2008, respectively.
- 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. This type of contract represented approximately 5 percent and 8 percent of contracted volumes for 2009 and 2008, respectively, with approximately 84 percent and 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 fee and POP contracts. We use derivative instruments to mitigate our sensitivity to fluctuations in the natural gas, crude oil and NGL prices received for our share of volumes sold.

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 coal bed methane gathering system serving a broad production area in northeast Wyoming;
- 37 percent ownership interest in Fort Union Gas Gathering, which gathers coal bed 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 N of the Notes to Consolidated Financial Statements in this Annual Report 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. Higher crude oil prices in the second half of 2009 and advances in horizontal drilling and completion technology are having a positive impact on drilling activity in the shale areas, providing an offset to the less favorable supply projections in the non-shale areas.

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. We anticipate continuing volumetric declines in most non-shale wells that supply our gathering and processing operations; however, we expect this to be more than offset by the increased drilling activity in the Cana Woodford Shale area of Western Oklahoma, in which we have a substantial gathering position.

In the Rocky Mountain region, we have seen declines in gathered volumes in the Powder River Basin; however, our Williston Basin volumes are growing as drilling activity increases, primarily driven by producer development of Bakken Shale oil wells, which also produce natural gas containing significant NGLs.

Demand - Demand for gathering and processing services is typically aligned with the production of natural gas. 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 reduce, to some extent, the amount of ethane and propane recovered if prices or processing margins are unfavorable.

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 as a result of receiving commodities in exchange for our services. To a lesser extent, exposures arise from 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 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 needed to meet the electricity demand required 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 as automotive travel increases and as seasonal gasoline formulation standards are implemented. During periods of peak demand for a certain commodity, prices for that product typically increase, which may influence processing decisions.

Competition - The gathering and processing business remains relatively fragmented despite significant consolidation in the industry. We compete for natural gas supplies with independent exploration and production companies that have gathering and processing assets, 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:

- fees charged under our gathering and processing contracts;
- pressures maintained on our gathering systems;
- location of our gathering systems relative to those of 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 natural gas processing efficiency 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. We believe our gathering facilities and operations meet the criteria used by the FERC for non-jurisdictional gathering facility status. However, we are subject to newly adopted FERC regulations that require us to publicly post certain gas flow information on our Web sites. 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 transport residue gas from our plants to interstate pipelines in accordance with Section 311(a) of the Natural Gas Policy Act.

Oklahoma, Kansas, Wyoming, Montana and North Dakota 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.

See further discussion in the “Environmental and Safety Matters” section.

Natural Gas Pipelines

Business Strategy - We seek to increase throughput and growth of our existing natural gas pipelines and storage assets through extensions and expansions supported by long-term transportation and storage commitments. We also seek to provide safe, reliable, efficient and consistent operations while maintaining a competitive cost structure.

Description of Business - Our Natural Gas Pipelines segment primarily owns and operates regulated natural gas transmission pipelines, natural gas storage facilities and natural gas gathering systems for non-processed gas. 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 North Dakota, Minnesota, Wisconsin, 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 to western markets, the Houston Ship Channel market to the east and the Mid-Continent market to the north.

We own 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 also a fee business, but are not subject to rate regulation by the OCC 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, an interstate, FERC-regulated pipeline which transports natural gas from the Montana-Saskatchewan border near Port of 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 N of the Notes to Consolidated Financial Statements in this Annual Report 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 Mountains, 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 Mid-Continent region, which includes the Anadarko Basin, Hugoton Basin, Central Kansas Uplift Basin, Permian Basin and the Texas Panhandle. United States natural gas drilling rig counts began to decline in 2008 and continued until mid-2009 when they began to increase.

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 consume 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 differential between receipt and delivery points along the pipeline, also known as basis differential, 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 needed to meet the electricity demand required 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 the value 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 firm-service agreements. A small portion of our storage capacity is retained for operational purposes.

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.

See further discussion in the “Environmental and Safety Matters” section.

Natural Gas Liquids

Business Strategy - We seek to increase throughput, maximize facility utilization and efficiently manage 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. We also 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 natural gas liquids assets by making capital investments to expand our access to new supply and market areas and increase our pipeline, fractionation, and storage capacity.

Description of Business - Our natural gas liquids assets consist of facilities that gather, fractionate and treat NGLs and store NGL products primarily in Oklahoma, Kansas and Texas. We own FERC-regulated natural gas liquids gathering and distribution pipelines in Oklahoma, Kansas, Texas, Wyoming and Colorado, and terminal and storage facilities in Missouri, Nebraska, Iowa and Illinois. We also own FERC-regulated natural gas liquids distribution and refined petroleum products pipelines in Kansas, Missouri, Nebraska, Iowa, Illinois and Indiana that connect our Mid-Continent assets with Midwest markets, including Chicago, Illinois. The majority 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 where the NGLs are separated into NGL products. These NGL products are then stored or distributed to our customers, such as petrochemical manufacturers, heating fuel users, refineries and propane distributors. 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 segment are derived primarily from exchange services, optimization and marketing, pipeline transportation, isomerization and storage, defined as follows:

- Our exchange services business primarily collects fees to gather, fractionate and treat unfractionated NGLs, thereby converting them into marketable NGL products that are stored and shipped to a market center or customer-designated location.
- Our optimization and marketing 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 pipeline transportation business transports NGLs and refined petroleum products primarily under our FERC-regulated tariffs. Tariffs specify the rates we charge our customers and the general terms and conditions for NGL transportation service on our pipelines.
- 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 primarily collects fees to store NGLs at our Mid-Continent and Mont Belvieu facilities.

Unconsolidated Affiliates - Our Natural Gas Liquids 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 185 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 N of the Notes to Consolidated Financial Statements in this Annual Report for additional discussion of unconsolidated affiliates.

Market Conditions and Seasonality - Supply - Supply for our Natural Gas Liquids 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 are primarily gathered from natural gas processing plants in Oklahoma, Kansas, Texas and the Rocky Mountain region. Our fractionation operations receive NGLs from a variety of processors and pipelines, including affiliates, located in these regions.

Our Natural Gas Liquids segment is 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. For the majority of 2009, ethane prices remained above natural gas prices on a relative Btu basis, which resulted in ethane recovery from processing plants that deliver NGLs to our natural gas liquids gathering pipelines. We expect ethane prices in 2010 to remain above natural gas prices on a relative Btu basis.

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, fractionation and distribution 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, denaturant for ethanol and diluents for crude oil. Ethane/propane mix, propane, normal butane and natural gasoline are 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, NGLs and individual NGL products, which impact our NGL purchases, sales, distribution, 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 and transportation revenues. When the basis differential between the Mid-Continent and Gulf Coast regions is narrow, optimization opportunities and NGL shipments may decline, resulting in a decline in margin. 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, gathered and distributed by our natural gas liquids facilities are subject to weather-related seasonal demand, such as propane, which can be used to heat homes during the winter heating season and for agricultural purposes such as grain drying in the fall. Demand for butanes and natural gasoline, which are primarily used by the refining industry as blending stocks for motor fuel, denaturant for ethanol and diluents for crude oil, may also be subject to some variability when automotive travel is higher and during seasonal periods when certain government restrictions on blending products are in place.

Competition - Our natural gas liquids business competes with other fractionators, intrastate and interstate pipeline companies, 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:

- quality of services provided;
- producer drilling activity;
- the petrochemical industry’s level of capacity utilization and feedstock requirements;
- fees charged under our contracts;
- current and forward NGL prices;
- pressures maintained on our gathering systems;
- location of our gathering systems relative to our competitors;
- location of our gathering systems relative to drilling activity;
- proximity to natural gas liquids supply areas and markets;
- efficiency and reliability of our operations; and
- delivery capabilities that exist in each system, plant, fractionator 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, withdrawal and injection capabilities and reduce operating costs so that we may effectively compete. We believe that we compete effectively with our fractionation, pipelines and storage assets due to their strategic locations connecting supply areas to market centers.

Government Regulation - The operations and revenues of our natural gas liquids pipelines are regulated by various state and federal government agencies. Our interstate natural gas liquids pipelines are regulated by the FERC, which has authority over the terms and conditions of service, rates, which includes depreciation and amortization policies, and initiation of service. In Kansas and Texas, our intrastate natural gas liquids pipelines that provide common carrier service are subject to the jurisdiction of the KCC and RRC, respectively, which have oversight regarding services provided.

See further discussion in the “Environmental and Safety Matters” section.

ENVIRONMENTAL AND SAFETY MATTERS

Additional information about our environmental matters is included in Note K of the Notes to Consolidated Financial Statements in this Annual Report.

Pipeline Safety - We are subject to United States Department of Transportation regulations, including integrity management regulations. The Pipeline Safety Improvement Act of 2002 requires pipeline companies to perform integrity assessments on pipeline segments that pass through densely populated areas or near specifically designated high consequence areas. We are in compliance with all material requirements associated with the various pipeline safety regulations. We cannot provide assurance that existing pipeline safety regulations will not be revised or interpreted in a different manner or that new regulations will not be adopted that could result in increased compliance costs or additional operating restrictions.

Air and Water Emissions - The Clean Air Act, the 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. We are in compliance with all material requirements associated with the various air and water regulations.

The United States Congress is actively considering legislation to reduce greenhouse gas emissions, including carbon dioxide and methane. In addition, other federal, state and regional initiatives to regulate greenhouse gas emissions are under way. We are monitoring federal and state legislation to assess the potential impact on our operations. We estimate our direct greenhouse gas emissions annually as we collect all applicable greenhouse gas emission data for the previous year. Our most recent estimate indicates that our emissions are less than 4 million metric tons of carbon dioxide equivalents on an annual basis. We expect to complete our annual estimate for 2009 during the second quarter of 2010 and will post the information on our Web site when available. We will continue efforts to improve our ability to quantify our direct greenhouse gas emissions and will report such emissions as required by the EPA's Mandatory Greenhouse Gas Reporting rule released in September 2009. The rule requires greenhouse gas emissions reporting for affected facilities on an annual basis, beginning with our 2010 emissions report that will be due in March 2011 and will require us to track the emission equivalents for all NGLs delivered to our customers. At this time, no legislation or other rules have been enacted as to what costs, fees or expense will be associated with any of these emissions. In addition, the EPA has issued a proposed rule on air-quality standards, "National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines," also known as RICE NESHAP, scheduled to be adopted in early 2013. The proposed rule will require capital expenditures over the next three years for the purchase and installation of new emissions-control equipment. We do not expect these expenditures to have a material impact on our results of operations, financial position or cash flows.

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, on a preliminary basis, one of four risk-based tiers ranging from high (Tier 1) to low (Tier 4) risk, or not tiered at all due to low risk. One of our facilities has been given a Tier 4 rating, and four of our facilities have been given a preliminary Tier 4 rating. We are currently waiting for Homeland Security's analysis to determine if any of our other facilities will be tiered and require Site Security Plans and possible physical security enhancements.

Pipeline Security - Homeland Security's Transportation Security Administration, along with the United States Department of Transportation, has completed a review and inspection of our "critical facilities" and identified no material security issues.

Environmental Footprint - 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 new rules issued by the EPA, (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. We expect to complete our annual estimate for 2009 during the second quarter of 2010 and will post the information on our Web site when available.

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, 2010, we utilized some or all of the services of 1,273 people in addition to the other resources provided by ONEOK and its affiliates.

INFORMATION AVAILABLE ON OUR WEB SITE

We make available on our Web site (www.oneokpartners.com) copies of our Annual Reports, 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 provide copies of these documents upon request. Our Web site and any contents thereof are not incorporated by reference into this report.

We also make available on our Web site the Interactive Data Files voluntarily submitted as Exhibit 101 to this Annual Report. In accordance with Rule 402 of Regulation S-T, the Interactive Data Files shall not be deemed to be "filed" for purposes of Section 18 of the Exchange Act, or otherwise subject to the liability of that section, and shall not be incorporated by reference into any registration statement or other document filed under the Securities Act or the Exchange Act, except as shall be expressly set forth by specific reference in such filing.

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, 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

Market volatility and capital availability could adversely affect our business.

The capital and credit markets have been experiencing volatility and disruption. During the fourth quarter of 2008 and continuing into 2009, the volatility and disruption reached unprecedented levels. In many cases, the capital markets have exerted downward pressure on equity values 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 similar or more severe levels of market disruption and volatility return, 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 materially 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 may 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, results of operations, and liquidity.

Uncertainty in the capital markets may increase the cost of debt and equity capital, which may have a material adverse effect on our results of operations and business.

In 2008 and continuing into 2009, economic conditions in the United States experienced a downturn, primarily due to the sub-prime lending crisis, volatile energy prices, inflation concerns, slower economic activity, decreased consumer confidence, reduced corporate profits and capital spending, and increased unemployment. These conditions had an adverse impact on the credit markets. Although some of these conditions have improved in 2009 and 2010, continued uncertainty about market conditions may have an adverse effect on us resulting from, but not limited to, difficulty in obtaining financing necessary to expand facilities or acquire assets, increased financing cost and 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 that are received as payment for gathering and processing services, for the transportation and storage of natural gas, and for the sale of purity NGL products in our natural gas liquids business. Commodity prices have been volatile and are likely to continue to be so in the future. 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 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 commodity price changes. 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 prices. Our primary commodity price exposures arise from:

- the differentials between NGL and natural gas prices associated with our gas processing agreements;
- the differential between the individual NGL products with respect to our NGL transportation, fractionation and exchange agreements;
- the locational differences in the price of natural gas and NGLs with respect to our natural gas and NGL transportation businesses; and
- the seasonal differentials in natural gas and NGL prices related to our storage operations.

To manage the risk from market fluctuations in natural gas, NGL and crude oil prices, we use physical forward transactions and 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 limit the benefit we would otherwise receive if market prices for natural gas, crude oil and NGLs exceed the stated price in the hedge instrument for these commodities.

Our inability to develop and execute growth projects and acquire new assets could result in reduced 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 materially adversely impact our results of operations and cash flows and, accordingly, result in reduced cash distributions over time.

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 may require significant capital expenditures, 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 materially 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 potential 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 our resources to future acquisitions.

We do not own all of the land on which our pipelines and facilities are located, and we lease certain facilities and equipment, 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 on acceptable terms or increased costs to renew such rights, could have a material adverse effect on our financial condition, results of operations and cash flows.

Additionally, certain gas processing or other facilities (or parts thereof) used by us are leased from third parties for specific periods. Our inability to renew equipment leases or otherwise maintain the right to utilize such facilities and equipment on acceptable terms, or the increased costs to maintain such rights, could have a material adverse effect on our results of operations and cash flows.

Our operations are subject to operational hazards and unforeseen interruptions, which could materially 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.

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. 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 by third parties in the Mid-Continent, Rocky Mountain, Texas and Gulf Coast regions. Drilling and production are impacted by factors beyond our control, including:

- demand and prices for natural gas, NGLs and crude oil;
- producers’ finding and development costs of reserves;
- 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 materially 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 for some of our interstate pipelines, primarily our investment in Northern Border Pipeline, that transports 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/or production remains flat or declines, demand for transportation service on our interstate natural gas pipelines could decrease significantly, which could materially adversely impact our results of operations and cash flows available for distributions.

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 the 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 Clean Air Act and analogous state laws that impose obligations related to air emissions;

- the Clean Water Act and analogous state laws that regulate discharge of waste water from our facilities to state and federal waters;
- the federal CERCLA 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;
- 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; and the EPA has issued a proposed rule on air quality standards, known as RICE NESHAP, scheduled to be adopted in early 2013.

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 CERCLA, 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, process and store, 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 K of the Notes to Consolidated Financial Statements in this Annual Report.

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 materially 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 materially 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 capacity on our natural gas and natural gas liquids pipelines, processing, fractionation and storage assets.

Our natural gas and natural gas liquids pipelines, processing, fractionation and storage assets compete with other pipelines, processing, fractionation 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, processing, fractionation 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 collateral 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 gathered, processed, fractionated, transported or stored on our assets, 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 in 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, which could affect 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, thus hiring outside resources, 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.

Greenhouse gas emissions originate primarily from combustion engine exhaust, heater exhaust and fugitive methane gas emissions. 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 that are actually attributable to our NGL customers. 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 require 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. These proposals 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. Further, we may not be able to pass on the higher costs to our customers or recover all costs related to complying with greenhouse gas regulatory requirements. Our future results of operations, cash flows or financial condition could be adversely affected if such costs are not recovered through regulated rates or otherwise passed on to our customers.

We continue to monitor legislative and regulatory developments in this area. Although 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 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.

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 operating territory could also have an impact on our revenues. Severe weather impacts our operating 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. Our business could be affected by the potential for lawsuits against greenhouse gas emitters, based on links drawn between greenhouse gas emissions and climate change.

RISKS INHERENT IN AN INVESTMENT IN US

ONEOK's sale of 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 constituted a 45.1 percent ownership interest in us as of December 31, 2009. As a result of our February 2010 public offering of common units, ONEOK and its subsidiaries own a 42.8 percent aggregate equity 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 Partners GP and NBP Services 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 Partners GP and NBP Services 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 Partners GP and NBP Services 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 Partners GP and NBP Services 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 or not inconsistent with 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 be indemnified by the Partnership 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 owned 100 percent of our general partner interest and a 45.1 percent aggregate equity interest in us as of December 31, 2009. As a result of our February 2010 public offering of common units, ONEOK and its subsidiaries own a 42.8 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. Six of the 10 members of the Board of Directors of our general partner are either members of ONEOK's Board of Directors or executive management of ONEOK. Three independent members and one management member of the Board of Directors of our general partner are also members of ONEOK's Board of Directors, with the management member being the only management member of ONEOK's Board of Directors. Conflicts of interest may arise between ONEOK and its other 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 other 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;
- Our Partnership Agreement provides that costs incurred by the Board of Directors, our general partner and its affiliates in the conduct of our business 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 and Conflicts Committees 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 or incur debt 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) and the investment-grade rating is not reinstated within a period of 40 days; however, once the $250 million 2010 senior notes have been retired, whether by maturity, redemption or otherwise, we will no longer have any obligation to offer to repurchase the $225 million 2011 senior notes in the event our credit rating falls below investment grade. 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, 2019, 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, 2019, 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, 2009, we had total indebtedness of approximately $3.6 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 partnership 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 agreements also require us to maintain certain financial ratios, which limit the amount of additional indebtedness we can incur. Please refer to the "Liquidity and Capital Resources" section of Management's Discussion and Analysis of Financial Condition and Results of Operation. 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 subject to entity-level taxation in certain states. 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.

We determine our depreciation and cost-recovery allowances using federal income tax methods and may use methods that result in the largest deductions being taken in the early years after assets are placed in service. Some of the states in which we do business or own property may not conform to these federal depreciation methods. A successful challenge to these methods could adversely affect the amount of taxable income or loss being allocated to our unitholders for state tax purposes. It also could affect the amount of gain from a unitholder's sale of common units and could have a negative impact on the value of the common units or result in audit adjustments to the unitholder's state tax returns.

It is each unitholder's responsibility to file all United States federal, state and local tax returns and foreign tax returns, as applicable. Our legal counsel has not rendered an opinion on the state and local tax consequences of an investment in our common units.

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 10,200 miles and 4,800 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 124 MMcf/d of processing capacity in the Rocky Mountain region; and
- approximately 24 MBbl/d of natural gas liquids fractionation capacity at various natural gas processing plants in the Mid-Continent and Rocky Mountain regions.

Utilization - The utilization rates for our natural gas processing plants were approximately 68 percent and 71 percent for 2009 and 2008, respectively.

Natural Gas Pipelines

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

- approximately 1,500 miles of FERC-regulated interstate natural gas pipelines with approximately 3.1 Bcf/d of peak transportation capacity;

- approximately 5,600 miles of intrastate natural gas gathering and state-regulated intrastate transmission pipelines with peak transportation capacity of approximately 3.4 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 - Our natural gas pipelines were approximately 86 percent and 83 percent subscribed for 2009 and 2008, respectively, and our storage facilities were fully subscribed for both years.

Natural Gas Liquids

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

- approximately 2,400 miles of natural gas liquids gathering pipelines with peak capacity of approximately 502 MBbl/d;
- approximately 160 miles of natural gas liquids distribution pipelines with peak transportation capacity of approximately 66 MBbl/d;
- approximately 1,800 miles of FERC-regulated natural gas liquids gathering pipelines with peak capacity of approximately 298 MBbl/d;
- approximately 3,500 miles of FERC-regulated natural gas liquids and refined petroleum products distribution pipelines with peak transportation capacity of 691 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 our proportional share of operating capacity of approximately 128 MBbl/d;
- interest in one natural gas liquids fractionator with our proportional share of operating capacity of approximately 11 MBbl/d;
- one isomerization unit with operating capacity of 9 MBbl/d;
- six NGL storage facilities in Oklahoma, Kansas and Texas with operating storage capacity of approximately 23.2 MMBbl;
- eight NGL product terminals in Missouri, Nebraska, Iowa and Illinois; and
- above- and below-ground storage facilities associated with our FERC-regulated natural gas liquids pipeline operations in Iowa, Illinois, Nebraska and Kansas with 978 MBbl operating capacity.

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 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. 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 rates for our various assets for 2009 and 2008, respectively, were as follows:

- our non-FERC-regulated natural gas liquids pipelines were approximately 51 percent and 73 percent;
- our FERC-regulated natural gas liquids gathering pipelines were approximately 58 percent and 55 percent;
- our FERC-regulated natural gas liquids distribution pipelines were approximately 62 percent and 49 percent;
- our average contracted natural gas storage volumes were approximately 58 percent and 74 percent of storage capacity; and
- our natural gas liquids fractionators were approximately 88 percent and 87 percent.

We calculate utilization rates using a weighted-average approach, adjusting for the in-service dates of assets placed in service during 2009 and 2008. The utilization rates of our non-FERC-regulated NGL pipelines and FERC-regulated NGL gathering pipelines reflect the Arbuckle Pipeline placed in service in August 2009.

Our fractionation utilization rate reflects approximate proportional capacity associated with ownership interests noted above and for our Bushton facility, which was placed in service during the second half 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 ONEOK, Inc. and its division, Oklahoma Natural Gas, our subsidiaries 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, successor to Koch Hydrocarbon Company), as well as approximately 225 other defendants. Plaintiffs sought class certification for their claims for monetary damages, alleging 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. On September 18, 2009, the Court denied the plaintiffs' motions for class certification, which, in effect, limits the named plaintiffs to pursuing individual claims against only those defendants who purchased or measured their gas. On October 2, 2009, the plaintiffs filed a motion for reconsideration of the Court's denial of class certification, and the defendants filed their brief on January 18, 2010, in opposition to plaintiffs' motion. Oral argument on the motion was held on February 10, 2010, and the Court took the matter under advisement.

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 denied class status in Price I. Plaintiffs are seeking monetary damages based upon a claim that 21 groups of defendants, including ONEOK, Inc. and its division, Oklahoma Natural Gas, our subsidiaries 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, successor to Koch Hydrocarbon Company), 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. On September 18, 2009, the Court denied the plaintiffs' motions for class certification, which, in effect, limits the named plaintiffs to pursuing individual claims against only those defendants who purchased or measured their gas. On October 2, 2009, the plaintiffs filed a motion for reconsideration of the Court's denial of class certification, and the defendants filed their brief on January 18, 2010, in opposition to plaintiffs' motion. Oral argument on the motion was held on February 10, 2010, and the Court took the matter under advisement.

Mont Belvieu Emissions, Texas Commission on Environmental Quality - The Texas Commission on Environmental Quality (TCEQ) issued a Notice of Enforcement on March 13, 2009, alleging that air emissions at our Mont Belvieu fractionator exceeded the emissions allowed under our air permit and that we failed to isolate the source of the emissions in a timely manner. We reached agreement with the TCEQ staff on the terms of a settlement under which we would pay $160,000 and confirm that we have adopted a plan to timely address similar emissions issues in the future. Half of our payment obligation would be satisfied by contributions to local environmental projects in Texas. This settlement was incorporated into an Agreed Order, which was approved by the TCEQ on January 27, 2010. Payment of all amounts due under the order has been made, and this matter is concluded.

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, 2009		Year Ended December 31, 2008	
	High	**Low**	**High**	**Low**
First Quarter	$ 52.75	$ 34.21	$ 63.89	$ 54.58
Second Quarter	$ 49.75	$ 40.06	$ 64.01	$ 55.90
Third Quarter	$ 53.30	$ 45.80	$ 60.05	$ 50.32
Fourth Quarter	$ 63.00	$ 52.20	$ 55.88	$ 39.25

At February 12, 2010, there were 761 holders of record of our 65,162,777 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 constituted a 42.8 percent ownership interest in us upon completion of our February 2010 public offering of common units.

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,		
	2009	**2008**	**2007**
First Quarter	**$ 1.08**	$ 1.025	$ 0.98
Second Quarter	**$ 1.08**	$ 1.040	$ 0.99
Third Quarter	**$ 1.08**	$ 1.060	$ 1.00
Fourth Quarter	**$ 1.09**	$ 1.080	$ 1.01

In January 2010, our general partner declared a cash distribution of $1.10 per unit ($4.40 per unit on an annualized basis) for the fourth quarter of 2009, which was paid on February 12, 2010, to unitholders of record as of January 29, 2010.

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 all 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 during the quarter. Under the incentive distribution provisions, our general partner receives:

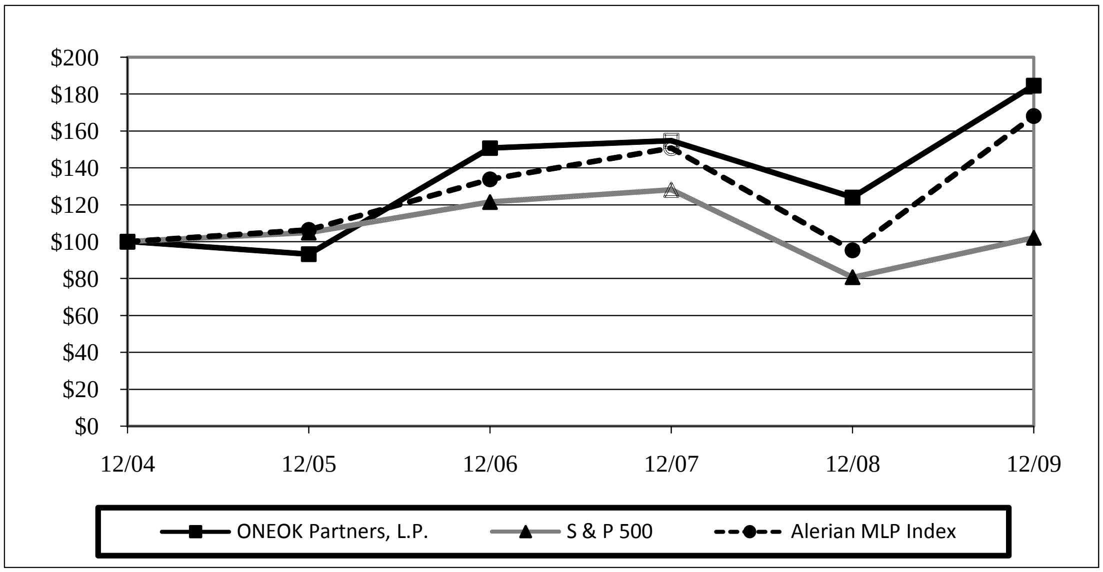
- 15 percent of amounts distributed in excess of $0.605 per unit;
- 25 percent of amounts distributed in excess of $0.715 per unit; and
- 50 percent of amounts distributed in excess of $0.935 per unit.

We paid cash distributions to our general and limited partners of $500.3 million for 2009 and $453.0 million for 2008, which included an incentive distribution to our general partner of $84.7 million for 2009 and $69.9 million for 2008. 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.

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, 2004, and ending on December 31, 2009. 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, 2004, and at the End of Every Year Through December 31, 2009, Among ONEOK Partners LP, the S&P 500 Index and the Alerian MLP Index



	Cumulative Total Return Years Ended December 31,					
	2004	2005	2006	2007	2008	2009
ONEOK Partners, L.P.	$ 100.00	$ 93.15	$ 150.70	$ 154.69	$ 123.94	**$ 184.68**
S&P 500 Index	$ 100.00	$ 104.91	$ 121.48	$ 128.15	$ 80.74	**$ 102.11**
Alerian MLP Index (a)	$ 100.00	$ 106.32	$ 133.77	$ 150.75	$ 95.24	**$ 168.06**

(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 the periods indicated:

	Years Ended December 31,				
	2009	2008	2007	2006	2005 (b)
	(In thousands of dollars, except per unit data)				
Revenues	**$ 6,474,491**	$ 7,720,206	$ 5,831,558	$ 4,738,248	$ 703,944
Income from continuing operations	**$ 434,704**	$ 626,057	$ 408,163	$ 447,578	$ 192,181
Net income	**$ 434,704**	$ 626,057	$ 408,163	$ 447,578	$ 192,687
Net income attributable to ONEOK Partners, L.P.	**$ 434,356**	$ 625,616	$ 407,747	$ 445,186	$ 147,013
Total assets	**$ 7,953,259**	$ 7,254,272	$ 6,112,065	$ 4,921,717	$ 2,527,766
Long-term debt, including current maturities	**$ 3,084,017**	$ 2,601,440	$ 2,617,326	$ 2,031,529	$ 1,123,971
Per unit income from continuing operations	**$ 3.60**	$ 6.01	$ 4.21	$ 5.01	$ 2.92
Per unit net income	**$ 3.60**	$ 6.01	$ 4.21	$ 5.01	$ 2.93
Distributions per common unit (a)	**$ 4.33**	$ 4.205	$ 3.98	$ 3.60	$ 3.20

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

(b) - Financial data for 2005 is not directly comparable with other periods presented due to the significance of the April 2006 ONEOK transactions when we completed the acquisition of and consolidated certain companies comprising ONEOK's former gathering and processing, natural gas liquids, and pipelines and storage segments.

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.

EXECUTIVE SUMMARY

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

Outlook - We expect a moderate economic recovery in 2010, with inflationary pressures beginning in 2011. Although recent volatility in the financial markets could limit our access to financial markets on a timely basis or increase our cost of capital in the future, we anticipate improved credit markets during 2010, compared with 2009; however, inflation risks may increase the cost of capital. We anticipate the consolidation of underperforming assets in the industry, particularly those with high commodity price exposure and/or high levels of debt. Additionally, we anticipate an improving commodity price environment during 2010, compared with 2009.

We intend to pursue growth in our natural gas businesses through well connections and contract renegotiations and through new plant construction, expansions and extensions of our existing systems and plants. For our natural gas liquids business, we intend to continue to focus on adding new supply connections and expanding our existing assets. We plan to spend approximately $362 million on capital expenditures in 2010, of which approximately $278 million will be for growth projects. We may also pursue strategic acquisitions related to gathering, processing, fractionating, storing, transporting or marketing natural gas and NGLs.

Segment Realignment - We implemented changes to the structure of our previous reportable business segments during the third quarter of 2009 to better align them with how we manage our businesses. Our financial results are now reported in these three reportable business segments: (i) Natural Gas Gathering and Processing; (ii) Natural Gas Pipelines, both of which remain unchanged; and (iii) Natural Gas Liquids, which consolidates our former natural gas liquids gathering and fractionation segment with our former natural gas liquids pipelines segment, due to the integrated manner in which they are managed. Prior-period amounts have been recast to reflect these segment changes.

Equity Issuances - In July 2009, we completed an underwritten public offering of 5,486,690 common units, including the partial exercise by the underwriters of their over-allotment option, at $45.81 per common unit, generating net proceeds of approximately $241.6 million. In conjunction with the offering, ONEOK Partners GP contributed an aggregate of $5.1 million in order to maintain its 2 percent general partner interest in us. We used the proceeds from the sale of common units and the general partner contributions to repay borrowings under our Partnership Credit Agreement and for general partnership purposes. As a result of these transactions, ONEOK and its subsidiaries held an aggregate 45.1 percent interest in us at December 31, 2009.

In February 2010, we completed an underwritten public offering of 5,500,900 common units, including the partial exercise by the underwriters of their over-allotment option, at $60.75 per common unit, generating net proceeds of approximately $322.6 million. In conjunction with the offering, ONEOK Partners GP contributed $6.8 million in order to maintain its 2 percent general partner interest in us. We used the proceeds from the sale of common units and the general partner contribution to repay borrowings under our Partnership Credit Agreement and for general partnership purposes. As a result of these transactions, ONEOK and its subsidiaries own a 42.8 percent aggregate equity interest in us.

Debt Issuance - In March 2009, we completed an underwritten public offering of $500 million aggregate principal amount of 8.625 percent Senior Notes due 2019. We used the net proceeds of approximately $494.3 million from the offering to repay indebtedness outstanding under our Partnership Credit Agreement.

Cash Distributions - During 2009, we paid cash distributions totaling $4.33 per unit, an increase of approximately 3 percent over the $4.205 per unit paid during 2008. In January 2010, our general partner declared a cash distribution of $1.10 per unit ($4.40 per unit on an annualized basis), an increase of approximately 2 percent over the $1.08 declared in January 2009.

Capital Projects - The following projects were placed in service during 2009:
- Guardian Pipeline’s natural gas pipeline expansion and extension project;
- Williston Basin natural gas processing plant expansion;
- Arbuckle natural gas liquids pipeline;
- D-J Basin lateral natural gas liquids pipeline; and
- Piceance lateral natural gas liquids pipeline.

Operating Results - Net income per unit decreased to $3.60 in 2009, compared with $6.01 in 2008. The decrease in net income per unit in 2009 was due primarily to the following:
- a decrease in net margin due primarily to:
  - lower realized commodity prices in our Natural Gas Gathering and Processing segment;
  - narrower NGL product price differentials in our Natural Gas Liquids segment; and
  - a decrease related to prior-year operational measurement gains, primarily at NGL storage caverns; offset partially by
  - higher NGL volumes gathered, fractionated and transported, primarily associated with the completion of the Overland Pass Pipeline and related expansion projects, and the Arbuckle Pipeline, as well as new NGL supply connections in our Natural Gas Liquids segment;
  - higher natural gas transportation margins from the Guardian Pipeline expansion and extension that was completed in February 2009 and an increase in volumes contracted on Midwestern Gas Transmission in our Natural Gas Pipelines segment; and
  - higher volumes processed and sold in our Natural Gas Gathering and Processing segment;
- an increase in operating costs resulting from the operation of the Overland Pass Pipeline and the Arbuckle Pipeline and increased costs at our fractionation facilities, which includes the expanded Bushton Plant fractionator;
- an increase in depreciation expense associated with our completed capital projects;
- an increase in interest expense due primarily to our March 2009 debt issuance and a decrease in capitalized interest due to the completion of our capital projects; and
- an increase in the number of common units outstanding.

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 Energy Partners, L.P. (Kinder Morgan) for approximately $300 million, before working capital adjustments. The FERC-regulated 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 transaction also included a 50 percent ownership interest in 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 products 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 working capital settlement was finalized in April 2008, with no material adjustments. These assets are included in our Natural Gas Liquids segment.

CAPITAL PROJECTS

Overland Pass Pipeline - 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. Overland Pass Pipeline Company is a joint venture between us and a subsidiary of The Williams Companies, Inc. (Williams). We own 99 percent of the joint venture and operate the pipeline. On or before November 17, 2010, Williams has the option to increase its ownership in Overland Pass Pipeline Company, which includes the Piceance Lateral and D-J Basin Lateral pipeline projects, up to a total of 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. If Williams does not elect to increase its ownership to at least 10 percent, we will have the right, but not the obligation, to purchase Williams' entire ownership interest, with the purchase price being determined in accordance with the joint venture's operating agreement. The project costs for the Overland Pass Pipeline, the Piceance Lateral Pipeline and the DJ Basin Lateral Pipeline in total are approximately $780 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, capable of delivering over 70 MBbl/d to the Overland Pass Pipeline. We provide downstream fractionation, storage and transportation services to Williams. We have also reached agreements with certain producers for supply commitments to the D-J Basin and Piceance Lateral pipelines. We have NGL production dedicated from new and existing plants that we expect to provide throughput of more than 200 MBbl/d to the Overland Pass Pipeline over 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, Kansas, location, which increased the total fractionation capacity at the Bushton facility to 150 MBbl/d from 80 MBbl/d. The addition of the new facilities and the upgrade to the existing fractionator were 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 and the associated expansions are included in our Natural Gas Liquids segment.

Piceance Lateral Pipeline - In October 2009, Overland Pass Pipeline Company placed in service the 150-mile natural gas liquids lateral pipeline from the Piceance Basin in Colorado to the Overland Pass Pipeline. The pipeline has capacity to transport as much as 100 MBbl/d of unfractionated NGLs. Williams has dedicated its NGL production from its new Willow Creek natural gas processing plant and will dedicate NGL production from an additional existing natural gas processing plant. Another plant owned by a third party has also been dedicated. We continue to negotiate with other producers for supply commitments.

D-J Basin Lateral Pipeline - In March 2009, Overland Pass Pipeline Company placed in service the 125-mile natural gas liquids lateral pipeline from the Denver-Julesburg Basin in northeastern Colorado to the Overland Pass Pipeline. The pipeline has capacity to transport as much as 55 MBbl/d of unfractionated NGLs. We continue to discuss with our producers opportunities from new drilling and plant upgrades over the next two years.

Arbuckle Natural Gas Liquids Pipeline - In August 2009, the 440-mile Arbuckle pipeline project, a natural gas liquids pipeline system that delivers unfractionated NGLs from points in southern Oklahoma and Texas to the Texas Gulf Coast, was placed in service. The Arbuckle pipeline system has the capacity to transport 160 MBbl/d of unfractionated NGLs, expandable to 240 MBbl/d with additional pump facilities, and connects our existing Mid-Continent infrastructure with our fractionation facility in Mont Belvieu, Texas, and other Gulf Coast region fractionators. We have NGL production dedicated from existing and new natural gas processing plants that we expect to provide throughput of more than 210 MBbl/d over the next three to five years.

The demand for surface easements increased dramatically in Texas and Oklahoma over the last two years because of increased oil and natural gas exploration and production activities, as well as pipeline construction. As previously reported, project costs have been more expensive than originally estimated due to delays associated with right-of-way acquisition, increased materials costs and difficult construction conditions associated with several weeks of heavy spring rains in 2009, resulting in greatly reduced construction productivity. We also experienced increased costs due to a number of scope changes, arising primarily from additional supply development opportunities. We estimate project costs will be approximately $490 million, excluding AFUDC, for the current capacity.

Williston Basin Gas Processing Plant Expansion - The expansion of our Grasslands natural gas processing facility in North Dakota was placed in service in March 2009. The expansion increased processing capacity to approximately 100 MMcf/d from its previous capacity of 63 MMcf/d and increased fractionation capacity to approximately 12 MBbl/d from 8 MBbl/d. The cost of the project was approximately $46 million, excluding AFUDC. This project is in our Natural Gas Gathering and Processing segment.

Guardian Pipeline Expansion and Extension - In February 2009, we completed the 119-mile extension of our Guardian Pipeline. The pipeline has 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 is close to fully subscribed. The project cost approximately $320 million, excluding AFUDC. This project is in our Natural Gas Pipelines segment.

IMPACT OF NEW ACCOUNTING STANDARDS

Information about the impact of new accounting standards is included in Note A of the Notes to Consolidated Financial Statements in this Annual Report:

- references to accounting standards literature under the FASB Accounting Standards Codification;
- presentation and disclosure requirements for noncontrolling interests;
- enhanced disclosures about derivative instruments and hedging activities;
- ASU 2010-06, “Improving Disclosures about Fair Value Measurements;”
- net income per unit calculations for master limited partnerships with incentive distributions rights; and
- disclosure of subsequent events review.

The above accounting standards did not or are not expected to have a material impact on our consolidated financial statements, results of operations or cash flows.

CRITICAL ACCOUNTING POLICIES AND 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 Goodwill, Long-Lived Assets and Intangible Assets - We assess our goodwill for impairment at least annually. There were no impairment charges resulting from our July 1, 2009, 2008 or 2007 impairment tests.

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. To estimate the fair value of our reporting units, we use two generally accepted valuation approaches, an income approach and a market approach. Under the income approach, we use anticipated cash flows over a period of years plus a terminal value and discount these amounts to their present value using appropriate rates of return that are consistent with a market participant’s perspective. Under the market approach, we apply multiples to forecasted cash flows. The multiples used are consistent with a market participant’s perspective of historical asset transactions The forecasted cash flows are consistent with a market participant’s perspective of average forecasted cash flows for a reporting unit over a period of years.

Our estimates of fair value significantly exceeded the book value of our reporting units in our July 1, 2009, impairment test. Even if the estimated fair values used in our July 1, 2009, impairment test were reduced by 10 percent, no impairment charges would have resulted. The following table sets forth our goodwill, by segment, at both December 31, 2009 and 2008:

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

See Notes A and F of the Notes to Consolidated Financial Statements in this Annual Report for additional discussion of goodwill and related disclosures.

We assess our long-lived assets, including intangible assets with a finite useful life, for impairment whenever events or changes in circumstances indicate that its carrying amount may exceed its fair value. In step one of the impairment test, the carrying amount of a long-lived asset is not recoverable if it exceeds the sum of the undiscounted future cash flows expected to result from the use and eventual disposition of the asset. If the carrying amount is not recoverable, we record an impairment loss equal to the difference between the carrying value and the fair value of the long-lived asset. This type of analysis requires us to make assumptions and estimates regarding industry economic factors and the profitability of future business strategies. We determined that there were no asset impairments in 2009, 2008 or 2007.

We had $272.2 million and $279.8 million of intangible assets recorded on our Consolidated Balance Sheets as of December 31, 2009 and 2008, respectively, all of which was recorded in our Natural Gas Liquids segment.

For the investments we account for under the equity method, the impairment test 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 re-evaluate the amount at which we carry our equity method investments to determine whether current events or circumstances warrant adjustments to our carrying value. We determined that there were no impairments to our investments in unconsolidated affiliates in 2009, 2008 or 2007.

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.

Derivatives and Risk Management - We utilize derivatives to reduce our market risk exposure to interest rate and commodity price fluctuations and achieve more predictable cash flows. Market value changes result in a change in the fair value of our derivative instruments. We do not believe that changes in our fair value estimates of our derivative instruments have a material impact on our results of operations, as the majority of our derivatives are accounted for as cash flow hedges for which ineffectiveness is not material. For more information on commodity price sensitivity and a discussion of the market risk of pricing changes, see Item 7A, Quantitative and Qualitative Disclosures about Market Risk.

See Notes C and D of the Notes to Consolidated Financial Statements in this Annual Report for additional discussion of fair value measurements and 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. 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. Our expenditures for environmental evaluation, mitigation, remediation and compliance to date have not been significant in relation to our financial position or results of operations, and our expenditures related to environmental matters had no material effects upon earnings or cash flows during 2009, 2008 and 2007. Actual results may differ from our estimates resulting in an impact, positive or negative, on earnings. See Note K of the Notes to Consolidated Financial Statements in this Annual Report 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, 2009	2008	2007	Variances 2009 vs. 2008 Increase (Decrease)		Variances 2008 vs. 2007 Increase (Decrease)	
				(Millions of dollars)			
Revenues	**$ 6,474.5**	$ 7,720.2	$ 5,831.6	**$ (1,245.7)**	**(16%)**	$ 1,888.6	32%
Cost of sales and fuel	**5,355.2**	6,579.5	4,935.7	**(1,224.3)**	**(19%)**	1,643.8	33%
Net margin	**1,119.3**	1,140.7	895.9	**(21.4)**	**(2%)**	244.8	27%
Operating costs	**411.3**	371.8	337.4	**39.5**	**11%**	34.4	10%
Depreciation and amortization	**164.1**	124.8	113.7	**39.3**	**31%**	11.1	10%
Gain on sale of assets	**2.7**	0.7	2.0	**2.0**	*****	(1.3)	(65%)
Operating income	**$ 546.6**	$ 644.8	$ 446.8	**$ (98.2)**	**(15%)**	$ 198.0	44%
Equity earnings from investments	**$ 72.7**	$ 101.4	$ 89.9	**$ (28.7)**	**(28%)**	$ 11.5	13%
Allowance for equity funds used during construction	**$ 26.9**	$ 50.9	$ 12.5	**$ (24.0)**	**(47%)**	$ 38.4	*
Interest expense	**$ (206.0)**	$ (151.1)	$ (138.9)	**$ 54.9**	**36%**	$ 12.2	9%
Capital expenditures	**$ 615.7**	$ 1,253.9	$ 709.9	**$ (638.2)**	**(51%)**	$ 544.0	77%

* Percentage change is greater than 100 percent.

2009 vs. 2008 - Net margin decreased due primarily to the following:

- lower realized commodity prices in our Natural Gas Gathering and Processing segment;
- narrower NGL product price differentials in our Natural Gas Liquids segment; and
- a decrease related to prior-year operational measurement gains, primarily at NGL storage caverns; offset partially by
- higher NGL volumes gathered, fractionated and transported, primarily associated with the completion of the Overland Pass Pipeline and related expansion projects, and the Arbuckle Pipeline, as well as new NGL supply connections in our Natural Gas Liquids segment;
- higher natural gas transportation margins from the Guardian Pipeline expansion and extension that was completed in February 2009 and an increase in volumes contracted on Midwestern Gas Transmission in our Natural Gas Pipelines segment; and
- higher volumes processed and sold in our Natural Gas Gathering and Processing segment.

Operating costs increased due primarily to higher employee-related costs, incremental costs associated with the operation of the Overland Pass Pipeline, the Arbuckle Pipeline and the expanded Bushton Plant fractionator, outside services expenses and general taxes related to our completed capital projects.

Depreciation and amortization increased due primarily to our completed capital projects, which are discussed beginning on page 37.

Equity earnings from investments decreased due primarily to lower subscription volumes and rates on Northern Border Pipeline. Additionally, there was a gain on the sale of Bison Pipeline LLC by Northern Border Pipeline in 2008. Equity earnings from investments also decreased due to lower volumes gathered in our Natural Gas Gathering and Processing segment's equity investments, whose assets are primarily located in the Powder River Basin of Wyoming.

Allowance for equity funds used during construction decreased due primarily to the completion of the Arbuckle Pipeline, the Overland Pass Pipeline and related expansion projects, and the Guardian Pipeline expansion and extension.

Interest expense increased due primarily to our March 2009 debt issuance and a decrease in capitalized interest due to the completion of our capital projects.

Capital expenditures decreased due primarily to the completion of our capital projects.

2008 vs. 2007 - Net margin increased due primarily 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 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 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 due primarily to incremental operating expenses associated with the assets acquired from Kinder Morgan, increased outside services primarily associated with scheduled maintenance activities 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 due primarily to our completed capital projects and the assets acquired from Kinder Morgan.

Equity earnings from investments increased due primarily to higher gathering revenues in our various investments as well as a gain on the sale of Bison Pipeline LLC by Northern Border Pipeline in 2008, offset partially 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 37.

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

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 - The following table sets forth certain selected financial results for our Natural Gas Gathering and Processing segment for the periods indicated:

	Years Ended December 31,			Variances 2009 vs. 2008		Variances 2008 vs. 2007	
Financial Results	**2009**	**2008**	**2007**	**Increase (Decrease)**		**Increase (Decrease)**	
			(Millions of dollars)				
NGL and condensate sales	**$ 578.5**	$ 851.7	$ 673.8	**$ (273.2)**	**(32%)**	$ 177.9	26%
Residue gas sales	**363.0**	750.4	636.8	**(387.4)**	**(52%)**	113.6	18%
Gathering, compression, dehydration and processing fees and other revenue	**153.1**	154.1	148.1	**(1.0)**	**(1%)**	6.0	4%
Cost of sales and fuel	**734.6**	1,321.0	1,092.2	**(586.4)**	**(44%)**	228.8	21%
Net margin	**360.0**	435.2	366.5	**(75.2)**	**(17%)**	68.7	19%
Operating costs	**135.1**	138.2	135.4	**(3.1)**	**(2%)**	2.8	2%
Depreciation and amortization	**59.3**	49.9	45.1	**9.4**	**19%**	4.8	11%
Gain on sale of assets	**2.8**	-	1.8	**2.8**	**100%**	(1.8)	(100%)
Operating income	**$ 168.4**	$ 247.1	$ 187.8	**$ (78.7)**	**(32%)**	$ 59.3	32%
Equity earnings from investments	**$ 28.4**	$ 32.8	$ 26.4	**$ (4.4)**	**(13%)**	$ 6.4	24%
Capital expenditures	**$ 105.5**	$ 146.2	$ 83.8	**$ (40.7)**	**(28%)**	$ 62.4	74%

2009 vs. 2008 - Net margin decreased primarily as a result of the following:

- a decrease of $106.0 million due to lower realized commodity prices; offset partially by
- an increase of $22.3 million due to higher volumes processed and sold;
- an increase of $6.5 million from selling our Lehman Brothers bankruptcy claims related to receivables owed to us; and
- an increase of $1.8 million due to improved contractual terms.

Operating costs decreased primarily as a result of lower costs for chemicals and maintenance activities. These decreases were offset partially by higher employee-related costs.

Depreciation and amortization increased primarily as a result of our completed capital projects.

Gain on sale of assets increased due to the sale of excess compression equipment.

Equity earnings from investments decreased primarily as a result of decreased earnings from lower volumes gathered in our equity investments, which are primarily located in the Powder River Basin of Wyoming.

Capital expenditures decreased due primarily to the completion of a pipeline expansion project into the Woodford Shale in September of 2008 in Oklahoma and the Williston Basin gas processing plant expansion.

2008 vs. 2007 - Net margin increased due primarily 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; offset partially by
- a decrease of $8.6 million due to a one-time favorable contract settlement that occurred in the fourth quarter of 2007.

Operating costs increased due primarily 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 offset partially by decreased equipment lease costs in 2008 associated with the Bushton Plant.

Depreciation and amortization increased primarily as a result of our completed capital projects.

Equity earnings from investments increased due primarily 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.

Selected Operating Information - The following tables set forth selected operating information for our Natural Gas Gathering and Processing segment for the periods indicated:

	Years Ended December 31,		
Operating Information	**2009**	**2008**	**2007**
Natural gas gathered *(BBtu/d)* (a)	**1,123**	1,164	1,171
Natural gas processed *(BBtu/d)* (a)	**658**	641	621
NGL sales *(MBbl/d)* (a)	**43**	39	38
Residue gas sales *(BBtu/d)* (a)	**291**	279	281
Realized composite NGL net sales price *($/gallon)* (b)	**$ 0.90**	$ 1.26	$ 0.98
Realized condensate net sales price *($/Bbl)* (b)	**$ 78.35**	$ 88.35	$ 67.11
Realized residue gas net sales price *($/MMBtu)* (b)	**$ 3.55**	$ 7.53	$ 5.17
Realized gross processing spread *($/MMBtu)* (a)	**$ 6.63**	$ 7.47	$ 5.21

(a) - Includes volumes for consolidated entities only.

(b) - Includes equity volumes only.

Operating Information (a)	Years Ended December 31, 2009	2008	2007
Percent of proceeds			
Wellhead purchases *(MMBtu/d)*	**53,581**	67,718	83,993
NGL sales *(Bbl/d)*	**5,472**	4,578	5,959
Residue gas sales *(MMBtu/d)*	**41,768**	39,724	34,010
Condensate sales *(Bbl/d)*	**1,735**	1,693	719
Percentage of total net margin	**50%**	62%	56%
Fee-based			
Wellhead volumes *(MMBtu/d)*	**1,122,861**	1,164,273	1,170,502
Average rate *($/MMBtu)*	**$ 0.30**	$ 0.26	$ 0.25
Percentage of total net margin	**35%**	23%	30%
Keep-whole			
NGL shrink *(MMBtu/d)*	**17,400**	21,354	23,636
Plant fuel *(MMBtu/d)*	**2,031**	2,288	2,846
Condensate shrink *(MMBtu/d)*	**1,727**	1,825	2,490
Condensate sales *(Bbl/d)*	**349**	369	504
Percentage of total net margin	**15%**	15%	14%

Commodity Price Risk - Our Natural Gas Gathering and Processing segment is exposed to commodity price risk 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 55 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:

Financial Results	Years Ended December 31, 2009	2008	2007	Variances 2009 vs. 2008 Increase (Decrease)		Variances 2008 vs. 2007 Increase (Decrease)	
				(Millions of dollars)			
Transportation revenues	**$ 230.6**	$ 240.0	$ 225.4	**$ (9.4)**	**(4%)**	$ 14.6	6%
Storage revenues	**62.1**	63.7	54.8	**(1.6)**	**(3%)**	8.9	16%
Gas sales and other revenues	**50.1**	38.4	21.8	**11.7**	**30%**	16.6	76%
Cost of sales	**57.0**	84.7	60.9	**(27.7)**	**(33%)**	23.8	39%
Net margin	**285.8**	257.4	241.1	**28.4**	**11%**	16.3	7%
Operating costs	**96.1**	89.9	96.6	**6.2**	**7%**	(6.7)	(7%)
Depreciation and amortization	**43.7**	34.3	32.4	**9.4**	**27%**	1.9	6%
Gain (loss) on sale of assets	**(0.7)**	-	0.1	**(0.7)**	**(100%)**	(0.1)	(100%)
Operating income	**$ 145.3**	$ 133.2	$ 112.2	**$ 12.1**	**9%**	$ 21.0	19%
Equity earnings from investments	**$ 41.9**	$ 66.7	$ 62.5	**$ (24.8)**	**(37%)**	$ 4.2	7%
Allowance for equity funds used during construction	**$ 1.6**	$ 14.0	$ 3.6	**$ (12.4)**	**(89%)**	$ 10.4	*
Capital expenditures	**$ 62.2**	$ 267.0	$ 138.9	**$ (204.8)**	**(77%)**	$ 128.1	92%

* Percentage change is greater than 100 percent.

Operating Information (a)	Years Ended December 31, 2009	2008	2007
Natural gas transportation capacity contracted *(MMcf/d)*	**5,551**	4,878	4,713
Transportation capacity subscribed	**86%**	83%	80%
Average natural gas price Mid-Continent region *($/MMBtu)*	**$ 3.28**	$ 7.17	$ 6.05

(a) - Includes volumes for consolidated entities only.

2009 vs. 2008 - Net margin increased primarily as a result of the following:

- an increase of $38.8 million from higher natural gas transportation margins, excluding retained fuel, primarily as a result of incremental margin from the Guardian Pipeline expansion and extension that was completed in February 2009 and an increase in volumes contracted on Midwestern Gas Transmission as a result of a new interconnect with the Rockies Express Pipeline that was placed in service beginning in June 2009; and
- an increase of $8.6 million from higher natural gas storage margins, excluding retained fuel, primarily as a result of contract renegotiations; offset partially by
- a decrease of $18.6 million from the impact of lower natural gas prices on retained fuel offset partially by higher natural gas sales volumes.

Operating costs increased due primarily to higher general taxes associated with the Guardian Pipeline expansion and extension and increased employee-related costs.

Depreciation and amortization increased primarily as a result of our completed capital projects.

Equity earnings from investments decreased due primarily to lower subscription volumes and rates on Northern Border Pipeline. Additionally, there was an $8.3 million gain on the sale of Bison Pipeline LLC by Northern Border Pipeline in 2008. We own a 50 percent equity interest in Northern Border Pipeline.

Allowance for equity funds used during construction and capital expenditures decreased due primarily to the Guardian Pipeline expansion and extension that was completed in February 2009. See discussion of the Guardian Pipeline expansion and extension beginning on page 38.

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 due primarily to lower general taxes and decreased employee-related costs.

Depreciation and amortization increased primarily as a result of our completed capital projects.

Equity earnings from investments increased due primarily to an $8.3 million gain on the sale of Bison Pipeline LLC by Northern Border Pipeline in 2008, offset partially 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 primarily to increased spending for our capital projects, which are discussed beginning on page 37.

Natural Gas Liquids

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

Financial Results	Years Ended December 31, 2009	2008	2007	Variances 2009 vs. 2008 Increase (Decrease)		Variances 2008 vs. 2007 Increase (Decrease)	
				(Millions of dollars)			
NGL and condensate sales	**$ 4,962.2**	$ 5,943.6	$ 4,314.8	**$ (981.4)**	**(17%)**	$ 1,628.8	38%
Exchange service and storage revenues	**365.1**	329.1	272.7	**36.0**	**11%**	56.4	21%
Transportation revenues	**94.4**	55.3	13.9	**39.1**	**71%**	41.4	*
Cost of sales and fuel	**4,945.3**	5,879.3	4,314.2	**(934.0)**	**(16%)**	1,565.1	36%
Net margin	**476.4**	448.7	287.2	**27.7**	**6%**	161.5	56%
Operating costs	**182.2**	143.1	99.6	**39.1**	**27%**	43.5	44%
Depreciation and amortization	**61.2**	40.6	36.2	**20.6**	**51%**	4.4	12%
Loss on sale of assets	**(0.2)**	-	-	**(0.2)**	**(100%)**	-	0%
Operating income	**$ 232.8**	$ 265.0	$ 151.4	**$ (32.2)**	**(12%)**	$ 113.6	75%
Equity earnings from investments	**$ 2.5**	$ 2.0	$ 1.0	**$ 0.5**	**25%**	$ 1.0	100%
Allowance for equity funds used during construction	**$ 25.3**	$ 36.9	$ 8.9	**$ (11.6)**	**(31%)**	$ 28.0	*
Capital expenditures	**$ 446.9**	$ 840.4	$ 487.0	**$ (393.5)**	**(47%)**	$ 353.4	73%

* Percentage change is greater than 100 percent.

Operating Information	Years Ended December 31, 2009	2008	2007
NGL sales *(MBbl/d)*	**408**	283	231
NGLs fractionated *(MBbl/d)*	**481**	389	356
NGLs transported-gathering lines *(MBbl/d)*	**372**	260	230
NGLs transported-distribution lines *(MBbl/d)*	**459**	331	240
Conway-to-Mont Belvieu OPIS average price differential Ethane *($/gallon)*	**$ 0.11**	$ 0.15	$ 0.06

2009 vs. 2008 - Net margin increased primarily as a result of the following:

- an increase of $68.7 million due to increased volumes gathered, fractionated and transported, primarily associated with the completion of the Overland Pass Pipeline and related expansion projects, and the Arbuckle Pipeline, as well as new supply connections; and
- an increase of $5.0 million due to higher storage margins as a result of contract renegotiations; offset partially by
- a decrease of $41.7 million related to narrower NGL product price differentials, offset partially by increased volumes marketed; and
- a decrease of $4.3 million due to higher operational measurement gains in the prior year, primarily at NGL storage caverns.

Operating costs increased due primarily to the operation of the Overland Pass Pipeline, the Arbuckle Pipeline and the expanded Bushton Plant fractionator, increased outside services expenses, incremental general taxes and higher employee-related costs, offset in part by lower maintenance costs due to a planned maintenance shutdown at our Mont Belvieu, Texas, fractionator in 2008.

Depreciation and amortization increased due primarily to the completion of the Arbuckle Pipeline and the Overland Pass Pipeline and related projects, including the new and modified fractionation facilities at the Bushton Plant.

Allowance for equity funds used during construction and capital expenditures decreased due primarily to the completion of the Overland Pass Pipeline, Arbuckle Pipeline and associated fractionation and storage expansions, which are discussed beginning on page 37.

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

- an increase of $88.6 million due to more favorable NGL product price differentials;
- an increase of $58.7 million due to increased volumes gathered, fractionated and transported, primarily associated with the assets acquired from Kinder Morgan in October 2007, new supply connections and Overland Pass Pipeline, which began operating during the fourth quarter of 2008; offset partially by increased fuel costs associated with higher volumes;
- an increase of $8.4 million from certain operational measurement gains, primarily at NGL storage caverns;
- an increase of $5.7 million due to higher storage margins in our Mid-Continent storage business.

Operating costs increased due primarily to $20.6 million in incremental operating expenses associated with the assets acquired from Kinder Morgan, costs associated with the startup of operations of Overland Pass Pipeline and our newly expanded Bushton, Kansas, fractionator, maintenance projects at our Medford, Oklahoma, fractionator, increased lease costs for our Bushton facility, expenses related to a planned maintenance shutdown at our Mont Belvieu fractionators and higher employee-related costs and outside services.

Capital expenditures increased due primarily to our growth activities associated with Overland Pass Pipeline and related projects, which include the expansion of the Bushton facility. See discussion of our capital projects beginning on page 37.

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. Additional information about legal proceedings is included under Part I, Item 3, Legal Proceedings, in this Annual Report.

LIQUIDITY AND CAPITAL RESOURCES

General - Part of our strategy is to grow through internally generated growth projects and acquisitions that strengthen and complement our existing assets. We have relied primarily on operating cash flow, bank credit facilities, debt issuances and the sale of common units for our liquidity and capital resources requirements. We fund our operating expenses, debt service and cash distributions to our limited partners and general partner primarily with operating cash flow. We expect to continue to use these sources for liquidity and capital resource needs on both a short- and long-term basis. We have no guarantees of debt or other similar commitments to unaffiliated parties.

During 2009, the capital markets improved significantly from year-end 2008. Throughout 2009 and continuing in 2010, we have continued to have access to our Partnership Credit Agreement to fund our short-term liquidity needs, and we have been able to access the public debt and equity markets for our long-term financing needs. In 2009 and February 2010, we issued common units, and in 2009, we issued debt in public offerings and received additional capital contributions from our general partner. See discussion below under “Equity Issuance” and “Debt Issuance” for more information.

We expect a moderate economic recovery in 2010, with inflationary pressures beginning in 2011. Although recent volatility in the financial markets could limit our access to financial markets on a timely basis or increase our cost of capital in the future, we anticipate improved credit markets during 2010, compared with 2009. Our ability to continue to access capital markets for debt and equity financing under reasonable terms depends on our financial condition and 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, as well as capital expenditures.

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

	December 31,	
	2009	**2008**
Long-term debt	**51%**	47%
Equity	**49%**	53%
Debt (including notes payable)	**55%**	54%
Equity	**45%**	46%

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 pursuant to FERC regulations or our operating agreement. 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 Partnership Credit Agreement.

The total amount of short-term borrowings authorized by our general partner's Board of Directors is $1.5 billion. At December 31, 2009, we had $523 million of borrowings outstanding under our Partnership Credit Agreement, which expires March 2012, and available cash and cash equivalents of approximately $3.2 million. As of December 31, 2009, our borrowing capacity was limited to $367.1 million of additional short- and long-term debt under the most restrictive provisions contained in our Partnership Credit Agreement. At December 31, 2009, we had a total of $24.2 million in letters of credit issued outside of the Partnership Credit Agreement.

Our Partnership Credit Agreement contains certain financial, operational and legal covenants as discussed in Note H of the Notes to Consolidated Financial Statements in this Annual Report. Among other things, these covenants include maintaining a ratio of indebtedness to adjusted EBITDA (EBITDA, as defined in our Partnership Credit Agreement, as adjusted for all non-cash charges and increased for projected EBITDA from certain lender-approved capital expansion projects) 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, 2009, our ratio of indebtedness to adjusted EBITDA was 4.5 to 1, and we were in compliance with all covenants under our Partnership Credit Agreement.

At December 31, 2009, the average interest rate on our short-term debt outstanding was 0.54 percent and the weighted average for the year ended December 31, 2009, was 2.13 percent. Based on the forward LIBOR curve, we expect the interest rates on our short-term borrowings to increase in 2010, compared with interest rates on amounts outstanding at December 31, 2009.

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 the sale and leaseback of facilities.

We are subject to changes in the debt and equity markets, and there is no assurance we will be able or willing to access the public or private markets in the future. 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. 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.

Equity Issuances - In July 2009, we completed an underwritten public offering of 5,486,690 common units, including the partial exercise by the underwriters of their over-allotment option, at $45.81 per common unit, generating net proceeds of approximately $241.6 million. In conjunction with the offering, ONEOK Partners GP contributed an aggregate of $5.1 million in order to maintain its 2 percent general partner interest in us. We used the proceeds from the sale of common units and the general partner contributions to repay borrowings under our Partnership Credit Agreement and for general partnership purposes.

In February 2010, we completed an underwritten public offering of 5,500,900 common units, including the partial exercise by the underwriters of their over-allotment option, at $60.75 per common unit, generating net proceeds of approximately $322.6 million. In conjunction with the offering, ONEOK Partners GP contributed $6.8 million in order to maintain its 2 percent general partner interest in us. We used the proceeds from the sale of common units and the general partner contribution to repay borrowings under our Partnership Credit Agreement and for general partnership purposes. As a result of these transactions, ONEOK and its subsidiaries own a 42.8 percent aggregate equity interest in us.

Debt Issuance - In March 2009, we completed an underwritten public offering of $500 million aggregate principal amount of 8.625 percent Senior Notes due 2019 (the 2019 Notes). We used the net proceeds of approximately $494.3 million from the offering to repay indebtedness outstanding under our Partnership Credit Agreement. The 2019 Notes are nonrecourse to our general partner. For more information regarding the 2019 Notes, refer to discussion in Note I of the Notes to Consolidated Financial Statements in this Annual Report.

Debt Covenants - The terms of the 2019 Notes are governed by an indenture, dated as of September 25, 2006, between us and Wells Fargo Bank, N.A., as trustee, as supplemented by the Fifth Supplemental Indenture, dated March 3, 2009 (Indenture). The Indenture 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 to sell and lease back our property.

Our $250 million and $225 million senior notes, due June 15, 2010, and March 15, 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;, however, once the $250 million 2010 senior notes have been retired, whether by maturity, redemption or otherwise, we will no longer have any obligation to offer to repurchase the $225 million 2011 senior notes in the event our credit rating falls below investment grade. 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, 2019, 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 events 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, 2019, 2036 and 2037 to declare those notes immediately due and payable in full.

We may redeem the notes due 2012, 2016, 2019, 2036 and 2037, in whole or in part, at any time prior to their maturity at a redemption price equal to the principal amount, 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 respective note plus accrued and unpaid interest to the redemption date. The notes due 2012, 2016, 2019, 2036 and 2037 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 and future debt and other liabilities of any non-guarantor subsidiaries. Our long-term debt is nonrecourse to our general partner.

Capital Expenditures - Our capital expenditures are typically financed through operating cash flows, short- and long-term debt and the issuance of equity. Capital expenditures were $615.7 million, $1,253.9 million and $709.9 million for 2009, 2008 and 2007, respectively, exclusive of acquisitions. 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.

Capital expenditures in 2009 were significantly less than 2008 capital expenditures, due primarily to the completion of the Arbuckle Pipeline, the Overland Pass Pipeline and related expansion projects, the Williston Basin gas processing plant expansion and the Guardian Pipeline expansion and extension.

The following tables set forth our growth and maintenance capital expenditures for the periods indicated:

Growth Capital Expenditures	2009	2008	2007
		(Millions of dollars)	
Natural Gas Gathering and Processing	**$ 85.1**	$ 123.0	$ 64.8
Natural Gas Pipelines	**46.9**	241.0	123.6
Natural Gas Liquids	**423.3**	808.0	461.9
Other	**1.1**	-	-
Total growth capital expenditures	**$ 556.4**	$ 1,172.0	$ 650.3

Maintenance Capital Expenditures	2009	2008	2007
		(Millions of dollars)	
Natural Gas Gathering and Processing	**$ 20.4**	$ 23.2	$ 19.0
Natural Gas Pipelines	**15.3**	26.0	15.3
Natural Gas Liquids	**23.6**	32.4	25.2
Other	**-**	0.3	0.1
Total maintenance capital expenditures	**$ 59.3**	$ 81.9	$ 59.6

The following table summarizes our 2010 projected growth and maintenance capital expenditures, excluding AFUDC:

2010 Projected Capital Expenditures	Growth	Maintenance	Total
		(Millions of dollars)	
Natural Gas Gathering and Processing	$ 115	$ 22	$ 137
Natural Gas Pipelines	9	22	31
Natural Gas Liquids	154	38	192
Other	-	2	2
Total projected capital expenditures	$ 278	$ 84	$ 362

Projected 2010 capital expenditures are significantly less than 2009 capital expenditures due to the completion of our growth capital expenditures in 2009 discussed in "Capital Projects" on page 37. We anticipate spending $300 million to $500 million per year on growth capital expenditures for the years 2010 through 2015. 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.

Investment in Northern Border Pipeline - In 2009, we made equity contributions of $42.3 million to Northern Border Pipeline. We do not anticipate making any material equity contributions in 2010.

Overland Pass Pipeline Company - We own 99 percent of Overland Pass Pipeline Company and operate the pipeline. On or before November 17, 2010, Williams has the option to increase its ownership in Overland Pass Pipeline Company up to a total of 50 percent, with the purchase price being determined in accordance with the joint venture's operating agreement.

Credit Ratings - Our credit ratings as of December 31, 2009, 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 currently 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 but could trigger repurchase obligations with respect to certain of our long-term debt. See additional discussion about our credit ratings under "Debt Covenants."

If our repurchase obligations are triggered, 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, seek alternative financing sources or sell assets 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.

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 required to provide additional collateral in the form of cash, letters of credit or other negotiable instruments as a condition of continuing to conduct business with such counterparties.

Other than the note repurchase obligations described under "Debt Covenants" or the provisions discussed in the previous paragraph, 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.

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,		
	2009	**2008**	**2007**
	(Millions of dollars)		
Common unitholders	**$ 247.6**	$ 220.6	$ 184.7
Class B unitholders	**158.0**	153.5	145.2
General partner	**94.7**	78.9	54.7
Total cash distributions paid before noncontrolling interests	**$ 500.3**	$ 453.0	$ 384.6

For the years ended December 31, 2009, 2008 and 2007, cash distributions paid to our general partner included incentive distributions of $84.7 million, $69.9 million and $47.1 million, respectively.

In January 2010, our general partner declared a cash distribution of $1.10 per unit ($4.40 per unit on an annualized basis) for the fourth quarter of 2009, which was paid on February 12, 2010, to unitholders of record as of January 29, 2010.

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 and natural gas 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 55 under "Commodity Price Risk" in Item 7A, Quantitative and Qualitative Disclosures about Market Risk, for information on our hedging activities.

ENVIRONMENTAL MATTERS

Information about our environmental matters is included in "Environmental and Safety Matters" of Item 1, Business and Note K of the Notes to Consolidated Financial Statements in this Annual Report. 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 could have a material adverse effect on our business, financial condition and results of operations. Our expenditures for environmental evaluation, mitigation, remediation and compliance to date have not been significant in relation to our financial position or results of operations, and our expenditures related to environmental matters had no material effects upon earnings or cash flows during 2009, 2008 and 2007.

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, equity earnings from investments, distributions received from unconsolidated affiliates, and changes in our assets and liabilities not classified as investing or financing activities.

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 2009 vs. 2008 Increase (Decrease)		Variances 2008 vs. 2007 Increase (Decrease)	
	2009	**2008**	**2007**				
				(Millions of dollars)			
Total cash provided by (used in):							
Operating activities	**$ 562.4**	$ 656.4	$ 701.5	**$ (94.0)**	**(14%)**	$ (45.1)	(6%)
Investing activities	**(618.1)**	(1,246.5)	(1,009.1)	**628.4**	**50%**	(237.4)	(24%)
Financing activities	**(118.8)**	764.5	289.7	**(883.3)**	*****	474.8	*
Change in cash and cash equivalents	**(174.5)**	174.4	(17.9)	**(348.9)**	*****	192.3	*
Cash and cash equivalents at beginning of period	**177.6**	3.2	21.1	**174.4**	*****	(17.9)	(85%)
Cash and cash equivalents at end of period	**$ 3.1**	$ 177.6	$ 3.2	**$ (174.5)**	**(98%)**	$ 174.4	*

* Percentage change is greater than 100 percent.

Operating Cash Flows - Operating cash flows are affected by earnings from our business activities. We provide services for producers and consumers of natural gas, condensate and NGLs. Changes in commodity prices and demand for our services or products, whether because of general economic conditions, changes in demand for the end products that are made with our products or increased competition from other service providers, could affect our earnings and operating cash flows.

<u>2009 vs. 2008</u> - Cash flows from operating activities, before changes in operating assets and liabilities, were $583.7 million for 2009, compared with $696.0 million for 2008. The decrease was due primarily to lower commodity prices, increased operating costs at our fractionation facilities, Overland Pass Pipeline and Arbuckle Pipeline, and increased interest cost as a result of borrowings to fund our capital projects.

The changes in operating assets and liabilities decreased operating cash flows $21.2 million for 2009, compared with a decrease of $39.6 million for 2008, primarily as a result of the following:

- the impact of commodity prices on our operating assets and liabilities;
- the timing of cash receipts from our revenues resulting in increased accounts receivable;
- the timing of payments for purchases of commodities and other expenses resulting in increased accounts payable; and
- the changes in volumes of commodities in storage.

<u>2008 vs. 2007</u> - Cash flows from operating activities, before changes in operating assets and liabilities, were $696.0 million for 2008, compared with $525.8 million for 2007. The increase was due primarily to higher commodity prices and increased NGL gathering and fractionation volumes.

The changes in operating assets and liabilities decreased operating cash flows $39.6 million for 2008, compared with an increase of $175.7 million for 2007, primarily as a result of the following:

- the timing of cash receipts from our revenues resulting in decreased accounts receivable;
- the timing of payments for purchases of commodities and other expenses resulting in decreased accounts payable; and
- the changes in volumes of commodities in storage.

Investing Cash Flows - Cash used in investing activities decreased for 2009, compared with 2008, due primarily to reduced capital expenditures as a result of the completion of the Arbuckle Pipeline and Overland Pass Pipeline and related expansion projects, the Williston Basin gas processing plant expansion and the Guardian Pipeline expansion and extension. Cash used in investing activities increased for 2008, compared with 2007, due primarily to increased spending for our capital projects.

Financing Cash Flows - In March 2009, we completed an underwritten public offering of senior notes totaling approximately $498.3 million, net of discounts but before offering expenses. The net proceeds from the notes were used to repay borrowings under our Partnership Credit Agreement. In 2007, we completed an underwritten public offering of senior notes totaling $598.1 million in net proceeds, before offering expenses. The net proceeds were used to finance our $300 million acquisition, before working capital adjustments, of an interstate natural gas liquids and refined petroleum products pipeline system and related assets from a subsidiary of Kinder Morgan and to repay debt outstanding under our Partnership Credit Agreement.

During 2009, our common unit offering generated net proceeds of approximately $241.6 million. In addition, ONEOK Partners GP contributed $5.1 million in order to maintain its 2 percent general partner interest in us. We used the proceeds and general partner contributions to repay borrowings under our Partnership Credit Agreement and for general partnership purposes. During 2008, our common unit offering and private placement of common units generated proceeds of approximately $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.

Cash distributions to our general and limited partners for 2009 were $500.3 million, compared with $453.0 million for 2008, an increase of $47.3 million. This increase was due primarily to additional units outstanding during 2009, as well as cash distributions of $4.33 per unit during 2009, compared with cash distributions of $4.205 per unit during 2008.

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. This increase was due primarily to additional units outstanding during 2008, as well as cash distributions of $4.205 per unit during 2008, compared with cash distributions of $3.98 per unit during 2007.

Net repayments of notes payable were $347 million during 2009, compared with net borrowings of $770 million for 2008 and net borrowings of $94 million for 2007.

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, 2009. For additional discussion of the debt and operating lease agreements, see Notes I and K, respectively, of the Notes to Consolidated Financial Statements in this Annual Report.

	Payments Due by Period						
Contractual Obligations	**Total**	**2010**	**2011**	**2012**	**2013**	**2014**	**Thereafter**
ONEOK Partners				*(Thousands of dollars)*			
$1 billion credit agreement	$ 523,000	$ 523,000	$ -	$ -	$ -	$ -	$ -
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 - 8.625%	500,000	-	-	-	-	-	500,000
Senior notes - 6.65%	600,000	-	-	-	-	-	600,000
Senior notes - 6.85%	600,000	-	-	-	-	-	600,000
Guardian Pipeline							
Senior notes - various	109,780	11,931	11,931	11,062	7,650	7,650	59,556
Interest payments on debt	2,984,200	215,500	191,700	172,000	166,100	164,600	2,074,300
Operating leases	41,880	14,849	13,985	7,193	2,327	1,936	1,590
Firm transportation and storage contracts	14,757	6,760	1,388	1,388	1,388	1,205	2,628
Financial and physical derivatives	196,027	196,027	-	-	-	-	-
Purchase commitments, rights of way and other	5,610	935	935	935	935	935	935
Total	$ 6,850,254	$ 1,219,002	$ 444,939	$ 542,578	$ 178,400	$ 176,326	$ 4,289,009

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, 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 and Storage Contracts - Our Natural Gas Gathering and Processing and Natural Gas Liquids segments are party to fixed-price contracts for firm transportation and storage capacity.

Financial and Physical Derivatives - Financial and physical derivatives represent fixed- and variable-price purchase commitments. Our estimated future variable-price purchase commitments are based on market information at December 31, 2009, associated with our Natural Gas Liquids segment. Actual future variable-price purchase obligations may vary depending on market prices at the time of delivery. Sales of the related physical volumes and net positive settlements of financial derivatives are not reflected in the table above.

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 are forward-looking statements within the meaning of Section 27A of the Securities Act, and Section 21E of the Exchange Act, 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 identified by words such as "anticipate," "estimate," "expect," "project," "intend," "plan," "believe," "should," "goal," "forecast," "guidance," "could," "may," "continue," "might," "potential," "scheduled" and other words and terms of similar meaning.

One should not place undue reliance on forward-looking statements, which are applicable only as of the date of this Annual Report. 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 foreign energy suppliers and transporters, as well as alternative forms of energy, including, but not limited to, solar power, wind power, geothermal energy and 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 of 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 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 with 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 liquidity risks in U.S. credit markets;
- the impact of recently issued and future accounting updates 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 Part I, Item 1A, "Risk Factors", in this Annual Report. 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 forward sales, swaps, options 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, condensate and NGL marketing activities to ensure our hedging activities mitigate market risks. We do not use financial instruments for trading purposes.

We record derivative instruments at fair value. We estimate the fair value of derivative instruments using available market information and appropriate valuation techniques. Changes in derivative instruments’ fair value are recognized in earnings unless the instrument qualifies as a hedge and meets specific hedge accounting criteria. The effective portion of 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, 2009, the interest rate on all of our long-term debt was fixed.

Fair Value Hedges - At December 31, 2009, we did not have any interest-rate swap agreements. See Note D of the Notes to Consolidated Financial Statements in this Annual Report for discussion of interest-rate swaps.

Total interest expense savings from amortization of terminated swaps for 2009 and 2008 were $3.7 million each year, and for 2007 were $2.5 million. Total swap savings from terminated swaps for 2010 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 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 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.

As of December 31, 2009, we had $0.5 million of derivative assets and $18.8 million of derivative liabilities, excluding the impact of netting, all of which related to commodity contracts. The following tables set forth our Natural Gas Gathering and Processing segment’s hedging information for the periods indicated as of February 22, 2010:

	Year Ending December 31, 2010		
	Volumes Hedged	Average Price	Percentage Hedged
NGLs *(Bbl/d)* (a)	5,304	$1.03 / gallon	75%
Condensate *(Bbl/d)* (a)	1,696	$1.80 / gallon	75%
Total *(Bbl/d)*	7,000	$1.21 / gallon	75%
Natural gas *(MMBtu/d)*	25,225	$5.55 / MMBtu	75%

(a) - Hedged with fixed-price swaps.

	Year Ending December 31, 2011		
	Volumes Hedged	Average Price	Percentage Hedged
NGLs *(Bbl/d)* (a)	902	$1.34 / gallon	13%
Condensate *(Bbl/d)* (a)	596	$2.12 / gallon	25%
Total *(Bbl/d)*	1,498	$1.65 / gallon	16%
Natural gas *(MMBtu/d)*	16,616	$6.29 / MMBtu	43%

(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, 2009, 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 $1.0 million;
- a $1.00 per barrel decrease in the price of crude oil would decrease annual net margin by approximately $1.1 million; and
- a $0.10 per MMBtu decrease in the price of natural gas would decrease annual net margin by approximately $1.2 million.

In our Natural Gas Liquids 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 can expose us to commodity price risk. At December 31, 2009, 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 for more information on our hedging activities.

COUNTERPARTY CREDIT RISK

We assess the creditworthiness of our counterparties on an ongoing basis and require security, including prepayments and other forms of 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, 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, 2009 and 2008, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2009, 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, 2009, 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, 2009. 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

Tulsa, Oklahoma
February 23, 2010

This page intentionally left blank.

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

	Years Ended December 31,		
	2009	**2008**	**2007**
	(Thousands of dollars, except per unit amounts)		
Revenues	**$ 6,474,491**	$ 7,720,206	$ 5,831,558
Cost of sales and fuel	**5,355,194**	6,579,547	4,935,665
Net margin	**1,119,297**	1,140,659	895,893
Operating expenses			
Operations and maintenance	**361,608**	337,526	302,544
Depreciation and amortization	**164,136**	124,765	113,704
General taxes	**49,619**	34,271	34,812
Total operating expenses	**575,363**	496,562	451,060
Gain on sale of assets	**2,668**	713	1,950
Operating income	**546,602**	644,810	446,783
Equity earnings from investments (Note N)	**72,722**	101,432	89,908
Allowance for equity funds used during construction	**26,868**	50,906	12,538
Other income	**10,658**	5,621	7,502
Other expense	**(3,167)**	(13,321)	(779)
Interest expense	**(206,016)**	(151,056)	(138,947)
Income before income taxes	**447,667**	638,392	417,005
Income taxes (Note L)	**(12,963)**	(12,335)	(8,842)
Net income	**434,704**	626,057	408,163
Less: Net income attributable to noncontrolling interests	**348**	441	416
Net income attributable to ONEOK Partners, L.P.	**$ 434,356**	$ 625,616	$ 407,747
Limited partners' interest in net income:			
Net income attributable to ONEOK Partners, L.P.	**$ 434,356**	$ 625,616	$ 407,747
General partner's interest in net income	**(96,421)**	(88,554)	(58,781)
Limited partners' interest in net income	**$ 337,935**	$ 537,062	$ 348,966
Limited partners' net income per unit, basic and diluted (Note O)	**$ 3.60**	$ 6.01	$ 4.21
Number of units used in computation (*thousands*)	**93,808**	89,309	82,891

See accompanying Notes to Consolidated Financial Statements.

ONEOK Partners, L.P. and Subsidiaries
CONSOLIDATED BALANCE SHEETS

		December 31, 2009		December 31, 2008
Assets		*(Thousands of dollars)*		
Current assets				
Cash and cash equivalents	**$**	**3,151**	$	177,635
Accounts receivable, net		**624,635**		317,182
Affiliate receivables		**32,397**		25,776
Gas and natural gas liquids in storage		**217,585**		190,616
Commodity imbalances		**188,177**		55,086
Derivative financial instruments (Notes C and D)		**-**		63,780
Other current assets		**36,148**		28,176
Total current assets		**1,102,093**		858,251
Property, plant and equipment				
Property, plant and equipment		**6,353,909**		5,808,679
Accumulated depreciation and amortization		**972,497**		875,279
Net property, plant and equipment (Note E)		**5,381,412**		4,933,400
Investments and other assets				
Investments in unconsolidated affiliates (Note N)		**765,163**		755,492
Goodwill and intangible assets (Note F)		**668,870**		676,536
Other assets		**35,721**		30,593
Total investments and other assets		**1,469,754**		1,462,621
Total assets	**$**	**7,953,259**	$	7,254,272
Liabilities and partners' equity				
Current liabilities				
Current maturities of long-term debt (Note I)	**$**	**261,931**	$	11,931
Notes payable (Note H)		**523,000**		870,000
Accounts payable		**694,290**		496,763
Affiliate payables		**21,866**		23,333
Commodity imbalances		**392,688**		191,165
Other current liabilities		**153,539**		100,832
Total current liabilities		**2,047,314**		1,694,024
Long-term debt, excluding current maturities (Note I)		**2,822,086**		2,589,509
Deferred credits and other liabilities		**73,798**		54,773
Commitments and contingencies (Note K)				
Partners' equity				
ONEOK Partners, L.P. partners’ equity:				
General partner		**84,434**		77,546
Common units: 59,912,777 and 54,426,087 units issued and outstanding at December 31, 2009 and 2008, respectively		**1,561,762**		1,361,058
Class B units: 36,494,126 units issued and outstanding at December 31, 2009 and 2008		**1,380,299**		1,407,016
Accumulated other comprehensive income (loss) (Note G)		**(22,037)**		64,405
Total ONEOK Partners, L.P. partners' equity		**3,004,458**		2,910,025
Noncontrolling interests in consolidated subsidiaries		**5,603**		5,941
Total partners' equity		**3,010,061**		2,915,966
Total liabilities and partners' equity	**$**	**7,953,259**	$	7,254,272

See accompanying Notes to Consolidated Financial Statements.

ONEOK Partners, L.P. and Subsidiaries
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Years Ended December 31,		
	2009	**2008**	**2007**
	(Thousands of dollars)		
Operating activities			
Net income	**$ 434,704**	$ 626,057	$ 408,163
Depreciation and amortization	**164,136**	124,765	113,704
Allowance for equity funds used during construction	**(26,868)**	(50,906)	(12,538)
Gain on sale of assets	**(2,668)**	(713)	(1,950)
Deferred income taxes	**11,707**	5,015	4,567
Equity earnings from investments	**(72,722)**	(101,432)	(89,908)
Distributions received from unconsolidated affiliates	**75,377**	93,261	103,785
Changes in assets and liabilities, net of effect of acquisitions:			
Accounts receivable	**(308,703)**	256,137	(268,963)
Affiliate receivables	**(6,621)**	26,703	36,093
Gas and natural gas liquids in storage	**(26,969)**	16,003	(47,973)
Derivative financial instruments	**(4,349)**	(2,538)	2,154
Accounts payable	**233,921**	(273,475)	368,452
Affiliate payables	**(1,467)**	5,035	(7,439)
Commodity imbalances, net	**68,432**	(33,979)	41,997
Accrued interest	**6,600**	5,669	9,069
Other assets and liabilities	**17,929**	(39,184)	42,321
Cash provided by operating activities	**562,439**	656,418	701,534
Investing activities			
Changes in investments in unconsolidated affiliates	**(12,031)**	3,963	(3,668)
Acquisitions	**-**	2,450	(299,560)
Capital expenditures (less allowance for equity funds used during construction)	**(615,691)**	(1,253,853)	(709,858)
Proceeds from sale of assets and other	**9,572**	990	3,980
Cash used in investing activities	**(618,150)**	(1,246,450)	(1,009,106)
Financing activities			
Cash distributions:			
General and limited partners	**(500,253)**	(453,021)	(384,646)
Noncontrolling interests	**(686)**	(302)	(220)
Borrowing (payment) of notes payable, net	**523,000**	(100,000)	94,000
Borrowing (payment) of notes payable with maturities over 90 days	**(870,000)**	870,000	-
Issuance of long-term debt, net of discounts	**498,325**	-	598,146
Long-term debt financing costs	**(4,000)**	-	(5,805)
Repayment of long-term debt	**(11,931)**	(11,929)	(11,931)
Issuance of common units, net of discounts	**241,642**	450,198	-
Contribution from general partner	**5,130**	9,508	-
Other financing activities	**-**	-	139
Cash provided by (used in) financing activities	**(118,773)**	764,454	289,683
Change in cash and cash equivalents	**(174,484)**	174,422	(17,889)
Cash and cash equivalents at beginning of period	**177,635**	3,213	21,102
Cash and cash equivalents at end of period	**$ 3,151**	$ 177,635	$ 3,213
Supplemental cash flow information:			
Cash paid for interest, net of amounts capitalized	**$ 201,773**	$ 148,417	$ 138,606
Cash paid for income taxes	**$ 5,248**	$ 4,722	$ 1,039

See accompanying Notes to Consolidated Financial Statements.

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

	ONEOK Partners, L.P. Partners' Equity			
	Common Units	**Class B Units**	**General Partner**	**Common Units**
	(Units)		*(Thousands of dollars)*	
January 1, 2007	46,397,214	36,494,126	$ 54,373	$ 803,599
Net income	-	-	58,781	195,329
Other comprehensive income (Note G)	-	-	-	-
Other	-	-	(1)	-
Distributions paid (Note J)	-	-	(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 (Note G)	-	-	-	-
Issuance of common units (Note J)	8,028,873	-	-	450,198
Contribution from general partner (Note J)	-	-	9,508	-
Distributions paid (Note J)	-	-	(78,931)	(220,632)
December 31, 2008	54,426,087	36,494,126	77,546	1,361,058
Net income	**-**	**-**	**96,421**	**206,633**
Other comprehensive loss (Note G)	-	-	-	-
Issuance of common units (Note J)	**5,486,690**	**-**	**-**	**241,642**
Contribution from general partner (Note J)	**-**	**-**	**5,130**	**-**
Distributions paid (Note J)	**-**	**-**	**(94,663)**	**(247,571)**
December 31, 2009	**59,912,777**	**36,494,126**	**$ 84,434**	**$ 1,561,762**

See accompanying Notes to Consolidated Financial Statements.

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

	ONEOK Partners, L.P. Partners' Equity			
	Class B Units	**Accumulated Other Comprehensive Income (Loss)**	**Noncontrolling Interests in Consolidated Subsidiaries**	**Total Partners' Equity**
		(Thousands of dollars)		
January 1, 2007	$ 1,332,276	$ (1,586)	$ 5,606	$ 2,194,268
Net income	153,637	-	416	408,163
Other comprehensive income (Note G)	-	(16,555)	-	(16,555)
Other	(29)	-	-	(30)
Distributions paid (Note J)	(145,246)	-	(220)	(384,866)
December 31, 2007	1,340,638	(18,141)	5,802	2,200,980
Net income	219,836	-	441	626,057
Other comprehensive income (Note G)	-	82,546	-	82,546
Issuance of common units (Note J)	-	-	-	450,198
Contribution from general partner (Note J)	-	-	-	9,508
Distributions paid (Note J)	(153,458)	-	(302)	(453,323)
December 31, 2008	1,407,016	64,405	5,941	2,915,966
Net income	**131,302**	**-**	**348**	**434,704**
Other comprehensive loss (Note G)	**-**	**(86,442)**	**-**	**(86,442)**
Issuance of common units (Note J)	**-**	**-**	**-**	**241,642**
Contribution from general partner (Note J)	-	-	**-**	**5,130**
Distributions paid (Note J)	**(158,019)**	**-**	**(686)**	**(500,939)**
December 31, 2009	**$ 1,380,299**	**$ (22,037)**	**$ 5,603**	**$ 3,010,061**

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

	Years Ended December 31,		
	2009	**2008**	**2007**
	(Thousands of dollars)		
Net income	**$ 434,704**	$ 626,057	$ 408,163
Other comprehensive income (loss) (Note G)	**(86,442)**	82,546	(16,555)
Comprehensive income	**348,262**	708,603	391,608
Less: Comprehensive income attributable to noncontrolling interests	**348**	441	416
Comprehensive income attributable to ONEOK Partners, L.P.	**$ 347,914**	$ 708,162	$ 391,192

See accompanying Notes to Consolidated Financial Statements.

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

A. SUMMARY OF SIGNIFICANT 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. As of December 31, 2009, ONEOK owned a 45.1 percent aggregate equity interest in us. As a result of our February 2010 public offering of common units, ONEOK and its subsidiaries own a 42.8 percent aggregate equity interest in us.

Our operations include gathering and processing of natural gas produced from crude oil and natural gas wells. We gather and process 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 and/or process natural gas in two producing basins in the Rocky Mountain region: the Williston Basin, which spans portions of Montana and North Dakota, and the Powder River Basin of Wyoming. The natural gas we gather in the Powder River Basin of Wyoming is coal bed methane, or dry gas, that does not require processing or NGL extraction, in order to be marketable; dry gas is gathered, compressed and delivered into a downstream pipeline or market for a fee.

Our interstate natural gas pipeline assets transport natural gas through FERC-regulated interstate natural gas pipelines in North Dakota, Minnesota, Wisconsin, 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;
- OkTex Pipeline has interconnects in Oklahoma, New Mexico and Texas; and
- Northern Border Pipeline, an interstate, FERC-regulated pipeline operated by an affiliate of TransCanada that transports natural gas from the Montana-Saskatchewan border near Port of Morgan, Montana, to a terminus near North Hayden, Indiana, of which we have a 50 percent interest.

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 to western markets, the Houston Ship Channel market to the east, and the Mid-Continent market to the north. We own 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 assets consist of facilities that gather, fractionate and treat NGLs and store NGL products primarily in Oklahoma, Kansas and Texas. We own FERC-regulated natural gas liquids gathering and distribution pipelines in Oklahoma, Kansas, Texas, Wyoming and Colorado, and terminal and storage facilities in Missouri, Nebraska, Iowa and Illinois. We also own FERC-regulated natural gas liquids distribution and refined petroleum products pipelines in Kansas, Missouri, Nebraska, Iowa and Illinois that connect our Mid-Continent assets with Midwest markets, including Chicago, Illinois. The majority 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.

Impairment of Goodwill, Long-Lived Assets and Intangible Assets - We assess our goodwill for impairment at least annually. 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 period of years plus a terminal value and discount these amounts to their present value using appropriate rates of return that are consistent with a market participant's perspective. Under the market approach, we apply multiples to forecasted cash flows. The multiples used are consistent with a market participant's perspective of historical asset transactions. The forecasted cash flows are consistent with a market participant's perspective of forecasted average cash flow amounts over a period of years.

We assess our long-lived assets, including intangible assets with a finite useful life, for impairment whenever events or changes in circumstances indicate that its carrying amount may exceed its fair value. In step one of the impairment test, an impairment is indicated if the carrying amount of a long-lived asset exceeds the sum of the undiscounted future cash flows expected to result from the use and eventual disposition of the asset. We record an impairment loss equal to the difference between the carrying value and the fair value of the long-lived asset. This type of analysis requires us to make assumptions and estimates regarding industry economic factors and the profitability of future business strategies. We determined that there were no asset impairments in 2009, 2008 or 2007.

For the investments we account for under the equity method, the impairment test 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 our equity method investments to determine whether current events or circumstances warrant adjustments to our carrying value. We determined that there were no impairments to our investments in unconsolidated affiliates in 2009, 2008 or 2007.

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.

See Note F for our goodwill and intangible assets disclosures.

Derivatives and Risk Management - We utilize derivatives to reduce our market risk exposure to interest rate and commodity price fluctuations and achieve more predictable cash flows. We record all derivative instruments at fair value, with the exception of normal purchases and normal sales that are expected to result in physical delivery. Commodity price volatility may have a significant impact on the fair value of derivative instruments as of a given date; however, we do not believe that changes in our fair value estimates of our derivative instruments have a material impact on our results of operations, as the majority of our derivatives are accounted for as cash flow hedges for which ineffectiveness is not material.

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 cash flow hedging relationship and, if so, the reason for holding it.

The table below summarizes the various ways in which we account for our derivative instruments and the impact on our consolidated financial statements:

	Recognition and Measurement	
Accounting Treatment	**Balance Sheet**	**Income Statement**
Normal purchases and normal sales	- Fair value not recorded	- Change in fair value not recognized in earnings
Mark-to-market	- Recorded at fair value	- Change in fair value recognized in earnings
Cash flow hedge	- Recorded at fair value	- Ineffective portion of the gain or loss on the derivative instrument is recognized in earnings
	- Effective portion of the gain or loss on the derivative instrument is reported initially as a component of accumulated other comprehensive income (loss)	- Effective portion of the gain or loss on the derivative instrument is reclassified out of accumulated other comprehensive income (loss) into earnings when the forecasted transaction affects earnings
Fair value hedge	- Recorded at fair value	- The gain or loss on the derivative instrument is recognized in earnings
	- Change in fair value of the hedged item is recorded as an adjustment to book value	- Change in fair value of the hedged item is recognized in earnings

To reduce our exposure to fluctuations in natural gas, NGLs and condensate prices, we periodically enter into futures, forward sales, 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 from time to time 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. We formally document all relationships between hedging instruments and hedged items, as well as risk management objectives and strategies, for undertaking various hedge transactions and methods for assessing and testing correlation and hedge ineffectiveness. We specifically identify the forecasted transaction that has been designated as the hedged item with a cash flow hedge. We assess the effectiveness of hedging relationships quarterly by performing a regression analysis on our fair value and cash flow hedging relationships to determine whether the hedge relationships are highly effective on a retrospective and prospective basis. We also document our normal purchases and normal sales transactions that we expect to result in physical delivery and that we elect to exempt from derivative accounting treatment.

Cash flows from futures, forwards and swaps that are accounted for as hedges are included in the same Consolidated Statement of Cash Flows category as the cash flows from the related hedged items.

See Notes C and D for more discussion of our fair value measurements and risk management and hedging activities using derivatives.

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. 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 K for additional discussion of contingencies.

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. 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. These amounts are recorded as investments in unconsolidated affiliates on our accompanying Consolidated Balance Sheets. See Note N for disclosures of our unconsolidated affiliates.

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 ongoing basis and require security, including prepayments and other forms of 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 - 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.

Commodity Imbalances - Natural gas and NGL imbalances are valued at market or their contractually stipulated rate. Natural gas and NGL imbalances are settled in cash or made up in-kind, subject to the terms of the pipelines’ tariffs or by agreement.

Property, Plant and Equipment - Our properties are stated at cost, including 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 costs during the construction or upgrade of qualifying assets. Interest costs capitalized in 2009, 2008 and 2007 were $16.1 million, $36.1 million and $13.6 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 depreciation 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 results of operations.

Property, plant and equipment on our Consolidated Balance Sheets includes construction work in progress for capital projects that have not yet been placed in service and therefore are not being depreciated. Assets are transferred out of construction work in progress when they are substantially complete and ready for their intended use.

See Note E for disclosures of our property, plant and equipment.

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 our facilities. Our Natural Gas Liquids 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 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. Deferred income taxes are provided for the difference between the financial statement and income tax basis of assets and liabilities and carry-forward items based on income tax laws and rates existing at the time the temporary differences are expected to reverse. Except for the regulated companies, 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 regulated companies, 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 if, as a result of an action by a regulator, it is probable that the effect of the change in tax rates will be recovered from or returned to customers through future rates.

In June 2006, the FASB provided guidance on accounting for uncertainty in income taxes recognized in the financial statements. The FASB prescribed a more-likely-than-not recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position that is taken or expected to be taken in a tax return. We reflect penalties and interest as part of income tax expense as they become applicable for tax provisions that do not meet the more-likely-than-not recognition threshold and measurement attribute. During 2009, 2008 and 2007, we had no tax positions that would require establishment of a reserve.

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. See Note L for additional discussion of income taxes.

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 and Natural Gas Liquids segments follow the accounting and reporting guidance for regulated operations. 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. A write-off of regulatory assets and costs not recovered may be required if all or a portion of the regulated operations have rates that are no longer:

- established by independent, third-party regulators;
- designed to recover the specific entity's costs of providing regulated services; and
- set at levels that will recover our costs when considering the demand and competition for our services.

At December 31, 2009 and 2008, we recorded regulatory assets of approximately $11.7 million and $12.8 million, respectively, which are currently being recovered and 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 - Asset retirement obligations represent legal obligations associated with the retirement of long-lived assets that result from the acquisition, construction, development and/or normal use of the asset. 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. However, these non-legal asset removal obligations are accounted for as a regulatory liability. Historically, the regulatory authorities that have jurisdiction over our regulated operations have not required us to quantify this amount; rather, these costs are addressed prospectively in 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.

Recently Issued Accounting Updates

The following recently issued accounting updates affect our consolidated financial statements:

FASB Accounting Standards Codification - In June 2009, the FASB established the FASB Accounting Standards Codification (Codification) as the source of authoritative accounting principles recognized by the FASB to be applied by nongovernmental entities in the preparation of financial statements in conformity with GAAP. While the Codification does not change GAAP, it does change the manner in which we reference authoritative accounting principles in our consolidated financial statements. The Codification is effective for and has been implemented in this Annual Report.

Noncontrolling Interests - Effective for our year beginning January 1, 2009, we retroactively adopted new presentation and disclosure requirements for existing noncontrolling interests (previously referred to as minority interests). We report noncontrolling interests as a component of equity in our Consolidated Balance Sheets and the amounts of consolidated net income attributable to noncontrolling interests and to us in our Consolidated Statements of Income.

Derivative Instruments and Hedging Activities Disclosure - Effective for our year beginning January 1, 2009, we provide enhanced disclosures about how derivative and hedging activities affect our financial position, financial performance and cash flows. These additional disclosures have been applied prospectively. See Notes A and D for applicable disclosures.

Fair Value Measurements and Disclosures - In January 2010, the FASB issued ASU 2010-06, “Improving Disclosures about Fair Value Measurements,” which provided new disclosure requirements and clarifies existing disclosures of fair value measurements. We will apply this guidance to our disclosures beginning with our March 31, 2010, Quarterly Report on Form 10-Q and do not expect the impact to be material.

See Note C for disclosures of our fair value measurements.

Limited Partners’ Net Income Per Unit - Effective for our year beginning January 1, 2009, the Emerging Issues Task Force issued guidance aimed to improve the comparability of net income per unit calculations for master limited partnerships with incentive distribution rights. We retroactively applied this guidance, and there was no impact on our limited partners’ net income per unit for the years ended December 31, 2008 and 2007. See Note O for a discussion of our calculation of basic and diluted limited partners’ net income per unit.

Subsequent Events - Effective for our quarter ended June 30, 2009, the FASB established standards related to the accounting for and disclosure of events that occur after the balance sheet date but before consolidated financial statements are issued. We have evaluated subsequent events through February 23, 2010, the date our consolidated financial statements were issued, and we believe all required subsequent events disclosures have been made.

B. ACQUISITION

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 Energy Partners, L.P. for approximately $300 million, before working capital adjustments. The FERC-regulated 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 transaction also included a 50 percent ownership interest in 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 products 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 working capital settlement was finalized in April 2008, with no material adjustments.

C. FAIR VALUE MEASUREMENTS

Determining Fair Value - We define 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.

The FASB has provided guidance that allows for companies to elect measuring 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. For the years ended December 31, 2009 and 2008, we did not elect the fair value option under this guidance, and therefore there was no impact on our consolidated financial statements.

Fair Value Hierarchy - We utilize a fair value hierarchy to prioritize inputs to our valuation techniques based on observable and unobservable data and categorize 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 - May include one or more unobservable inputs that are significant in establishing a fair value estimate. These unobservable inputs 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 tables set forth our recurring fair value measurements for the periods indicated:

	December 31, 2009				
	Level 1	**Level 2**	**Level 3**	**Netting (a)**	**Total**
	(Thousands of dollars)				
Derivatives					
Assets	**$ -**	**$ 459**	**$ -**	**$ (459)**	**$ -**
Liabilities (b)	**$ -**	**$ (5,720)**	**$ (13,052)**	**$ 459**	**$ (18,313)**

(a) - Our derivative assets and liabilities are presented in our Consolidated Balance Sheet on a net basis. We net derivative assets and liabilities when a legally enforceable master netting arrangement exists between us and the counterparty to a derivative contract.
(b) - Included in other current liabilities in our Consolidated Balance Sheet.

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

(a) - Our derivative assets and liabilities are presented in our Consolidated Balance Sheet on a net basis. We net derivative assets and liabilities when a legally enforceable master netting arrangement exists between us and the counterparty to a derivative contract.
(b) - Included in derivative financial instruments in our Consolidated Balance Sheet.

At December 31, 2009 and 2008, we had no cash collateral held or posted under our master netting arrangements.

We categorize derivatives for which fair value is determined using multiple inputs within a single level, based on the lowest level input that is significant to the fair value measurement in its entirety.

Our derivative instruments categorized as Level 2 include non-exchange traded fixed-price swaps for natural gas and condensate that are valued based on NYMEX-settled prices for natural gas and crude oil, respectively. Our derivative instruments categorized as Level 3 include over-the-counter fixed-price swaps for purity NGL products and natural gas basis swaps. These swaps are valued based on information from a pricing service, the forward NYMEX curve for crude oil, correlations of specific NGL purity products to crude oil and internally developed basis curves incorporating observable and unobservable market data. We corroborate the data on which our fair value estimates are based using our market knowledge of recent transactions and day-to-day pricing fluctuations and analysis of historical relationships of data from the pricing service compared with actual settlements and correlations. We do not believe that our derivative instruments categorized as Level 3 have a material impact on our results of operations, as the majority of our derivatives are accounted for as cash flow hedges for which ineffectiveness is not material.

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

	Years Ended December 31,	
Derivative Assets (Liabilities)	**2009**	**2008**
	(Thousands of dollars)	
Net assets (liabilities) at beginning of period	**$ 37,649**	$ (16,400)
Total realized/unrealized gains (losses):		
Included in earnings (a)	**5,074**	980
Included in other comprehensive income (loss)	**(55,775)**	58,143
Terminations prior to maturity	**-**	(5,074)
Net assets (liabilities) at end of period	**$ (13,052)**	$ 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 the end of the period (a)	**$ -**	$ -

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

The change in our Level 3 fair value measurements is 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.

Other Financial Instruments - The approximate fair value of cash and cash equivalents, accounts receivable and accounts payable is equal to book value, due to its short-term nature. The fair value of borrowings under our Partnership Credit Agreement approximates the carrying value since the interest rates are periodically adjusted to reflect current market conditions.

The estimated fair value of the aggregate of our senior notes outstanding, including current maturities, was $3.3 billion and $2.4 billion at December 31, 2009 and 2008, respectively. The book value of the aggregate of our senior notes outstanding, including current maturities, was $3.1 billion and $2.6 billion at December 31, 2009 and 2008, respectively. The estimated fair value of the aggregate of our senior notes outstanding has been determined using quoted market prices for similar issues with similar terms and maturities.

D. RISK MANAGEMENT AND HEDGING ACTIVITIES USING DERIVATIVES

Risk Management Activities - We are sensitive to changes in natural gas, crude oil and NGL prices, principally as a result of contractual terms under which these commodities are processed, purchased and sold. We use physical forward sales and financial derivatives to secure a certain price for a portion of our share of natural gas, condensate and NGL products. We follow established policies and procedures to assess risk and approve, monitor and report our risk management activities. We have not used these instruments for trading purposes. We are also subject to the risk of interest-rate fluctuation in the normal course of business.

<u>Commodity price risk</u> - Commodity price risk refers to the risk of loss in cash flows and future earnings arising from adverse changes in the price of natural gas, NGLs and condensate. We use the following commodity derivative instruments to mitigate the commodity price risk associated with a portion of the forecasted sales of these commodities:

- <u>Futures contracts</u> - Standardized exchange-traded contracts to purchase or sell natural gas and crude oil at a specified price, requiring delivery on, or settlement through, the sale or purchase of an offsetting contract by a specified future date under the provisions of exchange regulations;
- <u>Forward contracts</u> - Commitments to purchase or sell natural gas, crude oil or NGLs for delivery at some specified time in the future. Forward contracts are different from futures in that forwards are customized and non-exchange traded; and
- <u>Swaps</u> - Financial trades involving the exchange of payments based on two different pricing structures for a commodity. In a typical commodity swap, parties exchange payments based on changes in the price of a commodity or a market index, while fixing the price they effectively pay or receive for the physical commodity. As a result, one party assumes the risks and benefits of the movements in market prices while the other party assumes the risks and benefits of a fixed price for the commodity.

In our Natural Gas Gathering and Processing segment, we are exposed to commodity price risk as a result of receiving commodities in exchange for services associated with our POP contracts. 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 basis risk between the various production and market locations where we buy and sell commodities. As part of our hedging strategy, we use the previously described commodity derivative instruments to minimize the impact of price fluctuations related to natural gas, NGLs and condensate. 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. We hedge a portion of the forecasted sales of the commodities we retain, including NGLs, natural gas and condensate.

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 can expose us to commodity price risk depending on the regulatory treatment for this activity. We use physical forward sales or purchases to reduce the impact of price fluctuations related to natural gas. At December 31, 2009, we were not using any financial derivative instruments with respect to our natural gas pipeline operations.

In our Natural Gas Liquids segment, we are exposed to basis risk primarily as a result of the relative value of NGL purchases at one location and sales at another location. To a lesser extent, we are exposed to commodity price risk resulting from the relative values of the various NGL products to each other, NGLs in storage and the relative value of NGLs to natural gas. We utilize fixed-price physical forward contracts to reduce the impact of price fluctuations related to NGLs. At December 31, 2009, we were not using any financial derivative instruments with respect to our NGL activities.

Interest- rate risk - We manage interest-rate risk through the use of fixed-rate debt, floating-rate debt and, at times, interest-rate swaps. Interest-rate swaps are agreements to exchange an interest payment at some future point based on the differential between two interest rates. At December 31, 2009 and 2008, we did not have any interest-rate swap agreements.

Fair Values of Derivative Instruments - Fair value is defined 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. See Note C for a discussion of the inputs associated with our fair value measurements and our fair value hierarchy disclosures.

As of December 31, 2009, we had $0.5 million of derivative assets and $18.8 million of derivative liabilities, excluding the impact of netting, all of which related to commodity contracts.

As of December 31, 2009, we had fixed-price natural gas swaps with a notional quantity of 9.2 Bcf and natural gas basis swaps with a notional quantity of 9.2 Bcf. Additionally, we had fixed-price crude oil and NGL swaps with a notional quantity of 2.4 MMBbl.

Cash Flow Hedges - At December 31, 2009, our Consolidated Balance Sheet reflected a net unrealized loss of $18.2 million in accumulated other comprehensive income (loss), with a corresponding offset in derivative financial instrument assets and liabilities. If prices remain at current levels, the loss will be recognized within the next 12 months as the forecasted transactions affect earnings.

The following table sets forth the effect of cash flow hedges recognized in other comprehensive income (loss) for the period indicated:

Derivatives in Cash Flow Hedging Relationships	**Year Ended December 31, 2009**	
	(Thousands of dollars)	
Commodity contracts	**$**	**(34,905)**
Interest rate contracts		**1,599**
Total gain (loss) recognized in other comprehensive income (loss) (effective portion)	**$**	**(33,306)**

The following table sets forth the effect of cash flow hedges on our Consolidated Statements of Income for the period indicated:

Derivatives in Cash Flow Hedging Relationships	**Location of Gain (Loss) Reclassified from Accumulated Other Comprehensive Income (Loss) into Net Income (Effective Portion)**	**Year Ended December 31, 2009**	
		(Thousands of dollars)	
Commodity contracts	Revenues	**$**	**52,108**
Interest rate contracts	Interest expense		**1,240**
Total gain (loss) reclassified from accumulated other comprehensive income (loss) into net income (effective portion)		**$**	**53,348**

Ineffectiveness related to our cash flow hedges was not material for 2009, 2008 and 2007. 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 due to the discontinuance of cash flow hedge treatment during 2009, 2008 and 2007.

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 2009, 2008 and 2007 from amortization of terminated swaps was $3.7 million each year and the remaining amortization of terminated swaps will be recognized over the following periods.

	(Millions of dollars)	
2010	$	3.7
2011	$	0.9

Credit Risk - All the commodity derivative contracts we enter into are with ONEOK Energy Services Company, L.P. (OES), a subsidiary of ONEOK. OES enters into similar commodity derivative contracts with third parties at our direction and on our behalf. We have an indemnification agreement with OES that indemnifies and holds OES harmless from any liability they may incur solely as a result of entering into commodity derivative contracts on our behalf. At December 31, 2009, there were no derivative assets for which we would indemnify OES in the event of a default by the counterparty.

E. PROPERTY, PLANT AND EQUIPMENT

The following table sets forth our property, plant and equipment by property type, for the periods indicated:

	Estimated Useful Lives (Years)	**December 31, 2009**	**December 31, 2008**
		(Thousands of dollars)	
Non-Regulated			
Gathering pipelines and related equipment	5 to 46	**$ 982,849**	$ 899,169
Processing and fractionation and related equipment	5 to 46	**959,339**	837,306
Storage and related equipment	5 to 54	**219,898**	189,212
Transmission pipelines and related equipment	5 to 54	**190,734**	200,698
General plant and other	2 to 42	**71,860**	74,658
Construction work in process		**160,896**	264,326
Regulated			
Storage and related equipment	5 to 54	**134,934**	129,484
Natural gas transmission pipelines and related equipment	5 to 80	**1,383,210**	1,231,966
Natural gas liquids transmission pipelines and related equipment	5 to 80	**2,138,017**	1,390,545
General plant and other	2 to 53	**44,588**	45,663
Construction work in process		**67,584**	545,652
Property, plant and equipment		**6,353,909**	5,808,679
Accumulated depreciation and amortization		**972,497**	875,279
Net property, plant and equipment		**$ 5,381,412**	$ 4,933,400

The average depreciation rates for our regulated property are set forth, by segment, in the following table for the periods indicated:

	Years Ended December 31,		
	2009	**2008**	**2007**
Natural Gas Pipelines	**2.2%**	2.4%	2.4%
Natural Gas Liquids	**1.8%**	2.0%	2.5%

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

F. GOODWILL AND INTANGIBLE ASSETS

Goodwill Impairment Tests - There were no impairment charges resulting from our July 1, 2009, 2008 or 2007 impairment tests.

Goodwill - The following table sets forth our goodwill, by segment, at both December 31, 2009 and 2008:

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

Intangible Assets - Our intangible assets relate primarily to contracts acquired through acquisition, which are being amortized over an aggregate weighted-average period of 40 years. Amortization expense for intangible assets for 2009, 2008 and 2007 was $7.7 million each year, and the aggregate amortization expense for each of the next five years is estimated to be approximately $7.7 million. All of our intangible assets are accounted for in our Natural Gas Liquids segment. The following table reflects the gross carrying amount and accumulated amortization of intangible assets for the periods presented:

	December 31, 2009	**December 31, 2008**
	(Thousands of dollars)	
Gross Intangible Assets	**$ 306,650**	$ 306,650
Accumulated Amortization	**(34,498)**	(26,832)
Net Intangible Assets	**$ 272,152**	$ 279,818

G. OTHER COMPREHENSIVE INCOME (LOSS)

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

	Years Ended December 31,		
	2009	**2008**	**2007**
		(Thousands of dollars)	
Unrealized gains (losses) on derivatives	**$ (33,306)**	$ 68,159	$ (16,555)
Less: Realized gains (losses) on derivatives recognized in net income	**53,348**	(14,387)	-
Other	**212**	-	-
Other comprehensive income (loss)	**$ (86,442)**	$ 82,546	$ (16,555)

The balance in accumulated other comprehensive income (loss) in our Consolidated Balance Sheets as of December 31, 2009 and 2008 was attributable to unrealized gains and losses on derivatives.

H. CREDIT FACILITIES

Our Partnership Credit Agreement, which expires March 2012, contains certain financial, operational and legal covenants. Among other things, these requirements include maintaining a ratio of indebtedness to adjusted EBITDA (EBITDA, as defined in our Partnership Credit Agreement, as adjusted for all non-cash charges and increased for projected EBITDA from certain lender-approved capital expansion projects) 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. At December 31, 2009, our ratio of indebtedness to adjusted EBITDA was 4.5 to 1, and we were in compliance with all covenants under our Partnership Credit Agreement.

At December 31, 2009 and 2008, we had $523 million and $870 million, respectively, in borrowings outstanding under our Partnership Credit Agreement, and under the most restrictive provisions of our Partnership Credit Agreement we had $367.1 million and $130 million, respectively, of credit available. At December 31, 2009 and 2008, we had a total of $24.2 million and $49.2 million, respectively, issued in letters of credit outside of our Partnership Credit Agreement. Borrowings under our Partnership Credit Agreement are nonrecourse to our general partner.

The average interest rate on our short-term debt outstanding under this agreement was 0.54 percent and 4.22 percent at December 31, 2009 and 2008, respectively.

Borrowings under our Partnership Credit Agreement are typically short term in nature, ranging from one day to six months. Accordingly, these borrowings are classified as short-term notes payable.

I. LONG-TERM DEBT

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

	December 31, 2009	December 31, 2008
	(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
$500,000 at 8.625% due 2019	**500,000**	-
$600,000 at 6.65% due 2036	**600,000**	600,000
$600,000 at 6.85% due 2037	**600,000**	600,000
	2,975,000	2,475,000
Guardian Pipeline	**109,780**	121,711
Total long-term notes payable	**3,084,780**	2,596,711
Unamortized portion of terminated swaps	**4,673**	8,414
Unamortized debt premium	**(5,436)**	(3,685)
Current maturities	**(261,931)**	(11,931)
Long-term debt	**$ 2,822,086**	$ 2,589,509

The aggregate maturities of long-term debt outstanding for years 2010 through 2014 are shown below:

	ONEOK Partners	Guardian Pipeline	Total
		(Millions of dollars)	
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
2014	$ -	$ 7.7	$ 7.7

Debt Issuance - In March 2009, we completed an underwritten public offering of $500 million aggregate principal amount of 8.625 percent Senior Notes due 2019 (2019 Notes). The net proceeds from the 2019 Notes of approximately $494.3 million were used to repay indebtedness outstanding under our Partnership Credit Agreement. The 2019 Notes will mature on March 1, 2019. We will pay interest on the 2019 Notes on March 1 and September 1 of each year. The first payment of interest on the 2019 Notes was made on September 1, 2009.

Debt Covenants - The terms of the 2019 Notes are governed by an indenture, dated as of September 25, 2006, between us and Wells Fargo Bank, N.A., as trustee, as supplemented by the Fifth Supplemental Indenture, dated March 3, 2009 (Indenture). The Indenture 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 to sell and lease back our property.

Our $250 million and $225 million senior notes, due June 15, 2010, and March 15, 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; however, once the $250 million 2010 senior notes have been retired, whether by maturity, redemption or otherwise, we will no longer have any obligation to offer to repurchase the $225 million 2011 senior notes in the event our credit rating falls below investment grade. 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, 2019, 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 events 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, 2019, 2036 and 2037 to declare those notes immediately due and payable in full.

We may redeem the notes due 2012, 2016, 2019, 2036 and 2037, in whole or in part, at any time prior to their maturity at a redemption price equal to the principal amount, 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 respective note plus accrued and unpaid interest to the redemption date. The notes due 2012, 2016, 2019, 2036 and 2037 are senior unsecured obligations, ranking equally in right of payment with all of our existing and future unsecured senior indebtedness, and effectively junior to any of the existing and future debt and other liabilities of any non-guarantor subsidiaries.

Debt Guarantee - The notes due 2012, 2016, 2019, 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, 2009, the Intermediate Partnership held partnership interests and the equity in our subsidiaries, as well as a 50 percent interest in Northern Border Pipeline. Our long-term debt is nonrecourse to our general partner.

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 K and N 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 $109.8 million in notes outstanding at December 31, 2009, 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, as defined in the master shelf agreement dated as of November 8, 2001, 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, 2009, Guardian Pipeline's EBITDAR-to-fixed-charges ratio was 4.6 to 1, the ratio of indebtedness to EBITDAR was 2.2 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. PARTNERS' EQUITY

ONEOK - ONEOK and its affiliates owned all of the Class B units, 5.9 million common units and the entire 2 percent general partner interest in us, which together constituted a 45.1 percent ownership interest in us at December 31, 2009.

Equity Issuances - 2010 Activity - In February 2010, we completed an underwritten public offering of 5,500,900 common units, including the partial exercise by the underwriters of their over-allotment option, at $60.75 per common unit, generating net proceeds of approximately $322.6 million. In conjunction with the offering, ONEOK Partners GP contributed $6.8 million in order to maintain its 2 percent general partner interest in us. We used the proceeds from the sale of common units and the general partner contribution to repay borrowings under our Partnership Credit Agreement and for general partnership purposes. As a result of these transactions, ONEOK and its subsidiaries own a 42.8 percent aggregate equity interest in us.

2009 Activity - In July 2009, we completed an underwritten public offering of 5,486,690 common units, including the partial exercise by the underwriters of their over-allotment option, at $45.81 per common unit, generating net proceeds of approximately $241.6 million. In conjunction with the offering, ONEOK Partners GP contributed an aggregate of $5.1 million in order to maintain its 2 percent general partner interest in us. We used the proceeds from the sale of common units and the general partner contributions to repay borrowings under our Partnership Credit Agreement and for general partnership purposes.

2008 Activity - In March 2008, we completed an underwritten public offering of 2,628,873 common units, including the partial exercise by the underwriters of their over-allotment option, at $58.10 per common unit, generating net proceeds of approximately $147.0 million. 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 $9.5 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 - Cash distributions paid to our general partner of $94.7 million in 2009, $78.9 million in 2008 and $54.7 million in 2007, included incentive distributions of $84.7 million, $69.9 million and $47.1 million in 2009, 2008 and 2007, respectively. 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,		
	2009	**2008**	**2007**
First Quarter	**$ 1.08**	$ 1.025	$ 0.98
Second Quarter	**$ 1.08**	$ 1.040	$ 0.99
Third Quarter	**$ 1.08**	$ 1.060	$ 1.00
Fourth Quarter	**$ 1.09**	$ 1.080	$ 1.01

In January 2010, our general partner declared a cash distribution of $1.10 per unit ($4.40 per unit on an annualized basis) for the fourth quarter of 2009, an increase of $0.01 from the previous quarter, which was paid on February 12, 2009, to unitholders of record at the close of business on January 29, 2010.

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 less adjustments for cash disbursements and net changes to 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 O for additional information about distributions allocated to the general partner.

K. COMMITMENTS AND CONTINGENCIES

Commitments - Operating leases represent future minimum lease payments under non-cancelable operating leases on a natural gas processing plant, office space, pipeline equipment, rights-of-way and vehicles. Firm transportation and storage contracts are fixed-price contracts that provide us with firm transportation and storage capacity. The following table sets forth our operating lease and firm transportation and storage contracts payments for the periods presented:

	Operating Leases	Firm Transportation and Storage Contracts	Total
		(Millions of dollars)	
2010	$ 14.9	$ 6.8	$ 21.7
2011	$ 14.0	$ 1.4	$ 15.4
2012	$ 7.2	$ 1.4	$ 8.6
2013	$ 2.3	$ 1.4	$ 3.7
2014	$ 1.9	$ 1.2	$ 3.1

Investment in Northern Border Pipeline - In 2009, we made equity contributions of $42.3 million to Northern Border Pipeline. We do not anticipate any material equity contributions in 2010.

Overland Pass Pipeline Company - Overland Pass Pipeline Company is a joint venture between us and a subsidiary of The Williams Companies, Inc. (Williams). We own 99 percent of the joint venture and operate the pipeline. On or before November 17, 2010, Williams has the option to increase its ownership in Overland Pass Pipeline Company up to a total of 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 50 percent, Williams would have the option to become operator. Should Williams exercise its option to obtain a 50 percent ownership interest, we may be required to deconsolidate Overland Pass Pipeline Company and account for it under the equity method of accounting.

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 and 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 lines or facilities that we own, operate or otherwise use, we could be held jointly and severally liable for all resulting liabilities, including response, 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 could have a material adverse effect on our business, financial condition and results of operations.

Our expenditures for environmental evaluation, mitigation, remediation and compliance to date have not been significant in relation to our financial position or results of operations, and our expenditures related to environmental matters had no material effects upon earnings or cash flows during 2009, 2008 or 2007.

In addition, the EPA has issued a proposed rule on air-quality standards, "National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines," also known as RICE NESHAP, scheduled to be adopted in early 2013. The proposed rule will require capital expenditures over the next three years for the purchase and installation of new emissions-control equipment. We do not expect these expenditures to have a material impact on our results of operations, financial position or cash flows.

Legal Proceedings - We are a party to various litigation matters and claims that have arisen 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.

L. INCOME TAXES

The following table sets forth our provision for income taxes for the periods indicated:

	Years Ended December 31,		
	2009	**2008**	**2007**
		(Thousands of dollars)	
Current income tax provision			
Federal	**$ 83**	$ 80	$ 72
State	**1,173**	7,240	4,203
Total current income tax provision	**1,256**	7,320	4,275
Deferred income tax provision			
Federal	**9,782**	4,785	3,994
State	**1,925**	230	573
Total deferred income tax provision	**11,707**	5,015	4,567
Total provision for income taxes	**$ 12,963**	$ 12,335	$ 8,842

The following table is a reconciliation of our income tax provision for the periods indicated:

	Years Ended December 31,		
	2009	**2008**	**2007**
		(Thousands of dollars)	
Income before income taxes	**$ 447,667**	$ 638,392	$ 417,005
Less: Net income attributable to noncontrolling interests	**348**	441	416
Income attributable to ONEOK Partners, L.P. before income taxes	**447,319**	637,951	416,589
Federal statutory income tax rate	**35.0%**	35.0%	35.0%
Provision for federal income taxes	**156,562**	223,283	145,806
Partnership earnings not subject to tax	**(148,229)**	(216,332)	(141,884)
State income taxes, net of federal benefit	**2,594**	7,470	4,772
Other, net	**2,036**	(2,086)	148
Income tax provision	**$ 12,963**	$ 12,335	$ 8,842

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,	
	2009	**2008**
	(Thousands of dollars)	
Deferred tax assets		
Net operating loss carryforward	**$ 2,559**	$ 4,226
Other	**688**	44
Total deferred tax assets	**3,247**	4,270
Deferred tax liabilities		
Excess of tax over book depreciation and depletion	**20,020**	9,660
Regulatory assets	**3,722**	3,733
Other	**6**	1,613
Total deferred tax liabilities	**23,748**	15,006
Net deferred tax liabilities	**$ 20,501**	$ 10,736

At December 31, 2009, we had approximately $2.6 million of tax benefits available related to net operating loss carryforwards, which will expire between the years 2022 and 2028. 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 $3.0 million and $7.2 million at December 31, 2009 and 2008, respectively.

M. SEGMENTS

Segment Descriptions - We implemented changes to the structure of our previous reportable business segments during the third quarter of 2009 to better align them with how we manage our businesses. Our financial results are now reported in these three segments: (i) Natural Gas Gathering and Processing; (ii) Natural Gas Pipelines, both of which remain unchanged; and (iii) Natural Gas Liquids, which consolidates our former natural gas liquids gathering and fractionation segment with our former natural gas liquids pipelines segment, due to the integrated manner in which they are managed. Prior-period amounts have been recast to reflect these segment changes.

Our operations are divided into three reportable 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 natural gas;
- our Natural Gas Pipelines segment primarily operates regulated interstate and intrastate natural gas transmission pipelines and natural gas storage facilities; and
- our Natural Gas Liquids segment primarily gathers, treats, fractionates and transports NGLs and stores, markets and distributes NGL products.

Accounting Policies - The accounting policies of the segments are described in Notes A and P. Intersegment and affiliate sales are recorded on the same basis as sales to unaffiliated customers. Net margin is comprised of total revenues less cost of sales and fuel. Cost of sales and fuel includes commodity purchases, fuel and transportation costs.

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 segment's customers are primarily NGL and natural gas gathering and processing companies, propane distributors 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.

In 2009, 2008 and 2007, we had no single external customer from which we received 10 percent or more of our consolidated revenues.

For 2009 and 2008, sales to affiliated customers were less than 10 percent of our consolidated revenues, respectively. For 2007, sales to affiliated customers were 11 percent of our consolidated revenues. See Note P for additional information about our sales to affiliated customers.

Operating Segment Information - The following tables set forth certain selected financial information for our operating segments for the periods indicated:

Year Ended December 31, 2009	Natural Gas Gathering and Processing	Natural Gas Pipelines (a)	Natural Gas Liquids (b)	Other and Eliminations	Total
			(Thousands of dollars)		
Sales to unaffiliated customers	$ 362,012	$ 235,553	$ 5,401,161	$ -	$ 5,998,726
Sales to affiliated customers	369,324	106,441	-	-	475,765
Intersegment revenues	363,241	775	20,575	(384,591)	-
Total revenues	$ 1,094,577	$ 342,769	$ 5,421,736	$ (384,591)	$ 6,474,491
Net margin	$ 359,939	$ 285,767	$ 476,422	$ (2,831)	$ 1,119,297
Operating costs	135,085	96,093	182,210	(2,161)	411,227
Depreciation and amortization	59,288	43,676	61,163	9	164,136
Gain (loss) on sale of assets	2,795	(728)	(213)	814	2,668
Operating income	$ 168,361	$ 145,270	$ 232,836	$ 135	$ 546,602
Equity earnings from investments	$ 28,366	$ 41,886	$ 2,470	$ -	$ 72,722
Investments in unconsolidated affiliates	$ 325,541	$ 410,273	$ 29,349	$ -	$ 765,163
Total assets	$ 1,623,830	$ 1,895,613	$ 4,488,712	$ (54,896)	$ 7,953,259
Noncontrolling interests in consolidated subsidiaries	$ -	$ 5,523	$ 65	$ 15	$ 5,603
Capital expenditures	$ 105,475	$ 62,246	$ 446,898	$ 1,072	$ 615,691

(a) - Our Natural Gas Pipelines segment has regulated and non-regulated operations. Our Natural Gas Pipelines segment's regulated operations had revenues of $278.0 million, net margin of $245.0 million and operating income of $104.5 million.

(b) - Our Natural Gas Liquids segment has regulated and non-regulated operations. Our Natural Gas Liquids segment's regulated operations had revenues of $277.9 million, of which $170.4 million related to sales within the segment, net margin of $206.0 million and operating income of $95.8 million.

Year Ended December 31, 2008	Natural Gas Gathering and Processing	Natural Gas Pipelines (a)	Natural Gas Liquids (b)	Other and Eliminations	Total
			(Thousands of dollars)		
Sales to unaffiliated customers	$ 447,293	$ 223,223	$ 6,304,756	$ 48	$ 6,975,320
Sales to affiliated customers	627,774	117,112	-	-	744,886
Intersegment revenues	681,172	1,788	23,156	(706,116)	-
Total revenues	$ 1,756,239	$ 342,123	$ 6,327,912	$ (706,068)	$ 7,720,206
Net margin	$ 435,223	$ 257,362	$ 448,652	$ (578)	$ 1,140,659
Operating costs	138,196	89,878	143,152	571	371,797
Depreciation and amortization	49,883	34,279	40,582	21	124,765
Gain (loss) on sale of assets	4	(17)	44	682	713
Operating income (loss)	$ 247,148	$ 133,188	$ 264,962	$ (488)	$ 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
Total assets	$ 1,613,903	$ 1,869,902	$ 3,613,727	$ 156,740	$ 7,254,272
Noncontrolling interests in consolidated subsidiaries	$ -	$ 5,797	$ 129	$ 15	$ 5,941
Capital expenditures	$ 146,249	$ 267,029	$ 840,436	$ 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) - Our Natural Gas Liquids segment has regulated and non-regulated operations. Our Natural Gas Liquids segment's regulated operations had revenues of $152.3 million, of which $93.6 million related to sales within the segment, net margin of $130.6 million and operating income of $58.6 million.

Year Ended December 31, 2007	Natural Gas Gathering and Processing	Natural Gas Pipelines (a)	Natural Gas Liquids (b)	Other and Eliminations	Total
			(Thousands of dollars)		
Sales to unaffiliated customers	$ 433,139	$ 194,170	$ 4,577,458	$ 27	$ 5,204,794
Sales to affiliated customers	519,755	107,009	-	-	626,764
Intersegment revenues	505,756	785	23,934	(530,475)	-
Total revenues	$ 1,458,650	$ 301,964	$ 4,601,392	$ (530,448)	$ 5,831,558
Net margin	$ 366,511	$ 241,097	$ 287,236	$ 1,049	$ 895,893
Operating costs	135,422	96,584	99,650	5,700	337,356
Depreciation and amortization	45,099	32,380	36,196	29	113,704
Gain (loss) on sale of assets	1,825	79	46	-	1,950
Operating income (loss)	$ 187,815	$ 112,212	$ 151,436	$ (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
Total assets	$ 1,521,514	$ 1,660,489	$ 3,056,421	$ (126,359)	$ 6,112,065
Noncontrolling interests in consolidated subsidiaries	$ -	$ 5,758	$ 29	$ 15	$ 5,802
Capital expenditures	$ 83,820	$ 138,919	$ 487,015	$ 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) - Our Natural Gas Liquids segment has regulated and non-regulated operations. Our Natural Gas Liquids segment's regulated operations had revenues of $91.1 million, of which $76.6 million related to sales within the segment, net margin of $81.8 million and operating income of $39.8 million.

N. 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, 2009	December 31, 2008
		(Thousands of dollars)	
Northern Border Pipeline	50%	**$ 401,773**	$ 392,601
Bighorn Gas Gathering	49%	**96,492**	97,289
Fort Union Gas Gathering	37%	**111,675**	108,642
Lost Creek Gathering Company (a)	35%	**80,041**	77,773
Other	Various	**75,182**	79,187
Investments in unconsolidated affiliates (b)		**$ 765,163**	$ 755,492

(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 A) was $185.6 million at December 31, 2009 and 2008.

Equity Earnings from Investments - The following table sets forth our equity earnings from investments for the periods indicated:

	Years Ended December 31, 2009	2008	2007
		(Thousands of dollars)	
Northern Border Pipeline	**$ 41,300**	$ 65,912	$ 62,008
Bighorn Gas Gathering	**7,807**	8,195	7,416
Fort Union Gas Gathering	**14,533**	14,172	9,681
Lost Creek Gathering Company	**4,872**	5,365	4,790
Other	**4,210**	7,788	6,013
Equity earnings from investments	**$ 72,722**	$ 101,432	$ 89,908

Unconsolidated Affiliates Financial Information - The following tables set forth summarized combined financial information of our unconsolidated affiliates for the periods indicated:

	December 31, 2009	December 31, 2008
	(Thousands of dollars)	
Balance Sheet		
Current assets	**$ 84,910**	$ 106,833
Property, plant and equipment, net	**$ 1,717,825**	$ 1,777,350
Other noncurrent assets	**$ 28,675**	$ 27,547
Current liabilities	**$ 70,500**	$ 279,996
Long-term debt	**$ 653,937**	$ 543,894
Other noncurrent liabilities	**$ 12,144**	$ 14,360
Accumulated other comprehensive income (loss)	**$ (3,054)**	$ (5,708)
Owners' equity	**$ 1,097,883**	$ 1,079,188

	Years Ended December 31, 2009	2008	2007
		(Thousands of dollars)	
Income Statement			
Operating revenues	**$ 383,625**	$ 415,552	$ 404,399
Operating expenses	**$ 178,194**	$ 179,380	$ 172,997
Net income	**$ 164,002**	$ 209,915	$ 184,434
Distributions paid to us	**$ 109,807**	$ 118,010	$ 103,785

Distributions paid to us are classified as operating activities on our Consolidated Statements of Cash Flows until the cumulative distributions exceed our proportionate share of income from the unconsolidated affiliate since the date of our initial investment. The amount of cumulative distributions paid to us that exceeds our cumulative proportionate share of income in each period represents a return of investment and is classified as an investing activity on our Consolidated Statement of Cash Flows. Distributions paid to us include a $34.4 million and $24.7 million return of investment in 2009 and 2008, respectively. Distributions paid to us in 2007 did not exceed our cumulative proportionate share of income from our unconsolidated affiliates.

O. LIMITED PARTNERS' NET INCOME PER UNIT

Limited partners' net income per unit is computed by dividing net income attributable to ONEOK Partners, L.P., after deducting the general partner's allocation as discussed below, by the weighted-average number of outstanding limited partner units, which includes our common and Class B limited partner units. ONEOK, as sole holder of our Class B units, has waived its right to receive increased quarterly distributions on the Class B units. Because ONEOK has waived its right to increased quarterly distributions, currently each Class B unit and common unit share equally in the earnings of the partnership, and neither has any liquidation or other preferences. ONEOK retains the option to withdraw its waiver at any time by giving us no less than 90 days advance notice. ONEOK Partners GP owns the entire 2 percent interest in us, which entitles it to 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 limited partners' net income per unit, net income attributable to ONEOK Partners, L.P. is generally allocated to the general partner as follows: (i) an amount based upon the 2 percent general partner interest in net income attributable to ONEOK Partners, L.P. 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 $87.7 million, $76.0 million and $50.6 million for 2009, 2008 and 2007, respectively.

The terms of our Partnership Agreement limit the general partner's incentive distribution to the amount of available cash calculated for the period. As such, incentive distribution rights are not allocated on undistributed earnings or distributions in excess of earnings. 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. For additional information regarding our general partner's incentive distribution rights, see "Cash Distributions" in Note J.

P. 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. Additionally, our Natural Gas Gathering and Processing segment and Natural Gas Liquids segment purchase a portion of the natural gas used in their operations from ONEOK and its subsidiaries.

We have certain contractual rights to the Bushton Plant. Our Processing and Services Agreement with ONEOK and OBPI sets out the terms by which OBPI provides services to us 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 costs and expenses of the Bushton Plant, including reimbursement of a portion of OBPI's obligations under equipment leases covering the Bushton Plant.

Under the Services Agreement with ONEOK, ONEOK Partners GP and NBP Services (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 operating obligations.

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 includes gross plant and investment, earnings before interest and taxes and payroll expense. It is not practicable to determine what these general overhead costs would be on a stand-alone basis. All costs directly charged or allocated to us are included in our Consolidated Statements of Income.

Our derivative contracts with OES are discussed under “Credit Risk” in Note D.

The following table sets forth the transactions with related parties for the periods indicated:

	Years Ended December 31,		
	2009	**2008**	**2007**
	(Thousands of dollars)		
Revenues	**$ 475,765**	$ 744,886	$ 626,764
Expenses			
Cost of sales and fuel	**$ 46,824**	$ 107,983	$ 89,792
Administrative and general expenses	**200,002**	191,798	171,741
Total expenses	**$ 246,826**	$ 299,781	$ 261,533

In addition, concurrent with our March 2008 sale of common units to the public, we sold 5.4 million common units to ONEOK in a private placement, generating proceeds of approximately $303.2 million. ONEOK Partners GP also made additional general partner contributions to us of $5.1 million and $9.5 million in 2009 and 2008, respectively, to maintain its 2 percent general partner interest in connection with the issuance of common units. See Note J for additional information.

Cash Distributions to ONEOK - We paid cash distributions to ONEOK and its subsidiaries related to its general and limited partner interests of $278.2 million, $251.7 million and $202.0 million for 2009, 2008 and 2007, respectively.

Q. QUARTERLY FINANCIAL DATA (UNAUDITED)

Year Ended December 31, 2009	**First Quarter**	**Second Quarter**	**Third Quarter**	**Fourth Quarter**
	(Thousands of dollars, except per unit amounts)			
Revenues	**$ 1,250,865**	**$ 1,397,057**	**$ 1,560,003**	**$ 2,266,566**
Net margin	**$ 253,541**	**$ 261,982**	**$ 292,879**	**$ 310,895**
Operating income	**$ 124,819**	**$ 124,798**	**$ 144,734**	**$ 152,251**
Net income	**$ 99,610**	**$ 97,539**	**$ 121,705**	**$ 115,850**
Net income attributable to ONEOK Partners, L.P.	**$ 99,591**	**$ 97,538**	**$ 121,493**	**$ 115,734**
Limited partners' per unit net income	**$ 0.85**	**$ 0.81**	**$ 1.00**	**$ 0.93**

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	$ 145,141	$ 154,655	$ 203,983	$ 122,278
Net income attributable to ONEOK Partners, L.P.	$ 145,018	$ 154,521	$ 203,872	$ 122,205
Limited partners' per unit net income	$ 1.48	$ 1.46	$ 1.97	$ 1.09

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. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed by us in the reports that we file or submit under the Exchange Act is accumulated and communicated to management of ONEOK Partners GP, including the officers of ONEOK Partners GP who are the equivalent of our principal executive and principal financial officers, as appropriate to allow timely decisions regarding required disclosure. 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, 2009.

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, 2009.

Our internal control over financial reporting as of December 31, 2009, 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, 2009, 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

We are managed under the direction of the Board of Directors of our sole general partner, ONEOK Partners GP, which consists of 10 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 the members of our Board of Directors are not elected by unitholders, we do not have a procedure by which security holders may recommend nominees to 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 seven of the 10 members of our Board of Directors, Julie H. Edwards, Jim W. Mogg, Shelby E. Odell, Gary

N. Petersen, Gerald B. Smith, Craig F. Strehl 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.

In evaluating director candidates, ONEOK considers factors that are in the best interests of the Partnership and its unitholders, including the knowledge, experience, integrity and judgment of each candidate; the potential contribution of each candidate to the diversity of backgrounds, experience and competencies that the Board desires to have represented on the Board; each candidate's ability to devote sufficient time and effort to his or her duties as a director; independence and willingness to make independent analytical inquiries regarding the Partnership and its business; and any core competencies or technical expertise necessary to staff Board committees. In addition, ONEOK assesses whether a candidate possesses the integrity, judgment, knowledge, experience, skills and expertise that are likely to enhance the Board's ability to manage and direct the affairs and business of the Partnership. ONEOK believes that each member of our Board possesses the necessary integrity, skills, knowledge, judgment, expertise and experience to serve on our Board.

Our Board of Directors is led by John W. Gibson, the Chairman of the Board and our President and Chief Executive Officer. In addition, our Audit Committee and Conflicts Committee are each led by an independent chair and vice chair. We do not have a lead independent director. The Board believes this leadership structure, including the combined chairman and chief executive officer positions, enables our Board to take advantage of the leadership skills of both Mr. Gibson and the chairs and vice chairs of our Audit and Conflicts Committees, and provides a structure for strong independent oversight of our management.

Audit Committee

Our Board of Directors has appointed an Audit Committee consisting of the seven members of our Board of Directors who are independent under our Governance Guidelines and the listing standards of the NYSE. 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 2010, our Board of Directors affirmatively determined that Ms. Edwards and Messrs. Mogg, Odell, Petersen, Smith, Strehl and Van Lunsen meet the standards for independence set forth in the Governance Guidelines and are therefore independent.

Our Board of Directors annually reviews the financial expertise of the members of our Audit Committee. In February 2010, our Board of Directors determined that Ms. Edwards and Messrs. Mogg, Odell, Petersen, Smith and Van Lunsen are each "audit committee financial experts," as defined by the rules of the SEC.

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 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.

Conflicts Committee

Our Board of Directors has appointed a Conflicts Committee consisting of the four members of our Board of Directors who are independent under our Governance Guidelines and the listing standards of the NYSE and who are not also executive officers or members of the Board of Directors of ONEOK. The Conflicts Committee has the authority to review specific matters that may present a conflict of interest in order to determine if the resolution of such conflict is "fair and reasonable" to our unitholders. In making any such determination, the Conflicts Committee has the authority to engage advisors to assist it in carrying out its duties.

Risk Oversight

Risk identification, assessment and mitigation are an integral part of the deliberations of our Board of Directors and Audit Committee throughout the year. The Board annually reviews an assessment of the primary operational and regulatory risks facing the Partnership, their relative magnitude and management's plan for mitigating these risks. The Board discusses risks related to the Partnership's business strategy at its annual strategic planning meeting and at other meetings as appropriate.

In addition, our Audit Committee considers risk issues associated with our overall financial reporting and disclosure process and legal compliance, as well as reviews policies and procedures on risk control assessment and accounting risk exposure, including our business continuity and disaster recovery plans. The Audit Committee meets with the Chief Executive Officer, Chief Financial Officer, Chief Operating Officer, General Counsel of our general partner, and the Vice President-Financial Services of ONEOK as well as our independent registered public accounting firm in executive sessions at which risk issues are regularly discussed at each of its in-person meetings during the year.

Directors and Executive Officers

The following table sets forth the members of our Board of Directors, Audit Committee, Conflicts Committee and the executive officers of our general partner. The persons designated as our executive officers serve in that capacity at the discretion of our Board of Directors. There are no family relationships between any of our executive officers or members of the Board of Directors, Audit Committee or the Conflicts Committee. Some of these individuals are also officers of certain of our subsidiaries and affiliates.

Name	Age	Position
John W. Gibson	57	Chairman of the Board, President and Chief Executive Officer
Curtis L. Dinan	42	Executive Vice President, Chief Financial Officer and Treasurer, Member, Board of Directors
Terry K. Spencer	50	Chief Operating Officer and Member, Board of Directors
John R. Barker	62	Executive Vice President, General Counsel and Assistant Secretary
Derek S. Reiners	38	Senior Vice President and Chief Accounting Officer
Julie H. Edwards	51	Member, Board of Directors and Audit Committee
Jim W. Mogg	61	Member, Board of Directors and Audit Committee
Shelby E. Odell	70	Member, Board of Directors, Audit and Conflicts Committees
Gary N. Petersen	58	Member, Board of Directors and Chairman, Audit and Conflicts Committees
Gerald B. Smith	59	Member, Board of Directors and Audit Committee
Craig F. Strehl	52	Member, Board of Directors, Audit and Conflicts Committees
Gil J. Van Lunsen	67	Member, Board of Directors and Vice Chairman, Audit and Conflicts Committees

John W. Gibson is the Chairman, President and Chief Executive Officer of ONEOK Partners GP, our general partner. He became President of ONEOK Partners GP, on January 1, 2010. He has also served as Chief Executive Officer of ONEOK Partners GP since 2007 and as Chairman of the Board of Directors of ONEOK Partners GP, since October 2007. Mr. Gibson also serves on the Board of Directors and as President and Chief Executive Officer of ONEOK. From 2005 until May 2006, he was President of ONEOK Energy Companies, which included our gathering and processing, natural gas liquids, pipelines and storage, and ONEOK's energy services business segments, some of which were acquired by us in April 2006. Prior to that, he was President, Energy, from May 2000 to 2005 for ONEOK. Mr. Gibson joined ONEOK in May 2000 from Koch Energy, Inc., a subsidiary of Koch Industries, where he was an Executive Vice President. His career in the energy industry began in 1974 as a refinery engineer with Exxon USA. He spent 18 years with Phillips Petroleum Company in a variety of domestic and international positions in its natural gas, natural gas liquids and exploration and production businesses, including Vice President of Marketing of its natural gas subsidiary GPM Gas Corp. He holds an engineering degree from Missouri University of Science and Technology, formerly known as University of Missouri at Rolla. Mr. Gibson also serves on the Board of Directors of BOK Financial Corporation.

In addition to being our Chairman, President and Chief Executive Officer, Mr. Gibson is also President and Chief Executive Officer of ONEOK. Mr. Gibson has served in a variety of roles of continually increasing responsibility at ONEOK since 2000, at the Partnership since 2004 and prior to 2000 at Koch Energy, Inc., Exxon USA and Phillips Petroleum Company. In these roles, Mr. Gibson has gained extensive management and operational experience and has demonstrated a strong track record of achievement in a variety of sectors in the oil and gas industry. In light of the foregoing, ONEOK has concluded that Mr. Gibson should continue to serve on our Board of Directors.

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 the Management Committee and Chair of the Audit Committee of Northern Border Pipeline Company. 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.

In addition to being our Executive Vice President and Chief Financial Officer, Mr. Dinan is also Senior Vice President and Chief Financial Officer of ONEOK. Mr. Dinan has served in a number of roles of continually increasing responsibility in finance and accounting at both the Partnership and ONEOK since 2004 and prior to 2004 at Grant Thornton. In these roles, Mr. Dinan has gained extensive finance and accounting experience and has demonstrated a strong track record of achievement in finance and accounting in the oil and gas industry. In light of the foregoing, ONEOK has concluded that Mr. Dinan should continue to serve on our Board of Directors.

Terry K. Spencer was appointed to the Board of Directors on January 1, 2010. Mr. Spencer has served as ONEOK Partners GP's Chief Operating Officer since July 16, 2009. From 2007, until his appointment as ONEOK Partners GP's Chief Operating Officer, Mr. Spencer served as Executive Vice President – Natural Gas Liquids of ONEOK Partners GP. Mr. Spencer previously served as President – Natural Gas Liquids for ONEOK Partners GP from April 2006 and served as our Senior Vice President – Natural Gas Liquids from July 2005 to March 2006. From 2003 to 2005, he served as Vice President and General Manager of Gas Supply and Project Development for ONEOK.

Mr. Spencer has extensive senior management experience in the oil and gas industry as a result of his service in a variety of roles of continually increasing responsibility at both the Partnership and ONEOK since 2003. In these roles, Mr. Spencer has demonstrated a strong track record of achievement and sound judgment. In light of the foregoing, ONEOK has concluded that Mr. Spencer should continue to serve on our Board of Directors.

John R. Barker became our Executive Vice President and General Counsel 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 shareholder, President and Director of GableGotwals, a law firm with offices in Oklahoma, which provides legal services to us and to ONEOK.

Derek S. Reiners was named Senior Vice President and Chief Accounting Officer for us and ONEOK on August 10, 2009. Prior to joining ONEOK, Mr. Reiners had been a partner of the accounting firm Grant Thornton LLP since 2004 and senior manager and manager of Grant Thornton LLP for the period 2002 to 2004. Mr. Reiners is a member of the Audit Committee of Northern Border Pipeline Company.

Julie H. Edwards was appointed to our Board of Directors on August 4, 2009. Ms. Edwards also serves on the Board of Directors of ONEOK and its Audit and Corporate Governance Committees. Ms. Edwards served on ONEOK's Board of Directors from January 15, 2004, to July 1, 2005. Ms. Edwards served as Senior Vice President - Corporate Development of Southern Union Company from November 2006 to January 2007 and as Senior Vice President and Chief Financial Officer of Southern Union Company from July 2005 to November 2006. From April 2000 to June 2005, she was Executive Vice President—Finance and Administration and Chief Financial Officer of Frontier Oil Corporation. Ms. Edwards also serves on the Board of Directors of Noble Corporation. She served as a director of NATCO Group, Inc. until its merger with Cameron International Corporation in November 2009.

Ms. Edwards has gained broad senior accounting, financial, management and corporate development expertise in the oil and gas industry as a result of her service at Southern Union Company and Frontier Oil Corporation where she demonstrated a strong track record of achievement and sound judgment. In light of the foregoing, ONEOK has concluded that Ms. Edwards should continue to serve on our Board of Directors.

Jim W. Mogg was appointed to our Board of Directors on August 4, 2009. Mr. Mogg also serves on the Board of Directors of ONEOK and its Executive Compensation and Corporate Governance Committees. Mr. Mogg served as Chairman of the Board of DCP Midstream GP, LLC, the general partner of DCP Midstream Partners, L.P., from August 2005 to April 2007. From January 2004 to September 2006, he served as Group Vice President, Chief Development Officer and advisor to the Chairman of Duke Energy. Mr. Mogg served as President and Chief Executive Officer of DCP Midstream, LLC from

December 1994 to March 2000, and as Chairman, President, and Chief Executive Officer from April 2000 through December 2003. Mr. Mogg was Vice Chairman of TEPPCO Partners, LP from April 2000 to May 2002 and Chairman of TEPPCO Partners, LP from May 2002 to February 2005. Mr. Mogg serves on the Board of Directors of Bill Barrett Corporation, and is non-executive Chairman of the Board of First Wind Holdings, Inc.

Mr. Mogg has extensive senior management experience in a variety of sectors in the oil and gas industry as a result of his service at DCP Midstream GP, LLC and Duke Energy where he has demonstrated a strong track record of achievement and sound judgment. In addition, Mr. Mogg's current and previous directorships at other companies, including master limited partnerships, provide him with extensive corporate governance experience. In light of the foregoing, ONEOK has concluded that Mr. Mogg should continue to serve on our Board of Directors.

Shelby E. Odell was appointed to our Board of Directors on August 4, 2009. Mr. Odell served as a director of Hiland Partners LP and Hiland Holdings GP, LP from September 2005 until it ceased to be a publicly traded company in December 2009. Mr. Odell has 40 years experience in the petroleum business, including marketing, distribution, acquisitions, identification of new business opportunities and management. From 1974 to 2000, Mr. Odell held several positions with Koch Industries. He retired in 2000 as President of Koch Hydrocarbon and Senior Vice President of Koch Industries. Prior to joining Koch, Mr. Odell advanced through several positions with Phillips Petroleum Company. He is also a past member of the Board of Directors of the Gas Processors Association.

Mr. Odell has extensive senior management experience in a variety of sectors in the oil and gas industry as a result of his service at Koch Hydrocarbon, Koch Industries and Phillips Petroleum Company where he has demonstrated a strong track record of achievement and sound judgment. In addition, Mr. Odell's previous service as a director of a master limited partnership provides him with extensive corporate governance experience. In light of the foregoing, ONEOK has concluded that Mr. Odell should continue to serve on our Board of Directors.

Gary N. Petersen is President of Endres Processing LLC. Additionally, since 1998, he has also provided consulting services related to strategic and financial planning. 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.

Mr. Petersen has broad senior management, accounting and financial expertise in the oil and gas industry as a result of his service at Reliant Energy-Minnegasco as well as extensive senior management experience as a result of his service at Endres Processing LLC, where he has demonstrated a strong track record of achievement and sound judgment. In light of the foregoing, ONEOK has concluded that Mr. Petersen should continue to serve on our Board of Directors.

Gerald B. Smith 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).

Mr. Smith has extensive financial, operational, management and investment management experience as a result of his long-term tenure as Chairman and Chief Executive Officer of Smith, Graham & Company Investment Advisors and has demonstrated a strong track record of achievement and sound judgment. Mr. Smith's occupation and his current and former board memberships at other companies and institutions also provide him with extensive corporate governance experience. In light of the foregoing, ONEOK has concluded that Mr. Smith should continue to serve on our Board of Directors.

Craig F. Strehl was appointed to our Board of Directors on August 4, 2009. Mr. Strehl joined LONESTAR Midstream in October of 2007 as an independent director, serving on the Board of Directors for LONESTAR Midstream Partners, LP, and as Chief Operating Officer of LONESTAR Midstream Partners II, LP. Prior to his affiliation with LONESTAR, Mr. Strehl was the President of Sid Richardson Carbon & Energy Company. After Southern Union Company's purchase of the pipeline assets of Sid Richardson Carbon & Energy Company, he served as President of Southern Union Company's midstream assets until he retired in January of 2007. Mr. Strehl began his energy career in 1980 as a pipeline engineer with TXO. After managing various engineering and commercial responsibilities for TXO, he joined Aquila Energy in 1987. As Vice President of Marketing and Business Development for Aquila, he completed the purchase of Clajon Gas Company in 1990, which was subsequently renamed Aquila Gas Pipeline in 1993.

Mr. Strehl has extensive senior management experience in a variety of sectors in the oil and gas industry as a result of his service at LONESTAR Midstream Partners, LP, LONESTAR Midstream Partners II, LP, Sid Richardson Carbon & Energy Company and Southern Union Company where he has demonstrated a strong track record of achievement and sound judgment. In light of the foregoing, ONEOK has concluded that Mr. Strehl should continue to serve on our Board of Directors.

Gil J. Van Lunsen was a managing partner of KPMG LLP at the firm's Tulsa, Oklahoma, office prior to his retirement in 2000. He began his career with KPMG LLP in 1968. He is currently a Director and Audit Committee Chairman of Array Biopharma in Boulder, Colorado, and formerly served on the Board of Directors of Sirenza Microdevices, Inc.

Mr. Van Lunsen has broad senior accounting, financial and management expertise as a result of his service at KPMG LLP where he has demonstrated a strong track record of achievement and sound judgment. In addition, Mr. Van Lunsen's current and previous directorships at other companies provide him with extensive corporate governance experience. In light of the foregoing, ONEOK has concluded that Mr. Van Lunsen should continue to serve on our Board of Directors.

Director Compensation

Compensation for our non-management directors for the year ended December 31, 2009, consisted of an annual cash retainer of $75,000 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. Non-management directors are reimbursed for their expenses related to their attendance at Board of Directors, Audit Committee and Conflicts 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 2009.

2009 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 ($)
Julie H. Edwards (1)	$ 36,417	-	-	-	-	-	$ 36,417
Jim W. Mogg (1)	$ 36,917	-	-	-	-	-	$ 36,917
Shelby E. Odell (1)	$ 36,917	-	-	-	-	-	$ 36,917
Gary N. Petersen	$ 92,565	-	-	-	-	-	$ 92,565
Gerald B. Smith	$ 90,935	-	-	-	-	-	$ 90,935
Craig F. Strehl (1)	$ 36,917	-	-	-	-	-	$ 36,917
Gil J. Van Lunsen	$ 89,500	-	-	-	-	-	$ 89,500

(1) Ms. Edwards and Messrs. Mogg, Odell and Strehl joined our Board of Directors in August 2009.

Additional Governance Matters

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. Petersen, 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.

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 2009 fiscal year or written representations from certain reporting persons that no Form 5s were required for those persons, we believe that during 2009 our reporting persons complied with all applicable filing requirements in a timely manner, except that an Initial Statement of Beneficial Ownership on Form 3 reporting the holdings of Derek S. Reiners in connection with his appointment as our Senior Vice President and Chief Accounting Officer was filed late.

Governance Guidelines - Our Board of Directors 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. Our Board of Directors recognizes that effective governance is an ongoing process, and the Board of Directors will review our Governance Guidelines periodically as deemed necessary.

Code of Business Conduct and Ethics - Our Board of Directors has adopted a Code of Business Conduct and Ethics applicable to the members of our Board of Directors, 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 and Ethics 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 and Ethics, our Governance Guidelines and other matters impacting our governance principles. You may access copies of 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 the secretary of ONEOK Partners GP 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 chairman, president and 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.

Compensation Committee Interlocks and Insider Participation - We do not have a compensation committee. During 2009, 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 or employee of ONEOK Partners or any if its subsidiaries.

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 by ONEOK 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 2010 Proxy Statement as filed with the SEC (ONEOK 2010 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 paid by ONEOK to 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 that is attributable to us under the Services Agreement.

The following table summarizes the compensation attributable to us in 2009 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 2009

Name & Principal Position	Year	Salary ($)	Stock Awards ($) (1)	Non-Equity Incentive Plan Compensation ($) (2)	Change in Pension Value and Nonqualified Deferred Compensation Earnings ($) (3)	All Other Compensation ($) (4)	Total ($)
John W. Gibson	2009	$ 472,539	$ 1,613,278	$ 644,372	$ 1,287,541	$ 57,667	$ 4,075,397
Chairman, President and	2008	$ 442,365	$ 1,408,168	$ 457,379	$ 1,085,848	$ 63,181	$ 3,456,941
Chief Executive Officer	2007	$ 295,926	$ 3,225,231	$ 536,963	$ 505,584	$ 67,930	$ 4,631,634
Curtis L. Dinan	2009	$ 229,110	$ 378,112	$ 220,518	$ 75,953	$ 23,303	$ 926,996
Executive Vice President, Chief	2008	$ 214,480	$ 408,192	$ 147,455	$ 44,230	$ 25,094	$ 839,451
Financial Officer and Treasurer	2007	$ 143,190	$ 197,091	$ 181,374	$ 20,826	$ 13,667	$ 556,148
James C. Kneale (5)	2009	$ 343,665	$ 663,125	$ 429,581	$ 249,269	$ 39,521	$ 1,725,161
Former President and	2008	$ 321,720	$ 727,259	$ 294,910	$ 598,479	$ 45,531	$ 1,987,899
Chief Operating Officer	2007	$ 248,196	$ 1,382,423	$ 389,000	$ 420,392	$ 33,201	$ 2,473,212
Terry K. Spencer	2009	$ 283,667	$ 483,476	$ 258,444	$ 105,954	$ 28,479	$ 1,160,020
Chief Operating Officer	2008	$ 249,687	$ 263,583	$ 179,291	$ 66,818	$ 29,720	$ 789,099
	2007	$ 261,354	$ 225,210	$ 340,000	$ 55,580	$ 14,233	$ 896,377
Sheridan C. Swords	2009	$ 286,458	$ 379,653	$ 230,000	$ 19,505	$ 39,563	$ 955,179
President - Natural Gas Liquids	2008	$ 250,000	$ 315,012	$ 160,000	$ -	$ 46,436	$ 771,448
	2007	$ 180,677	$ 56,280	$ 200,000	$ -	$ 14,233	$ 451,190

(1) The amounts included in the table with respect to restricted stock incentive units and performance units granted under the ONEOK Long-Term Incentive Plan (LTI Plan) and the ONEOK Equity Compensation Plan reflect the aggregate grant date fair value attributable to us in 2007, 2008 and 2009 calculated pursuant to Financial Accounting Standards Board's Accounting Standards Codification 718, Compensation Stock Computation ("ASC Topic 718"). Material assumptions used in the calculation of the value of these equity grants are included in Note O to the ONEOK audited financial statements for the year ended December 31, 2009, included in the ONEOK 2009 Annual Report on Form 10-K filed with the SEC on February 23, 2010.

The aggregate grant date fair value of restricted stock incentive units for purposes of ASC Topic 718 was determined 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, the aggregate grant date fair value for purposes of ASC Topic 718 was determined using the probable outcome of the performance conditions as of the grant date based on a valuation model that considers the market condition (total shareholder return), using assumptions developed from historical information of ONEOK and a peer group of companies. The value included for the performance units is based on 100 percent of the performance units vesting at the end of the three-year vesting period. Using the maximum number of shares issuable upon vesting of the performance units (200 percent of the units granted), the aggregate grant date fair value of the performance units allocable to us would be as follows:

	2009	2008	2007
John W. Gibson	**$ 2,688,835**	$ 2,352,846	$ 1,004,468
Curtis L. Dinan	**$ 635,237**	$ 658,797	$ 304,928
James C. Kneale	**$ 1,105,783**	$ 1,176,423	$ 645,730
Terry K. Spencer	**$ 742,431**	$ 427,980	$ 338,220
Sheridan C. Swords	**$ 604,404**	$ 509,008	$ 75,160

(2) Reflects the amounts attributable to us under the ONEOK annual short-term incentive plan for each named executive officer. 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 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 short-term incentive plan, see “2009 Annual Short-Term Incentive Awards” in the ONEOK 2010 Proxy Statement.

(3) Reflects the portion of the aggregate current year change in pension values and above-market earnings on nonqualified deferred compensation attributable to us for each named executive officer. For a discussion of the Retirement Plan for Employees of ONEOK, Inc. and Subsidiaries, the ONEOK, Inc. Supplemental Executive Retirement Plan, and the ONEOK Nonqualified Deferred Compensation Plan, see the ONEOK 2010 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, December 31, 2008, and December 31, 2009, measurement dates for the ONEOK pension plan.

In 2008 ONEOK changed its pension plan measurement date, for financial accounting purposes, from September 30 of each year to December 31. As a result, the amounts attributable from included in the Summary Compensation Table with respect to the Retirement Plan for Employees of ONEOK, Inc. and Subsidiaries and the ONEOK, Inc. Supplemental Executive Retirement Plan are twelve-fifteenths of the amounts attributable to us that were earned over the 15-month period ending on December 31, 2008.

Only the portion of the above-market earnings attributable to us for 2007 is included in the table. For 2007, the amount attributable to us was $765 for Mr. Kneale. No other ONEOK named executive officers received above market earnings in 2007. No ONEOK named executive officers received above-market earnings in 2008 or 2009. For additional information on the ONEOK Nonqualified Deferred Compensation Plan, see “Long-Term Compensation Plans-Nonqualified Deferred Compensation Plan” in the ONEOK 2010 Proxy Statement.

(4) Reflects the portion attributable 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	2009	$ 49,247	$ 8,420
	2008	$ 55,336	$ 7,400
	2007	$ 30,070	$ 6,444
Curtis L. Dinan	2009	$ 14,778	$ 8,420
	2008	$ 17,694	$ 7,400
	2007	$ 6,873	$ 6,444
James C. Kneale	2009	$ 31,101	$ 8,420
	2008	$ 38,123	$ 7,400
	2007	$ 26,347	$ 6,444
Terry K. Spencer	2009	$ 17,138	$ 11,341
	2008	$ 19,823	$ 9,897
	2007	$ -	$ 13,500
Sheridan C. Swords	2009	$ 24,863	$ 14,700
	2008	$ 32,086	$ 13,800
	2007	$ -	$ 13,500

(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 2010 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.

With respect to Mr. Dinan, this amount also reflects a tax gross-up received in 2009 attributable to us in the amount of $34 in connection with his receipt of a service award.

With respect to Messrs. Gibson and Kneale, this amount also reflects tax gross-ups received in 2008 attributable to us in the amount of $445 and $8, respectively, with respect to income imputed to each of them under the Internal Revenue Code in connection with their personal use of ONEOK's aircraft.

With respect to Mr. Swords, this amount also reflects a tax gross-up received in 2008 attributable to us in the amount of $176 in connection with his receipt of a service award.

With respect to Messrs. Gibson, Kneale, Dinan, Spencer and Swords, this amount also reflects tax gross-ups received in 2007 attributable to us in the amount of $172, $172, $112, $235 and $235, respectively, in connection with their receipt of a stock award.

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 a country club membership fee in 2007 in the amount of $31,006.

(5) Mr. Kneale retired from ONEOK effective January 1, 2010.

Potential Post-Employment Payments and Payments upon a Change in Control

In this section, we describe the post-employment compensation and benefits that ONEOK provides our named executive officers. The objectives of the post-termination compensation and benefits that ONEOK provides are to:

- assist in recruiting and retaining talented executives in a competitive market;
- provide security for any compensation or benefits that have been earned;
- permit executives to focus on our business;
- eliminate any potential personal bias of an executive against a transaction that is in the best interest of our shareholders;
- avoid the costs associated with negotiating executive severance benefits separately; and
- provide us with the flexibility needed to react to a continually changing business environment.

ONEOK has not entered into individual employment agreements with named executive officers. Instead, the rights of our executives with respect to specific events, other than a change in control, including death, disability, severance or retirement are covered by our compensation and benefit plans. Under this approach, post-employment compensation and benefits are established separately from the other compensation elements of our executives.

The use of a "plan approach" instead of individual employment agreements serves several objectives. First, the plan approach provides ONEOK with more flexibility to change the terms of severance benefits from time to time, if necessary. Second, the plan approach is more transparent, both internally and externally. Internal transparency eliminates the need to negotiate separation benefits on a case-by-case basis and assures an executive that his or her severance benefits are comparable with those of his or her peers. Finally, the plan approach is easier for ONEOK to administer, as it requires less time and expense.

Payments Made Upon Any Termination - Regardless of the manner in which a named executive officer's employment terminates, he or she is entitled to receive amounts earned during their term of employment. Such amounts include:

- accrued but unpaid salary;
- amounts contributed under the Thrift Plan for Employees of ONEOK, Inc. and Subsidiaries, the ONEOK Profit Sharing Plan and the ONEOK, Inc. Employee Nonqualified Deferred Compensation Plan; and
- amounts accrued and vested through the ONEOK, Inc. Supplemental Executive Retirement Plan.

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 Long-Term Incentive Plan (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 either the ONEOK LTI Plan or 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 - We believe that the possibility of a change in control creates uncertainty for named executive officers because such transactions frequently result in changes in senior management. We provide change in control protections in termination agreements with our named executive officers to alleviate concerns regarding such a transaction, allowing them to focus their attention on our business.

ONEOK has entered into amended and restated termination agreements with each of Messrs. Gibson, Dinan and Spencer. 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. 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.

Under the termination agreements, all change-in-control benefits are "double trigger" and 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 Mr. Gibson three times, and for Messrs. Dinan 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 cash incentive compensation. Mr. Gibson would also be entitled to continuation of health and welfare benefits for 36 months and accelerated benefits under the ONEOK, Inc. Supplemental Executive Retirement Plan. Messrs. Dinan and Spencer would be entitled to continuation of health and welfare benefits for 24 months. In the case of Mr. Gibson, ONEOK will make gross-up payments to him to cover any excise taxes due if any portion of his severance payments and other benefits due constitute "excess parachute payments" under applicable tax law. For Messrs. Dinan 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 these officers only if the severance payments, as reduced, are subsequently deemed to constitute excess parachute payments. The termination agreements also include a restrictive covenant prohibiting the disclosure of trade secrets for three years following termination of employment.

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.

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 that adversely affects our business; any willful or intentional act of the executive that adversely affects our business, or reflects unfavorably on our reputation; the executive's use of alcohol or drugs that 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 that 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, 2009, and are estimates of the allocated amounts that 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 Spencer hold outstanding exercisable options with an allocated intrinsic value of $681,644 and $151,718 as of December 31, 2009.

John W. Gibson	**Termination Upon Death, Disability or Retirement**	**Termination Without Cause**	**Qualifying Termination Following a Change in Control**
Cash Severance	$ -	$ -	$ 2,822,564
Equity			
Restricted Stock/Units	$ 2,742,002	$ 2,742,002	$ 4,748,176
Performance Shares/Units	$ 2,561,932	$ -	$ 3,948,483
Total	$ 5,303,934	$ 2,742,002	$ 8,696,659
Other Benefits			
Health & Welfare	$ -	$ -	$ 12,074
Excise Tax Gross-up	$ -	$ -	$ 4,374,865
Total	$ -	$ -	$ 4,386,939
Total	$ 5,303,934	$ 2,742,002	$ 15,906,162

Curtis L. Dinan	**Termination Upon Death, Disability or Retirement**	**Termination Without Cause**	**Qualifying Termination Following a Change in Control**
Cash Severance	$ -	$ -	$ 756,945
Equity			
Restricted Stock/Units	$ 149,387	$ 149,387	$ 259,900
Performance Shares/Units	$ 691,417	$ -	$ 1,034,603
Total	$ 840,804	$ 149,387	$ 1,294,503
Other Benefits			
Health & Welfare	$ -	$ -	$ 11,513
Excise Tax Gross-up	$ -	$ -	$ -
Total	$ -	$ -	$ 11,513
Total	$ 840,804	$ 149,387	$ 2,062,961

James C. Kneale (1)	Termination Upon Retirement	Termination Without Cause	Qualifying Termination Following a Change in Control
Cash Severance	$ -	n/a	n/a
Equity			
Restricted Stock/Units	$ 304,701	n/a	n/a
Performance Shares/Units	$ 1,325,361	n/a	n/a
Total	$ 1,630,062	n/a	n/a
Other Benefits			
Health & Welfare	$ -	n/a	n/a
Excise Tax Gross-up	$ -	n/a	n/a
Total	$ -	n/a	n/a
Total	$ 1,630,062	n/a	n/a

(1) Mr. Kneale retired from the company effective January 1, 2010.

Terry K. Spencer	Termination Upon Death, Disability or Retirement	Termination Without Cause	Qualifying Termination Following a Change in Control
Cash Severance	$ -	$ -	$ 1,250,000
Equity			
Restricted Stock/Units	$ 194,994	$ 194,994	$ 414,501
Performance Shares/Units	$ 806,962	$ -	$ 1,234,589
Total	$ 1,001,956	$ 194,994	$ 1,649,090
Other Benefits			
Health & Welfare	$ -	$ -	$ 20,533
Excise Tax Gross-up	$ -	$ -	$ -
Total	$ -	$ -	$ 20,533
Total	$ 1,001,956	$ 194,994	$ 2,919,623

Sheridan C. Swords	Termination Upon Death, Disability or Retirement	Termination Without Cause	Qualifying Termination Following a Change in Control
Cash Severance	$ -	$ -	n/a
Equity			
Restricted Stock/Units	$ 106,473	$ 106,473	n/a
Performance Shares/Units	$ 409,884	$ -	n/a
Total	$ 516,357	$ 106,473	n/a
Other Benefits			
Health & Welfare	$ -	$ -	n/a
Excise Tax Gross-up	$ -	$ -	n/a
Total	$ -	$ -	n/a
Total	$ 516,357	$ 106,473	n/a

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, 2010, 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 5 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	15,000	*	-	-	*	184,805	(3)	*
James C. Kneale	-	-	-	-	-	232,711	(4)	*
Curtis L. Dinan	7,500	*	-	-	*	28,748	(5)	*
Terry K. Spencer	-	-	-	-	-	29,137	(6)	*
Sheridan C. Swords	-	-	-	-	-	5,581	(7)	*
Gary N. Petersen	11,392	*	-	-	*	-		-
Gerald B. Smith	-	-	-	-	-	750		*
Gil J. Van Lunsen	1,700	*	-	-	*	-		-
Julie H. Edwards	-	-	-	-	-	10,584		*
Jim W. Mogg	1,000	*	-	-	*	-		-
Shelby E. Odell	1,000	*	-	-	*	-		-
Craig F. Strehl	4,700	*	-	-	*	-		-
All directors and executive officers as a group	42,292	*	-	-	*	492,316		*
ONEOK, Inc. and affiliates	5,900,000	9.8	36,494,126	100.0	44.0	-		-

* 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, 2010, upon exercise of stock options granted under the ONEOK Long-Term Incentive Plan.

(3) Includes options for 59,948 shares exercisable within 60 days of February 1, 2010. Excludes 41,391 shares, the receipt of which was deferred upon vesting in January 2010 under the deferral provisions of the ONEOK Equity Compensation Plan, and which shares will be issued to Mr. Gibson on July 17, 2013.

(4) Includes options for 36,542 shares exercisable within 60 days of February 1, 2010.

(5) Excludes 12,565 shares, the receipt of which was deferred upon vesting in January 2010 under the deferral provisions of the ONEOK Equity Compensation Plan, and which shares will be issued to Mr. Dinan upon his separation of service from the company.

(6) Includes options for 5,500 shares exercisable within 60 days of February 1, 2010.

(7) Excludes 1,385 shares, the receipt of which was deferred upon vesting in January 2010 under the deferral provisions of the ONEOK Equity Compensation Plan, and which shares will be issued to Mr. Swords upon his separation of service from the company.

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, 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 with 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 Conflicts 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 Board of Directors and our Audit and

Conflicts Committees. These procedures are not in writing but are documented through the meeting agendas of the Board of Directors of our general partner.

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 our 36,494,126 Class B units, 5,900,000 of our common units and our entire 2 percent general partner interest, which together constituted a 45.1 percent ownership interest in us at December 31, 2009. For 2009, our general partner declared total cash distributions to ONEOK of $282.4 million, which included $87.7 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 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 entity, but which has no direct basis for allocation, is allocated by the modified Distrigas method, which is an allocation 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 2009, the aggregate amount charged by ONEOK, NBP Services and their affiliates to us for their services was approximately $191.4 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 2009, 1.4 percent of Northern Border Pipeline's design capacity was contracted on a firm basis with OES. Revenue from OES for 2009 was $4.2 million. As of January 31, 2010, 1.4 percent of Northern Border Pipeline's design capacity was contracted on a firm basis with OES for 2010.

Our Natural Gas Gathering and Processing segment sold $369.3 million of natural gas to ONEOK and its subsidiaries during 2009. Of our Natural Gas Pipelines segment's revenues, $106.4 million were from ONEOK and its subsidiaries during 2009 for both transportation and storage services.

Our Natural Gas Gathering and Processing segment and Natural Gas Liquids segment purchase a portion of the natural gas used in their operations from ONEOK and its subsidiaries. In 2009, the aggregate amount charged by ONEOK and its affiliates to us for their services was approximately $46.8 million.

Bushton Plant - 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 OBPI's capacity at the Bushton Plant. 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 2009, the aggregate amount charged by ONEOK and its affiliates related to the Bushton Plant was approximately $8.6 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 OES in which we have agreed to indemnify and hold 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 for a discussion of our derivative instruments and hedging activities.

Relationship with TransCanada

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

We are managed under the direction of the Board of Directors of our general partner, which establishes our business policies. ONEOK appoints the Board of Directors and may change the composition or size of the Board of Directors at its discretion.

ONEOK, which is the parent company of our general partner, and its affiliates currently engage or may engage in the businesses in which we engage or in which we may engage in the future and neither ONEOK nor any of its affiliates has any obligation to present business opportunities to us.

ONEOK and its other affiliates may from time to time engage in transactions with us. As a result, conflicts of interest may arise between ONEOK and its other affiliates, and us. If such conflicts arise, then, in accordance with the provisions of our Partnership Agreement, the members of our Board of Directors may themselves resolve such conflicts or may seek to have such conflicts of interest approved by either our Conflicts Committee (comprised of independent members of our Board of Directors who are not also members of ONEOK's Board of Directors) and/or by a vote of unitholders.

Unless otherwise provided for in a partnership agreement, the laws of Delaware 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 Board of Directors. Because of the competing interests identified above, our Partnership Agreement contains provisions that modify or in some cases eliminate 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 Conflicts 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 Conflicts 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. Insofar as indemnification for liabilities arising under the Securities Act may be permitted to directors, officers or persons controlling us pursuant to the foregoing provisions or otherwise, we have been advised that in the opinion of the SEC, such indemnification is against public policy as expressed in the Securities Act and is, therefore, unenforceable.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

Audit and Non-Audit Fees

Audit services provided by PricewaterhouseCoopers LLP during the 2009 and 2008 fiscal years included audits of our consolidated financial statements, audits 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.

The following table presents fees billed for audit services rendered by PricewaterhouseCoopers LLP for the audits of annual consolidated financial statements for the years ended December 31, 2009 and 2008, and fees billed for other services rendered by PricewaterhouseCoopers LLP during that period:

	2009	2008
Audit fees	**$ 1,423,729**	$ 1,320,179
Audit-related fees	**-**	-
Tax fees (1)	**842,475**	730,923
All other fees (2)	**750**	35,770
Total	**$ 2,266,954**	$ 2,086,872

(1) Tax fees consisted of fees for tax compliance, tax planning or tax services, including preparation of our K-1 statements.

(2) 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, attestation 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 compared with 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 Not used.

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 Not used.

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 Not used.

4.9 Not used.

4.10 Not used.

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 Not used.

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 Not used.

4.15 Fifth Supplemental Indenture, dated as of March 3, 2009, among ONEOK Partners, L.P., ONEOK Partners Intermediate Limited Partnership and Wells Fargo Bank, N.A., as trustee, with respect to the 8.625 percent Senior Notes due 2019 (incorporated by reference to Exhibit 4.2 to the Current Report on Form 8-K, filed by ONEOK Partners, L.P. on March 3, 2009 (File No. 1-12202)).

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 Underwriting Agreement dated June 16, 2009, 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 June 22, 2009).

10.3 Services Agreement executed April 6, 2006 but effective as of April 1, 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 Underwriting Agreement, dated February 26, 2009, among ONEOK Partners, L.P. and ONEOK Partners Intermediate Limited Partnership 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 3, 2009).

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 Third Amended and Restated Limited Liability Company Agreement of ONEOK Partners GP, L.L.C. effective July 14, 2009 (incorporated by reference to Exhibit 99.1 to ONEOK Partners, L.P.'s report on Form 8-K filed on July 17, 2009).

10.9 First Amended and Restated Limited Liability Company Agreement of ONEOK ILP GP, L.L.C. effective July 14, 2009 (incorporated by reference to Exhibit 99.2 to ONEOK Partners, L.P.'s report on Form 8-K filed on July 17, 2009).

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	Not used.
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).
10.15	Underwriting Agreement dated February 2, 2010, 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 February 5, 2010).
12	Computation of Ratio of Earnings to Fixed Charges for the years ended December 31, 2009, 2008, 2007, 2006 and 2005.
16	Not used.
21	Required information concerning the registrant's subsidiaries.
23.1	Consent of Independent Registered Public Accounting Firm - PricewaterhouseCoopers LLP.
23.2	Not used.
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, 2009.
101.INS	XBRL Instance Document.
101.SCH	XBRL Taxonomy Extension Schema Document.
101.CAL	XBRL Taxonomy Calculation Linkbase Document.
101.DEF	XBRL Taxonomy Extension Definitions Document.
101.LAB	XBRL Taxonomy Label Linkbase Document.

101.PRE XBRL Taxonomy Presentation Linkbase Document.

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 23, 2010

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 23th day of February 2010.

/s/ John W. Gibson John W. Gibson Chairman of the Board, President and Chief Executive Officer	/s/ Curtis L. Dinan Curtis L. Dinan Director, Executive Vice President, Chief Financial Officer and Treasurer
/s/ Terry K. Spencer Terry K. Spencer Director and Chief Operating Officer	/s/ Julie H. Edwards Julie H. Edwards Director
/s/ Gil J. Van Lunsen Gil J. Van Lunsen Director	/s/ Jim W. Mogg Jim W. Mogg Director
/s/ Shelby E. Odell Shelby E. Odell Director	/s/ Gary N. Petersen Gary N. Petersen Director
/s/ Gerald B. Smith Gerald B. Smith Director	/s/ Craig F. Strehl Craig F. Strehl Director
/s/ Derek S. Reiners Derek S. Reiners Senior Vice President and Chief Accounting Officer	

ONEOK PARTNERS

100 West Fifth Street
Tulsa, OK 74103-4298

Post Office Box 871
Tulsa, OK 74102-0871

www.oneokpartners.com