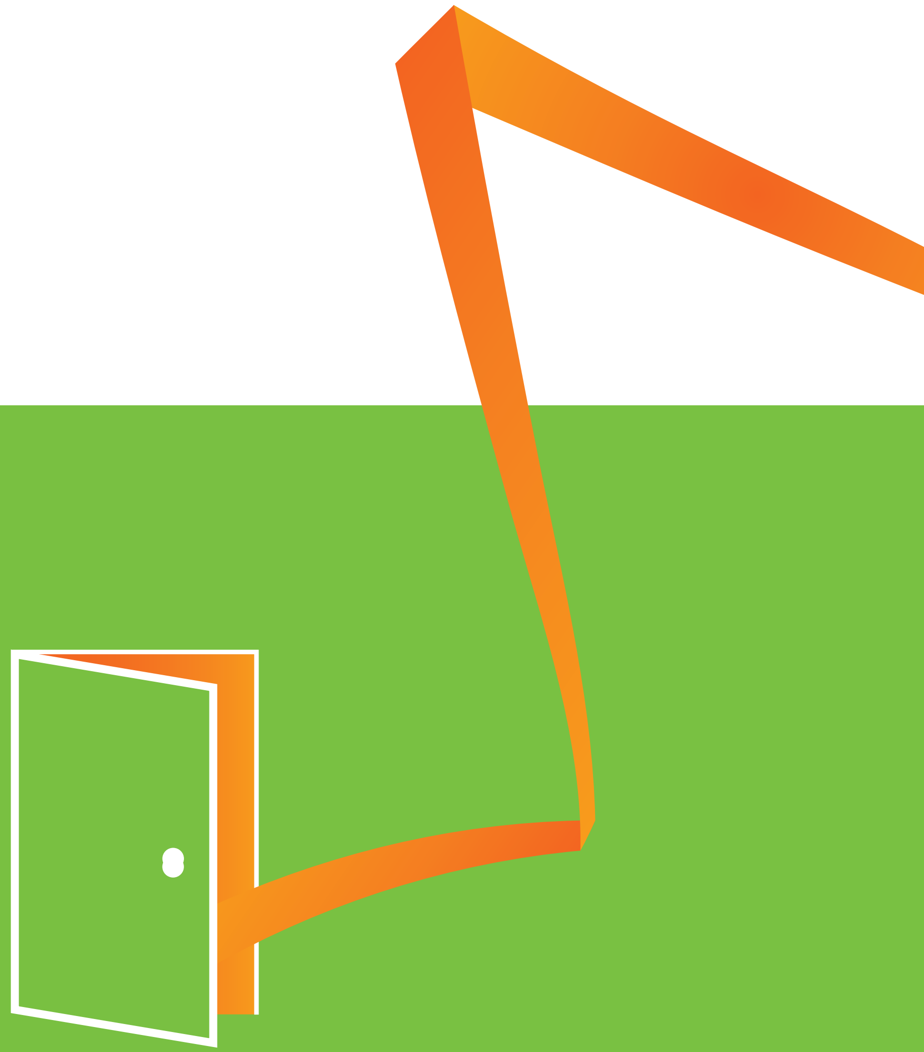
ONEOK PARTNERS 2010 ANNUAL REPORT



OPENING DOORS. GROWING POTENTIAL.

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

## FINANCIAL HIGHLIGHTS

| Year Ended December 31 | 2010 | 2009 | 2008 |
|---|---|---|---|
| **Consolidated financial information** (millions of dollars) | | | |
| Net margin | $ 1,144.9 | $ 1,119.3 | $ 1,140.7 |
| Operating income | $ 586.3 | $ 546.6 | $ 644.8 |
| Net income attributable to ONEOK Partners, L.P. | $ 472.7 | $ 434.4 | $ 625.6 |
| Total assets | $ 7,920.1 | $ 7,953.3 | $ 7,254.3 |
| Total debt to capitalization | 50 % | 55 % | 54 % |
| **Capital expenditures** (millions of dollars) | | | |
| Growth | $ 290.2 | $ 556.4 | $ 1,172.0 |
| Maintenance | $ 62.5 | $ 59.3 | $ 81.9 |
| Total capital expenditures | $ 352.7 | $ 615.7 | $ 1,253.9 |
| **Common unit data** | | | |
| Common units outstanding at year-end | 65,413,677 | 59,912,777 | 54,426,087 |
| Class B units outstanding at year-end | 36,494,126 | 36,494,126 | 36,494,126 |
| Total units outstanding at year-end | 101,907,803 | 96,406,903 | 90,920,213 |
| **Data per limited partner unit** | | | |
| Net income | $ 3.50 | $ 3.60 | $ 6.01 |
| Distributions declared | $ 4.50 | $ 4.35 | $ 4.26 |
| **Market price range** | | | |
| High | $ 81.51 | $ 63.00 | $ 64.01 |
| Low | $ 55.95 | $ 34.21 | $ 39.25 |
| Year-end | $ 79.50 | $ 62.30 | $ 45.55 |

# LETTER TO UNITHOLDERS

**WE ARE OPENING MORE DOORS** In business as in life, the doors we open shape our future. That's certainly true of the doors we've opened at ONEOK Partners, which have led repeatedly to additional growth opportunities.

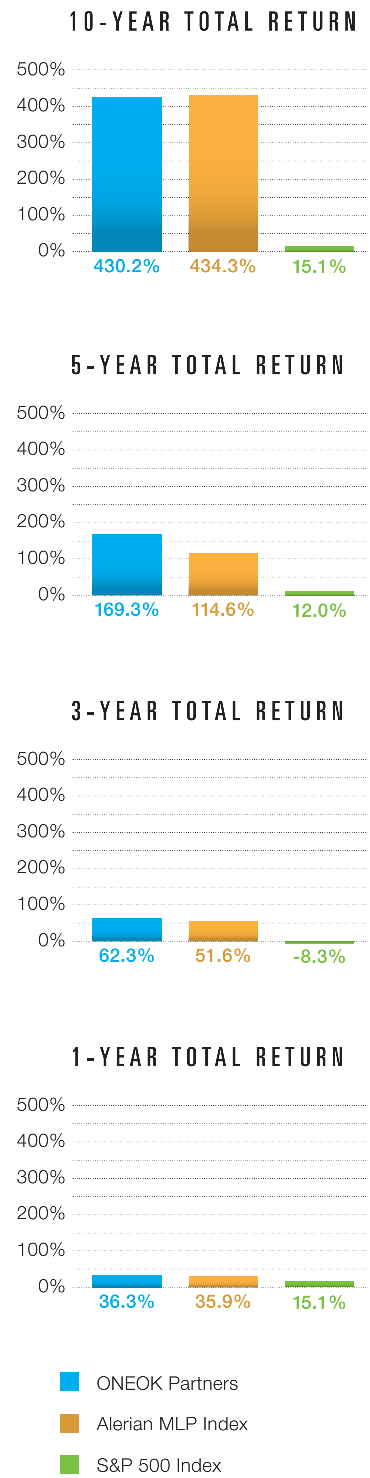
Decisions made helped turn the keys to those doors, but the credit for opening them – turning opportunity into value creation – belongs to the more than 1,200 employees who work for the partnership.

The ONEOK Partners team turned in another good performance in 2010. All of the projects in our 2006 to 2009 growth program – totaling more than $2 billion – were operating for a full calendar year for the first time in 2010. Total operating income was $586.3 million, compared with $546.6 million in 2009. Over the past three years, operating income has increased 31 percent.

**MORE GROWTH AHEAD** During 2010 and in January 2011, we announced additional capital-investment projects in our natural gas gathering and processing and natural gas liquids (NGL) segments totaling $1.8 billion to $2.1 billion for 2011 to 2014.

We expect the partnership's earnings before interest, depreciation and amortization (EBITDA)* to increase by an average of 14 to 18 percent annually from 2011 to 2013 during this multiyear growth phase, as volumes continue ramping up on past projects and new projects go into service. This will result in higher distributable cash flow and increased distributions to unitholders.

Distributions to unitholders have increased 43 percent since 2006; they are expected to increase one penny per quarter in 2011 and 5 to 10 percent *annually* in 2012 to 2013, pending board approval.




*As of December 31, 2010*

**See inside back cover for a description of a non-GAAP financial measure.*

**MORE THAN CLICHÉS** We've all heard the sayings, *strength builds on strength* and *one door opens another*. At ONEOK Partners, these are more than clichés. In fact, they ring with clarity when applied to each of our major growth projects directly ahead.

The majority of the $1.8 billion to $2.1 billion of future investments between 2011 and 2014 are related to the Bakken Shale play of western North Dakota. Producers there are focused on increasing domestic crude-oil production and are looking to companies like ours to meet their needs. Favorable crude-oil prices, combined with the reserve-life estimates and extremely high well-completion rates found in these plays, provide assurance for the continued, long-term flow of natural gas that is extremely rich in NGLs – provided the necessary infrastructure can be built to meet producers' needs.

**REMARKABLE NGL GROWTH** In 2005, our general partner, ONEOK, made a strategic acquisition, acquiring a comprehensive NGL business in the Mid-Continent. Then, in 2006, after completing a series of transactions, ONEOK became the sole general partner of ONEOK Partners and sold its expanded midstream assets to the partnership.

With that structure in place, we began rolling out our 2006 to 2009 internal-growth program. Of those more than $2 billion in projects, $1.5 billion was invested in the natural gas liquids segment – more than what ONEOK paid for the NGL assets in 2005.

**BUILDING ON STRENGTHS** The doors of opportunity we've opened over the past several years in the Bakken Shale have established us as the number-one independent natural gas gatherer and processor there. This presence and our reputation for doing what we say we will do serve as the foundation for our 2011 to 2014 growth program.

In 2010, we announced that we were building two new natural gas processing plants and related infrastructure in the Bakken Shale. This past January, we announced additional natural gas gathering and processing projects there involving the construction of a third new natural gas processing facility, along with expansions, upgrades and more new well connections. In 2011 alone, we expect to connect more than 400 new natural gas wells to our natural gas gathering systems in the Bakken.

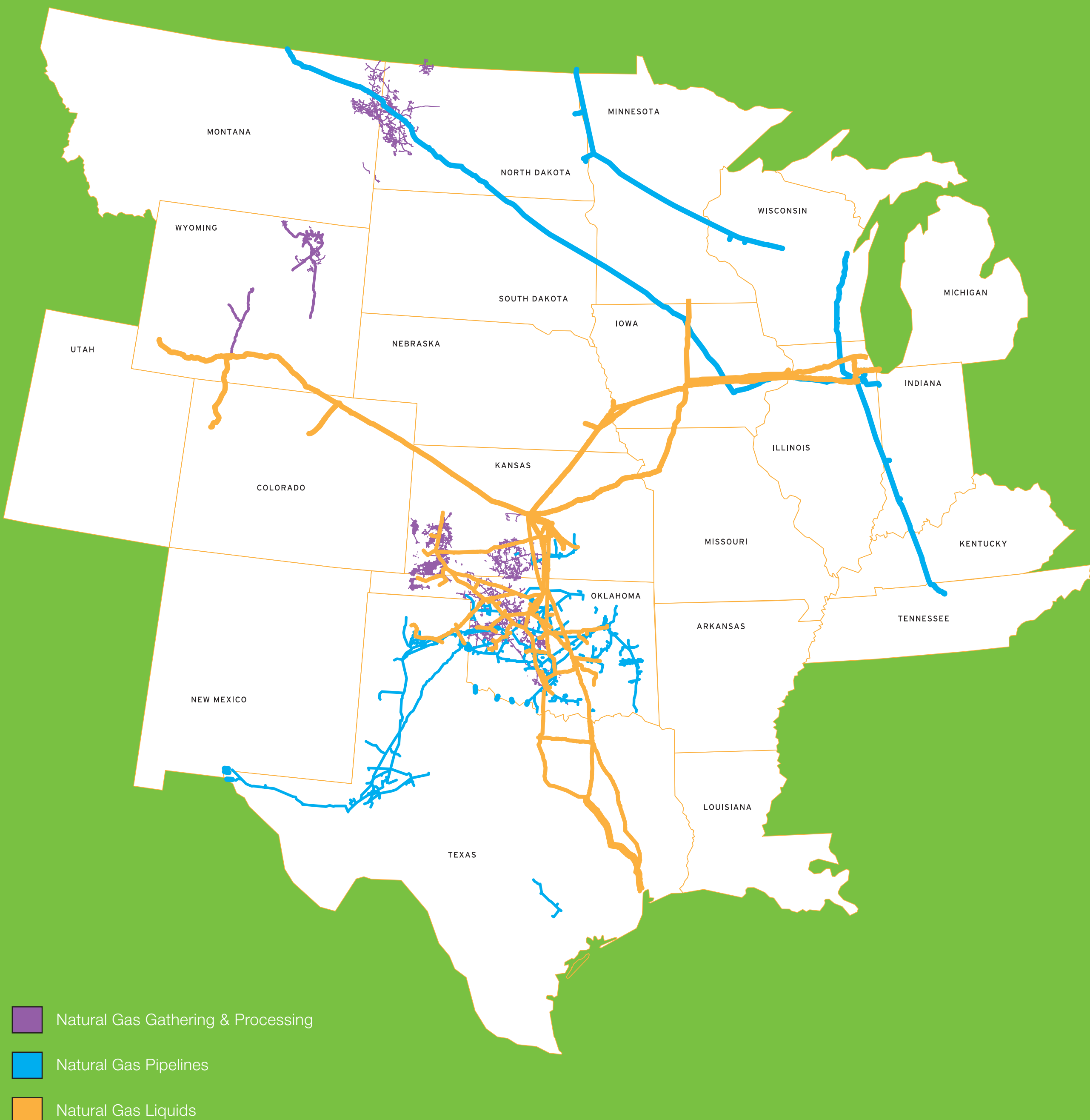
To accommodate the raw NGLs produced at our natural gas processing plants and those of third parties, we will build the 525-mile Bakken Pipeline from the Bakken Shale to connect with our 50-percent-owned Overland Pass Pipeline in northeastern Colorado. Overland Pass Pipeline, as well as our fractionation capacity at Bushton, Kansas, will be expanded to accommodate these new NGL supplies.

Does this story sound familiar? It's what we did when we built the Overland Pass Pipeline to transport NGLs produced in the Rockies to our fractionator at Bushton. Without the Overland Pass Pipeline, completed in late 2008, NGL opportunities in the Bakken Shale would have remained limited due to market constraints imposed by transportation and fractionation limitations. One door is now opening another.

**STRONG FOUNDATIONS** The Arbuckle Pipeline, commissioned in 2009, and our Mid-Continent NGL infrastructure – acquired four years earlier – provided the foundation for our decision to build another NGL pipeline, the Bakken Pipeline.

We also announced plans in December 2010 to build more than 230 miles of NGL pipelines that will deliver 75,000 to 80,000 barrels per day (bpd) of raw NGLs from the Cana-Woodford Shale and Granite Wash plays to our existing Mid-Continent NGL gathering systems and to the Arbuckle Pipeline, which is linked directly to the NGL market center at Mont Belvieu, Texas.

# NETWORK OF ASSETS



The Arbuckle Pipeline, like the Overland Pass Pipeline, was built to transport raw NGLs to fractionators. In the case of Arbuckle, we are serving the Barnett Shale natural gas producers and processors. Building the Arbuckle Pipeline opened the door to the Cana-Woodford and Granite Wash producers and processors.

Since 2006, we have more than doubled the size of our NGL business. Later in this report, we provide details on our next phase of growth projects, including our viewpoint on NGL supply and demand, and the progress we are making on expanding our fractionation capacity. Please see the business-segment narratives that follow this letter.

**LONG-TERM VIEW** With the exception of the 2007 acquisition of the North System, an NGL and refined petroleum products pipeline system that serves markets up through the Midwest as far north as Chicago, ONEOK Partners' growth has involved new construction.

We remain interested in acquisitions and have evaluated a number of opportunities but haven't found the right one at the right price. Our opportunities to build new assets have provided better returns than assets we've had the opportunity to buy. Our strategy of consistent growth *and* sustainable earnings demands a long-term view as we determine which assets to build or acquire – and when to act. This long-term view is supported by our employees' sense of urgency to grow and to improve at all levels.

**STAYING STRONG AND NIMBLE** A little more than two years ago, as the nation's financial institutions faltered and a severe recession ensued, we continued executing successfully the largest internal-growth program in our history and the century-long history of our general partner, ONEOK. Both ONEOK Partners and ONEOK maintain investment-grade credit ratings and strong balance sheets.

Staying strong financially has allowed us to chart our own course – and stay on it – while remaining flexible and responsive to new opportunities, challenges and ongoing change. In early 2010, ONEOK Partners sold 5.5 million common units at $60.75 per unit, netting $323 million. In September, we received $424 million from Williams Partners for its purchase of a 49-percent equity interest in the Overland Pass Pipeline, increasing its ownership to 50 percent, with ONEOK Partners retaining a 50-percent interest.

Proceeds from these transactions were used to repay short-term debt and to fund capital projects. At year-end 2010, our debt-to-capitalization ratio had improved to 50 percent and our debt-to-EBITDA ratio was 3.8.

In early 2011, we completed a $1.3 billion public debt offering to repay amounts outstanding under our $1 billion commercial paper program, repay the $225 million principal amount of senior notes due March 2011 and for general partnership purposes.

**MAKING ONE OF THE BEST BETTER** I believe the ONEOK Partners team of employees is one of the best in the industry. And it's getting better. Retaining these great people demands that we provide an environment dedicated to developing them. This, in turn, helps ensure that we can continue to attract the best employees as our workforce ages and the partnership continues to grow.

I believe that *all* of our employees should return home to their families and loved ones as safe and sound as when they left for work.

And I'm pleased to report that our heightened emphasis on environmental, safety and health matters is already producing measurable improvements. For example, we have reduced accidents in two key safety areas. For a review on how we are doing, please see page 19.

This spring marks the fifth anniversary of ONEOK being our sole general partner and our being publicly traded under the OKS symbol. It's been a busy, challenging and rewarding five years. We look forward to the work ahead as we open new doors of opportunity.

**On behalf of all of us at ONEOK Partners, we thank you for your continued support.**

John W. Gibson
*Chairman, President and Chief Executive Officer*
*March 10, 2011*



# EXECUTIVE LEADERSHIP

In February 2011, we announced a series of executive management changes designed to continue the development of both ONEOK's and ONEOK Partners' executive leadership team and create long-term value for all stakeholders.

The management realignment ensures that our next generation of leaders has the skills and experience to lead the continued growth and future success of ONEOK Partners. We are fortunate to have such exceptional leadership from which to draw for these assignments.

All changes were effective March 1, 2011, and include:

- Robert F. Martinovich, formerly ONEOK's chief operating officer, became senior vice president, chief financial officer and treasurer of ONEOK and ONEOK Partners and a member of the ONEOK Partners board of directors.
- Curtis L. Dinan, formerly senior vice president, chief financial officer and treasurer of ONEOK and ONEOK Partners, became president – natural gas of ONEOK Partners. He was also succeeded on the ONEOK Partners board of directors by Martinovich.
- Robert S. Mareburger, formerly president – natural gas of ONEOK Partners, became senior vice president, corporate planning and development of ONEOK and ONEOK Partners.

*Commitment to growing volumes...*

*basin diversity* NATURAL GAS GATHERING AND PROCESSING

# FOCUS ON SUPPLY

**NATURAL GAS GATHERING AND PROCESSING** Our natural gas gathering and processing business segment increased processed volumes and maintained solid operating income in 2010, while announcing approximately $1 billion of growth projects for 2011 to 2014 in the Bakken Shale in the Williston Basin in North Dakota, which includes more than $300 million of growth projects announced in early 2011. *(See page 9.)*

Year-over-year operating income decreased 9 percent. In 2010, processed volumes increased 2 percent and gathered volumes decreased 5 percent. Our commitment to growing volumes connected to our natural gas gathering systems – from a diverse portfolio of producing basins – was demonstrated by our connecting more than 400 new wells in 2010, compared with just over 300 in 2009. In the past four years, we have connected more than 1,500 new wells to our systems.

In late 2010, we connected our western Oklahoma gathering system to our Maysville natural gas processing plant in central Oklahoma, allowing us to access additional supplies from the highly active Cana-Woodford Shale play in western Oklahoma. Our expansions will continue to accommodate volume growth there and in the Granite Wash area in the Texas Panhandle, as well as elsewhere on our system.

**GROWTH IN THE BAKKEN SHALE** The prolific Bakken Shale provided 12 percent of our gathered volumes in 2010. We expect it to provide almost 40 percent of our gathered volumes by 2013. Growing natural gas volumes in the Bakken Shale and other shale plays will mitigate normal production declines in Kansas and in Wyoming's Powder River Basin. The absence of NGLs in the Powder River Basin and the decline of natural gas prices in the second half of 2008 caused production and drilling activity to decline there, although it stabilized somewhat in 2010. Kansas production continues to decline as well.

**OPERATING INCOME**
MILLIONS OF DOLLARS


Variances:

- $9.1 million increase due to higher natural gas volumes gathered and processed in the Williston Basin.
- $7.8 million decrease due to lower natural gas volumes processed and sold in Oklahoma and Kansas.
- $6.3 million decrease due to lower natural gas volumes gathered in the Powder River Basin.

We are currently the largest independent natural gas gatherer and processor in the Bakken Shale. The completion of the natural gas gathering and processing segment's nearly $1 billion capital-investment program in the region is expected to quadruple our current processing capacity – to 400 million cubic feet per day (MMcf/d) – by mid-2013. That same year, we expect the number of new well connections in this segment to exceed 600, with a large number of those in the Bakken Shale.

**STRONG ECONOMICS** With an estimated reserve life of 40 years or more, the Bakken Shale is the number-one crude-oil play in the nation. Crude-oil drilling activity in western North Dakota has quadrupled in less than two years, with accompanying flows of natural gas extremely rich in NGLs.

The well-completion and flow rates in the Bakken Shale ensure that the economics underpinning this play will continue even if crude-oil prices decline substantially from their current level. The crude-oil portion of the play provides approximately 90 percent of the producers' economics that support the drilling.

**VERTICAL INTEGRATON** In conjunction with the natural gas gathering and processing projects, ONEOK Partners' natural gas liquids segment also has announced approximately $700 million in Bakken-related projects. Most of the raw NGLs transported by the partnership's planned NGL pipeline from the Bakken Shale to the markets in the Mid-Continent and beyond will come from our new and expanded natural gas processing plants, as well as those of third parties.

*"In the past four years, we have connected more than 1,500 new wells to our systems."*

This vertically integrated value chain strengthens the economics of the partnership's $1.8 billion to $2.1 billion capital-investment program, provides customers with a full range of cost-efficient, value-added services, benefits the natural gas gathering and processing and natural gas liquids segments and, ultimately, rewards ONEOK Partners unitholders.

With the exception of the Powder River Basin, the natural gas we gather contains NGLs, which are removed at natural gas processing facilities to meet pipeline-quality specifications. The NGLs are then gathered and fractionated by us and others before being delivered to the market.

**SCALE AND SERVICE** Our natural gas gathering and processing systems serve a wide range and large number of producers in six basins. Our large scale and customer base – producers connected to our systems – when combined with our financial capability and reputation for reliable service, create opportunities and provide us with a competitive advantage.

We have hedged 68 percent of our expected NGL and condensate, and 81 percent of our expected natural gas equity volumes for 2011, reducing our exposure to commodity price and processing spread changes.

Planned capital expenditures in the natural gas gathering and processing segment in 2011 are approximately $544 million, primarily for new natural gas processing plant construction, infrastructure upgrades and new well connections. Most of the capital investments in the Bakken Shale will occur in 2011 and 2012.

*expansion* | NATURAL GAS GATHERING AND PROCESSING

# GROWTH PLANNED IN THE BAKKEN SHALE

Our natural gas gathering and processing segment's 2011 to 2014 capital-investment program includes the construction of three new natural gas processing plants, infrastructure upgrades and numerous well connections – all within a three-county area of the Bakken Shale play in western North Dakota.

Here is a snapshot of these projects totaling approximately $1 billion:

- Our new, 100 MMcf/d Garden Creek natural gas processing plant is expected to go into service by the end of 2011, doubling our existing processing capacity in that region. Cost estimate: $150 million to $210 million.
- Construction of the 100 MMcf/d Stateline I natural gas processing plant is scheduled for completion by mid-2012. When it comes on line, our processing capacity in the Bakken Shale will be three times its current capacity. Cost estimate: $180 million to $205 million.
- Construction of the 100 MMcf/d Stateline II natural gas processing plant is scheduled for completion in the first half of 2013. When it comes on line, our natural gas processing capacity in the Bakken Shale will be four times its current capacity. Cost estimate: $135 million to $150 million.
- Well connections, upgrades and expansions to the existing Bakken Shale infrastructure comprise the rest of this $1 billion growth program. We expect to connect nearly 400 new wells in the Bakken Shale alone in 2011, matching the number completed in all of our basins in 2010.
- Our Grasslands processing plant expansion, whose capacity was increased to 100 MMcf/d in 2009, saw its first full year of service with expanded capacity in 2010. The combined processing capacity of the Grasslands, Garden Creek, Stateline I and Stateline II facilities will be approximately 400 MMcf/d.

*Consistent cash flow and earnings...*

*stability* | NATURAL GAS PIPELINES

# RELIABILITY

**NATURAL GAS PIPELINES** Our natural gas pipelines segment turned in an excellent performance in 2010, improving its operating income 12 percent. The segment benefited from a continued high rate of firm-demand contracts, the first full year of service from a major pipeline expansion and filling available capacity with short-term business.

Projects experiencing their first full year of service in 2010 were:

- The Guardian Pipeline Expansion and Extension that went into service in February 2009 as part of our more than $2 billion internal-growth program and was completed that same year. The expansion is anchored by 15-year, firm-demand contracts with two Wisconsin utilities.

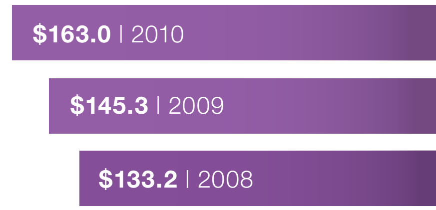
- The interconnection of our bi-directional Midwestern Gas Transmission system with the Rockies Express Pipeline in mid-2009.

- The expansion of a lateral pipeline on our Viking Gas Transmission system to Fargo, North Dakota, that went into service in October 2009.

Our natural gas pipelines business is predominantly fee based, with 75 percent of gross margin coming from firm, demand-based rates. In 2010, our interstate pipeline systems were 95 percent subscribed, our intrastate pipelines were 74 percent subscribed and our natural gas storage facilities were fully subscribed.

**EQUITY INCOME IMPROVES** Equity income from the 50-percent-owned Northern Border Pipeline improved 65 percent in 2010 due to increased contracted capacity and favorable shipper economics as a result of larger natural gas price differentials between Canada and the Midwestern United States.

### OPERATING INCOME
MILLIONS OF DOLLARS




Variances:

- $8.7 million increase in natural gas 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 Pipeline as a result of a new interconnection with the Rockies Express Pipeline.

- $3.5 million increase in natural gas storage margins.

The combination of a relatively warm winter in Canada and a cold winter in the U.S. resulted in surplus gas available from Canada. Also, demand in the Chicago and Upper Midwest markets was high due to an unusually hot summer. These conditions, combined with the wider Canadian-to-U.S. price differentials, benefited Northern Border Pipeline – of which we own 50 percent – and our Viking Gas Transmission system.

We expect Northern Border Pipeline to continue performing well in 2011 as it accesses new natural gas supplies from the U.S. Rockies via the recently completed Bison Pipeline. Also, Northern Border Pipeline traverses the Bakken Shale play in North Dakota, where our natural gas gathering and processing segment has announced nearly $1 billion of capital investments planned for 2011 to 2014, which include quadrupling its Bakken Shale natural gas processing capacity.


▲ *Reviewing results of hydrostatic testing, done in connection with a project that will increase the maximum allowable operating pressure of selected pipelines.*

*"Our natural gas pipelines segment turned in an excellent performance in 2010, improving its operating income 12 percent."*

**OPPORTUNITIES ON THE HORIZON** The majority of our customers are natural gas and electric utilities. Utilities and industrial customers across the nation appear to be taking a wait-and-see attitude regarding major growth. Their caution is understandable, given the uncertainties surrounding new public policies and the pace and timing of the economic recovery.

We expect natural gas-fired generation of electricity to increase as coal-plant conversions to natural gas grow significantly in the next five years. Our assets are well positioned to serve many of these potential conversions.

Our natural gas pipelines segment's large scope and scale, diversity of supply, low cost of service, reputation for reliability and financial strength give us the ability to accommodate pipeline capacity growth as it is needed.

Planned capital expenditures for 2011 are estimated at $40 million, primarily for increased investments related to non-discretionary environmental-compliance projects.

# CREATING VALUE FROM SPACE

Each morning, members of the natural gas pipelines segment's short-term-business commercial team gather to discuss opportunities to optimize our assets by filling available space on our natural gas pipelines and storage facilities. Their mission – optimizing the small amount of short-term available capacity – never changes.

By contrast, their real-time view of market opportunities is changing continually, sometimes by the minute. Which of our pipelines and storage facilities have available space? How long will that particular space be open? What is the weather doing here and there? What is the price of natural gas at this and that location? What does the trading look like on the NYMEX (New York Mercantile Exchange) futures index? Does this customer need transportation, storage or premium, bundled services, or park-and-loan capabilities?

The decisions made at these daily meetings benefit the bottom line of our natural gas pipelines segment. During the year, our wholly owned interstate natural gas pipeline system was 95 percent subscribed under firm, demand-based, long-term transportation contracts; and our storage facilities were fully subscribed.

To the layman, that bit of information might falsely indicate there is little space available for extra business. However, on any given day, a pipeline may meet its firm-demand obligations in, say, six hours of operation, leaving that pipeline – or a portion of it – open for extra business the rest of the day.

Similarly, natural gas storage space may also become available.

> ***"Their mission – optimizing the small amount of short-term available capacity..."***

The short-term business team also captures opportunities for interruptible service on our intrastate natural gas pipeline system. In 2010, our intrastate natural gas pipelines were 74 percent subscribed under firm, demand-based contracts.

Our natural gas pipelines segment's other teams are:

- The long-term business team. As its name implies, this group works with our long-term, firm-demand customers comprised of natural gas utilities, natural gas-fired electric-generation utilities and industrial customers. Long-term business represents the predominant share of this segment's operating income, providing consistent cash flow and stable earnings. The average length of our demand-based contracts is approximately seven years.
- The operational group, which ensures that the facilities operate safely, reliably and efficiently.
- The business-development group, which identifies growth opportunities, such as the Guardian Pipeline Expansion and Extension that saw its first full year of service in 2010.


Creating additional
growth opportunities...

*connections* | NATURAL GAS LIQUIDS

# DELIVERING GROWTH

**NATURAL GAS LIQUIDS** Our natural gas liquids segment achieved record volumes and established a new level of operating income in 2010. It was the first full year in which *all* of the projects in its 2006 to 2009 internal-growth program – totaling more than $1.5 billion – were operating.

Gathered volumes increased 18 percent; fractionated volumes rose 6 percent; and operating income improved 17 percent. Since 2006, the more than $1.5 billion in capital investments in this segment expanded dramatically its integrated footprint, which continues to create additional growth opportunities. During 2010, we announced approximately $1 billion in new NGL capital-investment growth projects related to the Bakken Shale in North Dakota, the Cana-Woodford Shale in Oklahoma and the Granite Wash play in the Texas Panhandle.

In 2010, Conway-to-Mont Belvieu price differentials for ethane, a key driver in our optimization activities, declined approximately 9 percent – to 10 cents per gallon from 11 cents per gallon – but remained at attractive levels. As recently as a few years ago, the differential was a few pennies per gallon.

The ability to capture these price differentials is a key component of our optimization activities and provides earnings upside for this predominantly fee-based business, which was 78 percent fee based in 2010, a 7-percent increase over the previous year. These fee-based, non-discretionary services – gathering, fractionation, transportation and storage – provide our customers with valuable services that enable them to get their products to market and provide us with consistent, sustainable earnings.

### OPERATING INCOME
MILLIONS OF DOLLARS


Variances:

- $51.4 million increase from higher NGL volumes gathered, fractionated and transported, associated primarily with the completion of the Arbuckle Pipeline, Piceance Lateral Pipeline and D-J Lateral Pipeline, as well as new supply connections.
- $10.9 million increase due to higher NGL storage margins.
- $34.7 million decrease from lower optimization margins as a result of limited NGL fractionation and transportation capacity available for optimization activities between the Mid-Continent and Gulf Coast markets and less favorable NGL price differentials.
- $4.4 million decrease from operational measurement adjustments.
- Operating costs decreased as a result of lower than estimated property taxes and lower outside services costs; offset partially by an increase in property insurance costs.
- $16.3 million from the gain on the sale of a 49-percent ownership interest in Overland Pass Pipeline Company.

The Arbuckle Pipeline, which was placed into service in 2009, transports raw NGLs to fractionation facilities along the Texas Gulf Coast. It not only facilitates our fee-based exchange services, but it also allows us to add more capacity for optimization activities by delivering raw NGLs to our Gulf Coast infrastructure for fractionation, complementing our Sterling NGL purity-products pipeline that delivers finished NGL products to customers on the Gulf Coast. In December 2010, we announced plans to increase the Arbuckle Pipeline's capacity to 240,000 bpd by mid-2012, enhancing our capabilities to deliver raw, unfractionated NGLs to the Gulf Coast NGL market center.

**CAPACITY TO INCREASE IN 2011** In the second quarter of 2011, we will increase capacity by 15,000 bpd on our Sterling Pipeline, which transports NGL purity products from our Mid-Continent fractionation infrastructure to the market center at Mont Belvieu, Texas. This pipeline also allows us to capture price differentials between Mont Belvieu and the market center at Conway, Kansas.

Fractionation capacity remains tight in our NGL business and industrywide.

A large legacy fractionation contract at the partnership's Mont Belvieu, Texas, fractionator expired in September 2010, opening up that capacity to current market rates and providing increased optimization opportunities and fee-based services.

We will gain direct access to an additional 60,000 bpd of fractionation capacity through a 10-year fractionation services agreement with Targa Resources Partners when an expansion of its fractionator at Mont Belvieu goes into service in the second quarter of 2011. Currently, we own net fractionation capacity of nearly 550,000 bpd, one of the largest in the nation.

Prolific natural gas production from shale plays continued to put downward pressure on natural gas prices, which in turn lowers NGL prices. However, the petrochemical industry's use of ethane and other light NGL feedstocks has increased significantly as a result of these lower cost NGL-based feedstocks being favored over the higher-cost, oil-based feeds.

Petrochemical demand, also driven partly by export demand, reached record levels in 2010 and is expected to remain robust. Petrochemical demand accounts for more than 50 percent of our nation's NGL purity-product consumption.

**SERVING THE BAKKEN SHALE** The most recent example of our expanded footprint opening new doors of opportunity involves our plans to invest approximately $700 million in three major NGL projects related to the Bakken Shale play.

These projects include constructing the 525-mile Bakken Pipeline to deliver raw NGLs from the partnership's and third-party natural gas processing plants in a three-county area of western North Dakota to the Overland Pass Pipeline; increasing capacity on our 50-percent owned Overland Pass Pipeline to accommodate these NGLs; and expanding our fractionation capacity by 60,000 bpd at Bushton, Kansas. *(Please see accompanying article on page 18.)*

Having Overland Pass Pipeline, which went into service in 2008, made our ability to transport NGLs produced in the Bakken Shale practical and economically attractive. NGL content in the natural gas from the Bakken Shale is extremely high – 10 to 12 gallons per thousand cubic feet of natural gas – and is among the highest in the nation.

*(In September 2010, Williams Partners exercised its option to buy an additional 49-percent equity interest in Overland Pass Pipeline, increasing its ownership to 50 percent, with ONEOK Partners retaining a 50-percent interest. ONEOK Partners received $424 million for this transaction. That same month, we began accounting for our income from this pipeline as equity earnings. Williams will become operator of Overland Pass Pipeline in the first half of 2011.)*

## CANA-WOODFORD AND GRANITE WASH GROWTH

In December 2010, we announced that we will invest approximately $180 million to $240 million by the first half of 2012 for NGL projects in the Cana-Woodford Shale and Granite Wash plays in western Oklahoma and the Texas Panhandle.

These investments will connect our existing Mid-Continent NGL gathering system to three new third-party natural gas processing plants being constructed and to three existing third-party natural gas processing plants that are being expanded. This investment includes constructing 230 miles of NGL pipelines and expanding the capacity of the 440-mile Arbuckle Pipeline to 240,000 bpd. When completed, these projects are expected to add approximately 75,000 to 80,000 bpd of raw, unfractionated NGLs to our Mid-Continent NGL gathering system and the Arbuckle Pipeline.

**SUPPLY AND DEMAND** In view of the abundant production from shale plays and the resulting NGL production growth, we often are asked if NGL supply will overrun demand.

The short answer is not in the foreseeable future.

While NGL growth continues at a rapid pace, those production gains are masked by the inherent natural decline of the base natural gas production. Some experts say this decline exceeds 20 percent per year, and it is getting steeper each year with more shale plays, whose decline rate is more rapid than in conventional fields.

Apply this assumed 20-percent decline rate to the production of approximately 2 million bpd of NGLs from U.S. natural gas processing plants, and you have a 400,000 bpd production "hole" that has to be filled just to stay even with the previous year's production. Also, consider this: NGL supply is still short of the peak level reached a decade ago.

We and many others believe that NGL demand will more than keep pace with supply, and that regional processing and NGL infrastructure will continue to be needed. This supply outlook – coupled with strong petrochemical demand for ethane (driven by NGLs' price advantage over crude-oil-derived petrochemical feedstocks), which makes up almost half of the NGL barrel – means that the need for NGLs will continue to increase.

**VOLUME GROWTH CONTINUES** We continue to experience NGL volume growth in the D-J and Piceance basins in Colorado, the Woodford Shale in southeastern Oklahoma and the Granite-Wash area in the Texas Panhandle – among other areas – and will access NGL production this year from the Cana-Woodford Shale in western Oklahoma.

Also, we are positioned to contract NGL volumes that will result from the emerging, crude-oil-driven Niobrara Shale play via our D-J Lateral Pipeline's interconnection with the Overland Pass Pipeline and the upcoming Bakken Pipeline, which will traverse the northern part of this shale.

Planned capital expenditures in the natural gas liquids segment for 2011 are approximately $531 million, primarily for the announced growth projects.

# BAKKEN SHALE INVESTMENTS

**BRINGING VALUE TO AN NGL BARREL FROM THE BAKKEN** In less than five years, our natural gas liquids business has become one of the largest and fastest growing in the nation. Access to NGLs in the Bakken Shale will further broaden our footprint, provide incremental volumes and create additional opportunities.

Transporting NGLs removed from the natural gas in the Bakken Shale is currently restricted by limited truck and railcar transportation – and the local market is saturated.

We will provide value to the producers of the NGLs from the Bakken Shale by utilizing our fully integrated infrastructure, which stretches from the Rockies to the Mid-Continent – and north from there through the Upper Midwest and south to the Texas Gulf Coast.

Our range of NGL services includes gathering, fractionation, transportation, storage, marketing and distribution. This comprehensive offering provides cost efficiencies and "one-stop" services to customers. And, it provides us with a competitive advantage.

After the raw NGLs from the Bakken Shale are transported on the new Bakken Pipeline to northeastern Colorado and on to Kansas on the Overland Pass Pipeline, they can be fractionated and then stored or sent to the marketplace. The finished NGL products, also referred to as purity products, can be distributed to:

- The market center at Conway, Kansas.
- The market center at Mont Belvieu, Texas, via our Sterling Pipeline, which also enables us to capture price differentials between Conway and Mont Belvieu.
- Or through the Midwest as far north as Chicago on the North System, our refined petroleum products and NGL distribution pipeline.

All of this, beginning at our own or third-party natural gas processing plants in the Bakken Shale, occurs on our NGL gathering, fractionation, transportation, storage and distribution systems.

The fractionated products – ethane, ethane/propane mix, propane, normal butane, iso-butane and natural gasoline – are used for many different purposes, including feedstocks in the petrochemical industry, motor-fuel blending stocks in the refinery sector and for home and business heating and crop-drying.

**$700 MILLION IN BAKKEN SHALE-RELATED NATURAL GAS LIQUIDS PROJECTS** The largest project in our Bakken Shale-related capital-investment program is the Bakken Pipeline, which will have an initial capacity to transport 60,000 bpd of raw NGLs.

Raw NGLs from western North Dakota will be transported more than 500 miles on the Bakken Pipeline, which will connect to the Overland Pass Pipeline in northeastern Colorado. From there, the raw NGLs can be shipped either to our Mid-Continent NGL infrastructure or to our Gulf Coast NGL infrastructure via our Arbuckle Pipeline.

Here is a snapshot of these interrelated NGL projects – scheduled for completion in the first half of 2013.

- Constructing the Bakken Pipeline is expected to begin in the second quarter of 2012. The cost-estimate range of $450 million to $550 million will narrow as the final route is determined and permits are obtained.
- Increasing the capacity on the Overland Pass Pipeline, in which we have a 50-percent interest, to accommodate flow from the Bakken Pipeline. The 60,000 bpd expansion involves adding pumps, which will bring capacity on this pipeline to 255,000 bpd. Our share of this expansion cost is estimated to be $35 million to $40 million.
- Expanding our fractionation capacity at Bushton, Kansas, is expected to cost from $110 million to $140 million. The 60,000 bpd expansion will bring the facility's total capacity to 210,000 bpd. This expansion will bring our total net fractionation capacity to approximately 610,000 bpd.


*commitment* CORPORATE RESPONSIBILITY

# SUSTAINABLE IMPROVEMENT

**CORPORATE RESPONSIBILITY** The direction of our strengthened environmental, safety and health (ESH) efforts can be distilled into these two words: *sustainable improvement.*

At ONEOK Partners, that phrase means that we are working together to:

- Plan, pursue and achieve measurable improvements in ESH efforts companywide.
- Ensure that the improvements continue.
- Raise the bar and move forward with the strategies and changes necessary to achieve the next level of performance.

Our efforts are rooted in the belief that a vibrant and effective ESH program is key to ONEOK Partners' long-term success and the fulfillment of our vision as a premier energy company. Over the last few years, we have formed a new ESH organization, provided leadership and staffing, established key initiatives and priorities, placed greater emphasis on tracking and measuring performance, set targets and achieved measurable improvements.

We've also increased our ESH communications, both internally and externally. While we are pleased with our ESH progress so far, we are not satisfied. We want to be a recognized leader in protecting the environment, safety and health of our employees, contractors, customers and the public. The continuing commitment, support and involvement from employees are critically important to the continued success of our ESH efforts.

In an independent, third-party administered, companywide employee survey in 2010, employees ranked ESH at the top of a nine-item list of strengths in terms of "overall favorability." The survey indicated that more than 80 percent of employees participating in the survey believe that safety and health are important to the company and that concerns will be addressed.

**ACCIDENT REDUCTION** We have initiated a behavior-based safety program designed to replace unsafe individual behaviors and reduce accidents. We also are focused on innovative ways to reduce vehicle accidents.

On average at any given time, we operate more than 850 fleet vehicles, which drive approximately 15 million miles annually. In addition to traditional safe-driving training and education, we developed a companywide vehicle-safety policy that establishes the minimum requirements to be followed by each business segment.

**CLIMATE CHANGE** Studies have shown that human activity, including the burning of fossil fuels, could increase concentrations of greenhouse gas emissions in the atmosphere. We recognize the importance of this issue and are committed to acting in an environmentally responsible manner to ensure that our actions will benefit future generations.

As a part of our ESH Leadership Committee, our Climate Change Action Team proactively monitors greenhouse gas-related regulatory and legislative activity to help us understand and address these issues. The team reviews activities that cost effectively can reduce our carbon footprint and provides information to business segments about the costs and resources required to comply with proposed legislation and regulations.

Beginning in 2011, the federal Environmental Protection Agency will require the annual reporting of greenhouse gas emissions.

We believe that natural gas is a key to a less carbon-intensive economy and that its expanded use is the most economical way to achieve future reductions of carbon-dioxide emissions. Natural gas is abundant in the United States, and our long-term domestic supply is important to our country's energy security.

**PIPELINE INTEGRITY** U.S. Department of Transportation statistics show that pipelines continue to be the safest and most efficient way to transport natural gas, natural gas liquids and other energy products.

The safe operation of all assets – including pipelines – is our highest priority. In addition to protecting life and property, operating safely makes good business sense. We believe that if we manage the businesses first from an environmental, safety and health perspective, reliable pipeline operations will follow, which are critical for our customers.

ONEOK Partners operates approximately 7,000 miles of natural gas transmission pipelines, approximately 7,000 miles of NGL pipelines and approximately 15,000 miles of natural gas gathering pipelines in more than 16 states. In addition to 24-hour, seven-day-a-week electronic surveillance, we use a number of inspection methods and processes to mitigate corrosion, minimize the potential for third-party damage and address other outside forces, such as erosion and flooding.

Federal and state regulations require us to develop, implement and maintain formal integrity-management programs for natural gas and natural gas liquids pipelines that cross what are referred to as high-consequence areas, including large populations, navigable waterways and sensitive environmental areas. These regulations require assessments on certain natural gas pipelines at least once every seven years and on NGL pipelines every five years. We have completed or are on schedule in meeting these requirements.

As part of the ESH Leadership Committee, the newly formed Pipeline Safety Action Team proactively monitors proposed pipeline-safety legislation and regulations to determine the potential impact on ONEOK Partners' operations and assets. The team will work with pipeline-industry trade associations as they address these issues. The team will also review current company pipeline-integrity programs for the identification and sharing of best practices.

Most pipeline accidents are caused by third-party damage. We actively support and participate in one-call systems that require notification before excavation begins. In 2010, the number of pipeline incidents on our systems caused by third-party damage was reduced significantly.

**CONSERVATION MATTERS** We know that an effective ESH program strengthens ONEOK Partners, not only in terms of operations and fulfillment of responsibilities but also in our ability to attract and retain new employees, which is vitally important to our company's future.

Employee passion regarding conservation measures, large and small, is growing at ONEOK Partners.

Across the company, we see conservation activities increasing at the workplace and in the communities we call home. We are a part of that change. Here is a sampling of some of the ways we are conserving the environment:

- In numerous places throughout our operating footprint, we participate in recycling programs. Items recycled range from soft-drink cans and newspapers to used car batteries and scrap steel.
- At our headquarters in Tulsa, Oklahoma, we continue to search for ways to improve the energy efficiency of our multistory office building. We've saved hundreds of thousands of kilowatt hours annually and captured more savings recently.

Taken individually, these examples and numerous others are small steps. But taken as a whole, they reduce our footprint and speak to the collective ONEOK Partners mindset – conservation matters.

**COMMUNITY INVESTMENTS** Established in 1997, the ONEOK Foundation invests in education, health and human services, arts and culture, and community improvement. In 2010, the ONEOK Foundation invested approximately $5 million in the communities where we operate and where our employees live.

In addition, our employees volunteered nearly 10,000 hours in their communities.

**ETHICS AND COMPLIANCE** We created an officer-level position to oversee companywide compliance with rules, regulations and laws and for the development and implementation of continuing companywide compliance and ethics training. Hired last fall, the vice president reports jointly to the partnership's general counsel and chief executive officer.

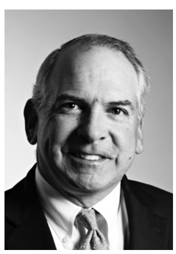
# BOARD OF DIRECTORS












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

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

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

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

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

**Robert F. Martinovich**
*Senior Vice President, Chief Financial Officer and Treasurer,* ONEOK Partners, L.P. and ONEOK, Inc.
Tulsa, Oklahoma

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

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

**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, 58
*Chairman, President and Chief Executive Officer*

Terry K. Spencer, 51
*Chief Operating Officer*

Robert F. Martinovich, 53
*Senior Vice President, Chief Financial Officer and Treasurer*

John R. Barker, 63
*Senior Vice President, General Counsel and Secretary*

Derek S. Reiners, 39
*Senior Vice President and Chief Accounting Officer*

Robert S. Mareburger, 49
*Senior Vice President, Corporate Planning and Development*

David E. Roth, 55
*Senior Vice President, Administrative Services*

Dandridge L. Harrison, 57
*Vice President, Investor Relations and Public Affairs*

NATURAL GAS

Curtis L. Dinan, 43
*President*

David R. Scharf, 54
*President, Gathering & Processing*

W. Kent Shortridge, 44
*President, Pipelines*

Michel E. Nelson, 63
*Senior Vice President, Pipeline Operations*

NATURAL GAS LIQUIDS

Sheridan C. Swords, 41
*President*

Michael L. Turner, 37
*Vice President, Gathering & Fractionation*

Roger G. Thorpe, 43
*President, Pipelines*

Wesley J. Christensen, 57
*Senior Vice President, Operations*

Randy L. Jordan, 61
*Vice President, Optimization*

*Ages as of December 31, 2010*

# 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, 2010.
OR
__ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from __________ to __________.

Commission file number **1-12202**

# 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 website, 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 X 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, 2010, was $4.2 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 14, 2011 |
|---|---|
| Common units | 65,413,677 units |
| Class B units | 36,494,126 units |

**DOCUMENTS INCORPORATED BY REFERENCE:** None.

**ONEOK PARTNERS, L.P.**
**2010 ANNUAL REPORT**



As used in this Annual Report, references to "we," "our," "us" or the "Partnership" refer 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, 2010 |
| 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 |
| CFTC | Commodities Futures Trading Commission |
| Clean Air Act | Federal Clean Air Act, as amended |
| Clean Water Act | Federal Water Pollution Control Act, as amended |
| EBITDA | Earnings before interest expense, income taxes, depreciation and amortization |
| EBITDAR | Earnings before 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 |
| MDth/d | Thousand dekatherms 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 |
| Quarterly Report | Quarterly Report(s) on Form 10-Q |
| RRC | Railroad Commission of Texas |
| 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.

## 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 Board members who are independent under NYSE listing standards and one management member of our Board are also members of ONEOK's Board of Directors. 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 and sustainable earnings growth while focusing on safe, reliable, environmentally responsible and legally compliant operations for our customers, employees, contractors and the public through the following:

- Operate in a safe, reliable and environmentally responsible manner - environmental, safety and health issues continue to be a primary focus for us; our emphasis on environmental, safety and health initiatives has produced improvements in the key indicators we track;
- Grow fee-based earnings - we added to our fee-based earnings with the completion of more than $2.0 billion of capital projects completed in 2009, which generate predominately fee-based earnings;
- Increase cash distributions - during 2010, cash distributions increased by one cent per unit each quarter, an approximate 3.0 percent increase compared with 2009;
- Develop and execute internally generated growth projects - 2010 was the first full year of earnings from our more than $2.0 billion of capital projects completed in 2009; we announced in 2010 and early 2011 an additional $1.8 billion to $2.1 billion in new capital projects in the Bakken Shale, the Cana-Woodford Shale and the Granite Wash areas, which, when completed, we anticipate will provide us additional earnings and cash flows;
- Execute strategic acquisitions that provide long-term value - we remain a disciplined buyer of assets and continue to evaluate assets that come to market. We did not consummate any acquisitions in 2010;
- Manage our balance sheet and maintain strong credit ratings - our balance sheet remains strong, ending 2010 with a capital structure of 50-percent debt and 50-percent equity. We will seek to maintain our investment-grade credit ratings; and
- Attract, develop and retain employees to support strategy execution - we continue to execute on our recruiting strategy that targets colleges, universities and vocational technical schools in our operating areas. We also continue to focus on employee development efforts with our current employees.

## EXECUTIVE SUMMARY

Our 2010 operating results include the benefits from a full year of operation of more than $2.0 billion in growth projects completed in 2009, reflecting increases in volumes gathered, fractionated and sold in our Natural Gas Liquids segment, capacity contracted in our Natural Gas Pipelines segment and volumes processed in the Williston Basin in our Natural Gas Gathering and Processing segment. We expect continued development of the reserves in the Bakken Shale and Three Forks formations in the Williston Basin and in the Cana-Woodford Shale and Granite Wash areas in Oklahoma and Texas as drilling activities increase in these areas.

We announced approximately $1.8 billion to $2.1 billion in growth projects in 2010 and early 2011, primarily in the Williston Basin in North Dakota and the Cana-Woodford Shale and Granite Wash areas in Oklahoma and Texas that will enable us to meet the rapidly growing needs of crude oil and natural gas producers as they increase their drilling activities.

Drilling rig counts in Dunn, McKenzie and Williams counties in North Dakota have increased dramatically since the beginning of 2010. The development of the reserves in the Bakken Shale and Three Forks formations in the Williston Basin are being driven primarily by crude oil economics, with the associated natural gas production having a high NGL content. Current natural gas processing and natural gas liquids infrastructure in the Williston Basin is being expanded to accommodate the additional production from the increased development activities. We have announced plans to invest $1.5 to $1.8 billion in the Williston Basin in North Dakota.

In addition to the growth projects in the Williston Basin, we have announced plans to invest approximately $270 million to $330 million in our existing Mid-Continent infrastructure, primarily in the Cana-Woodford Shale and Granite Wash areas. The expansions and upgrades will increase our ability to accommodate the growing natural gas and NGL supply from producers and natural gas processors as drilling activities increase in these areas. These investments will expand our ability to transport raw NGLs from these supply areas to fractionation facilities in Kansas, Oklahoma and Texas and distribute purity NGL products to the Mid-Continent, Gulf Coast and upper Midwest market centers. A portion of these investments will also allow us to increase utilization of our natural gas processing capacity in Oklahoma.

During 2010, we paid cash distributions totaling $4.46 per unit, an increase of approximately 3.0 percent over the $4.33 per unit paid during 2009. In January 2011, our general partner declared a cash distribution of $1.14 per unit ($4.56 per unit on an annualized basis), an increase of approximately 3.6 percent over the $1.10 declared in January 2010.

During 2010, we utilized available cash, our Partnership Credit Agreement, our commercial paper program and the proceeds from the sale of a 49-percent ownership interest in Overland Pass Pipeline Company to fund our short-term liquidity needs, repay $250 million of maturing senior notes and fund our capital expenditures. Additionally, we accessed the public equity markets in February 2010, generating net proceeds of approximately $322.7 million for our long-term financing needs.

In January 2011, we completed an underwritten public offering of senior notes generating net proceeds of approximately $1.28 billion. Our ability to continue to access capital markets for debt and equity financing under reasonable terms depends on our financial condition, credit ratings and market conditions. We anticipate that our cash flow generated from operations, existing capital resources and ability to obtain financing will enable us to maintain our current level of operations and our planned operations, as well as fund our capital expenditures.

See Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operation, for information on our growth projects, results of operations, liquidity and capital resources.

## SEGMENT FINANCIAL INFORMATION

**Operating Income, Customers and Total Assets -** See Note N of the Notes to Consolidated Financial Statements in this Annual Report for disclosure by segment of our operating income and total assets and for a discussion of revenues from external customers.

## 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 recently announced plans to construct three new natural gas processing plants in the Williston Basin in North Dakota and we completed an expansion connecting our gathering assets in western Oklahoma with our processing assets in central Oklahoma. 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 that contains the NGL-rich Cana-Woodford Shale formation 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 includes the oil-producing, NGL-rich Bakken Shale and Three Forks formations, 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 natural gas, that does not require processing or NGL extraction in order to be marketable; dry natural 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 primarily utilize field gas processing plants to extract NGLs and remove water vapor and other contaminants from the unprocessed natural gas stream. Field gas processing plants process natural gas gathered from multiple producing wells.

We generally gather and process natural 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 35 percent and 32 percent of contracted volumes for 2010 and 2009, 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, treated, 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 61 percent and 63 percent of contracted volumes for 2010 and 2009, respectively.
- Keep-Whole - Under a keep-whole 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." 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 4 percent and 5 percent of contracted volumes for 2010 and 2009, respectively, with approximately 85 percent and 84 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 expect that our recently announced capital projects will provide additional revenues from fee and POP contracts when completed. 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.

**Unconsolidated Affiliates** - Our Natural Gas Gathering and Processing segment includes 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 natural gas processing complex near Venice, Louisiana.

See Note K of the Notes to Consolidated Financial Statements in this Annual Report for additional discussion of our 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, access to capital and regulatory control. Higher crude oil prices 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 natural gas 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 natural gas 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 natural gas gathering and processing position.

In the Rocky Mountain region, 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 amounts of NGLs; however, we have seen declines in gathered natural gas volumes in the Powder River Basin.

Demand - Demand for natural gas gathering and processing services is typically aligned with the production of natural gas. Our natural gas processing 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 such as storage injection and withdrawal rates, available storage capacity and demand for our products by the petrochemical industry and other consumers. We are exposed to commodity price risk and the cost of natural gas transportation at various market locations as a result of receiving commodities through our POP contracts in exchange for our services. To a lesser extent, exposures arise from the gross processing spread with respect to our keep-whole contracts.

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-generation 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 natural gas gathering and processing business remains relatively fragmented despite significant consolidation in the industry. We compete for natural gas supplies with major integrated oil companies, 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 construct and expand our assets, improve natural gas processing efficiency and reduce operating costs, evaluating consolidation opportunities to maximize earnings, and renegotiating low-margin contracts. The principal goal of the contract renegotiation effort is to improve margins and reduce risk.

**Government Regulation** - The FERC has traditionally maintained that a natural gas 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 natural gas gathering facilities and operations meet the criteria used by the FERC for non-jurisdictional natural gas gathering facility status. However, we are subject to FERC regulations that require us to publicly post certain natural gas flow information on our websites. 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 natural gas from our natural gas processing 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. The execution of these strategies seeks to provide incremental fee-based earnings. Extensions and expansions completed in 2009 include the Guardian Pipeline expansion and extension; Viking Gas Transmission Fargo lateral; and the Midwestern Gas Transmission interconnect with the Rockies Express Pipeline.

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

- Midwestern Gas Transmission, which is a bi-directional system that interconnects with Tennessee Gas Transmission Company’s pipeline near Portland, Tennessee, and with several interstate pipelines near Joliet, Illinois;
- Viking Gas Transmission, which transports natural gas from an interconnection with TransCanada’s pipeline near Emerson, Manitoba, to an interconnection with ANR Pipeline Company near Marshfield, Wisconsin;
- Guardian Pipeline, which interconnects with several pipelines near 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, which are connected to our intrastate natural gas pipeline assets.

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 derived typically from fee-based services provided to our customers. Our fee-based services have increased primarily due to our previously completed capital projects including the Guardian Pipeline expansion and extension; Viking Gas Transmission Fargo lateral; and Midwestern Gas Transmission interconnect with the Rockies Express Pipeline. Our revenues are generated from the following types of fee-based 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 includes 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, a natural gas gathering system with compression located in south central Oklahoma.

See Note K 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 Canada and United States 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 that contains the Cana-Woodford Shale formation, Hugoton Basin, Central Kansas Uplift Basin, Permian Basin and the Texas Panhandle.

Demand - Demand for natural gas pipeline transportation service and natural gas storage is related directly 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. Demand for our services can also be impacted as coal-fired electric generators consider natural gas as an alternative fuel. 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 North America 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 and storage facilities compete directly with other intrastate and interstate pipeline companies and other storage facilities in providing natural gas transportation and storage services. 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 new infrastructure projects are completed and 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 the 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 provide safe, reliable, efficient and consistent operations, while providing competitive services. In addition, we seek to increase throughput and to continue to provide cost-effective transportation of NGLs between the Rocky Mountain, Mid-Continent and Gulf Coast regions and the Midwest markets near Chicago, Illinois. We pursue growth of our 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. These capital investments include the Overland Pass Pipeline and related projects, the Arbuckle Pipeline, the recently announced Bakken Pipeline, Sterling I Pipeline expansion and expansion of our gathering systems to better serve the Cana-Woodford Shale and Granite Wash plays. The execution of these strategies seeks to provide incremental fee-based earnings.

**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 or have an ownership interest in 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, ethanol producers, 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 fee-based services provided to our customers and physical optimization of our assets. Our fee-based services have increased primarily due to our previously completed capital projects, including Overland Pass Pipeline and its associated lateral pipelines, and Arbuckle Pipeline. Our sources of revenue are categorized as exchange services, optimization and marketing, pipeline transportation, isomerization and storage, which are 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 transport NGL products between the Mid-Continent and Gulf Coast in order to capture the locational price differentials between the two market centers. Our natural gas liquids storage facilities are also utilized to capture seasonal price variances.
- Our pipeline transportation business transports raw NGLs, finished NGL products 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 collects fees to store NGLs at our Mid-Continent and Mont Belvieu facilities.

**Unconsolidated Affiliates** - Our Natural Gas Liquids segment includes the following unconsolidated affiliates:

- 50-percent ownership interest in Overland Pass Pipeline Company which operates an interstate natural gas liquids pipeline system extending approximately 760 miles, originating in Wyoming and Colorado and terminating in Kansas;
- 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 terminating in 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 K of the Notes to Consolidated Financial Statements in this Annual Report for additional discussion of unconsolidated affiliates.

**Market Conditions and Seasonality** - <u>Supply</u> - 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 2010, ethane prices remained above natural gas prices on a relative Btu basis, which resulted in ethane recovery from natural gas processing plants that deliver NGLs to our natural gas liquids gathering pipelines. We expect ethane prices in 2011 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 market centers 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 motor fuel 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 NGL 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 compete effectively. We believe our fractionation, pipelines and storage assets are located strategically, connecting diverse 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, including 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.

## FINANCIAL MARKETS LEGISLATION

In July 2010, the Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank Act) was enacted, representing a far-reaching overhaul of the framework for regulation of United States financial markets. Various regulatory agencies, including the SEC and the CFTC, have proposed regulations for implementation of many of the provisions of the Dodd-Frank Act and are currently seeking comments on the proposals. We expect additional proposed regulations as the remaining provisions of the Dodd-Frank Act are implemented. Until the final regulations are established, we are unable to ascertain how we may be affected. Based on our assessment of the proposed regulations issued to date, we expect to be able to continue to participate in financial markets for hedging certain risks inherent in our business, including commodity and interest-rate risks; however, the costs of doing so may increase as a result of the new legislation. We may also incur additional costs associated with our compliance with the new regulations and anticipated additional record-keeping, reporting and disclosure obligations.

**ENVIRONMENTAL AND SAFETY MATTERS**

**Pipeline Safety** - We are subject to Pipeline and Hazardous Materials Safety Administration 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. Currently, Congress is reauthorizing existing Pipeline Safety legislation, and there are also a number of new bills addressing pipeline safety being considered. We are monitoring activity concerning the reauthorization and proposed new legislation, as well as potential changes in the Pipeline and Hazardous Materials Safety Administration's regulations, to assess the potential impact on our operations. At this time, no revised or new legislation has been enacted, and potential cost, fees or expenses associated with changes or new legislation are unknown. 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.

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 certain greenhouse gas emission data for the previous year. Our most recent estimate indicates that our direct emissions were less than 3.5 million metric tons of carbon dioxide equivalents during 2009. This does not include the carbon dioxide-equivalents of product delivered to certain customers as required by the EPA's Mandatory Greenhouse Gas Reporting Rule. The EPA's Mandatory Greenhouse Gas Reporting Rule released in September 2009, 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 requires us to track the emission equivalents for all NGLs delivered to our customers. Also, the EPA has recently released a subpart to the Mandatory Greenhouse Gas Reporting Rule that will require the reporting of vented and fugitive emissions of methane from our facilities. The new requirements began in January 2011, with the first reporting of fugitive emissions due March 31, 2012. We do not expect the cost to gather this emission data to have a material impact on our results of operations, financial position or cash flows. In addition, the United States Congress has considered and may consider in the future legislation to reduce greenhouse gas emissions, including carbon dioxide and methane. At this time, no rules or legislation have been enacted that assess any costs, fees or expense on any of these emissions.

In May 2010, the EPA finalized the "Tailoring Rule" that will regulate greenhouse gas emissions at new or modified facilities that meet certain criteria. Affected facilities will be required to review best available control technology, conduct air-quality analysis, impact analysis and public reviews with respect to such emissions. The rule was phased in beginning January 2011 and, at current emission threshold levels, will have a minimal impact on our existing facilities. The EPA has stated it will consider lowering the threshold levels over the next five years, which could increase the impact on our existing facilities. However, potential costs, fees or expenses associated with the potential adjustments are unknown.

In addition, the EPA issued a 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 2013. The 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.

Finally, while the Texas Commission on Environmental Quality (TCEQ) has been delegated primary responsibility for implementing federal environmental programs under the Clean Air Act and Clean Water Act in Texas, the EPA retains program oversight. Recently, an apparent division has arisen between TCEQ and EPA over key aspects of these Texas regulatory programs (including among others, air and new source review permitting). This division led to increased

EPA scrutiny of TCEQ’s environmental permitting decisions and uncertainty with respect to how these programs will be administered in the future.

**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. We do not expect our current responsibilities under CERCLA, if any, to have a material impact on our results of operations, financial position or cash flows.

**Chemical Site Security** - The United States Department of Homeland Security (Homeland Security) released an interim rule in April 2007 that requires companies to provide reports on sites where certain chemicals, including many hydrocarbon products, are stored. We completed the Homeland Security assessments, and our facilities were subsequently assigned one of four risk-based tiers ranging from high (Tier 1) to low (Tier 4) risk, or not tiered at all due to low risk. To date, four of our facilities have been given a Tier 4 rating. Facilities receiving a Tier 4 rating are required to complete Site Security Plans and possible physical security enhancements. We do not expect the Site Security Plans and possible security enhancement costs to have a material impact on our results of operations, financial position or cash flows.

**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 current 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; and (iv) following developing technologies to capture carbon dioxide to keep it from reaching the atmosphere.

We participate in the EPA’s Natural Gas STAR Program to voluntarily reduce methane emissions. In 2010, we received a Continuing Excellence Award for five years of active participation in the program including consistent reporting of emission-reduction activities by our Natural Gas Pipelines segment. 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 2010 during the second quarter of 2011 and will post the information on our website 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 Guardian Pipeline, Viking Gas Transmission and Midwestern Gas Transmission 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, 2011, we utilized some or all of the services of 1,275 people in addition to the other resources provided by ONEOK and its affiliates.

## INFORMATION AVAILABLE ON OUR WEBSITE

We make available on our website (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 website, and we will provide copies of these documents upon request. Our website and any contents thereof are not incorporated by reference into this report.

We also make available on our website 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 experienced volatility and disruption. 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. Similar or more severe levels of market disruption and volatility may have an adverse affect on us resulting from, but not limited to, disruption of our access to capital and credit markets, difficulty in obtaining financing necessary to expand facilities or acquire assets, increased financing cost and increasingly restrictive covenants.

**Our operating results may be affected materially and adversely 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.

**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 natural gas 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, but not limited to 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 third-party transportation, natural gas processing and NGL fractionation 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;

- the effect of worldwide energy conservation measures; and
- the impact of new supplies, new pipelines, processing and fractionation facilities on basis differentials.

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 after the 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 depends principally upon the cash we generate from our operations, which includes activities with our affiliates. 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 value of the NGLs and natural gas we receive in exchange for the natural gas gathering and processing services we provide;
- the differentials between NGL and natural gas prices associated with our keep-whole contracts;
- the differential between the individual NGL products with respect to our NGL transportation, fractionation and exchange agreements;
- the locational differentials in the price of natural gas and NGLs with respect to our natural gas and NGL transportation businesses;
- the seasonal differentials in natural gas and NGL prices related to our storage operations; and
- the fuel costs and the value of the retained fuel in-kind in our natural gas pipelines and 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 had 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 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, legal and weather-related 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:

- inaccurate 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, for which our indemnity is inadequate or for which our insurance policies may exclude from coverage;
- 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;
- inaccurate 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 natural gas processing, natural gas liquids fractionators 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 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 purchase 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 declines substantially 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 or regulation of drilling and production technologies including, but not limited to, hydraulic fracturing. 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 Viking Gas Transmission and our investment in Northern Border Pipeline that transport Canadian natural gas from the Western Canada Sedimentary Basin to the Midwestern United States 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 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 remediate, as well as initiate 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, CFTC and/or the United States Congress in the future. In response to previous market power abuse by certain companies engaged in interstate commerce, 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. In addition to the authority granted to the FERC under EPACT, the CFTC also has the authority to regulate market manipulation under the Commodities Exchange Act and the Dodd-Frank Act.

**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 its 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 rule on air quality standards, known as RICE NESHAP, that is scheduled to be adopted in early 2013.

Various federal and state 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 increase significantly 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 M 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 affect materially our profitability.

**The adoption and implementation of new statutory and regulatory requirements for derivative transactions could have an adverse impact on our ability to hedge risks associated with our business and increase the working capital requirements to conduct these activities.**

In July 2010, the Dodd-Frank Act was enacted, which provides for new statutory and regulatory requirements for financial derivative transactions. Certain derivative transactions will be required to be cleared on exchanges, and cash collateral will be required for these transactions. However, the Dodd-Frank Act provides for a potential exemption from these clearing and cash collateral requirements for commercial end-users and includes a number of defined terms that will be used in determining how this exemption applies to particular derivative transactions and to the parties to those transactions. Additionally, the Dodd-Frank Act calls for various regulatory agencies, including the SEC and the CFTC, to establish regulations for implementation of many of the provisions of the act. It also requires the CFTC to establish new position trading limits.

We expect to be able to continue to participate in financial markets for hedging certain risks inherent in our business, including commodity and interest-rate risks; however, the costs of doing so may increase as a result of the new legislation. We may also incur additional costs associated with our compliance with the new regulations and anticipated additional record-keeping, reporting and disclosure obligations. These requirements could adversely affect market liquidity and pricing of derivative contracts, and the anticipated increased costs of compliance by dealers and counterparties will likely be passed on to customers, which could decrease the benefits of hedging to us and could reduce our profitability and liquidity.

**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 could 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 workers 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 workers 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 may be 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 42.8-percent ownership interest in us as of December 31, 2010. 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 other types of 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, held on 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 Conflicts 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 owns 100 percent of our general partner interest, and 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. 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.

**An event of default may require us to offer to repurchase certain of our senior notes or may impair our ability to access capital.**

The indenture governing our senior notes due 2011 includes an event of default upon acceleration of other indebtedness of $25 million or more, and the indenture governing our other senior notes includes an event of default upon the acceleration of other indebtedness of $100 million or more. Such an event of default would entitle the trustee or the holders of 25 percent in aggregate principal amount of the outstanding senior notes 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, 2010, we had total indebtedness of approximately $3.2 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. For example, our Partnership Credit Agreement contains a legal covenant requiring us to maintain a ratio of indebtedness to adjusted EBITDA (EBITDA, as defined in our Partnership Credit Agreement, 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.

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 or other 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 distributions to our general partner related to its incentive distribution rights may increase and 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, as well as our not being subject to a material amount of entity-level taxation by individual states. If the IRS were to treat us as a corporation for federal income tax purposes 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.

Despite the fact that we are a limited partnership under Delaware law, it is possible, in certain circumstances, for a partnership such as ours to be treated as a corporation for federal income tax purposes. 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 would likely pay additional state income taxes at varying rates. 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, if we were treated as a corporation for federal income tax purposes, there would be a material reduction in the anticipated free cash flow and after-tax return to our common unitholders, likely causing a substantial reduction in the value of our common units.

Changes in current state law may subject us to additional entity-level taxation by individual states. 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 and other forms of taxation. For example, starting January 1, 2008, we have been required to pay Texas franchise tax each year at a maximum effective rate of 0.7 percent of our gross revenue that is apportioned to Texas in the prior year. Imposition of any similar taxes by any other state may reduce substantially the cash available for distribution to our common unitholders and, therefore, impact negatively the value of an investment in our common units.

Our partnership agreement provides that, if a law is enacted or existing law is modified or interpreted in a manner that subjects us to taxation as a corporation or otherwise subjects us to additional entity-level taxation for federal, state or local income tax purposes, the minimum quarterly distribution amount and the target distribution amounts may be adjusted to reflect the impact of that law on us.

**The tax treatment of publicly traded partnerships or an investment in our common or other units could be subject to potential legislative, judicial or administrative changes and differing interpretations, possibly on a retroactive basis.**

The present federal income tax treatment of publicly traded partnerships, including us, or an investment in our common units may be modified by administrative, legislative or judicial interpretation at any time. Recently, members of the United States Congress considered substantive changes to the existing federal income tax laws that would have affected the tax treatment of certain publicly traded partnerships. Any modification to the federal income tax laws and interpretations thereof may or may not be applied retroactively. We are unable to predict whether any of these changes or any other proposals will be enacted ultimately. 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 IRS contest will reduce our cash available for distribution to our unitholders.**

We have not requested a ruling from the IRS with respect to our treatment as a partnership for federal income tax purposes. The IRS may adopt positions that differ from the federal income tax positions we take and such positions may not ultimately be sustained. 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 impact materially and adversely 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 be borne indirectly by our unitholders and our general partner because such costs will reduce our cash available for distribution.

**A unitholder’s share of our income will be taxable to the unitholder for federal income tax purposes even if the unitholder does not receive any cash distributions from us.**

Because our unitholders will be treated as partners to whom we will allocate taxable income, which could be different in amount than the cash we distribute, a unitholder’s share of our taxable income will be taxable to the unitholder, which may require the payment of federal income taxes and, in some cases, state and local income taxes on the unitholder’s share of our taxable income, even if the unitholder receives no 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 that income.

In the event we issue additional units or engage in certain other transactions in the future, the allocable share of nonrecourse liabilities allocated to the unitholders will be recalculated to take into account our issuance of any additional units. Any reduction in a unitholder’s share of our nonrecourse liabilities will be treated as a distribution of cash to that unitholder and will result in a corresponding tax basis reduction in a unitholder’s units. A deemed cash distribution may, under certain circumstances, result in the recognition of taxable gain by a unitholder, to the extent that the deemed cash distribution exceeds such unitholder’s tax basis in its units.

In addition, the federal income tax liability of a unitholder could be increased if we make a future offering of units and use the proceeds of the offering in a manner that does not produce substantial additional deductions, such as to repay indebtedness currently outstanding or to acquire property that is not eligible for depreciation or amortization for federal income tax purposes or that is depreciable or amortizable at a rate significantly slower than the rate currently applicable to the our assets.

**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 for federal income tax purposes on the sale of common units equal to the difference between the amount realized and the unitholder’s tax basis in those common units. Because distributions in excess of the unitholder’s allocable share of our net taxable income decrease the unitholder’s tax basis in the common units, the amount, if any, of such prior excess distributions with respect to the common units the unitholder sells will, in effect, become taxable income to a unitholder if the common units are sold at a price greater than the tax basis in those units, even if the price the unitholder receives is less than the original cost. Furthermore, a substantial portion of the amount realized on a sale of common units, whether or not representing gain, may be taxed as ordinary income due to potential recapture items, including depreciation recapture. In addition, because the amount realized may include a unitholder’s share of our nonrecourse liabilities, a unitholder who sells common units may incur a tax liability in excess of the amount of cash received from the sale.

**Tax-exempt entities and non-United States 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 employee benefit plans and individual retirement accounts and non-United States persons, raises issues unique to them. For example, virtually all of our income allocated to organizations that are 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-United States persons will be reduced by withholding taxes at the highest applicable effective tax rate, and non-United States persons will be required to file United States 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 existing 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 for federal income tax purpose 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 our proration 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 may 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 may be subject to other taxes, including state and local income taxes, unincorporated business taxes and estate, inheritance or intangible taxes that are imposed by the various jurisdictions in which we conduct business or own property, even if the unitholder does not live in any of those jurisdictions. Unitholders may 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. As we make acquisitions or expand our business, we may own assets or conduct business in additional states or foreign countries that impose a personal income tax or an entity level tax.

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 our capital and profits interests during any 12-month period will result in the termination of our partnership for federal income tax purposes.**

We will be considered to have technically terminated our partnership 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. For purposes of determining whether the 50-percent threshold has been met, multiple sales of the same interest will be counted only once.

Our technical termination would, among other things, result in the closing of our taxable year for all unitholders, which would result in us filing two tax returns (and our unitholders could receive two Schedules K-1 if relief was not available, as described below) for one fiscal year and could also result in a deferral of depreciation deductions allowable in computing our taxable income. In the case of a unitholder reporting on a taxable year other than a fiscal year ending December 31, the closing of our taxable year may result in more than 12 months of our taxable income or loss being included in the unitholder's taxable income for the year of termination. Our technical termination would not affect our classification as a partnership for federal income tax purposes, but instead, we would be treated as a new partnership, and would be required to make new tax elections, and we could be subject to penalties if we are unable to determine that a technical termination occurred.

The IRS has recently announced a publicly traded partnership technical termination relief procedure, whereby if a publicly traded partnership that has technically terminated requests and the IRS grants special relief, among other things, the partnership will only have to provide one Schedule K-1 to unitholders for the year, notwithstanding two partnership tax years resulting from the technical termination.

**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 federal income 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 federal income 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 10,300 miles and 4,900 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 69 percent and 68 percent for 2010 and 2009, 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 51.7 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. In compliance with a KDHE order, we began injecting brine into that 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 2012. Monitoring of the facility and review of the data for the geo-engineering 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 87 percent and 86 percent subscribed for 2010 and 2009, respectively, and our storage facilities were fully subscribed both years.

**Natural Gas Liquids**

**Property** - Our Natural Gas Liquids segment owns the following assets:
- approximately 2,500 miles of natural gas liquids gathering pipelines with peak capacity of approximately 500 MBbl/d;
- approximately 160 miles of natural gas liquids distribution pipelines with peak transportation capacity of approximately 66 MBbl/d;
- approximately 780 miles of FERC-regulated natural gas liquids gathering pipelines with peak capacity of approximately 200 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 combined operating capacity of approximately 260 MBbl/d, which are located in Oklahoma and Kansas;
- 80-percent ownership interest in one natural gas liquids fractionator in Texas with our proportional share of operating capacity of approximately 128 MBbl/d;
- interest in one natural gas liquids fractionator in Kansas with our proportional share of operating capacity of approximately 11 MBbl/d;
- one isomerization unit in Kansas with operating capacity of 9 MBbl/d;
- six natural gas liquids storage facilities in Oklahoma, Kansas and Texas with operating storage capacity of approximately 23.2 MMBbl;
- eight natural gas liquids 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 combined operating capacity of 978 MBbl.

In addition, we lease approximately 2.9 MMBbl of combined NGL storage capacity at facilities in Kansas and Texas. We also own and lease assets through an affiliate at the Bushton facility in Kansas, which includes 150 MBbl/d of fractionation capacity.

**Utilization** - The utilization rates for our various assets, including leased assets, for 2010 and 2009, respectively, were as follows:

- our non-FERC-regulated natural gas liquids pipelines were approximately 56 percent and 51 percent;
- our FERC-regulated natural gas liquids gathering pipelines were approximately 70 percent and 58 percent;
- our FERC-regulated natural gas liquids distribution pipelines were approximately 63 percent and 62 percent;
- our average contracted natural gas storage volumes were approximately 64 percent and 58 percent of storage capacity; and
- our natural gas liquids fractionators were approximately 93 percent and 88 percent.

We calculate utilization rates using a weighted-average approach, adjusting for the dates that assets were placed in service during 2010 and 2009. The utilization rates of our FERC-regulated natural gas liquids gathering pipelines reflect Overland Pass Pipeline and its related lateral pipelines from the date they were placed in service until Overland Pass Pipeline Company was deconsolidated in September 2010. Our fractionation utilization rate reflects approximate proportional capacity associated with ownership interests noted above and for our Bushton facility.

## ITEM 3. LEGAL PROCEEDINGS

**Thomas F. Boles, et al. v. El Paso Corporation, et al. (f/k/a 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 ("Boles I").** Plaintiffs brought suit on May 28, 1999, against ONEOK, Inc. and its Oklahoma Natural Gas division, 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. 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. The plaintiffs motion for reconsideration of the Court's denial of class certification was denied on March 31, 2010.

**Thomas F. Boles, et al. v. El Paso Corporation, et al. (f/k/a 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 ("Boles II").** This action was filed by the plaintiffs on May 12, 2003, after the Court denied class status in Boles I. Plaintiffs are seeking monetary damages based upon a claim that 21 groups of defendants, including ONEOK, Inc. and its Oklahoma Natural Gas division, 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. Boles II has been consolidated with Boles I for the determination of whether either or both cases may be certified properly as class actions. 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. The plaintiffs motion for reconsideration of the Court's denial of class certification was denied on March 31, 2010.

## 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, 2010 | | Year Ended December 31, 2009 | |
|---|---|---|---|---|
| | **High** | **Low** | **High** | **Low** |
| First Quarter | **$ 66.67** | **$ 57.98** | $ 52.75 | $ 34.21 |
| Second Quarter | **$ 65.34** | **$ 55.95** | $ 49.75 | $ 40.06 |
| Third Quarter | **$ 74.92** | **$ 63.57** | $ 53.30 | $ 45.80 |
| Fourth Quarter | **$ 81.51** | **$ 74.50** | $ 63.00 | $ 52.20 |

At February 14, 2011, there were 711 holders of record of our 65,413,677 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.

### 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, | | |
|---|---|---|---|
| | **2010** | **2009** | **2008** |
| First Quarter | **$ 1.10** | $ 1.08 | $ 1.025 |
| Second Quarter | **$ 1.11** | $ 1.08 | $ 1.040 |
| Third Quarter | **$ 1.12** | $ 1.08 | $ 1.060 |
| Fourth Quarter | **$ 1.13** | $ 1.09 | $ 1.080 |

In January 2011, our general partner declared a cash distribution of $1.14 per unit ($4.56 per unit on an annualized basis) for the fourth quarter of 2010, which was paid on February 14, 2011, to unitholders of record as of January 31, 2011.

### 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.

Our Class B limited partner units are entitled to receive increased quarterly distributions equal to 110 percent of the distributions paid with respect to our common units. ONEOK, as the sole holder of our Class B limited partner units, has waived its right to receive the increased quarterly distributions on the Class B units. ONEOK retains the option to withdraw its waiver of increased distributions on our Class B units at any time by giving us no less than 90 days advance notice. Any such withdrawal of the waiver will be effective with respect to any distribution on the Class B units declared or paid on or after the 90 days following delivery of the notice.

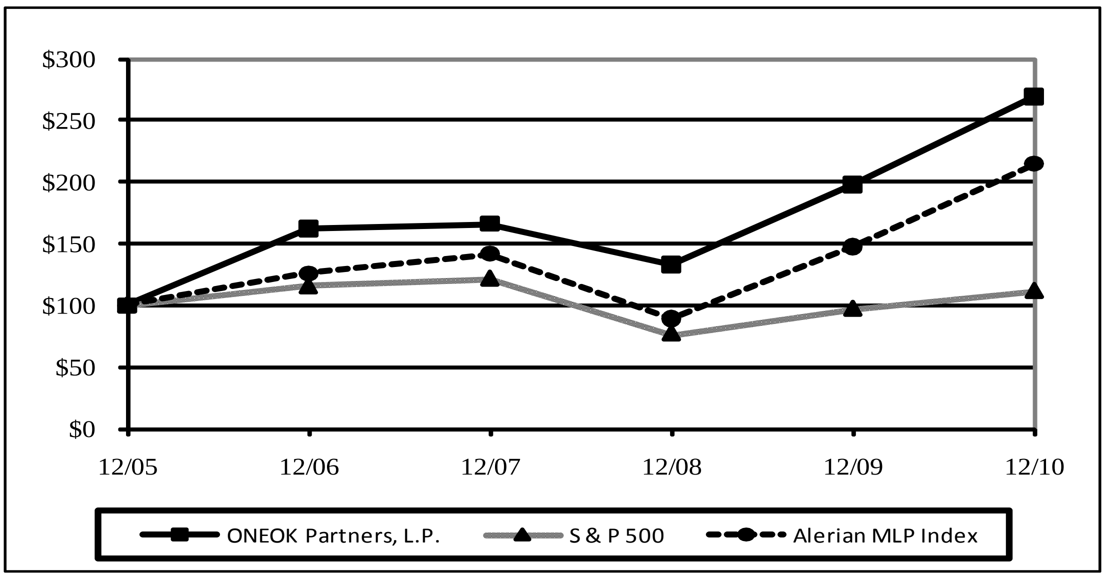
If our common unitholders vote at any time to remove ONEOK or its affiliates as our general partner, quarterly distributions payable on the Class B limited partner units would increase to 123.5 percent of the distributions payable with respect to the common units, and distributions payable upon liquidation of the Class B limited partner units would increase to 123.5 percent of the distributions payable with respect to the common units.

We paid cash distributions to our general and limited partners of $563.2 million, $500.3 million and $453.0 million for 2010, 2009 and 2008, respectively, which included an incentive distribution to our general partner of $103.5 million, $84.7 million and $69.9 million for 2010, 2009 and 2008, respectively. 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, 2005, and ending on December 31, 2010. 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, 2005, and at the End of Every Year Through December 31, 2010,**
**Among ONEOK Partners L.P., the S&P 500 Index and the Alerian MLP Index**




| | Cumulative Total Return | | | | | |
|---|---|---|---|---|---|---|
| | Years Ended December 31, | | | | | |
| | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 |
| ONEOK Partners, L.P. | $ 100.00 | $ 161.67 | $ 165.96 | $ 132.74 | $ 197.56 | **$ 269.27** |
| S&P 500 Index | $ 100.00 | $ 115.78 | $ 122.14 | $ 76.96 | $ 97.33 | **$ 112.01** |
| Alerian MLP Index (a) | $ 100.00 | $ 125.82 | $ 141.69 | $ 89.58 | $ 147.56 | **$ 214.66** |

(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, | | | | |
|---|---|---|---|---|---|
| | **2010** | **2009** | **2008** | **2007** | **2006** |
| | *(In millions of dollars, except per unit data)* | | | | |
| Revenues | **$ 8,675.9** | $ 6,474.5 | $ 7,720.2 | $ 5,831.6 | $ 4,738.2 |
| Net income | **$ 473.3** | $ 434.7 | $ 626.1 | $ 408.2 | $ 447.6 |
| Net income attributable to ONEOK Partners, L.P. | **$ 472.7** | $ 434.4 | $ 625.6 | $ 407.7 | $ 445.2 |
| Per unit net income | **$ 3.50** | $ 3.60 | $ 6.01 | $ 4.21 | $ 5.01 |
| Distributions paid per common unit (a) | **$ 4.46** | $ 4.33 | $ 4.21 | $ 3.98 | $ 3.60 |
| Total assets | **$ 7,920.1** | $ 7,953.3 | $ 7,254.3 | $ 6,112.1 | $ 4,921.7 |
| Long-term debt, including current maturities | **$ 2,818.5** | $ 3,084.0 | $ 2,601.4 | $ 2,617.3 | $ 2,031.5 |

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

## 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.

## RECENT DEVELOPMENTS

The following discussion highlights some of our planned activities, recent achievements and significant issues affecting us. Please refer to the "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.

**Growth Projects** - We announced in 2010 and early 2011 approximately $1.8 billion to $2.1 billion in growth projects, primarily in the Williston Basin in North Dakota and the Cana-Woodford Shale and Granite Wash areas in Oklahoma and Texas, that will enable us to meet the rapidly growing needs of crude oil and natural gas producers as they increase their drilling activities.

Williston Basin Projects - Drilling rig counts in Dunn, McKenzie and Williams counties in North Dakota have increased dramatically since the beginning of 2010. The development of the reserves in these counties from the Bakken Shale and Three Forks formations in the Williston Basin are being driven primarily by crude oil economics, with the associated natural gas production having a high NGL content. Current natural gas processing and natural gas liquids infrastructure in the Williston Basin is being expanded to accommodate the additional production from the increased development activities.

We are the largest independent gatherer and processor of natural gas in the Williston Basin. With our Natural Gas Gathering and Processing segment's existing infrastructure and acreage dedications, we are well positioned to provide midstream services to crude oil and natural gas producers as they develop Bakken Shale and Three Forks reserves. Additional natural gas liquids infrastructure is also needed due to the continued NGL production growth that has saturated the area's current truck and railcar transportation capacity and market. The following provides additional details about our individual projects.

*Williston Basin Processing Plants and related projects* - We announced plans to construct three new 100 MMcf/d natural gas processing facilities, the Garden Creek plant in eastern McKenzie County, North Dakota, and the Stateline I and II plants in western Williams County, North Dakota. In addition, we plan to make investments in related natural gas liquids infrastructure, expansions and upgrades to our existing gathering and compression infrastructure and new well connections associated with these plants. The Garden Creek plant and related projects are expected to be in service by the end of 2011 and cost approximately $350 million to $415 million, excluding AFUDC. The Stateline I plant, which is expected to be in service during the third quarter of 2012, and related projects are expected to cost approximately $300 million to $355 million, excluding AFUDC. The Stateline II plant, which is expected to be in service during the first half of 2013, and related projects are expected to cost approximately $260 million to $305 million, excluding AFUDC. These projects are in our Natural Gas Gathering and Processing segment.

*Bakken Pipeline and related projects* - We announced plans to build a 525- to 615-mile natural gas liquids pipeline, the Bakken Pipeline, that will transport unfractionated NGLs from the Williston Basin in North Dakota to the Overland Pass Pipeline. The Bakken Pipeline will initially have capacity to transport up to 60 MBbl/d of unfractionated NGL production from our natural gas gathering and processing assets in the Williston Basin originating in eastern Montana and connecting to the Overland Pass Pipeline in northeastern Colorado. The unfractionated NGLs will then be delivered to our existing natural gas liquids fractionation and distribution infrastructure in the Mid-Continent. Additional pump facilities could increase the Bakken Pipeline's capacity to 110 MBbl/d. Supply commitments for the Bakken Pipeline will be anchored by NGL production from our natural gas processing plants. We are also discussing NGL supply commitments with third-party processors. Following receipt of all necessary permits, construction of the 12-inch diameter pipeline is expected to begin in the second quarter of 2012 and be in service during the first half of 2013. Project costs for the new pipeline are estimated to be $450 million to $550 million, excluding AFUDC.

The unfractionated NGLs from the Bakken Pipeline and other supply sources under development in the Rockies will require additional pump stations and the expansion of existing pump stations on the Overland Pass Pipeline. These additions and expansions will increase the capacity of Overland Pass Pipeline to 255 MBbl/d. Our anticipated share of the costs for this project is estimated to be $35 million to $40 million, excluding AFUDC. The Bakken Pipeline and related projects are in our Natural Gas Liquids segment.

*Bushton Fractionator Expansion* - To accommodate the additional volume from the Bakken Pipeline, we will invest $110 million to $140 million, excluding AFUDC, to expand and upgrade our existing fractionation capacity at Bushton, Kansas, increasing our capacity to 210 MBbl/d from 150 MBbl/d. This project is expected to be in service during the first half of 2013 and is in our Natural Gas Liquids segment.

Cana-Woodford Shale and Granite Wash projects - In addition to the growth projects in the Williston Basin, we have also announced plans to invest approximately $270 million to $330 million, excluding AFUDC, in our existing Mid-Continent infrastructure, primarily in the Cana-Woodford Shale and Granite Wash areas. The expansions and upgrades will increase our ability to accommodate the growing natural gas and NGL supply from producers and natural gas processors as drilling activities increase in these areas. These investments will expand our ability to transport unfractionated NGLs from these Mid-Continent supply areas to fractionation facilities in Oklahoma and Texas and distribute purity NGL products to the Mid-Continent, Gulf Coast and upper Midwest market centers. A portion of these investments will also allow us to increase utilization of our natural gas processing capacity in Oklahoma.

We announced plans to construct more than 230 miles of natural gas liquids pipeline that will expand our existing Mid-Continent natural gas liquids gathering system in the Cana-Woodford Shale and Granite Wash areas. The pipeline will connect to three new third-party natural gas processing facilities that are under construction and to three existing third-party natural gas processing facilities that are being expanded. Additionally, we will install additional pump stations on the Arbuckle Pipeline to increase its capacity to 240 MBbl/d. When completed, these projects are expected to add approximately 75 to 80 MBbl/d of raw, unfractionated NGLs to our existing natural gas liquids gathering systems. These projects are expected to be in service during the first half of 2012 and cost approximately $180 million to $240 million, excluding AFUDC. These projects are in our Natural Gas Liquids segment.

We will invest an additional $55 million in the Cana-Woodford Shale development in Oklahoma. The investments include approximately $20 million for new well connections in 2010 and 2011 to gather additional Cana-Woodford Shale natural gas volumes. In addition, we also completed in the fourth quarter of 2010 the connection of our Western Oklahoma natural gas gathering system to our existing Maysville natural gas processing facility in central Oklahoma and the connection of a new natural gas processing plant to our natural gas liquids gathering system. These projects are in our Natural Gas Gathering and Processing and Natural Gas Liquids segments, respectively.

Sterling I Pipeline Expansion - We will install seven additional pump stations for approximately $36 million, excluding AFUDC, along our existing Sterling I natural gas liquids distribution pipeline, increasing its capacity by 15 MBbl/d, which will be supplied by our Mid-Continent natural gas liquids infrastructure. The Sterling I pipeline transports purity NGL products from our fractionator in Medford, Oklahoma, to the Mont Belvieu, Texas, market center and is currently operating at capacity. The pump stations are expected to be in service in the second half of 2011. This project is in our Natural Gas Liquids segment.

For a discussion of our capital expenditure financing, see "Capital Expenditures" in "Liquidity and Capital Resources" on page 50.

**Overland Pass Pipeline Company** - In September 2010, we completed a transaction to sell a 49-percent ownership interest in Overland Pass Pipeline Company to a subsidiary of Williams Partners resulting in each joint-venture member now owning 50 percent of Overland Pass Pipeline Company. In accordance with the joint-venture agreement, we received approximately $423.7 million in cash at closing. We used the proceeds from the transaction to repay short-term debt and to fund a portion of our recently announced capital projects. A subsidiary of Williams Partners has elected to become the operator of Overland

Pass Pipeline Company and is expected to assume the role of operator in the second quarter of 2011. As a result of the transaction, we no longer control Overland Pass Pipeline Company and began accounting for our investment under the equity method of accounting in September 2010. In connection with the deconsolidation of Overland Pass Pipeline Company, we recognized a gain of approximately $16.3 million.

**Cash Distributions** - During 2010, we paid cash distributions totaling $4.46 per unit, an increase of approximately 3.0 percent over the $4.33 per unit paid during 2009. In January 2011, our general partner declared a cash distribution of $1.14 per unit ($4.56 per unit on an annualized basis), an increase of approximately 3.6 percent over the $1.10 declared in January 2010.

**Commercial Paper Program** - In June 2010, we established a commercial paper program providing for the issuance of up to $1.0 billion of unsecured commercial paper notes. Amounts outstanding under the commercial paper program reduce the borrowings available under our Partnership Credit Agreement. In July 2010, we repaid all borrowings outstanding under our Partnership Credit Agreement with the issuance of commercial paper.

**Equity Issuance** - 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 $322.7 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.

**Long-Term Debt** - In June 2010, we repaid $250 million of maturing senior notes with available cash and short-term borrowings. With the repayment of these notes, we no longer have any obligation to offer to repurchase the $225 million senior notes due March 2011, in the event that our long-term debt credit ratings fall below investment grade.

**Debt Issuance** - In January 2011, we completed an underwritten public offering of $1.3 billion senior notes, consisting of $650 million of 3.25-percent senior notes due 2016 and $650 million of 6.125-percent senior notes due 2041. The net proceeds, from the offering of approximately $1.28 billion were used to repay amounts outstanding under our commercial paper program and for general partnership purposes, including capital expenditures, and will be used to repay the $225 million principal amount of senior notes due March 2011.

## REGULATORY

**Environmental Liabilities** - We are subject to multiple historical and wildlife preservation laws and environmental 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 pipelines 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 affect materially our results of operations and cash flows. In addition, emission controls required under the 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.

In May 2010, the EPA finalized the “Tailoring Rule” that will regulate greenhouse gas emissions at new or modified facilities that meet certain criteria. Affected facilities will be required to review best available control technology, conduct air-quality analysis, impact analysis and public reviews with respect to such emissions. The rule was phased in beginning January 2011 and, at current emission threshold levels, will have a minimal impact on our existing facilities. The EPA has stated it will consider lowering the threshold levels over the next five years, which could increase the impact on our existing facilities; however, potential costs, fees or expenses associated with the potential adjustments are unknown.

In addition, the EPA 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 2013. The 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.

**Financial Markets Legislation** - In July 2010, the Dodd-Frank Act was enacted, representing a far-reaching overhaul of the framework for regulation of United States financial markets. Various regulatory agencies, including the SEC and the CFTC, have proposed regulations for implementation of many of the provisions of the Dodd-Frank Act and are currently seeking comments on the proposals. We expect additional proposed regulations as the remaining provisions of the Dodd-Frank Act are implemented. Until the final regulations are established, we are unable to ascertain how we may be affected. Based on our assessment of the proposed regulations issued to date, we expect to be able to continue to participate in financial markets for hedging certain risks inherent in our business, including commodity and interest-rate risks; however, the costs of doing so may increase as a result of the new legislation. We may also incur additional costs associated with our compliance with the new regulations and anticipated additional record-keeping, reporting and disclosure obligations.

## 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. ASU 2010-06, "Improving Disclosures about Fair Value Measurements," is a disclosure-only standard, which did not have a material impact. See Note B of the Notes to Consolidated Financial Statements for discussion of our fair value measurements.

## ESTIMATES AND CRITICAL ACCOUNTING POLICIES

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 policies, which are defined as those estimates and 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 estimates and critical accounting policies with the Audit Committee of our Board of Directors.

**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. The accounting for changes in the fair value of a derivative instrument depends on whether it qualifies and has been designated as part of a hedging relationship. When possible, we implement effective hedging strategies using derivative financial instruments that qualify as hedges for accounting purposes. We have not used derivative instruments for trading purposes.

For a derivative designated as a cash flow hedge, the effective portion of the gain or loss from a change in fair value of the derivative instrument is deferred in accumulated other comprehensive income (loss) until the forecasted transaction affects earnings, at which time the fair value of the derivative instrument is reclassified into earnings. The ineffective portion of the gain or loss on a derivative instrument designated as a cash flow hedge is recognized in earnings.

We assess the effectiveness of hedging relationships quarterly by performing an effectiveness test on our hedging relationships to determine whether they are highly effective on a retrospective and prospective basis. 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. However, if a derivative instrument is ineligible for cash flow hedge accounting or if we fail to appropriately designate it as a cash flow hedge, changes in fair value of the derivative instrument would be recorded currently in earnings. Additionally, if a cash flow hedge ceases to qualify for hedge accounting treatment because it is no longer probable that the forecasted transaction will occur, the change in fair value of the derivative instrument would be recognized in earnings. 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 B and C of the Notes to Consolidated Financial Statements in this Annual Report for additional discussion of fair value measurements and derivatives and risk management activities.

**Impairment of Goodwill and Long-Lived Assets, including Intangible Assets** - We assess our goodwill for impairment at least annually as of July 1. There were no impairment charges resulting from our 2010, 2009 or 2008 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, using assumptions consistent with a market participant's perspective. 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 discount rates. Under the market approach, we apply multiples to forecasted cash flows. The multiples used are consistent with historical asset transactions. The forecasted cash flows are based on average forecasted cash flows for a reporting unit over a period of years.

Our estimates of fair values significantly exceeded the book values of our reporting units in our July 1, 2010, impairment test. Even if the estimated fair values used in our July 1, 2010, impairment tests were reduced by 10 percent, no impairment charges would have resulted. The following table sets forth our goodwill, by segment, at both December 31, 2010 and 2009:

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

We assess our long-lived assets, including intangible assets with finite useful lives, for impairment whenever events or changes in circumstances indicate that an asset's carrying amount may not be recoverable. 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. If an impairment is indicated, we record an impairment loss equal to the difference between the carrying value and the fair value of the long-lived asset. We determined that there were no asset impairments in 2010, 2009 or 2008.

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 2010, 2009 or 2008.

Our impairment tests require the use of assumptions and estimates such as industry economic factors and the profitability of future business strategies. 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 future impairment charges.

See Notes A, D and E of the Notes to Consolidated Financial Statements in this Annual Report for additional discussion of goodwill and long-lived assets.

**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 assessments of the ultimate outcome or resolution. Accruals for estimated losses from environmental remediation obligations generally are recognized no later than completion of a 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 effect on earnings or cash flows during 2010, 2009 and 2008. Actual results may differ from our estimates resulting in an impact, positive or negative, on earnings. See Note M of the Notes to Consolidated Financial Statements in this Annual Report for additional discussion of contingencies.

**FINANCIAL RESULTS AND OPERATING INFORMATION**

**Consolidated Operations**

The following table sets forth certain selected consolidated financial results for the periods indicated:

| Financial Results | Years Ended December 31, 2010 | 2009 | 2008 | Variances 2010 vs. 2009 Increase (Decrease) | | Variances 2009 vs. 2008 Increase (Decrease) | |
|---|---|---|---|---|---|---|---|
| | | | *(Millions of dollars)* | | | | |
| Revenues | **$ 8,675.9** | $ 6,474.5 | $ 7,720.2 | **$ 2,201.4** | **34%** | $ (1,245.7) | (16%) |
| Cost of sales and fuel | **7,531.0** | 5,355.2 | 6,579.5 | **2,175.8** | **41%** | (1,224.3) | (19%) |
| Net margin | **1,144.9** | 1,119.3 | 1,140.7 | **25.6** | **2%** | (21.4) | (2%) |
| Operating costs | **403.5** | 411.3 | 371.8 | **(7.8)** | **(2%)** | 39.5 | 11% |
| Depreciation and amortization | **173.7** | 164.1 | 124.8 | **9.6** | **6%** | 39.3 | 31% |
| Gain (loss) on sale of assets | **18.6** | 2.7 | 0.7 | **15.9** | ***** | 2.0 | * |
| Operating income | **$ 586.3** | $ 546.6 | $ 644.8 | **$ 39.7** | **7%** | $ (98.2) | (15%) |
| | | | | | | | |
| Equity earnings from investments | **$ 101.9** | $ 72.7 | $ 101.4 | **$ 29.2** | **40%** | $ (28.7) | (28%) |
| Allowance for equity funds used during construction | **$ 1.0** | $ 26.9 | $ 50.9 | **$ (25.9)** | **(96%)** | $ (24.0) | (47%) |
| Interest expense | **$ (204.3)** | $ (206.0) | $ (151.1) | **$ (1.7)** | **(1%)** | $ 54.9 | 36% |
| Capital expenditures | **$ 352.7** | $ 615.7 | $ 1,253.9 | **$ (263.0)** | **(43%)** | $ (638.2) | (51%) |

* Percentage change is greater than 100 percent.

**2010 vs. 2009 -** Energy markets were affected by higher commodity prices during 2010, compared with 2009. The increase in commodity prices had a direct impact on our revenues and cost of sales and fuel. We completed more than $2.0 billion in growth projects at the end of 2008 and in 2009. Our 2010 operating results include the benefits from a full year of our completed projects, including the following projects placed in service in 2009:

- February - Guardian Pipeline's expansion and extension project in our Natural Gas Pipelines segment;
- March - Grasslands natural gas processing plant expansion in our Natural Gas Gathering and Processing segment;
- March - D-J Basin lateral pipeline in our Natural Gas Liquids segment;
- July - Arbuckle Pipeline in our Natural Gas Liquids segment; and
- October - Piceance lateral pipeline in our Natural Gas Liquids segment.

Operating income increased 7 percent in 2010 compared with 2009. The increase in operating income for the 2010 period reflects the benefit of a full year of operations of our capital projects completed in 2009, resulting in higher NGL volumes in the Natural Gas Liquids segment; higher contracted natural gas transportation capacity on the Midwestern Gas Transmission and Viking Gas Transmission pipelines in the Natural Gas Pipelines segment; and an increase in Williston Basin volumes in our Natural Gas Gathering and Processing segment. Additionally, our Natural Gas Liquids and Natural Gas Pipelines segments produced higher storage margins, primarily as a result of contract renegotiations. Operating income also included the gain on the sale of a 49-percent ownership interest in Overland Pass Pipeline Company. Operating income also benefited from lower than estimated ad valorem taxes associated with our capital projects completed in 2009 and lower outside service costs for maintenance at our fractionators in 2009, offset partially by incremental employee-related costs and property insurance costs associated with our capital projects completed in 2009.

These increases were offset partially by lower optimization margins in the Natural Gas Liquids segment due to limited NGL fractionation and transportation capacity available for optimization activities between the Mid-Continent and Gulf Coast NGL market centers until September 2010 and less favorable NGL price differentials; and decreased margins in our Natural Gas Gathering and Processing segment from lower natural gas volumes processed and sold in western Oklahoma and Kansas, selling our bankruptcy claims with Lehman Brothers in 2009 and lower natural gas volumes gathered in the Powder River Basin in Wyoming.

Equity earnings from investments increased due primarily to increased contracted capacity on Northern Border Pipeline due to wider natural gas price differentials. Additionally, in September 2010, we began accounting for our 50-percent investment in Overland Pass Pipeline Company, which includes the Overland Pass Pipeline and the D-J Basin and Piceance lateral pipelines, as an equity investment.

Allowance for equity funds used during construction and capital expenditures decreased due primarily to the completion of our capital projects in 2009.

We expect continued development of the reserves in the Bakken Shale and Three Forks formations in the Williston Basin. The development of these reserves is being driven primarily by crude oil economics, with the associated natural gas production having a high NGL content. Current natural gas processing and natural gas liquids infrastructure in the Williston Basin is being expanded to accommodate the additional production from the increased development activities. We have announced plans to invest $1.5 to $1.8 billion in the Williston Basin in North Dakota and Bushton, Kansas to serve the needs of crude oil and natural gas producers.

In addition to the growth projects in the Williston Basin, we have also announced plans to invest $270 to $330 million to expand and upgrade our existing Mid-Continent infrastructure, primarily in the Cana-Woodford Shale and Granite Wash areas, to accommodate the growing natural gas and NGL supply from producers and natural gas processors as drilling activities increase in these areas. These investments will expand our ability to transport unfractionated NGLs from these supply areas to fractionation facilities in Kansas, Oklahoma and Texas and distribute purity NGL products to Mid-Continent, Gulf Coast and upper Midwest market centers and allow us to increase utilization of our natural gas processing capacity in Oklahoma.

Additional NGL fractionation capacity, which benefits optimization activities in our Natural Gas Liquids segment, became available on September 1, 2010. Additional capacity also will become available when our fractionation services agreement with Targa Resources Partners begins in the second quarter 2011. As part of our growth projects announced in 2010 and early 2011, the expansion of the Sterling I natural gas liquids distribution pipeline, expected to be completed in the second half of 2011, and our expansion of the Arbuckle Pipeline, expected to be completed in the first half of 2012, will enable the transportation of additional NGLs to the Gulf Coast market.

We expect these projects will increase our fee-based earnings, as well as improve our margins from POP contracts in our Natural Gas Gathering and Processing segment and our exchange and optimization activities in our Natural Gas Liquids segment.

**2009 vs. 2008** - Energy markets were affected by decreased commodity prices during 2009 compared with 2008. The decrease in commodity prices had a direct impact on our revenues and cost of sales and fuel.

Operating income in 2009 decreased 15 percent when compared with 2008, due primarily to lower realized commodity prices in the Natural Gas Gathering and Processing segment and less favorable NGL price differentials and a prior-year operational measurement gain in the Natural Gas Liquids segment. These decreases were offset partially by substantially higher NGL volumes in the Natural Gas Liquids segment, associated primarily with the completion of the Overland Pass Pipeline and related expansion projects and the Arbuckle Pipeline, as well as new NGL supply connections; higher natural gas transportation margins as a result of the completion of the Guardian Pipeline expansion and extension and an increase in contracted volumes on Midwestern Gas Transmission as the result of a new interconnection with the Rockies Express Pipeline in the Natural Gas Pipelines segment; and higher natural gas volumes processed and sold in the Natural Gas Gathering and Processing segment. Additionally, operating costs and depreciation and amortization expense increased for 2009 as compared to 2008 due to higher employee-related costs and incremental costs associated with the capital projects completed at the end of 2008 and in 2009.

Equity earnings from investments decreased due primarily to lower subscription volumes and rates on Northern Border Pipeline due to narrower natural gas price differentials between the markets it serves. Additionally, we benefited from an $8.3 million gain due to Northern Border Pipeline’s sale of Bison Pipeline LLC in 2008.

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.

Allowance for equity funds used during construction and capital expenditures decreased due primarily to the completion of our capital projects in 2009.

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 2010 vs. 2009 | | Variances 2009 vs. 2008 | |
|---|---|---|---|---|---|---|---|
| **Financial Results** | **2010** | **2009** | **2008** | **Increase (Decrease)** | | **Increase (Decrease)** | |
| | *(Millions of dollars)* | | | | | | |
| NGL and condensate sales | **$ 722.6** | $ 578.5 | $ 851.7 | **$ 144.1** | **25%** | $ (273.2) | (32%) |
| Residue gas sales | **446.9** | 363.0 | 750.4 | **83.9** | **23%** | (387.4) | (52%) |
| Gathering, compression, dehydration and processing fees and other revenue | **148.4** | 153.1 | 154.1 | **(4.7)** | **(3%)** | (1.0) | (1%) |
| Cost of sales and fuel | **966.5** | 734.6 | 1,321.0 | **231.9** | **32%** | (586.4) | (44%) |
| Net margin | **351.4** | 360.0 | 435.2 | **(8.6)** | **(2%)** | (75.2) | (17%) |
| Operating costs | **136.8** | 135.1 | 138.2 | **1.7** | **1%** | (3.1) | (2%) |
| Depreciation and amortization | **60.7** | 59.3 | 49.9 | **1.4** | **2%** | 9.4 | 19% |
| Gain (loss) on sale of assets | **(0.3)** | 2.8 | - | **(3.1)** | ***** | 2.8 | 100% |
| Operating income | **$ 153.6** | $ 168.4 | $ 247.1 | **$ (14.8)** | **(9%)** | $ (78.7) | (32%) |
| | | | | | | | |
| Equity earnings from investments | **$ 27.5** | $ 28.4 | $ 32.8 | **$ (0.9)** | **(3%)** | $ (4.4) | (13%) |
| Capital expenditures | **$ 216.0** | $ 105.5 | $ 146.2 | **$ 110.5** | ***** | $ (40.7) | (28%) |

* Percentage change is greater than 100 percent.

**2010 vs. 2009** - Net margin decreased primarily as a result of the following:

- a decrease of $7.8 million due to lower natural gas volumes processed and sold in western Oklahoma and Kansas as a result of natural production declines, operational outages and a period of ethane rejection;
- a decrease of $6.5 million from selling our Lehman Brothers bankruptcy claims in 2009; and
- a decrease of $6.3 million due to lower natural gas volumes gathered as a result of natural production declines and reduced drilling activity by our customers in the Powder River Basin; offset partially by
- an increase of $9.1 million due to higher natural gas volumes gathered and processed in the Williston Basin, primarily due to the increased drilling activity in the Bakken Shale;
- an increase of $2.2 million due to a favorable contract settlement in the third quarter 2010; and
- an increase of $1.3 million due to changes in contract terms.

Capital expenditures increased due primarily to our recently announced capital projects in the Williston Basin. We expect capital expenditures to increase in 2011 as construction continues on these projects. See more detail of our growth projects and projected capital expenditures at "Recent Developments" and "Liquidity and Capital Resources."

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

- a decrease of $106.0 million due to lower net realized commodity prices;
- a decrease of $5.7 million due to lower natural gas volumes gathered as a result of natural production declines and reduced drilling activity by our customers in the Powder River Basin; offset partially by
- an increase of $23.5 million due to higher natural gas volumes gathered and processed in the Williston Basin, due primarily to the increased drilling activity in the Bakken Shale;
- an increase of $6.5 million from selling our Lehman Brothers bankruptcy claims related to receivables owed to us;
- an increase of $4.5 million due to higher natural gas volumes processed and sold in western Oklahoma and Kansas; and
- an increase of $1.8 million due to improved contractual terms.

Operating costs decreased due primarily to $2.6 million in lower chemicals costs and $2.0 million in lower maintenance costs, offset partially by higher employee-related costs.

Depreciation and amortization increased primarily as a result of our Grasslands natural gas processing plant expansion completed in 2009.

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

Capital expenditures decreased due primarily to the completion of a pipeline expansion project into the Cana-Woodford Shale in September of 2008 in Oklahoma and the Grasslands natural gas processing plant expansion completed in March 2009.

**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** | **2010** | **2009** | **2008** |
| Natural gas gathered *(BBtu/d)* (a) | **1,067** | 1,123 | 1,164 |
| Natural gas processed *(BBtu/d)* (a) | **674** | 658 | 641 |
| NGL sales *(MBbl/d)* (a) | **44** | 43 | 39 |
| Residue gas sales *(BBtu/d)* (a) | **286** | 291 | 279 |
| Realized composite NGL net sales price *($/gallon)* (b) | **$ 0.94** | $ 0.90 | $ 1.26 |
| Realized condensate net sales price *($/Bbl)* (b) | **$ 63.81** | $ 78.35 | $ 88.35 |
| Realized residue gas net sales price *($/MMBtu)* (b) | **$ 5.58** | $ 3.55 | $ 7.53 |
| Realized gross processing spread *($/MMBtu)* (a) | **$ 6.41** | $ 6.63 | $ 7.47 |

(a) - Includes volumes for consolidated entities only.

(b) - Presented net of the impact of hedging activities and includes equity volumes only.

| | Years Ended December 31, | | |
|---|---|---|---|
| **Operating Information** (a) | **2010** | **2009** | **2008** |
| **Percent of proceeds** | | | |
| NGL sales *(Bbl/d)* | **6,310** | 5,472 | 4,578 |
| Residue gas sales *(MMBtu/d)* | **41,813** | 41,768 | 39,724 |
| Condensate sales *(Bbl/d)* | **1,763** | 1,735 | 1,693 |
| Percentage of total net margin | **54%** | 50% | 62% |
| **Fee-based** | | | |
| Wellhead volumes *(MMBtu/d)* | **1,067,090** | 1,122,861 | 1,164,273 |
| Average rate *($/MMBtu)* | **$ 0.31** | $ 0.30 | $ 0.26 |
| Percentage of total net margin | **35%** | 35% | 23% |
| **Keep-whole** | | | |
| NGL shrink *(MMBtu/d) (b)* | **13,545** | 17,400 | 21,354 |
| Plant fuel *(MMBtu/d) (b)* | **1,648** | 2,031 | 2,288 |
| Condensate shrink *(MMBtu/d) (b)* | **1,433** | 1,727 | 1,825 |
| Condensate sales *(Bbl/d)* | **290** | 349 | 369 |
| Percentage of total net margin | **11%** | 15% | 15% |

(a) - Includes volumes for consolidated entities only.

(b) - Refers to the Btus that are removed from natural gas through processing.

**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, are provided through keep-whole contracts. See discussion regarding our commodity price risk beginning on page 57 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, 2010 | 2009 | 2008 | Variances 2010 vs. 2009 Increase (Decrease) | | Variances 2009 vs. 2008 Increase (Decrease) | |
|---|---|---|---|---|---|---|---|
| | (Millions of dollars) | | | | | | |
| Transportation revenues | **$ 244.2** | $ 230.6 | $ 240.0 | **$ 13.6** | **6%** | $ (9.4) | (4%) |
| Storage revenues | **67.8** | 62.1 | 63.7 | **5.7** | **9%** | (1.6) | (3%) |
| Gas sales and other revenues | **39.1** | 50.1 | 38.4 | **(11.0)** | **(22%)** | 11.7 | 30% |
| Cost of sales | **50.9** | 57.0 | 84.7 | **(6.1)** | **(11%)** | (27.7) | (33%) |
| Net margin | **300.2** | 285.8 | 257.4 | **14.4** | **5%** | 28.4 | 11% |
| Operating costs | **96.5** | 96.1 | 89.9 | **0.4** | **0%** | 6.2 | 7% |
| Depreciation and amortization | **44.1** | 43.7 | 34.3 | **0.4** | **1%** | 9.4 | 27% |
| Gain (loss) on sale of assets | **3.4** | (0.7) | - | **4.1** | ***** | (0.7) | (100%) |
| Operating income | **$ 163.0** | $ 145.3 | $ 133.2 | **$ 17.7** | **12%** | $ 12.1 | 9% |
| | | | | | | | |
| Equity earnings from investments | **$ 68.8** | $ 41.9 | $ 66.7 | **$ 26.9** | **64%** | $ (24.8) | (37%) |
| Capital expenditures | **$ 27.6** | $ 62.2 | $ 267.0 | **$ (34.6)** | **(56%)** | $ (204.8) | (77%) |

* Percentage change is greater than 100 percent.

| **Operating Information** (a) | Years Ended December 31, 2010 | 2009 | 2008 |
|---|---|---|---|
| Natural gas transportation capacity contracted *(MDth/d) (b)* | **5,616** | 5,507 | 4,835 |
| Transportation capacity subscribed | **87%** | 86% | 83% |
| Average natural gas price | | | |
| Mid-Continent region *($/MMBtu)* | **$ 4.17** | $ 3.28 | $ 7.17 |

(a) - Includes volumes for consolidated entities only.

(b) - Unit of measure converted from MMcf/d in the third quarter of 2010. Prior periods have been recast to reflect this change.

**2010 vs. 2009** - Net margin increased primarily as a result of the following:

- an increase of $8.7 million from higher natural gas transportation margins, excluding retained fuel, primarily as a result of increased capacity contracted on Midwestern Gas Transmission due to a new interconnection with the Rockies Express Pipeline that was placed in service beginning in June 2009; Viking Gas Transmission's Fargo lateral that was completed in October 2009; and the incremental margin from the Guardian Pipeline expansion and extension project that was completed in February 2009; and
- an increase of $3.5 million from higher natural gas storage margins, excluding retained fuel, primarily as a result of contract renegotiations.

Equity earnings from investments increased due primarily to increased contracted capacity on Northern Border Pipeline due to wider natural gas price differentials.

Capital expenditures decreased due primarily to the completion of our capital projects in 2009, including the completion of the Guardian Pipeline extension and expansion, Viking Gas Transmission's Fargo lateral and Midwestern Gas Transmission's interconnect with the Rockies Express Pipeline.

**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 $3.3 million in incremental ad valorem taxes associated with the Guardian Pipeline expansion and extension and a $3.1 million increase in labor costs associated with additional personnel to operate our completed capital projects in 2009.

Depreciation and amortization increased primarily as a result of our capital projects completed in 2009.

Equity earnings from investments decreased due primarily to lower subscription volumes and rates on Northern Border Pipeline due to narrower natural gas price differentials between the markets it serves. Additionally, there was an $8.3 million gain on the sale of Bison Pipeline LLC by Northern Border Pipeline in 2008.

Capital expenditures decreased due primarily to the completion of the Guardian Pipeline extension and expansion in February 2009.

## 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:

| | Years Ended December 31, | | | Variances 2010 vs. 2009 | | Variances 2009 vs. 2008 | |
|---|---|---|---|---|---|---|---|
| **Financial Results** | **2010** | **2009** | **2008** | **Increase (Decrease)** | | **Increase (Decrease)** | |
| | | | | *(Millions of dollars)* | | | |
| NGL and condensate sales | **$ 7,219.0** | $ 4,962.2 | $ 5,943.6 | **$ 2,256.8** | **45%** | $ (981.4) | (17%) |
| Exchange service and storage revenues | **470.9** | 365.1 | 329.1 | **105.8** | **29%** | 36.0 | 11% |
| Transportation revenues | **85.1** | 94.4 | 55.3 | **(9.3)** | **(10%)** | 39.1 | 71% |
| Cost of sales and fuel | **7,275.4** | 4,945.3 | 5,879.3 | **2,330.1** | **47%** | (934.0) | (16%) |
| Net margin | **499.6** | 476.4 | 448.7 | **23.2** | **5%** | 27.7 | 6% |
| Operating costs | **173.9** | 182.2 | 143.1 | **(8.3)** | **(5%)** | 39.1 | 27% |
| Depreciation and amortization | **68.9** | 61.2 | 40.6 | **7.7** | **13%** | 20.6 | 51% |
| Gain (loss) on sale of assets | **15.5** | (0.2) | - | **15.7** | ***** | (0.2) | (100%) |
| Operating income | **$ 272.3** | $ 232.8 | $ 265.0 | **$ 39.5** | **17%** | $ (32.2) | (12%) |
| | | | | | | | |
| Equity earnings from investments | **$ 5.6** | $ 2.5 | $ 2.0 | **$ 3.1** | ***** | $ 0.5 | 25% |
| Allowance for equity funds used during construction | **$ 0.9** | $ 25.3 | $ 36.9 | **$ (24.4)** | **(96%)** | $ (11.6) | (31%) |
| Capital expenditures | **$ 107.9** | $ 446.9 | $ 840.4 | **$ (339.0)** | **(76%)** | $ (393.5) | (47%) |

* Percentage change is greater than 100 percent.

| | Years Ended December 31, | | |
|---|---|---|---|
| **Operating Information** | **2010** | **2009** | **2008** |
| NGL sales *(MBbl/d)* (a) | **457** | 408 | 283 |
| NGLs fractionated *(MBbl/d)* (a) | **512** | 481 | 389 |
| NGLs transported-gathering lines *(MBbl/d)* (a) | **440** | 372 | 260 |
| NGLs transported-distribution lines *(MBbl/d)* (a) | **468** | 459 | 331 |
| Conway-to-Mont Belvieu OPIS average price differential Ethane *($/gallon)* | **$ 0.10** | $ 0.11 | $ 0.15 |

(a) Includes volumes for consolidated entities only.

**2010 vs. 2009** - Net margin increased primarily as a result of the following:

- an increase of $51.4 million due to increased NGL volumes gathered, fractionated and transported, primarily associated with the completion of the Arbuckle Pipeline, Piceance lateral pipeline and D-J Basin lateral pipeline, as well as new supply connections; and
- an increase of $10.9 million due to higher NGL storage margins as a result of contract renegotiations; offset partially by
- a decrease of $34.7 million related to lower optimization margins due to limited fractionation and transportation capacity available for optimization activities between the Mid-Continent and Gulf Coast NGL market centers until September 2010 and less favorable NGL price differentials; and
- a decrease of $4.4 million due to the impact of operational measurement gains and losses in 2010.

Additional NGL fractionation capacity, which benefits optimization activities, became available on September 1, 2010, when a contract at our Mont Belvieu, Texas, fractionator expired. Additional capacity also will become available when a 60,000 barrel-per-day fractionation services agreement with Targa Resources Partners begins in the second quarter 2011. Expansions of the Sterling I natural gas liquids distribution pipeline, expected to be completed in the second half of 2011, and the Arbuckle Pipeline, expected to be completed in the first half of 2012, will enable the transportation of additional NGLs to the Gulf Coast market.

Operating costs decreased due primarily to the following:

- a decrease of $8.2 million resulting from lower than estimated ad valorem taxes associated with our capital projects completed in 2009;
- a decrease of $3.4 million in outside services costs attributable primarily to maintenance projects at our fractionators in 2009; offset partially by
- an increase of $2.3 million in property insurance costs related to increased coverage for our assets; and
- an increase of $1.4 million due primarily to increased employee labor costs resulting from the operations of our capital projects completed in 2009.

Depreciation and amortization increased due primarily to higher depreciation expense associated with our capital projects completed in 2009.

Gain (loss) on sale of assets increased due primarily to the sale of a 49-percent ownership interest in Overland Pass Pipeline Company in September 2010.

Equity earnings from investments increased due primarily to the deconsolidation of Overland Pass Pipeline Company in September 2010.

Allowance for equity funds used during construction and capital expenditures decreased due primarily to the completion of our capital projects in 2009. We expect to record AFUDC on the Bakken Pipeline project in 2011, continuing through the project's completion. See more detail of our growth projects and projected capital expenditures at "Recent Developments" and "Liquidity and Capital Resources".

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

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

Operating costs increased for 2009 due primarily to the following:

- an increase of $22.1 million related to incremental costs for operation of the Overland Pass Pipeline, the Arbuckle Pipeline and the expanded Bushton Plant fractionator;
- an increase of $10.5 million in ad valorem taxes related to our capital projects completed in 2008 and 2009 and higher ad valorem taxes associated with our existing assets; and
- an increase of $5.5 million in outside services costs attributable primarily to maintenance projects at our fractionators and natural gas liquids storage facilities and incremental pipeline-integrity costs on our natural gas

liquids pipelines 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 41.

**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, commercial paper, 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.

In June 2010, we established a commercial paper program providing for the issuance of up to $1.0 billion of unsecured commercial paper notes to fund our short-term borrowing needs. The maturities of our commercial paper notes vary but may not exceed 270 days from the date of issue. Our commercial paper notes are generally sold at a negotiated discount from par. Our Partnership Credit Agreement, which expires in March 2012, is available to repay our commercial paper notes, if necessary. Amounts outstanding under the commercial paper program reduce the borrowings available under our Partnership Credit Agreement.

During 2010, we utilized our Partnership Credit Agreement and our commercial paper program to fund our short-term liquidity needs, and we accessed the public equity markets for our long-term financing needs. See discussion below under “Equity Issuance” for more information.

Our ability to continue to access capital markets for debt and equity financing under reasonable terms depends on our financial condition, credit ratings and market conditions. We anticipate that our cash flow generated from operations, existing capital resources and ability to obtain financing will enable us to maintain our current level of operations and our planned operations, as well as fund our capital expenditures.

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

| | December 31, | |
|---|---|---|
| | **2010** | **2009** |
| Long-term debt | **46%** | 51% |
| Equity | **54%** | 49% |
| Debt (including notes payable) | **50%** | 55% |
| Equity | **50%** | 45% |

**Cash Management** - We use a centralized cash management program that concentrates the cash assets of our operating subsidiaries in joint accounts for the purpose of providing financial flexibility and lowering the cost of borrowing, transaction costs and bank fees. Our centralized cash management program provides that funds in excess of the daily needs of our operating subsidiaries are concentrated, consolidated or made available for use by other entities within our consolidated group. Our operating subsidiaries participate in this program to the extent they are permitted 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, our commercial paper program and our Partnership Credit Agreement.

The total amount of short-term borrowings authorized by our general partner's Board of Directors is $2.5 billion. At December 31, 2010, we had $429.9 million of commercial paper outstanding and no borrowings outstanding under our Partnership Credit Agreement, leaving approximately $570.1 million of credit available under the Partnership Credit Agreement and approximately $0.9 million of available cash and cash equivalents. As of December 31, 2010, we could have issued $1.0 billion of additional short- and long-term debt under the most restrictive provisions contained in our various borrowing agreements. At December 31, 2010, we had $24.2 million in letters of credit issued outside of our Partnership Credit Agreement.

Our Partnership Credit Agreement is available to repay the commercial paper notes, if necessary. Amounts outstanding under the commercial paper program reduce the borrowings available under our Partnership Credit Agreement. In July 2010, we repaid all borrowings outstanding under our Partnership Credit Agreement with proceeds from the issuance of commercial paper.

Our Partnership Credit Agreement contains certain financial, operational and legal covenants as discussed in Note F 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, 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 increase 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, 2010, our ratio of indebtedness to adjusted EBITDA was 3.79 to 1, and we were in compliance with all covenants under our Partnership Credit Agreement. As a result of our January 2011 debt offering, available borrowings are limited by the ratio of indebtedness to adjusted EBITDA covenant under our Partnership Credit Agreement; however, we had approximately $956 million in cash at January 31, 2011, and $266 million of available borrowings that provide ample liquidity to meet our funding needs. We expect the limitation of our available borrowings to be eliminated during 2011.

At December 31, 2010, the weighted-average interest rate on our short-term debt outstanding was 0.38 percent, and the weighted average for the year ended December 31, 2010, was 0.58 percent. Based on the forward LIBOR curve, we expect the interest rates on our short-term borrowings to increase in 2011, compared with interest rates on amounts outstanding at December 31, 2010.

**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.

<u>Debt Maturity</u> - In June 2010, we repaid $250 million of maturing senior notes with available cash and short-term borrowings. With the repayment of these notes, we no longer have any obligation to offer to repurchase the $225 million senior notes due 2011 in the event that our long-term debt credit ratings fall below investment grade.

<u>Equity Issuance</u> - 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 a public offering price of $60.75 per common unit, generating net proceeds of approximately $322.7 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.

<u>Debt Issuance</u> - In January 2011, we completed an underwritten public offering of $1.3 billion senior notes, consisting of $650 million of 3.25-percent senior notes due 2016 and $650 million of 6.125-percent senior notes due 2041. The net proceeds from the offering of approximately $1.28 billion were used to repay amounts outstanding under our commercial paper program, and for general partnership purposes, including capital expenditures, and will be used to repay the $225 million principal amount of senior notes due March 2011.

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, borrowing under our commercial paper program or our existing credit facility, 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.

ONEOK Partners Debt Covenants - The indentures governing our senior notes due March 2011 include an event of default upon acceleration of other indebtedness of $25 million or more, and the indentures governing our other senior notes include an event of default upon the acceleration of other indebtedness of $100 million or more.  Such events of default would entitle the trustee or the holders of 25 percent in aggregate principal amount of the outstanding senior notes to declare those notes immediately due and payable in full.

We may redeem the notes due 2011, 2012, 2016 (6.15 percent), 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.  We may redeem our 3.25-percent senior notes due 2016 and our 6.125-percent senior notes due 2041 at par starting one and six months, respectively, before their maturity dates.  Prior to these times, we may redeem these notes on the same terms as our other senior notes.  Our senior notes are senior unsecured obligations, ranking equally in right of payment with all of our existing and future unsecured senior indebtedness, and structurally subordinate 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** - 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.  Our capital expenditures are typically financed through operating cash flows, short- and long-term debt and the issuance of equity.

Capital expenditures were $352.7 million, $615.7 million and $1,253.9 million for 2010, 2009 and 2008, respectively. Capital expenditures in 2010 were significantly less than 2009 capital expenditures, due primarily to the completion of the Arbuckle Pipeline, the D-J Basin lateral pipeline, Piceance lateral pipeline, the Grasslands natural gas processing plant expansion, and the Guardian Pipeline expansion and extension in our Natural Gas Liquids and Natural Gas Pipelines segments.  This decrease is offset partially by an increase in capital expenditures in our Natural Gas Gathering and Processing segment related primarily to our projects in the Williston Basin.

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

| **Growth Capital Expenditures** | **2010** | **2009** | **2008** |
|---|---|---|---|
| | | *(Millions of dollars)* | |
| Natural Gas Gathering and Processing | **$ 198.4** | $ 85.1 | $ 123.0 |
| Natural Gas Pipelines | **6.1** | 46.9 | 241.0 |
| Natural Gas Liquids | **85.7** | 423.3 | 808.0 |
| Other | **-** | 1.1 | - |
| Total growth capital expenditures | **$ 290.2** | $ 556.4 | $1,172.0 |

| **Maintenance Capital Expenditures** | **2010** | **2009** | **2008** |
|---|---|---|---|
| | | *(Millions of dollars)* | |
| Natural Gas Gathering and Processing | **$ 17.6** | $ 20.4 | $ 23.2 |
| Natural Gas Pipelines | **21.5** | 15.3 | 26.0 |
| Natural Gas Liquids | **22.2** | 23.6 | 32.4 |
| Other | **1.2** | - | 0.3 |
| Total maintenance capital expenditures | **$ 62.5** | $ 59.3 | $ 81.9 |

The following table summarizes our 2011 projected growth and maintenance capital expenditures, excluding AFUDC:

| 2011 Projected Capital Expenditures | Growth | Maintenance | Total |
|---|---|---|---|
| | | *(Millions of dollars)* | |
| Natural Gas Gathering and Processing | $ 514 | $ 30 | $ 544 |
| Natural Gas Pipelines | 9 | 31 | 40 |
| Natural Gas Liquids | 488 | 43 | 531 |
| Other | - | 1 | 1 |
| Total projected capital expenditures | $ 1,011 | $ 105 | $ 1,116 |

Projected 2011 capital expenditures are significantly higher than 2010 capital expenditures due to the announced growth capital expenditures discussed in "Growth Projects" on page 36. We have announced spending of $1.8 billion to $2.1 billion on growth capital expenditures for the years 2011 through 2014. We expect to continue to finance future capital expenditures with a combination of operating cash flows, short- and long-term debt, including proceeds from our January 2011 senior notes issuance, and the issuance of common units.

**Overland Pass Pipeline Company** - In September 2010, we completed a transaction to sell a 49-percent ownership interest in Overland Pass Pipeline Company, resulting in each joint-venture member now owning 50 percent of Overland Pass Pipeline Company. In accordance with the joint-venture agreement, we received approximately $423.7 million in cash at closing. We used the proceeds from the transaction to repay short-term debt and to fund a portion of our recently announced capital projects.

In 2011, we expect to make contributions of approximately $35 million to $40 million for additional pump stations and the expansion of existing pump stations to increase the capacity of Overland Pass Pipeline to accommodate increased volumes of unfractionated NGLs from the Bakken Pipeline and other supply sources under development in the Rockies.

**Other** - 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 necessary for operation and maintenance of the Bushton Plant, and we reimburse ONEOK for OBPI's obligations under equipment leases covering portions of the Bushton Plant. The Bushton equipment leases will expire in 2012, unless, in the second quarter of 2011, OBPI provides irrevocable notice of its intent to either renew the equipment leases at fair market rental value or purchase the original leased equipment (and any replacement parts) pursuant to the terms of the equipment leases. Our Processing and Services Agreement provides that we will reimburse OBPI for amounts incurred in connection with the foregoing option, if any.

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 EBITDA 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 Note K of the Notes to Consolidated Financial Statements in this Annual Report for discussion of our investment in Northern Border Pipeline.

Northern Border Pipeline anticipates requiring an additional equity contribution of approximately $100 million to $120 million from its partners in 2011, of which our share will be approximately $50 million to $60 million based on our 50-percent equity interest.

**Credit Ratings** - Our credit ratings as of December 31, 2010, are shown in the table below:

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

Our commercial paper program is rated Prime-2 by Moody's and A2 by S&P. Our credit ratings, which are currently investment grade, may be affected by a material change in our financial ratios or a material event affecting our business. The most common criteria for assessment of our credit ratings are the debt-to-EBITDA ratio, interest coverage, business risk profile and liquidity. We do not anticipate a downgrade in our credit ratings. However, if our credit ratings were downgraded, our cost to borrow funds under our commercial paper program or Partnership Credit Agreement would increase, and a potential loss of access to the commercial paper market could occur. In the event that we are unable to borrow funds under our commercial paper program and there has not been a material adverse change in our business, we would continue to have access to our Partnership Credit Agreement. An adverse rating change alone is not a default under our Partnership Credit Agreement. See additional discussion about our credit ratings under "Long-term Financing."

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.

**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, | | |
|---|---|---|---|
| | **2010** | **2009** | **2008** |
| | *(Millions of dollars)* | | |
| Common unitholders | **$ 285.7** | $ 247.6 | $ 220.6 |
| Class B unitholders | **162.8** | 158.0 | 153.5 |
| General partner | **114.7** | 94.7 | 78.9 |
| Total cash distributions paid | **$ 563.2** | $ 500.3 | $ 453.0 |

For the years ended December 31, 2010, 2009 and 2008, cash distributions paid to our general partner included incentive distributions of $103.5 million, $84.7 million and $69.9 million, respectively.

In January 2011, our general partner declared a cash distribution of $1.14 per unit ($4.56 per unit on an annualized basis) for the fourth quarter of 2010, which was paid on February 14, 2011, to unitholders of record as of January 31, 2011.

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 57 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 M 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 did not have a material impact on earnings or cash flows during 2010, 2009 and 2008.

## 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, deferred income taxes, 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 2010 vs. 2009 | | Variances 2009 vs. 2008 | |
|---|---|---|---|---|---|---|---|
| | **2010** | **2009** | **2008** | **Increase (Decrease)** | | **Increase (Decrease)** | |
| | | | *(Millions of dollars)* | | | | |
| Total cash provided by (used in): | | | | | | | |
| Operating activities | **$ 495.2** | $ 562.4 | $ 656.4 | **$ (67.2)** | **(12%)** | $ (94.0) | (14%) |
| Investing activities | **92.3** | (618.1) | (1,246.5) | **710.4** | ***** | 628.4 | 50% |
| Financing activities | **(589.7)** | (118.8) | 764.5 | **(470.9)** | ***** | (883.3) | * |
| Change in cash and cash equivalents | **(2.2)** | (174.5) | 174.4 | **172.3** | **(99%)** | (348.9) | * |
| Cash and cash equivalents at beginning of period | **3.1** | 177.6 | 3.2 | **(174.5)** | **(98%)** | 174.4 | * |
| Cash and cash equivalents at end of period | **$ 0.9** | $ 3.1 | $ 177.6 | **$ (2.2)** | **(71%)** | $ (174.5) | (98%) |

* 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>2010 vs. 2009</u> - Cash flows from operating activities, before changes in operating assets and liabilities, were $633.3 million for 2010, compared with $583.7 million for 2009. The increase was due primarily to changes in net margin and operating expenses discussed under Financial Results and Operating Information in Item 7, Management’s Discussion and Analysis of Financial Condition and Results of Operations, in this Annual Report.

The changes in operating assets and liabilities decreased operating cash flows $138.1 million for 2010, compared with a decrease of $21.2 million for 2009, primarily as a result of the impact of commodity prices on our operating assets and liabilities and an increase in volumes of commodities in storage primarily in our Natural Gas Liquids segment.

<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 impact of commodity prices on our operating assets and liabilities and the changes in volumes of commodities in storage.

**Investing Cash Flows** - Cash provided by investing activities increased significantly in 2010, compared with 2009, due primarily to the $423.7 million in proceeds received from the sale of a 49-percent interest in Overland Pass Pipeline Company, reduced capital expenditures as a result of our capital projects completed in 2009 and reduced contributions to unconsolidated affiliates, offset partially by reduced distributions received from unconsolidated affiliates.

Cash used in investing activities decreased for 2009, compared with 2008, due primarily to reduced capital expenditures as a result of the completion of our capital projects in 2009.

**Financing Cash Flows** - Cash used in financing activities increased for 2010 compared with 2009, due primarily to decreased borrowings resulting from the completion our capital projects in 2009, repayment of $250 million of maturing senior notes in 2010, increased cash distributions to our general and limited partners resulting from additional units outstanding resulting from our February 2010 equity offering and an approximate 3.0 percent increase in distributions per limited partner unit paid in 2010, compared with 2009, offset partially by increased net proceeds generated from our common unit offering in 2010.

Cash used in financing activities decreased for 2009 compared with 2008 due primarily to decreased borrowings resulting from the completion of our capital projects in 2009, and decreased net proceeds generated from our common unit offering in 2009, compared with 2008, offset partially by increased distributions to our general and limited partners.

## 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, 2010. For additional discussion of the debt and operating lease agreements, see Notes G and M, respectively, of the Notes to Consolidated Financial Statements in this Annual Report.

| | Payments Due by Period | | | | | | |
|---|---|---|---|---|---|---|---|
| **Contractual Obligations** | **Total** | **2011** | **2012** | **2013** | **2014** | **2015** | **Thereafter** |
| **ONEOK Partners** | | | | *(Thousands of dollars)* | | | |
| Commercial paper | $ 429,855 | $ 429,855 | $ - | $ - | $ - | $ - | $ - |
| 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 | 97,850 | 11,931 | 11,062 | 7,650 | 7,650 | 7,650 | 51,907 |
| **Interest payments on debt** | 2,697,300 | 183,100 | 163,400 | 157,500 | 156,000 | 154,300 | 1,883,000 |
| **Operating leases** | 37,303 | 14,892 | 7,812 | 2,932 | 2,513 | 996 | 8,158 |
| **Firm transportation and storage contracts** | 42,688 | 6,487 | 6,784 | 6,658 | 6,268 | 6,081 | 10,410 |
| **Financial and physical derivatives** | 154,524 | 154,524 | - | - | - | - | - |
| **Purchase commitments, rights of way and other** | 449,941 | 174,784 | 66,577 | 25,911 | 25,905 | 25,629 | 131,135 |
| **Total** | $6,634,461 | $1,200,573 | $ 605,635 | $ 200,651 | $ 198,336 | $ 194,656 | $4,234,610 |

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 natural gas processing, fractionation 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, fractionation 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, 2010, 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, rights of way and other - Purchase commitments include commitments related to our growth capital expenditures and other rights-of-way and contractual commitments. Purchase commitments exclude commodity purchase contracts, which are included in the “Financial and physical derivatives” amounts.

**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, as amended, 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, including climate change, 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 and authorized rates of recovery of natural gas and natural 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 the parent of our general partner;
- the results of administrative proceedings and litigation, regulatory actions, rule changes and receipt of expected clearances involving the OCC, KCC, Texas regulatory authorities or any other local, state or federal regulatory body, including the FERC, the Pipeline and Hazardous Materials Safety Administration and EPA;
- 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 United States economy or the risk of delay in growth recovery in the United States economy, including liquidity risks in United States 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 our 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 values 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.

### 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 contracts. We are also exposed to the risk of locational price differentials and the cost of third-party transportation to 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, 2010, we had $17.6 million of derivative assets and $6.5 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 21, 2011:

| | Year Ending December 31, 2011 | | |
|---|---|---|---|
| | **Volumes Hedged** | **Average Price** | **Percentage Hedged** |
| NGLs *(Bbl/d)* (a) | 5,469 | $1.17 / gallon | 67% |
| Condensate *(Bbl/d)* (a) | 1,713 | $2.13 / gallon | 75% |
| Total *(Bbl/d)* | 7,182 | $1.40 / gallon | 69% |
| Natural gas *(MMBtu/d)* | 24,596 | $5.61 / MMBtu | 74% |

(a) - Hedged with fixed-price swaps.

| | Year Ending December 31, 2012 | | |
|---|---|---|---|
| | **Volumes Hedged** | **Average Price** | **Percentage Hedged** |
| NGLs *(Bbl/d)* (a) | 513 | $2.34 / gallon | 4% |
| Condensate *(Bbl/d)* (a) | 1,245 | $2.34 / gallon | 50% |
| Total *(Bbl/d)* | 1,758 | $2.34 / gallon | 12% |

(a) - Hedged with fixed-price swaps.

Our Natural Gas Gathering and Processing segment's commodity price risk is estimated as a hypothetical change in the price of NGLs, crude oil and natural gas at December 31, 2010, 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 change in the composite price of NGLs would change annual net margin by approximately \$1.2 million;
- a \$1.00 per barrel change in the price of crude oil would change annual net margin by approximately \$1.1 million; and
- a \$0.10 per MMBtu change in the price of natural gas would change annual net margin by approximately \$1.1 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 transport NGL products between the Mid-Continent and Gulf Coast NGL market centers in order to capture the locational price differentials. Our NGL storage facilities are also utilized to capture seasonal price differentials. We utilize fixed-price physical forward contracts to reduce earnings volatility related to NGL price fluctuations in our storage and optimization activities. 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 retain 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, 2010, there were no hedges in place with respect to natural gas price risk from our intrastate and interstate pipeline operations.

See Note C 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.

## 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 may be used to reduce our risk of increased interest costs during periods of rising interest rates. Floating-rate swaps may be used to convert the fixed rates of long-term borrowings into short-term variable rates. At December 31, 2010, the interest rate on all of our long-term debt was fixed, and we had no interest-rate swaps.

## 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, changes in 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, 2010 and 2009, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2010, in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Partnership maintained, in all material respects, effective internal control over financial reporting as of December 31, 2010, based on criteria established in *Internal Control - Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The 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, 2010. Our responsibility is to express opinions on these financial statements and on the Partnership's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

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 22, 2011

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

| | Years Ended December 31, | | |
|---|---|---|---|
| | **2010** | **2009** | **2008** |
| | *(Thousands of dollars, except per unit amounts)* | | |
| **Revenues** | **$ 8,675,900** | $ 6,474,491 | $ 7,720,206 |
| Cost of sales and fuel | **7,531,047** | 5,355,194 | 6,579,547 |
| Net margin | **1,144,853** | 1,119,297 | 1,140,659 |
| **Operating expenses** | | | |
| Operations and maintenance | **363,482** | 361,608 | 337,526 |
| Depreciation and amortization | **173,708** | 164,136 | 124,765 |
| General taxes | **39,994** | 49,619 | 34,271 |
| Total operating expenses | **577,184** | 575,363 | 496,562 |
| Gain on sale of assets | **18,632** | 2,668 | 713 |
| **Operating income** | **586,301** | 546,602 | 644,810 |
| Equity earnings from investments (Note K) | **101,880** | 72,722 | 101,432 |
| Allowance for equity funds used during construction | **1,018** | 26,868 | 50,906 |
| Other income | **6,009** | 10,658 | 5,621 |
| Other expense | **(2,511)** | (3,167) | (13,321) |
| Interest expense | **(204,307)** | (206,016) | (151,056) |
| Income before income taxes | **488,390** | 447,667 | 638,392 |
| Income taxes (Note J) | **(15,082)** | (12,963) | (12,335) |
| Net income | **473,308** | 434,704 | 626,057 |
| Less: Net income attributable to noncontrolling interests | **606** | 348 | 441 |
| **Net income attributable to ONEOK Partners, L.P.** | **$ 472,702** | $ 434,356 | $ 625,616 |
| | | | |
| Limited partners' interest in net income: | | | |
| Net income attributable to ONEOK Partners, L.P. | **$ 472,702** | $ 434,356 | $ 625,616 |
| General partner's interest in net income | **(118,165)** | (96,421) | (88,554) |
| Limited partners' interest in net income | **$ 354,537** | $ 337,935 | $ 537,062 |
| | | | |
| Limited partners' net income per unit, basic and diluted (Note I) | **$ 3.50** | $ 3.60 | $ 6.01 |
| | | | |
| Number of units used in computation (*thousands*) | **101,369** | 93,808 | 89,309 |

See accompanying Notes to Consolidated Financial Statements.

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

| | December 31, 2010 | December 31, 2009 |
|---|---|---|
| **Assets** | *(Thousands of dollars)* | |
| **Current assets** | | |
| Cash and cash equivalents | **$ 898** | $ 3,151 |
| Accounts receivable, net | **815,141** | 624,635 |
| Affiliate receivables | **5,161** | 32,397 |
| Gas and natural gas liquids in storage | **317,159** | 217,585 |
| Commodity imbalances | **92,353** | 188,177 |
| Other current assets | **48,060** | 36,148 |
| Total current assets | **1,278,772** | 1,102,093 |
| **Property, plant and equipment** | | |
| Property, plant and equipment | **5,857,000** | 6,353,909 |
| Accumulated depreciation and amortization | **1,099,548** | 972,497 |
| Net property, plant and equipment (Note D) | **4,757,452** | 5,381,412 |
| **Investments and other assets** | | |
| Investments in unconsolidated affiliates (Note K) | **1,188,124** | 765,163 |
| Goodwill and intangible assets (Note E) | **661,204** | 668,870 |
| Other assets | **34,548** | 35,721 |
| Total investments and other assets | **1,883,876** | 1,469,754 |
| Total assets | **$ 7,920,100** | $ 7,953,259 |
| **Liabilities and equity** | | |
| **Current liabilities** | | |
| Current maturities of long-term debt (Note G) | **$ 236,931** | $ 261,931 |
| Notes payable (Note F) | **429,855** | 523,000 |
| Accounts payable | **852,330** | 694,290 |
| Affiliate payables | **29,765** | 21,866 |
| Commodity imbalances | **291,110** | 392,688 |
| Other current liabilities | **134,151** | 153,539 |
| Total current liabilities | **1,974,142** | 2,047,314 |
| **Long-term debt, excluding current maturities (Note G)** | **2,581,572** | 2,822,086 |
| **Deferred credits and other liabilities** | **87,393** | 73,798 |
| **Commitments and contingencies (Note M)** | | |
| **Equity** | | |
| ONEOK Partners, L.P. partners' equity: | | |
| General partner | **94,691** | 84,434 |
| Common units: 65,413,677 and 59,912,777 units issued and outstanding at December 31, 2010 and December 31, 2009, respectively | **1,825,521** | 1,561,762 |
| Class B units: 36,494,126 units issued and outstanding at December 31, 2010 and December 31, 2009 | **1,345,322** | 1,380,299 |
| Accumulated other comprehensive income (loss) | **6,283** | (22,037) |
| Total ONEOK Partners, L.P. partners' equity | **3,271,817** | 3,004,458 |
| Noncontrolling interests in consolidated subsidiaries | **5,176** | 5,603 |
| Total equity | **3,276,993** | 3,010,061 |
| Total liabilities and equity | **$ 7,920,100** | $ 7,953,259 |

See accompanying Notes to Consolidated Financial Statements.

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

| | Years Ended December 31, | | |
|---|---|---|---|
| | **2010** | **2009** | **2008** |
| | *(Thousands of dollars)* | | |
| **Operating Activities** | | | |
| Net income | **$ 473,308** | $ 434,704 | $ 626,057 |
| Depreciation and amortization | **173,708** | 164,136 | 124,765 |
| Allowance for equity funds used during construction | **(1,018)** | (26,868) | (50,906) |
| Gain on sale of assets | **(18,632)** | (2,668) | (713) |
| Deferred income taxes | **10,824** | 11,707 | 5,015 |
| Equity earnings from investments | **(101,880)** | (72,722) | (101,432) |
| Distributions received from unconsolidated affiliates | **96,958** | 75,377 | 93,261 |
| Changes in assets and liabilities: | | | |
| Accounts receivable | **(196,293)** | (308,703) | 256,137 |
| Affiliate receivables | **27,236** | (6,621) | 26,703 |
| Gas and natural gas liquids in storage | **(100,167)** | (26,969) | 16,003 |
| Accounts payable | **138,900** | 233,921 | (273,475) |
| Affiliate payables | **7,899** | (1,467) | 5,035 |
| Commodity imbalances, net | **(5,754)** | 68,432 | (33,979) |
| Other assets and liabilities | **(9,885)** | 20,180 | (36,053) |
| Cash provided by operating activities | **495,204** | 562,439 | 656,418 |
| **Investing Activities** | | | |
| Contributions to unconsolidated affiliates | **(1,331)** | (46,461) | (20,786) |
| Distributions received from unconsolidated affiliates | **17,847** | 34,430 | 24,749 |
| Acquisitions | **-** | - | 2,450 |
| Capital expenditures (less allowance for equity funds used during construction) | **(352,714)** | (615,691) | (1,253,853) |
| Proceeds from sale of assets | **428,485** | 9,572 | 990 |
| Cash provided by (used in) investing activities | **92,287** | (618,150) | (1,246,450) |
| **Financing Activities** | | | |
| Cash distributions: | | | |
| General and limited partners | **(563,184)** | (500,253) | (453,021) |
| Noncontrolling interests | **(1,005)** | (686) | (302) |
| Borrowing (repayment) of notes payable, net | **(93,145)** | 523,000 | (100,000) |
| Borrowing (repayment) of notes payable with maturities over 90 days | **-** | (870,000) | 870,000 |
| Issuance of long-term debt, net of discounts | **-** | 498,325 | - |
| Long-term debt financing costs | **-** | (4,000) | - |
| Repayment of long-term debt | **(261,931)** | (11,931) | (11,929) |
| Issuance of common units, net of discounts | **322,701** | 241,642 | 450,198 |
| Contribution from general partner | **6,820** | 5,130 | 9,508 |
| Cash provided by (used in) financing activities | **(589,744)** | (118,773) | 764,454 |
| Change in cash and cash equivalents | **(2,253)** | (174,484) | 174,422 |
| Cash and cash equivalents at beginning of period | **3,151** | 177,635 | 3,213 |
| Cash and cash equivalents at end of period | **$ 898** | $ 3,151 | $ 177,635 |
| Supplemental cash flow information: | | | |
| Cash paid for interest, net of amounts capitalized | **$ 206,706** | $ 201,773 | $ 148,417 |
| Cash paid for income taxes | **$ 7,215** | $ 5,248 | $ 4,722 |

See accompanying Notes to Consolidated Financial Statements.

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

| | ONEOK Partners, L.P. Partners' Equity | | | |
|---|---|---|---|---|
| | **Common Units** | **Class B Units** | **General Partner** | **Common Units** |
| | *(Units)* | | *(Thousands of dollars)* | |
| January 1, 2008 | 46,397,214 | 36,494,126 | $ 58,415 | $ 814,266 |
| Net income | - | - | 88,554 | 317,226 |
| Other comprehensive income | - | - | - | - |
| Issuance of common units (Note H) | 8,028,873 | - | - | 450,198 |
| Contribution from general partner (Note H) | - | - | 9,508 | - |
| Distributions paid (Note H) | - | - | (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 | - | - | - | - |
| Issuance of common units (Note H) | 5,486,690 | - | - | 241,642 |
| Contribution from general partner (Note H) | - | - | 5,130 | - |
| Distributions paid (Note H) | - | - | (94,663) | (247,571) |
| December 31, 2009 | 59,912,777 | 36,494,126 | 84,434 | 1,561,762 |
| Net income | **-** | **-** | **118,165** | **226,752** |
| Other comprehensive income | **-** | **-** | **-** | **-** |
| Issuance of common units (Note H) | **5,500,900** | **-** | **-** | **322,701** |
| Contribution from general partner (Note H) | **-** | **-** | **6,820** | **-** |
| Distributions paid (Note H) | **-** | **-** | **(114,728)** | **(285,694)** |
| Other | **-** | **-** | **-** | **-** |
| **December 31, 2010** | **65,413,677** | **36,494,126** | **$ 94,691** | **$ 1,825,521** |

See accompanying Notes to Consolidated Financial Statements.

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

| | ONEOK Partners, L.P. Partners' Equity | | | | |
|---|---|---|---|---|---|
| | **Class B Units** | **Accumulated Other Comprehensive Income (Loss)** | **Noncontrolling Interests in Consolidated Subsidiaries** | **Total Equity** |
| | | *(Thousands of dollars)* | | |
| January 1, 2008 | $ 1,340,638 | $ (18,141) | $ 5,802 | $ 2,200,980 |
| Net income | 219,836 | - | 441 | 626,057 |
| Other comprehensive income | - | 82,546 | - | 82,546 |
| Issuance of common units (Note H) | - | - | - | 450,198 |
| Contribution from general partner (Note H) | - | - | - | 9,508 |
| Distributions paid (Note H) | (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 | - | (86,442) | - | (86,442) |
| Issuance of common units (Note H) | - | - | - | 241,642 |
| Contribution from general partner (Note H) | - | - | - | 5,130 |
| Distributions paid (Note H) | (158,019) | - | (686) | (500,939) |
| December 31, 2009 | 1,380,299 | (22,037) | 5,603 | 3,010,061 |
| Net income | **127,785** | **-** | **606** | **473,308** |
| Other comprehensive income | **-** | **28,320** | **-** | **28,320** |
| Issuance of common units (Note H) | **-** | **-** | **-** | **322,701** |
| Contribution from general partner (Note H) | **-** | **-** | **-** | **6,820** |
| Distributions paid (Note H) | **(162,762)** | **-** | **(1,005)** | **(564,189)** |
| Other | **-** | **-** | **(28)** | **(28)** |
| **December 31, 2010** | **$ 1,345,322** | **$ 6,283** | **$ 5,176** | **$ 3,276,993** |

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

| | Years Ended December 31, | | |
|---|---|---|---|
| | **2010** | **2009** | **2008** |
| | *(Thousands of dollars)* | | |
| Net income | **$ 473,308** | $434,704 | $ 626,057 |
| Other comprehensive income (loss) | | | |
| Unrealized gains (losses) on derivatives | **31,296** | (33,306) | 68,159 |
| Less: Realized gains (losses) on derivatives recognized in net income | **2,976** | 53,348 | (14,387) |
| Other | **-** | 212 | - |
| Total other comprehensive income (loss) | **28,320** | (86,442) | 82,546 |
| Comprehensive income | **501,628** | 348,262 | 708,603 |
| Less: Comprehensive income attributable to noncontrolling interests | **606** | 348 | 441 |
| **Comprehensive income attributable to ONEOK Partners, L.P.** | **$ 501,022** | $347,914 | $ 708,162 |

See accompanying 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. 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 that contains the NGL-rich Cana-Woodford Shale formation 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 includes the oil-producing, NGL-rich Bakken Shale and Three Forks formations, 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 natural gas, that does not require processing or NGL extraction in order to be marketable; dry natural gas is gathered, compressed and delivered into a downstream pipeline or market for a fee.

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

- Midwestern Gas Transmission, which is a bi-directional system that interconnects with Tennessee Gas Transmission Company's pipeline near Portland, Tennessee, and with several interstate pipelines near Joliet, Illinois;
- Viking Gas Transmission, which transports natural gas from an interconnection with a TransCanada pipeline near Emerson, Manitoba, to an interconnection with ANR Pipeline Company near Marshfield, Wisconsin;
- Guardian Pipeline, which interconnects with several pipelines near 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.

Our natural gas pipelines serve primarily local distribution companies, large industrial companies, municipalities, irrigation customers, power-generation facilities and marketing companies.

We own underground natural gas storage facilities in Oklahoma, Kansas and Texas, which are connected to our intrastate natural gas pipeline assets.

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 or have an ownership interest in 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 natural gas liquids gathering systems.

**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 K for disclosures of our unconsolidated affiliates.

Distributions paid to us from our unconsolidated affiliates 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 Statements of Cash Flows.

**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.

**Fair Value Measurements -** Determining Fair Value - We define fair value as the price that would be received from the sale of an asset or the transfer of 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 prices. 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 using the interest rate-yields to calculate present-value discount factors derived from LIBOR, Eurodollar futures and United States treasury swaps. Finally, we consider the credit risk of our counterparties with whom our derivative assets and liabilities are executed. Although we use our best estimates to determine the fair value of the derivative contracts we have executed, the ultimate market prices realized could differ from our estimates, and the differences could be significant.

Fair Value Hierarchy - At each balance sheet date, we utilize a fair value hierarchy to classify fair value amounts recognized or disclosed in our financial statements based on the observability of inputs used to estimate such fair value. The levels of the hierarchy 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.

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.

See Note B for discussion of our fair value measurements.

**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.

**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. A portion of our 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.

**Accounts Receivable** - 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. At December 31, 2010 and 2009, our allowance for doubtful accounts was not material.

**Inventory** - 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.

**Derivatives and Risk Management** - We utilize derivatives to reduce our market risk exposure to commodity price and interest rate fluctuations and to 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.

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 may also be 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 an effectiveness 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.

The realized revenues and purchase costs of our derivative instruments not considered held for trading purposes and derivatives that qualify as normal purchases or normal sales that are expected to result in physical delivery are reported on a gross basis.

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

**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 2010, 2009 and 2008 were $3.8 million, $16.1 million and $36.1 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, 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 process 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 process when they are substantially complete and ready for their intended use.

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

**Impairment of Goodwill and Long-Lived Assets, including Intangible Assets** - We assess our goodwill for impairment at least annually as of July 1. 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. There were no impairment charges resulting from our 2010, 2009 or 2008 impairment tests.

To estimate the fair value of our reporting units, we use two generally accepted valuation approaches, an income approach and a market approach, using assumptions consistent with a market participant's perspective. 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 discount rates. Under the market approach, we apply multiples to forecasted cash flows. The multiples used are consistent with historical asset transactions. The forecasted cash flows are based on average forecasted cash flows for a reporting unit over a period of years.

We assess our long-lived assets, including intangible assets with finite useful lives, for impairment whenever events or changes in circumstances indicate that an asset's carrying amount may not be recoverable. 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. If an impairment is indicated, we record an impairment loss equal to the difference between the carrying value and the fair value of the long-lived asset. We determined that there were no asset impairments in 2010, 2009 or 2008.

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 2010, 2009 or 2008.

Our impairment tests require the use of assumptions and estimates such as industry economic factors and profitability of future business strategies. 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 future impairment charges.

See Notes D and E for our goodwill and long-lived assets disclosures.

**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, 2010 and 2009, we recorded regulatory assets of approximately $10.5 million and $11.7 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.

**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.

We utilize 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 2010, 2009 and 2008, our tax positions did not require an establishment of a material reserve.

We file numerous consolidated and separate income tax returns with federal tax authorities of the United States and Canada along with the tax authorities of several states. There are no United States federal audits or statute waivers at this time. See J for additional discussion of income taxes.

**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. We are not able to reasonably estimate the fair value of the asset retirement obligations for portions of our assets because the settlement dates are indeterminable. For our assets that we are able to make an estimate, 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 accretion expense are 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.

**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 a 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 M for additional discussion of contingencies.

**Recently Issued Accounting Standards Update -** In January 2010, the FASB issued ASU 2010-06, "Improving Disclosures about Fair Value Measurements," which established new disclosure requirements and clarified existing requirements for disclosures of fair value measurements. ASU 2010-06 requires us to add two new disclosures, when applicable: (i) transfers in and out of Level 1 and 2 fair value measurements including the reasons for the transfers, and (ii) a gross presentation of activity within the reconciliation of Level 3 fair value measurements. Except for separate disclosure of purchases, sales, issuances and settlements in the reconciliation of our Level 3 fair value measurements, we applied this guidance in 2010. The separate disclosure of purchases, sales, issuances and settlements in the reconciliation of our Level 3 fair value measurements will be required beginning with our March 31, 2011, Quarterly Report. We do not expect the impact to be material. ASU 2010-06 requires prospective application in the period of adoption, and we have not recast our prior-year disclosures. See Note B for more discussion of our fair value measurements.

## B. FAIR VALUE MEASUREMENTS

**Recurring Fair Value Measurements** - The following tables set forth our recurring fair value measurements for the periods indicated:

| | December 31, 2010 | | | | | |
|---|---|---|---|---|---|---|
| | **Level 1** | **Level 2** | **Level 3** | **Total - Gross** | **Netting (a)** | **Total - Net (b)** |
| | | | *(Thousands of dollars)* | | | |
| **Derivatives - commodity** | | | | | | |
| Assets | $ - | **$ 15,305** | **$ 2,311** | **$ 17,616** | **$ (6,516)** | **$ 11,100** |
| Liabilities | $ - | **$ (5,361)** | **$ (1,155)** | **$ (6,516)** | **$ 6,516** | **$ -** |

| | December 31, 2009 | | | | | |
|---|---|---|---|---|---|---|
| | **Level 1** | **Level 2** | **Level 3** | **Total - Gross** | **Netting (a)** | **Total - Net (c)** |
| | | | *(Thousands of dollars)* | | | |
| **Derivatives - commodity** | | | | | | |
| Assets | $ - | $ 459 | $ - | $ 459 | $ (459) | $ - |
| Liabilities | $ - | $ (5,720) | $ (13,052) | $ (18,772) | $ 459 | $ (18,313) |

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

At December 31, 2010 and 2009, we had no cash collateral held or posted under our master netting arrangements.

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 NGL products, natural gas basis swaps and certain physical forward contracts for NGL products. These instruments 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.

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

| Derivative Assets (Liabilities) | Years Ended December 31, 2010 | 2009 |
|---|---|---|
| | *(Thousands of dollars)* | |
| Net assets (liabilities) at beginning of period | **$ (13,052)** | $ 37,649 |
| Total realized/unrealized gains (losses): | | |
| Included in earnings (a) | **885** | 5,074 |
| Included in other comprehensive income (loss) | **13,323** | (55,775) |
| Net assets (liabilities) at end of period | **$ 1,156** | $ (13,052) |
| 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) | **$ 885** | $ - |

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

**Other Financial Instruments** - The approximate fair value of cash and cash equivalents, accounts receivable, accounts payable and notes payable is equal to book value, due to the short-term nature of these items.

The estimated fair value of the aggregate of our senior notes outstanding, including current maturities, was $3.1 billion and $3.3 billion at December 31, 2010 and 2009, respectively. The book value of the aggregate of our senior notes outstanding, including current maturities, was $2.8 billion and $3.1 billion at December 31, 2010 and 2009, respectively. The estimated fair value of the aggregate of our senior notes outstanding was determined using quoted market prices for similar issues with similar terms and maturities.

## C. 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 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 production 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 retain 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, 2010 and 2009, there were no 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 physical forward contracts to reduce the impact of price fluctuations related to NGLs. At December 31, 2010 and 2009, there were no financial derivative instruments with respect to our NGL operations.

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, 2010 and 2009, 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 B for a discussion of the inputs associated with our fair value measurements and our fair value hierarchy disclosures. The following table sets forth, the fair values of our derivative instruments for the periods indicated:

| | **December 31, 2010** | | **December 31, 2009** | |
|---|---|---|---|---|
| | **Assets (a)** | **(Liabilities) (b)** | **Assets (a)** | **(Liabilities) (b)** |
| | *(Thousands of dollars)* | | | |
| **Commodity derivatives designated as hedging instruments - financial** | **$ 13,782** | **$ (3,556)** | $ 459 | $ (18,772) |
| **Commodity derivatives not designated as hedging instruments** | | | | |
| Financial | **2,218** | **(2,960)** | - | - |
| Physical | **1,616** | **-** | - | - |
| Total derivatives not designated as hedging instruments | **3,834** | **(2,960)** | - | - |
| Total derivatives | **$ 17,616** | **$ (6,516)** | $ 459 | $ (18,772) |

(a) - Included on a net basis in other current assets and other assets on our Consolidated Balance Sheets.
(b) - Included on a net basis in other current liabilities on our Consolidated Balance Sheets.

**Notional Quantities for Derivative Instruments** - The following table sets forth the notional quantities for derivative instruments held for the periods indicated:

| | Contract Type | December 31, 2010 Purchased/ Payor | December 31, 2010 Sold/ Receiver | December 31, 2009 Purchased/ Payor | December 31, 2009 Sold/ Receiver |
|---|---|---|---|---|---|
| **Derivatives designated as hedging instruments:** | | | | | |
| Cash flow hedges | | | | | |
| Fixed price | | | | | |
| - Natural gas *(Bcf)* | Swaps | **-** | **(8.2)** | - | (9.2) |
| - Crude oil and NGLs *(MMBbl)* | Swaps | **-** | **(1.5)** | - | (2.4) |
| Basis | | | | | |
| - Natural gas *(Bcf)* | Swaps | **-** | **(8.2)** | - | (9.2) |
| **Derivatives not designated as hedging instruments:** | | | | | |
| Fixed price | | | | | |
| - Natural gas *(Bcf)* | Swaps | **2.6** | **(2.6)** | - | - |
| - Crude oil and NGLs *(MMBbl)* | Forwards and Swaps | **0.6** | **(0.6)** | - | - |
| Basis | | | | | |
| - Natural gas *(Bcf)* | Swaps | **2.6** | **(2.6)** | - | - |

**Cash Flow Hedges** - At December 31, 2010, our Consolidated Balance Sheets reflected a net unrealized gain of $10.2 million in accumulated other comprehensive income (loss), with a corresponding offset in derivative financial instrument assets and liabilities that will be realized 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):

| **Derivatives in Cash Flow Hedging Relationships** | **Years Ended December 31, 2010** | **2009** |
|---|---|---|
| | *(Thousands of dollars)* | |
| Commodity contracts | **$ 31,296** | $ (34,905) |
| Interest rate contracts | **-** | 1,599 |
| Total gain recognized in other comprehensive income (loss) (effective portion) | **$ 31,296** | $ (33,306) |

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

| **Derivatives in Cash Flow Hedging Relationships** | **Location of Gain (Loss) Reclassified from Accumulated Other Comprehensive Income (Loss) into Net Income (Effective Portion)** | **Years Ended December 31, 2010** | **2009** |
|---|---|---|---|
| | | *(Thousands of dollars)* | |
| Commodity contracts | Revenues | **$ 2,949** | $ 52,108 |
| Interest-rate contracts | Interest expense | **27** | 1,240 |
| Total gain (loss) reclassified from accumulated other comprehensive income (loss) into net income (effective portion) | | **$ 2,976** | $ 53,348 |

Ineffectiveness related to our cash flow hedges was not material for 2010, 2009 and 2008. 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 2010, 2009 and 2008.

The balance in accumulated other comprehensive income in our Consolidated Balance Sheets at December 31, 2010 and 2009, was attributable to unrealized gains and losses on derivatives.

**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 2010, 2009 and 2008 from amortization of terminated swaps was $3.7 million each year, with the remaining $0.9 million of terminated swaps to be amortized in 2011.

**Credit Risk** - All of our commodity derivative financial contracts are with ONEOK Energy Services Company, L.P. (OES), a subsidiary of ONEOK. OES has entered similar commodity derivative financial 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 it may incur solely as a result of its entering into commodity derivative financial contracts on our behalf. Derivative assets for which we would indemnify OES in the event of a default by the counterparty totaled $9.5 million at December 31, 2010, and were with investment-grade counterparties that are primarily in the oil and gas and financial services sectors. At December 31, 2009, there were no derivative assets for which we would indemnify OES in the event of a default by the counterparty.

## D. 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, 2010 | December 31, 2009 |
|---|---|---|---|
| | | *(Thousands of dollars)* | |
| **Non-Regulated** | | | |
| Gathering pipelines and related equipment | 5 to 46 | **$ 1,144,753** | $ 982,849 |
| Processing and fractionation and related equipment | 5 to 42 | **993,100** | 959,339 |
| Storage and related equipment | 5 to 54 | **263,125** | 219,898 |
| Transmission pipelines and related equipment | 15 to 54 | **198,373** | 190,734 |
| General plant and other | 2 to 42 | **63,021** | 71,860 |
| Construction work in process | - | **212,395** | 160,896 |
| **Regulated** | | | |
| Storage and related equipment | 5 to 54 | **133,314** | 134,934 |
| Natural gas transmission pipelines and related equipment | 5 to 80 | **1,380,598** | 1,383,210 |
| Natural gas liquids transmission pipelines and related equipment | 5 to 80 | **1,351,245** | 2,138,017 |
| General plant and other | 2 to 53 | **48,048** | 44,588 |
| Construction work in process | - | **69,028** | 67,584 |
| Property, plant and equipment | | **5,857,000** | 6,353,909 |
| Accumulated depreciation and amortization - non-regulated | | **(638,756)** | (557,713) |
| Accumulated depreciation and amortization - regulated | | **(460,792)** | (414,784) |
| Net property, plant and equipment | | **$ 4,757,452** | $ 5,381,412 |

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, | | |
|---|---|---|---|
| | 2010 | 2009 | 2008 |
| Natural Gas Pipelines | **2.2%** | 2.2% | 2.4% |
| Natural Gas Liquids | **1.9%** | 1.8% | 2.0% |

## E. GOODWILL AND INTANGIBLE ASSETS

**Goodwill** - The following table sets forth our goodwill, by segment, at both December 31, 2010 and 2009:

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

**Intangible Assets** - Our intangible assets relate primarily to contracts acquired through acquisitions in our Natural Gas Liquids segment, which are being amortized over an aggregate weighted-average period of 40 years. Amortization expense for intangible assets for 2010, 2009 and 2008 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. The following table reflects the gross carrying amount and accumulated amortization of intangible assets for the periods presented:

| | **December 31, 2010** | **December 31, 2009** |
|---|---|---|
| | *(Thousands of dollars)* | |
| Gross intangible assets | **$ 306,650** | $ 306,650 |
| Accumulated amortization | **(42,164)** | (34,498) |
| Net intangible assets | **$ 264,486** | $ 272,152 |

## F. CREDIT FACILITIES AND SHORT-TERM NOTES PAYABLE

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, 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 increase to 5.5 to 1 for the three calendar quarters following the acquisition. Upon any breach of any covenant by us in our Partnership Credit Agreement, amounts outstanding under our Partnership Credit Agreement may become due and payable immediately. At December 31, 2010, our ratio of indebtedness to adjusted EBITDA was 3.79 to 1, and we were in compliance with all covenants under our Partnership Credit Agreement. As a result of our January 2011 debt offering, available borrowings are limited by the ratio of indebtedness to adjusted EBITDA covenant under our Partnership Credit Agreement; however, we had approximately $956 million in cash at January 31, 2011, and $266 million of available borrowings that provide ample liquidity to meet our funding needs. We expect the limitation of our available borrowings to be eliminated during 2011.

In June 2010, we initiated a commercial paper program under which we may issue unsecured commercial paper notes up to a maximum amount outstanding of $1.0 billion to fund our short-term borrowing needs. The maturities of the commercial paper notes vary but may not exceed 270 days from the date of issue. The commercial paper notes are generally sold at a negotiated discount from par.

Our Partnership Credit Agreement is available to repay the commercial paper notes, if necessary. Amounts outstanding under the commercial paper program reduce the borrowings available under our Partnership Credit Agreement. In July 2010, we repaid all borrowings outstanding under our Partnership Credit Agreement with the issuance of commercial paper.

At December 31, 2010, we had $429.9 million in commercial paper outstanding and no borrowing under our Partnership Credit Agreement, leaving approximately $570.1 million of credit available under the Partnership Credit Agreement. At December 31, 2009, we had $523.0 million in borrowings outstanding under our Partnership Credit Agreement. At December 31, 2010 and 2009, we had a total of $24.2 million issued in letters of credit outside of our Partnership Credit Agreement. Borrowings under our Partnership Credit Agreement are nonrecourse to our general partner.

The weighted-average interest rate on our short-term debt outstanding under this agreement was 0.38 percent and 0.54 percent at December 31, 2010 and 2009, respectively.

## G. 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, 2010 | December 31, 2009 |
|---|---|---|
| | *(Thousands of dollars)* | |
| **ONEOK Partners** | | |
| $250,000 at 8.875% due 2010 | **$ -** | $ 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** | 500,000 |
| $600,000 at 6.65% due 2036 | **600,000** | 600,000 |
| $600,000 at 6.85% due 2037 | **600,000** | 600,000 |
| **Guardian Pipeline** | | |
| Average 7.85%, due 2022 | **97,850** | 109,780 |
| **Total long-term notes payable** | **2,822,850** | 3,084,780 |
| **Unamortized portion of terminated swaps** | **932** | 4,673 |
| **Unamortized debt premium** | **(5,279)** | (5,436) |
| **Current maturities** | **(236,931)** | (261,931) |
| **Long-term debt** | **$ 2,581,572** | $ 2,822,086 |

The aggregate maturities of long-term debt outstanding for years 2011 through 2015 are shown below:

| | ONEOK Partners | Guardian Pipeline | Total |
|---|---|---|---|
| | | *(Millions of dollars)* | |
| 2011 | $ 225.0 | $ 11.9 | $ 236.9 |
| 2012 | $ 350.0 | $ 11.1 | $ 361.1 |
| 2013 | $ - | $ 7.7 | $ 7.7 |
| 2014 | $ - | $ 7.7 | $ 7.7 |
| 2015 | $ - | $ 7.7 | $ 7.7 |

**Debt Repayment -** In June 2010, we repaid $250 million of maturing senior notes with available cash and short-term borrowings. With the repayment of these notes, we no longer have any obligation to offer to repurchase the $225 million senior notes due 2011 in the event that our long-term debt credit ratings fall below investment grade.

**Debt Issuance** - In January 2011, we completed an underwritten public offering of $1.3 billion senior notes, consisting of $650 million of 3.25-percent senior notes due 2016 and $650 million of 6.125-percent senior notes due 2041. The net proceeds from the offering of approximately $1.28 billion were used to repay amounts outstanding under our commercial paper program, and for general partnership purposes, including capital expenditures, and will be used to repay the $225 million principal amount of senior notes due March 2011. We will pay interest on the senior notes due 2016 and 2041 on February 1 and August 1 of each year, beginning August 1, 2011.

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

**ONEOK Partners Debt Covenants** - The terms of the 2019 Notes, and the recently issued senior notes due 2016 and 2041 are governed by an indenture, dated as of September 25, 2006, between us and Wells Fargo Bank, N.A., as trustee, as supplemented. 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.

The indentures governing our senior notes due 2011 include an event of default upon acceleration of other indebtedness of $25 million or more and the indentures governing our other senior notes include an event of default upon the acceleration of other indebtedness of $100 million or more. Such events of default would entitle the trustee or the holders of 25 percent in aggregate principal amount of any of our outstanding senior notes to declare those notes immediately due and payable in full.

We may redeem the notes due 2011, 2012, 2016 (6.15 percent), 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. We may redeem our 3.25-percent senior notes due 2016 and our 6.125-percent senior notes due 2041 at par starting one and six months, respectively, before their maturity dates. Prior to these times, we may redeem these notes on the same terms as our other notes. Our senior notes are senior unsecured obligations, ranking equally in right of payment with all of our existing and future unsecured senior indebtedness, and structurally subordinate to any of the existing and future debt and other liabilities of any non-guarantor subsidiaries.

**ONEOK Partners Debt Guarantee** - Our senior notes 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, 2010, 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.

**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 $97.9 million in notes outstanding at December 31, 2010, 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 4.75 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, 2010, Guardian Pipeline's EBITDAR-to-fixed-charges ratio was 6.1 to 1, the ratio of indebtedness to EBITDAR was 2.0 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.

## H. 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 42.8-percent ownership interest in us at December 31, 2010.

**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 a public offering price of $60.75 per common unit, generating net proceeds of approximately $322.7 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.

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** - We paid cash distributions to our general and limited partners of $563.2 million, $500.3 million and $453.0 million in 2010, 2009 and 2008, respectively, which included incentive distributions of $103.5 million, $84.7 million and $69.9 million in 2010, 2009 and 2008, 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, | | |
|---|---|---|---|
| | **2010** | **2009** | **2008** |
| First Quarter | **$ 1.10** | $ 1.08 | $ 1.025 |
| Second Quarter | **$ 1.11** | $ 1.08 | $ 1.040 |
| Third Quarter | **$ 1.12** | $ 1.08 | $ 1.060 |
| Fourth Quarter | **$ 1.13** | $ 1.09 | $ 1.080 |

In January 2011, our general partner declared a cash distribution of $1.14 per unit ($4.56 per unit on an annualized basis) for the fourth quarter of 2010, an increase of $0.01 from the previous quarter, which was paid on February 14, 2011, to unitholders of record at the close of business on January 31, 2011.

**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 Class B limited partner units are entitled to receive increased quarterly distributions equal to 110 percent of the distributions paid with respect to our common units. ONEOK, as the sole holder of our Class B limited partner units, has waived its right to receive the increased quarterly distributions on the Class B units. ONEOK retains the option to withdraw its waiver of increased distributions on Class B units at any time by giving us no less than 90 days advance notice. Any such withdrawal of the waiver will be effective with respect to any distribution on the Class B units declared or paid on or after the 90 days following delivery of the notice.

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 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 L for additional information about distributions allocated to the general partner.

## I. 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. 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 Partners GP owns the entire 2-percent general partnership 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 partner totaled $108.7 million, $87.7 million and $76.0 million for 2010, 2009 and 2008, 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 "Partnership Agreement" in Note H.

## J. INCOME TAXES

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

| | Years Ended December 31, | | |
|---|---|---|---|
| | **2010** | **2009** | **2008** |
| | *(Thousands of dollars)* | | |
| Current income tax provision | | | |
| Federal | **$ 539** | $ 83 | $ 80 |
| State | **3,719** | 1,173 | 7,240 |
| Total current income tax provision | **4,258** | 1,256 | 7,320 |
| Deferred income tax provision | | | |
| Federal | **10,125** | 9,782 | 4,785 |
| State | **699** | 1,925 | 230 |
| Total deferred income tax provision | **10,824** | 11,707 | 5,015 |
| Total provision for income taxes | **$ 15,082** | $ 12,963 | $ 12,335 |

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

| | Years Ended December 31, | | |
|---|---|---|---|
| | **2010** | **2009** | **2008** |
| | *(Thousands of dollars)* | | |
| Income before income taxes | **$ 488,390** | $ 447,667 | $ 638,392 |
| Less: Net income attributable to noncontrolling interests | **606** | 348 | 441 |
| Income attributable to ONEOK Partners, L.P. before income taxes | **487,784** | 447,319 | 637,951 |
| Federal statutory income tax rate | **35.0%** | 35.0% | 35.0% |
| Provision for federal income taxes | **170,724** | 156,562 | 223,283 |
| Partnership earnings not subject to tax | **(160,219)** | (148,229) | (216,332) |
| State income taxes, net of federal benefit | **4,398** | 2,594 | 7,470 |
| Other, net | **179** | 2,036 | (2,086) |
| Income tax provision | **$ 15,082** | $ 12,963 | $ 12,335 |

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, | |
|---|---|---|
| | **2010** | **2009** |
| | *(Thousands of dollars)* | |
| Deferred tax assets | | |
| Net operating loss carryforward | **$ -** | $ 2,559 |
| Other | **448** | 688 |
| Total deferred tax assets | **448** | 3,247 |
| Deferred tax liabilities | | |
| Excess of tax over book depreciation | **28,773** | 20,020 |
| Regulatory assets | **2,685** | 3,722 |
| Other | **-** | 6 |
| Total deferred tax liabilities | **31,458** | 23,748 |
| Net deferred tax liabilities | **$ 31,010** | $ 20,501 |

We had income taxes payable of approximately $0.1 million and $3.0 million at December 31, 2010 and 2009, respectively.

## K. UNCONSOLIDATED AFFILIATES

**Overland Pass Pipeline Company** - In September 2010, we completed a transaction to sell a 49-percent ownership interest in Overland Pass Pipeline Company to a subsidiary of Williams Partners resulting in each joint-venture member now owning 50 percent of Overland Pass Pipeline Company. In accordance with the joint-venture agreement, we received approximately $423.7 million in cash at closing. As a result of the transaction, we no longer control Overland Pass Pipeline Company and began accounting for our investment under the equity method of accounting in September 2010. In connection with the deconsolidation of Overland Pass Pipeline Company, we recognized approximately $16.3 million in gain on sale of assets, primarily attributable to the remeasurement of our retained investment in Overland Pass Pipeline Company to its fair value, and have recorded our retained investment of approximately $438.0 million in investments in unconsolidated affiliates. Our estimate of the fair value of our retained interest in Overland Pass Pipeline Company was based upon the income and market valuation approaches.

In 2011, we expect to make contributions of approximately $35 million to $40 million to Overland Pass Pipeline Company for additional pump stations and the expansion of existing pump stations.

**Northern Border Pipeline** - The Northern Border Pipeline partnership agreement provides that distributions to Northern Border Pipeline's partners are to be made on a pro rata basis according to each partner's percentage interest. The Northern Border Pipeline Management Committee determines the amount and timing of such distributions. Any changes to, or suspension of, the cash distribution policy of Northern Border Pipeline requires the unanimous approval of the Northern Border Pipeline Management Committee. Cash distributions are equal to 100 percent of distributable cash flow as determined from Northern Border Pipeline's financial statements based upon EBITDA 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.

Northern Border Pipeline anticipates requiring an additional equity contribution of approximately $100 million to $120 million from its partners in 2011, of which our share will be approximately $50 million to $60 million based on our 50-percent equity interest.

**Investments in Unconsolidated Affiliates** - The following table sets forth our investments in unconsolidated affiliates for the periods indicated:

| | Net Ownership Interest | December 31, 2010 | December 31, 2009 |
|---|---|---|---|
| | | *(Thousands of dollars)* | |
| Overland Pass Pipeline Company | 50% | **$ 443,392** | $ - |
| Northern Border Pipeline | 50% | **384,011** | 401,773 |
| Fort Union Gas Gathering | 37% | **115,148** | 111,675 |
| Bighorn Gas Gathering | 49% | **92,659** | 96,492 |
| Lost Creek Gathering Company (a) | 35% | **80,765** | 80,041 |
| Other | Various | **72,149** | 75,182 |
| Investments in unconsolidated affiliates (b) | | **$ 1,188,124** | $ 765,163 |

(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, 2010 and 2009.

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

| | Years Ended December 31, 2010 | 2009 | 2008 |
|---|---|---|---|
| | | *(Thousands of dollars)* | |
| Overland Pass Pipeline Company | **$ 5,421** | $ - | $ - |
| Northern Border Pipeline | **68,124** | 41,300 | 65,912 |
| Fort Union Gas Gathering | **14,367** | 14,533 | 14,172 |
| Bighorn Gas Gathering | **5,495** | 7,807 | 8,195 |
| Lost Creek Gathering Company | **4,391** | 4,872 | 5,365 |
| Other | **4,082** | 4,210 | 7,788 |
| Equity earnings from investments | **$ 101,880** | $ 72,722 | $ 101,432 |

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

| | December 31, 2010 | December 31, 2009 |
|---|---|---|
| | *(Thousands of dollars)* | |
| **Balance Sheet** | | |
| Current assets | **$ 93,698** | $ 84,910 |
| Property, plant and equipment, net | **$ 2,500,708** | $ 1,717,825 |
| Other noncurrent assets | **$ 28,222** | $ 28,675 |
| Current liabilities | **$ 74,969** | $ 70,500 |
| Long-term debt | **$ 616,210** | $ 653,937 |
| Other noncurrent liabilities | **$ 13,773** | $ 12,144 |
| Accumulated other comprehensive income (loss) | **$ (2,883)** | $ (3,054) |
| Owners' equity | **$ 1,920,559** | $ 1,097,883 |

| | Years Ended December 31, | | |
|---|---|---|---|
| | 2010 | 2009 | 2008 |
| | (Thousands of dollars) | | |
| **Income Statement** (a) | | | |
| Operating revenues | **$ 440,826** | $ 383,625 | $ 415,552 |
| Operating expenses | **$ 189,437** | $ 178,194 | $ 179,380 |
| Net income | **$ 223,715** | $ 164,002 | $ 209,915 |
| **Distributions paid to us** | **$ 114,805** | $ 109,807 | $ 118,010 |

(a) - Overland Pass Pipeline Company was deconsolidated as of September 2010; therefore, we have only included summarized financial information for the last four months of 2010.

## L. 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 necessary for operation and maintenance of the Bushton Plant, and we reimburse ONEOK for OBPI's obligations under equipment leases covering portions of the Bushton Plant. The Bushton equipment leases will expire in 2012 unless, in the second quarter of 2011, OBPI provides irrevocable notice of its intent to either renew the equipment leases at fair market rental value or purchase the original leased equipment (or any replacement parts) pursuant to the terms of the equipment leases. Our Processing and Services Agreement provides that we will reimburse OBPI for amounts incurred in connection with the foregoing option, if any.

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 Guardian Pipeline, Viking Pipeline Transmission and Midwestern Gas Transmission 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, legal and 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, operating income 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 C.

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

| | Years Ended December 31, 2010 | 2009 | 2008 |
|---|---|---|---|
| | *(Thousands of dollars)* | | |
| Revenues | **$ 457,740** | $ 475,765 | $ 744,886 |
| Expenses | | | |
| Cost of sales and fuel | **$ 53,107** | $ 46,824 | $ 107,983 |
| Administrative and general expenses | **207,282** | 200,002 | 191,798 |
| Total expenses | **$ 260,389** | $ 246,826 | $ 299,781 |

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 $6.8 million, $5.1 million and $9.5 million in 2010, 2009 and 2008, respectively, to maintain its 2-percent general partner interest in connection with the issuance of common units. See Note H 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 $303.8 million, $278.2 million and $251.7 million for 2010, 2009 and 2008, respectively, which included incentive distributions related to its general partner interest of $103.5 million, $84.7 million and $69.9 million for 2010, 2009 and 2008, respectively.

## M. COMMITMENTS AND CONTINGENCIES

**Commitments** - Operating leases represent future minimum lease payments under non-cancelable equipment leases covering a portion of the Buston 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)* | |
| 2011 | $ 14.9 | $ 6.5 | $ 21.4 |
| 2012 | $ 7.8 | $ 6.8 | $ 14.6 |
| 2013 | $ 2.9 | $ 6.7 | $ 9.6 |
| 2014 | $ 2.5 | $ 6.3 | $ 8.8 |
| 2015 | $ 1.0 | $ 6.1 | $ 7.1 |

**Environmental Matters** - We are subject to multiple historical and wildlife preservation laws and environmental 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 pipelines 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 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 on earnings or cash flows during the years ended December 31, 2010, 2009 or 2008.

In May 2010, the EPA finalized the "Tailoring Rule" that will regulate greenhouse gas emissions at new or modified facilities that meet certain criteria. Affected facilities will be required to review best available control technology, conduct air-quality analysis, impact analysis and public reviews with respect to such emissions. The rule was phased in beginning January 2011 and, at current emission threshold levels, will have a minimal impact on our existing facilities. The EPA has stated it will consider lowering the threshold levels over the next five years, which could increase the impact on our existing facilities; however, potential costs, fees or expenses associated with the potential adjustments are unknown.

In addition, the EPA has issued a 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 2013. The 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.

**Financial Markets Legislation** - In July 2010, the Dodd-Frank Act was enacted, representing a far-reaching overhaul of the framework for regulation of United States financial markets. Various regulatory agencies, including the SEC and the CFTC, have proposed regulations for implementation of many of the provisions of the Dodd-Frank Act and are currently seeking comments on the proposals. We expect additional proposed regulations as the remaining provisions of the Dodd-Frank Act are implemented. Until the final regulations are established, we are unable to ascertain how we may be affected. Based on our assessment of the proposed regulations issued to date, we expect to be able to continue to participate in financial markets for hedging certain risks inherent in our business, including commodity and interest-rate risks; however, the costs of doing so may increase as a result of the new legislation. We may also incur additional costs associated with our compliance with the new regulations and anticipated additional record-keeping, reporting and disclosure obligations.

**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.

## N. SEGMENTS

**Segment Descriptions** - Our operations are divided into three reportable business segments, 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 L. 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, ethanol producers 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.

For the three years ended December 31, 2010, 2009 and 2008, we had no single customer from which we received 10 percent or more of our consolidated revenues.

See Note L 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, 2010 | Natural Gas Gathering and Processing | Natural Gas Pipelines (a) | Natural Gas Liquids (b) | Other and Eliminations | Total |
|---|---|---|---|---|---|
| | | | *(Thousands of dollars)* | | |
| Sales to unaffiliated customers | $ 236,620 | $ 239,749 | $ 7,741,791 | $ - | $ 8,218,160 |
| Sales to affiliated customers | 347,909 | 109,831 | - | - | 457,740 |
| Intersegment revenues | 733,374 | 1,486 | 33,260 | (768,120) | - |
| Total revenues | $ 1,317,903 | $ 351,066 | $ 7,775,051 | $ (768,120) | $ 8,675,900 |
| | | | | | |
| Net margin | $ 351,372 | $ 300,174 | $ 499,627 | $ (6,320) | $ 1,144,853 |
| Operating costs | 136,757 | 96,525 | 173,940 | (3,746) | 403,476 |
| Depreciation and amortization | 60,700 | 44,133 | 68,875 | - | 173,708 |
| Gain (loss) on sale of assets | (359) | 3,488 | 15,503 | - | 18,632 |
| Operating income | $ 153,556 | $ 163,004 | $ 272,315 | $ (2,574) | $ 586,301 |
| | | | | | |
| Equity earnings from investments | $ 27,495 | $ 68,761 | $ 5,624 | $ - | $ 101,880 |
| Investments in unconsolidated affiliates | $ 324,936 | $ 392,079 | $ 471,109 | $ - | $ 1,188,124 |
| Total assets | $ 1,809,469 | $ 1,887,595 | $ 4,224,410 | $ (1,374) | $ 7,920,100 |
| Noncontrolling interests in consolidated subsidiaries | $ - | $ 5,161 | $ - | $ 15 | $ 5,176 |
| Capital expenditures | $ 216,049 | $ 27,621 | $ 107,933 | $ 1,111 | $ 352,714 |

(a) - Our Natural Gas Pipelines segment has regulated and non-regulated operations. Our Natural Gas Pipelines segment's regulated operations had revenues of $279.8 million, net margin of $234.9 million and operating income of $116.1 million.

(b) - Our Natural Gas Liquids segment has regulated and non-regulated operations. Our Natural Gas Liquids segment's regulated operations had revenues of $332.4 million, of which $214.5 million related to sales within the segment, net margin of $244.2 million and operating income of $134.8 million.

| 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.

## O. QUARTERLY FINANCIAL DATA (UNAUDITED)

| Year Ended December 31, 2010 | First Quarter | Second Quarter | Third Quarter | Fourth Quarter |
|---|---|---|---|---|
| | *(Thousands of dollars, except per unit amounts)* | | | |
| **Revenues** | **$ 2,204,006** | **$ 2,055,121** | **$ 2,070,144** | **$ 2,346,629** |
| **Net margin** | **$ 261,125** | **$ 288,162** | **$ 286,005** | **$ 309,561** |
| **Operating income** | **$ 120,162** | **$ 145,957** | **$ 160,511** | **$ 159,671** |
| **Net income** | **$ 84,020** | **$ 105,149** | **$ 141,697** | **$ 142,442** |
| **Net income attributable to ONEOK Partners, L.P.** | **$ 83,868** | **$ 105,015** | **$ 141,536** | **$ 142,283** |
| **Limited partners' per unit net income** | **$ 0.57** | **$ 0.75** | **$ 1.09** | **$ 1.09** |

| 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 |

## 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

The Chief Executive Officer and the Chief Financial Officer of ONEOK Partners GP, our general partner, who are the equivalent of our principal executive and principal financial officers, have concluded that our disclosure controls and procedures were effective as of the end of the period covered by this report based on the evaluation of the controls and procedures required by Rule 13a-15(b) of the Exchange Act.

### 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, 2010.

Our internal control over financial reporting as of December 31, 2010, 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

There have been no changes in our internal controls over financial reporting during the quarter ended December 31, 2010, 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

**General Partner 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 appointed 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; 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, and that their individual and collective skills and qualifications provide them the ability to engage management and each other in a constructive and collaborative fashion and, when necessary and appropriate, challenge management in the execution of our business operations and strategy.

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.

**The 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 2011, 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 our Governance Guidelines and are independent.

Our Board of Directors annually reviews the financial expertise of the members of our Audit Committee. In February 2011, our Board of Directors determined that Ms. Edwards and Messrs. Mogg, Odell, Petersen, Smith, Strehl 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 audited and quarterly unaudited financial statements. The Audit Committee has all other responsibilities required by the applicable NYSE listing standards and applicable SEC rules. Our Board of Directors has adopted a written charter for our Audit Committee which is available on and may be printed from our website at www.oneokpartners.com and is also available from the corporate secretary of our general partner.

The Audit Committee held six meetings in 2010.

**The 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.

The Conflicts Committee did not meet in 2010.

**Risk Oversight**

Enterprise risk management is a company-wide process that involves our Board of Directors and management in identifying, assessing and managing risks that could affect our ability to fulfill our business objectives or execute our business strategy. Our enterprise risk management activities involve the identification and assessment of a broad range of risks and the development of plans to mitigate their effects. These risks generally relate to strategic, operational, financial, regulatory compliance and human resource issues.

Not all risks can be dealt with in the same way. Some risks may be easily perceived and controllable, and other risks are unknown; some risks can be avoided or mitigated by particular behavior, and some risks are unavoidable as a practical matter. For some risks, the potential adverse impact would be minor, and, as a matter of business judgment, it may not be appropriate to allocate significant resources to avoid the adverse impact; in other cases, the adverse impact could be significant, and it is prudent to expend resources to seek to avoid or mitigate the potential adverse impact. In some cases, a higher degree of risk may be acceptable because of a greater perceived potential for reward. Management is responsible for identifying risk and risk controls related to our significant business activities, mapping the risks to our partnership strategy; and developing programs and recommendations to determine the sufficiency of risk identification, the balance of potential risk to potential reward and the appropriate manner in which to control and mitigate risk.

The Board implements its risk oversight responsibilities by having management provide periodic briefing and informational sessions on the significant voluntary and involuntary risks that the Partnership faces and how the Partnership is seeking to control and mitigate these risks if and when appropriate. In some cases, as with risks relating to significant acquisitions, risk oversight is addressed as part of the full Board's engagement with the Chief Executive Officer and management.

The Board annually reviews a management assessment of the primary operational and regulatory risks facing the Partnership, their relative magnitude and management's plan for mitigating these risks. The Board also reviews risks related to the Partnership's business strategy at its annual strategic planning meeting and at other meetings as appropriate.

Our Audit Committee oversees 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 Operating Officer, Chief Financial Officer, General Counsel, Vice President – Financial Services and Director - Audit Services 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 | 58 | Chairman of the Board, President and Chief Executive Officer |
| Curtis L. Dinan | 43 | Senior Vice President, Chief Financial Officer and Treasurer, Member, Board of Directors (through February 28, 2011) President – Natural Gas (effective March 1, 2011) |
| Robert F. Martinovich | 53 | Senior Vice President, Chief Financial Officer and Treasurer, Member, Board of Directors (effective March 1, 2011) |
| Terry K. Spencer | 51 | Chief Operating Officer and Member, Board of Directors |
| John R. Barker | 63 | Senior Vice President and General Counsel |
| Derek S. Reiners | 39 | Senior Vice President and Chief Accounting Officer |
| Julie H. Edwards | 52 | Member, Board of Directors and Audit Committee |
| Jim W. Mogg | 62 | Member, Board of Directors and Audit Committee |
| Shelby E. Odell | 71 | Member, Board of Directors, Audit and Conflicts Committees |
| Gary N. Petersen | 59 | Member, Board of Directors and Chairman, Audit and Conflicts Committees |
| Gerald B. Smith | 60 | Member, Board of Directors and Audit Committee |
| Craig F. Strehl | 53 | Member, Board of Directors, Audit and Conflicts Committees |
| Gil J. Van Lunsen | 68 | Member, Board of Directors and Vice Chairman, Audit and Conflicts Committees |

*John W. Gibson* is Chairman, President and Chief Executive Officer of ONEOK Partners GP, the general partner of ONEOK Partners, L.P., and President and Chief Executive Officer of ONEOK. He served as the Chief Executive Officer of ONEOK Partners GP from 2007 through 2009. He has served as Chairman of the Board of Directors of ONEOK Partners GP since October 2007. From 2005 until May 2006, he was President of ONEOK Energy Companies, which included ONEOK's gathering and processing, natural gas liquids, pipelines, and storage and energy services business segments, some of which were acquired by us in April 2006. Prior to that, he was ONEOK's President, Energy, from May 2000 to 2005. 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.

Mr. Gibson has served in a variety of roles of continually increasing responsibility at ONEOK Partners, L.P. since 2004, ONEOK since 2000, and prior to 2000, at Koch Energy, Inc., Exxon USA, and Phillips Petroleum. In these roles, Mr. Gibson has had direct responsibility for and extensive experience in strategic and financial planning, acquisitions and divestitures, operations, management supervision and development, and compliance. As the executive responsible for numerous merger-and-acquisition transactions over the course of his career, Mr, Gibson has significant experience in assessing merger-and-acquisition opportunities, and in structuring, financing and completing merger-and-acquisition transactions. Over the course of his lengthy career in a variety of sectors of the oil and gas industry, Mr. Gibson has gained extensive management and operational experience and has demonstrated a strong track record of leadership, strategic vision and risk management. In light of Mr. Gibson's role as the top executive officer of our general partner and his extensive industry and managerial experience and knowledge, ONEOK has concluded that Mr. Gibson should continue as a member of our Board of Directors.

*Curtis L. Dinan* has served as our Senior Vice President, Chief Financial Officer and Treasurer since January 1, 2007. He was appointed 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.

Effective March 1, 2011, Mr Dinan will become President – Natural Gas, responsible for our commercial and operational activities in our Natural Gas Gathering and Processing and Natural Gas Pipeline segments and will no longer serve on our Board of Directors.

*Robert F. Martinovich* will become Senior Vice President, Chief Financial Officer and Treasurer and become a member of our Board of Directors effective March 1, 2011. Mr. Martinovich has been ONEOK's chief operating officer from July 2009 through February 2011, responsible for ONEOK's Distribution and Energy Services operating segments. He joined ONEOK in 2007 as President of our Natural Gas Gathering and Processing segment. Prior to joining ONEOK, he held a variety of executive management positions for DCP Midstream, LLC since joining the company in 2000. Previously, he was senior vice president of GPM Gas Corporation, the natural gas gathering, processing and marketing division of Phillips Petroleum Company, holding a variety of marketing, financial and operational leadership roles. Martinovich joined Phillips in 1980 and held various engineering, sales and marketing positions in the research and development and the plastics divisions of Phillips, and also served on the company's corporate planning and development staff.

Mr. Martinovich has extensive senior management experience in the oil and natural gas industry as a result of his service in a variety of roles of continually increasing responsibility at both the Partnership and ONEOK since 2007 and prior to 2007, at DCP Midstream and Phillips. In these roles, Mr. Martinovich has demonstrated a strong track record of achievement and sound judgment. In light of Mr. Martinovich's extensive industry and executive managerial experience, ONEOK has concluded that Mr. Martinovich should 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 our Chief Operating Officer since July 16, 2009. From 2007, until his appointment as Chief Operating Officer, Mr. Spencer served as Executive Vice President – Natural Gas Liquids of ONEOK Partners. Mr. Spencer previously served as President – Natural Gas Liquids of ONEOK Partners from April 2006 and served as Senior Vice President – Natural Gas Liquids of ONEOK Partners 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 natural 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 Mr. Spencer's extensive industry and executive managerial experience, ONEOK has concluded that Mr. Spencer should continue to serve on our Board of Directors.

*John R. Barker* has served as our Senior Vice President and General Counsel since May 2006. Mr. Barker is also Senior Vice President and General Counsel 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 retired in 2007 from Southern Union Company where she served as Senior Vice President-Corporate Development from November 2006 to January 2007 and as Senior Vice President and Chief Financial Officer from July 2005 to November 2006. Prior to June 2005, she was an executive officer of Frontier Oil Corporation, having served as Chief Financial Officer from 1994 to 2005 and as Treasurer from 1991 to 1994. Prior to joining Frontier Oil Corporation in 1991, Ms. Edwards was an investment banker with Smith Barney, Harris, Upham & Co., Inc. in New York and Houston, after joining the company as an associate in 1985, when she graduated from the Wharton School of the University of Pennsylvania with an M.B.A. Prior to attending Wharton, she worked as an exploration geologist in the oil industry, having earned a B.S. in Geology and Geophysics from Yale University in 1980.

Ms. Edwards is also a member of the Board of Directors of Noble Corporation, an international contract drilling company. She was a member of the Board of Directors of NATCO Group, Inc., an oil field services and equipment manufacturing company, from 2004 until its sale to Cameron International Corporation in November 2009.

In addition to her experience from service on the boards of directors of several public companies, Ms. Edwards brings to our Board broad experience and understanding of various segments within the energy industry (exploration and production, refining and marketing, natural gas transmission, processing and distribution, production technology and contract drilling), and significant senior accounting, finance, capital markets, corporate development and management experience and expertise. In light of Ms. Edwards' extensive industry and executive managerial and financial experience and knowledge, ONEOK has concluded that Ms. Edwards should continue as a member of 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. In addition to presiding over board meetings and providing strategic oversight, he was involved in launching DCP Midstream Partners as a public company. From January 2004 to September 2006, Mr. Mogg served as Group Vice President, Chief Development Officer and advisor to the Chairman of Duke Energy Corporation and, in that capacity, was responsible for the merger and acquisition, strategic planning and human resources activities of Duke Energy. Additionally, Duke Energy affiliates Crescent Resources and Teppco Partners, LP reported to Mr. Mogg and he was the executive sponsor of Duke Energy's Finance and Risk Management Committee of the Board of Directors. 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. Under Mr. Mogg's leadership DCP Midstream became the nation's largest producer of natural gas liquids and one of the largest gatherers and processors of natural gas. DCP Midstream achieved this significant growth via acquisitions, construction and optimization of assets. DCP Midstream was the general partner of Teppco Partners, LP and, as a result, Mr. Mogg was Vice Chairman of TEPPCO Partners, LP from April 2000 to May 2002 and Chairman from May 2002 to February 2005. Mr. Mogg serves on the Board of Directors of Bill Barrett Corporation, where he is currently the lead director, 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 natural gas industry as a result of his service at DCP Midstream Partners and Duke Energy where he has demonstrated a strong track record of achievement and sound judgment. As the executive responsible for numerous merger-and-acquisition transactions at DCP Midstream Partners, Teppco Partners and Duke Energy Corporation, he has significant experience in assessing acquisition opportunities and in structuring, financing and completing merger-and-acquisition transactions. In addition, Mr. Mogg's current and previous directorships at other companies, including publicly traded master limited partnerships, provide him with extensive corporate and master limited partnership governance experience. As a result of his experience, Mr. Mogg is qualified to analyze the various financial and operational aspects of the Partnership. In light of Mr. Mogg's extensive industry and executive managerial experience and knowledge, ONEOK has concluded that Mr. Mogg should continue as a member of 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 of management and operations experience in the petroleum business, including marketing, distribution, acquisitions and identification of new business opportunities. From 1974 to 2000, Mr. Odell held several senior management 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 held several positions of continually increasing responsibility with Phillips Petroleum Company. He is 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 Mr. Odell's extensive industry and executive managerial experience and knowledge, ONEOK has concluded that Mr. Odell should continue to serve on our Board of Directors.

*Gary N. Petersen* was appointed to our Board of Directors in May of 2006. Mr. Petersen retired in July 2010 as President of Endres Processing LLC, a recycler and processor of food waste into livestock feed ingredients, where he was responsible for strategic planning, merger/acquisitions, financial analysis, budgets and forecasts, and management development. He continues to provide consulting services to Endres Processing.

Additionally, Mr. Petersen has been a consultant for the past 12 years to a number of small businesses and not-for-profit organizations. His consulting work with senior management includes facilitation of strategic thinking and planning processes, business acquisitions and sales, feasibility studies, financial reporting and analysis, organizational development and crisis management.

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 where he directed Minnegasco's total operations. The first 10 years of his Minnegasco career included numerous management positions of continually increasing responsibility in the areas of state utility regulation, gas supply procurement, strategic planning, financial reporting and analysis, mergers and acquisitions and rate case preparation and expert testimony. Prior to his employment at Minnegasco, Mr. Petersen was a senior auditor with Arthur Andersen & Co. 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 experience 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 Mr. Petersen's extensive industry and executive managerial and financial experience and knowledge, ONEOK has concluded that Mr. Petersen should continue to serve on our Board of Directors.

*Gerald B. Smith* was appointed to our Board of Directors in May of 2006. Mr. Smith is Chairman and Chief Executive Officer of Smith, Graham & Company Investment Advisors, a global investment management firm, which was founded in 1990. He is a member of the board of trustees of Charles Schwab Family of Funds; lead independent director and Deputy Chairman of Cooper Industries; and a former director of the Fund Management Board of Robeco Group, Rorento N.V. (Netherlands). He is also a member of the Board of Directors of ONEOK, Inc.

Mr. Smith has extensive financial, operational, management, investment and risk management experience as a result of his long-term tenure as Chairman and Chief Executive Officer of Smith, Graham & Company Investment Advisors where he has a strong track record of achievement, sound judgment and risk management. Mr. Smith's current and former board memberships at other companies and institutions also provide him with extensive corporate governance experience. In light of Mr. Smith's significant executive managerial and financial experience and knowledge, ONEOK has concluded that Mr. Smith should continue as a member of 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, a private natural gas midstream and chemical manufacturing company where he managed significant growth through approximately $200 million in acquisitions and numerous internal capital projects. In 2006, he led the sale of the midstream business to Southern Union Company for $1.6 billion. He then 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 with TXO, where he served in various engineering positions related to the construction, operation and acquisition of gas pipeline and gas processing facilities. He later served in various commercial capacities at TXO. He left TXO in 1987 to join Aquila Energy. 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 Corporation in 1993. As Chief Executive Officer of Aquila Gas Pipeline, he led the company's initial public offering in 1993. During his tenure as Chief Operating Officer of Aquila Gas Pipeline, Mr. Strehl managed all investor and rating agency relations and was responsible for all filings with the SEC.

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, Southern Union Company and Aquila Gas Pipeline where he has demonstrated a strong track record of achievement and sound judgment. In light of Mr. Strehl's extensive industry and executive managerial experience and knowledge, ONEOK has concluded that Mr. Strehl should continue to serve on our Board of Directors.

*Gil Van Lunsen* was appointed to our Board of Directors in May of 2006. Mr. Van Lunsen was a managing partner of KPMG LLP and led the firm's Tulsa, Oklahoma, office prior to his retirement in June 2000. During his 33-year career, Mr. Van Lunsen held various positions of increasing responsibility within KPMG and was elected to the partnership 1977. He is currently Chairman of the Audit Committee of Array Biopharma, Inc. in Boulder, Colorado, and has been a member of its Board of Directors since 2002. Additionally, Mr. Van Lunsen was the Chairman of the Audit Committee of Sirenza Microdevices, Inc. and its predecessor entities in Broomfield, Colorado, from July 2002 until December 2007. Mr. Van Lunsen received a B.S./B.A. in Accounting from the University of Denver.

As a former partner of KPMG LLP, Mr. Van Lunsen has extensive experience with complex financial and accounting and internal control issues, as well as significant accounting and governance experience related to his current and past responsibilities as chairman of the audit committee of other publicly traded companies. During his tenure on our Board of Directors and the Audit Committee, Mr. Van Lunsen has also developed an in-depth knowledge of the critical accounting, operational and financial issues facing our company and our industry. In light of Mr. Van Lunsen's extensive industry, finance and accounting experience and knowledge, 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, 2010, 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 2010.

**2010 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 | $ 89,000 | - | - | - | - | - | $ 89,000 |
| Jim W. Mogg | $ 89,500 | - | - | - | - | - | $ 89,500 |
| Shelby E. Odell | $ 89,500 | - | - | - | - | - | $ 89,500 |
| Gary N. Petersen | $ 94,500 | - | - | - | - | - | $ 94,500 |
| Gerald B. Smith | $ 89,000 | - | - | - | - | - | $ 89,000 |
| Craig F. Strehl | $ 88,500 | - | - | - | - | - | $ 88,500 |
| Gil J. Van Lunsen | $ 89,500 | - | - | - | - | - | $ 89,500 |

**Additional Governance Matters**

**Executive Sessions of the Board and the Audit Committee** - Our Board of Directors has documented its governance practices in our Governance Guidelines. Our Board of Directors 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.

**Governance Guidelines** - Our Board of Directors has adopted Governance Guidelines that address several Partnership governance matters, including responsibilities of our 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 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, reporting of compliance issues and discipline for violations of the code. We intend to promptly post on our website 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 website at www.oneokpartners.com to current information relating to Partnership 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 website. You may also contact the office of the secretary of ONEOK Partners GP for printed copies of these documents free of charge. Our website 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 the Partnership. 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, materials that are abusive, threatening or otherwise inappropriate, or correspondence not clearly identified as interested party or unitholder correspondence.

**Compensation Committee Interlocks and Insider Participation** - We do not have a compensation committee. During 2010, 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, ONEOK Partners GP or any of their subsidiaries.

**Section 16(a) Beneficial Ownership Reporting Compliance** - Section 16(a) of the Exchange Act requires executive officers, members of our 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 2010 fiscal year or written representations from certain reporting persons that no Form 5s were required for those persons, we believe that during 2010 our reporting persons complied with all applicable filing requirements in a timely manner.

## 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. 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 the Executive Compensation Discussion and Analysis section of ONEOK's 2011 Proxy Statement as filed with the SEC (ONEOK 2011 Proxy Statement), which is incorporated herein by this reference. A copy of the ONEOK 2011 Proxy Statement will be provided on, and may be copied from, ONEOK's website at www.oneok.com and is available free of charge from the secretary of our general partner upon request.

Under our Services Agreement with ONEOK, a portion of the compensation paid by ONEOK to our named executive officers is allocated to us and reimbursed by us to ONEOK. The compensation amounts shown in the following table represent that portion of the named executive officer's total compensation that is allocated to and reimbursed by us under the Services Agreement.

The following table summarizes the compensation allocated to and reimbursed by us in 2010 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 2010**

| Name and 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 | 2010 | $ 492,990 | $ 1,912,411 | $ 547,767 | $ 1,412,014 | $ 67,628 | $ 4,432,810 |
| *Chairman, President and* | 2009 | $ 472,539 | $ 1,613,278 | $ 644,372 | $ 1,287,541 | $ 57,667 | $ 4,075,397 |
| *Chief Executive Officer* | 2008 | $ 442,365 | $ 1,408,168 | $ 457,379 | $ 1,085,848 | $ 63,181 | $ 3,456,941 |
| Curtis L. Dinan | 2010 | $ 219,107 | $ 440,358 | $ 178,024 | $ 123,771 | $ 25,844 | $ 987,104 |
| *Senior Vice President, Chief* | 2009 | $ 229,110 | $ 378,112 | $ 220,518 | $ 75,953 | $ 23,303 | $ 926,996 |
| *Financial Officer and Treasurer* | 2008 | $ 214,480 | $ 408,192 | $ 147,455 | $ 44,230 | $ 25,094 | $ 839,451 |
| Terry K. Spencer | 2010 | $ 415,000 | $ 1,330,050 | $ 400,000 | $ 220,450 | $ 45,080 | $ 2,410,580 |
| *Chief Operating Officer* | 2009 | $ 283,667 | $ 483,476 | $ 258,444 | $ 105,954 | $ 28,479 | $ 1,160,020 |
| | 2008 | $ 249,687 | $ 263,583 | $ 179,291 | $ 66,818 | $ 29,720 | $ 789,099 |
| Sheridan C. Swords | 2010 | $ 315,000 | $ 550,180 | $ 235,000 | $ 34,311 | $ 47,780 | $ 1,182,271 |
| *President - Natural Gas Liquids* | 2009 | $ 286,458 | $ 379,653 | $ 230,000 | $ 19,505 | $ 39,563 | $ 955,179 |
| | 2008 | $ 250,000 | $ 315,012 | $ 160,000 | $ 16,134 | $ 46,436 | $ 787,582 |
| Robert S. Mareburger | 2010 | $ 300,000 | $ 550,180 | $ 220,000 | $ - | $ 53,430 | $ 1,123,610 |
| *President - Natural Gas* | 2009 | $ 200,470 | $ 103,666 | $ 142,723 | $ - | $ 35,315 | $ 482,174 |
| | 2008 | $ 123,326 | $ 77,361 | $ 67,025 | $ - | $ 17,695 | $ 285,407 |

(1) The amounts included in the table relate to restricted stock incentive units and performance units granted under the ONEOK Long-Term Incentive Plan (LTI Plan) and the ONEOK Equity Compensation Plan, respectively, and reflect the aggregate grant date fair value attributable to us in 2008, 2009 and 2010 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 K to the ONEOK audited financial statements for the year ended December 31, 2010, included in the ONEOK 2010 Annual Report on Form 10-K filed with the SEC on February 22, 2011.

The aggregate grant date fair value of restricted stock incentive units for purposes of ASC Topic 718 was determined based on the closing 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), and 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 performance 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:

| Name | 2010 | 2009 | 2008 |
|---|---|---|---|
| John W. Gibson | $ 3,203,248 | $ 2,688,835 | $ 2,352,846 |
| Curtis L. Dinan | $ 737,590 | $ 635,237 | $ 658,797 |
| Terry K. Spencer | $ 2,212,140 | $ 742,431 | $ 427,980 |
| Sheridan C. Swords | $ 913,710 | $ 604,404 | $ 509,008 |
| Robert S. Mareburger | $ 913,710 | $ 149,392 | $ 117,642 |

(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 "2010 Annual Short-Term Incentive Awards" in the Executive Compensation Discussion and Analysis section of the ONEOK 2011 Proxy Statement.

(3) Reflects the portion of the aggregate current year change in pension values and above-market earnings on nonqualified deferred compensation allocated to us for each named executive officer. For a discussion of the Retirement Plan for Employees of

ONEOK, Inc. and Subsidiaries, the ONEOK, Inc. Supplemental Executive Retirement Plan, and the ONEOK Nonqualified Deferred Compensation Plan, see the Executive Compensation and Discussion and Analysis section of the ONEOK 2011 Proxy Statement. The present value is based on the earliest age for which an unreduced benefit is available (age 62) and assumptions from the December 31, 2008, through the December 31, 2010, measurement dates for the ONEOK pension plan.

In 2008 ONEOK changed its pension plan measurement date, for financial accounting purposes, to December 31 of each year from September 30. As a result, the amounts 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 allocated to us that were earned over the 15-month period ending on December 31, 2008.

No ONEOK named executive officers received above-market earnings in 2008, 2009 or 2010 under the ONEOK Nonqualified Deferred Compensation Plan. For additional information on the ONEOK Nonqualified Deferred Compensation Plan, see "Long-Term Compensation Plans-Nonqualified Deferred Compensation Plan" in the Executive Compensation Discussion and Analysis section of the ONEOK 2011 Proxy Statement.

(4) Reflects the portion allocated to us of the amounts paid as ONEOK's dollar-for-dollar match of contributions made by the named executive officer under both the ONEOK, Inc. Nonqualified Deferred Compensation Plan, the Thrift Plan for Employees of ONEOK, Inc. and Subsidiaries and the ONEOK Profit Sharing Plan, as follows:

| Name | Year | Match Under Nonqualified Deferred Compensation Plan (a) | Match Under Thrift Plan (b) | Company contribution to Profit Sharing Plan (c) | Service Award | Stock Award |
|---|---|---|---|---|---|---|
| John W. Gibson | 2010 | $ 58,501 | $ 8,052 | $ - | $ 137 | $ 30 |
| | 2009 | $ 49,247 | $ 8,420 | $ - | $ - | $ - |
| | 2008 | $ 55,336 | $ 7,400 | $ - | $ - | $ - |
| Curtis L. Dinan | 2010 | $ 17,748 | $ 8,052 | $ - | $ - | $ 30 |
| | 2009 | $ 14,778 | $ 8,420 | $ - | $ 72 | $ - |
| | 2008 | $ 17,694 | $ 7,400 | $ - | $ - | $ - |
| Terry K. Spencer | 2010 | $ 30,300 | $ 14,700 | $ - | $ - | $ 55 |
| | 2009 | $ 17,138 | $ 11,341 | $ - | $ - | $ - |
| | 2008 | $ 19,823 | $ 9,897 | $ - | $ - | $ - |
| Sheridan C. Swords | 2010 | $ 33,000 | $ 14,700 | $ - | $ - | $ 55 |
| | 2009 | $ 24,863 | $ 14,700 | $ - | $ - | $ - |
| | 2008 | $ 32,086 | $ 13,800 | $ - | $ 375 | $ - |
| Robert S. Mareburger | 2010 | $ 26,400 | $ 14,700 | $ 12,250 | $ - | $ 55 |
| | 2009 | $ 12,633 | $ 11,341 | $ 11,341 | $ - | $ - |
| | 2008 | $ 4,129 | $ 7,400 | $ 6,166 | $ - | $ - |

(a) For additional information on the ONEOK, Inc. Employee Nonqualified Deferred Compensation Plan, see "Long-Term Compensation Plans - Nonqualified Deferred Compensation Plan" in the Executive Compensation Discussion and Analysis section of the ONEOK 2011 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.

(c) ONEOK's profit-sharing plan covers all non-bargaining unit employees hired after December 31, 2004. ONEOK plans to make a contribution to the profit-sharing plan each quarter equal to 1 percent of each participant's eligible compensation during the quarter. Additional discretionary employer contributions may be made by ONEOK at the end of each year. Employee contributions are not allowed under the plan.

With respect to Messrs. Gibson, Dinan, Spencer, Swords and Mareburger, this amount also reflects the portion of tax gross-ups received and allocated to us in 2010 in the amount of $22, $14, $25, $25 and $25, respectively, in connection with their receipt of a stock award under ONEOK's Employee Stock Award Program.

With respect to Mr. Gibson, this amount also reflects that portion of tax gross-ups received and allocated to us in 2010 in the amount of $99 in connection with his receipt of a ONEOK cash service award.

With respect to Mr. Dinan, this amount also reflects that portion of tax gross-ups received and allocated to us in 2009 in the amount of $34 in connection with his receipt of a ONEOK cash service award.

With respect to Mr. Swords, this amount also reflects that portion of tax gross-ups received and allocated to us in 2008 in the amount of $176 in connection with his receipt of a ONEOK cash service award.

With respect to Mr. Gibson, this amount also reflects the portion of tax gross-up received and allocated to us in 2010 and 2008 in the amount of $787 and $445, respectively, with respect to income imputed to him under the Internal Revenue Code in connection with his personal use of ONEOK's aircraft.

The named executive officers did not receive perquisites or other personal benefits with an aggregate value of $10,000 or more during 2008, 2009 or 2010.

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

The following is a description of 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 ONEOK shareholders and our unitholders;
- avoid the costs associated with negotiating executive severance benefits separately; and
- provide ONEOK and us with the flexibility needed to react to a continually changing business environment.

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

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 ONEOK's 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 ONEOK, in its sole discretion, provided, that nothing contained in these provisions of these agreements are to be deemed to interfere in any way with ONEOK's 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 ONEOK from those in effect on the date of a change in control, a reduction of salary of the executive from that received from ONEOK 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 ONEOK's principal executive offices to a location outside the metropolitan area of Tulsa, Oklahoma, or ONEOK 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 by ONEOK 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, 2010, 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 ONEOK.

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 $533,711 and $211,668 as of December 31, 2010.

| John W. Gibson | Termination Upon Death, Disability or Retirement | Termination Without Cause | Qualifying Termination Following a Change in Control |
|---|---|---|---|
| Cash Severance | $ - | $ - | $ 3,298,725 |
| Equity | | | |
| Restricted Stock/Units | $ 4,344,004 | $ 4,344,004 | $ 5,879,465 |
| Performance Shares/Units | $ 5,294,263 | $ - | $ 5,746,936 |
| Total | $ 9,638,267 | $ 4,344,004 | $ 11,626,401 |
| Other Benefits | | | |
| Health & Welfare | $ - | $ - | $ 12,970 |
| SERP Enhancement | $ - | $ - | $ 842,734 |
| Excise Tax Gross-up | $ - | $ - | $ 5,164,532 |
| Total | $ - | $ - | $ 6,020,236 |
| Total | $ 9,638,267 | $ 4,344,004 | $ 20,945,362 |

| Curtis L. Dinan | Termination Upon Death, Disability or Retirement | Termination Without Cause | Qualifying Termination Following a Change in Control |
|---|---|---|---|
| Cash Severance | $ - | $ - | $ 852,510 |
| Equity | | | |
| Restricted Stock/Units | $ 215,443 | $ 215,443 | $ 343,370 |
| Performance Shares/Units | $ 1,309,132 | $ - | $ 1,412,638 |
| Total | $ 1,524,575 | $ 215,443 | $ 1,756,008 |
| Other Benefits | | | |
| Health & Welfare | $ - | $ - | $ 12,439 |
| SERP Enhancement | $ - | $ - | $ - |
| Excise Tax Gross-up | $ - | $ - | $ - |
| Total | $ - | $ - | $ 12,439 |
| Total | $ 1,524,575 | $ 215,443 | $ 2,620,957 |

| Terry K. Spencer | Termination Upon Death, Disability or Retirement | Termination Without Cause | Qualifying Termination Following a Change in Control |
|---|---|---|---|
| Cash Severance | $ - | $ - | $ 1,500,000 |
| Equity | | | |
| Restricted Stock/Units | $ 398,460 | $ 398,460 | $ 765,486 |
| Performance Shares/Units | $ 2,116,279 | $ - | $ 2,562,714 |
| Total | $ 2,514,739 | $ 398,460 | $ 3,328,200 |
| Other Benefits | | | |
| Health & Welfare | $ - | $ - | $ 22,908 |
| SERP Enhancement | $ - | $ - | $ - |
| Excise Tax Gross-up | $ - | $ - | $ - |
| Total | $ - | $ - | $ 22,908 |
| Total | $ 2,514,739 | $ 398,460 | $ 4,851,108 |

| Sheridan C. Swords | Termination Upon Death, Disability or Retirement | Termination Without Cause | Qualifying Termination Following a Change in Control |
|---|---|---|---|
| Cash Severance | $ - | $ - | $ 315,000 |
| Equity | | | |
| Restricted Stock/Units | $ 230,971 | $ 230,971 | $ 399,384 |
| Performance Shares/Units | $ 1,269,112 | $ - | $ 1,420,032 |
| Total | $ 1,500,083 | $ 230,971 | $ 1,819,416 |
| Other Benefits | | | |
| Health & Welfare | $ - | $ - | $ - |
| SERP Enhancement | $ - | $ - | $ - |
| Excise Tax Gross-up | $ - | $ - | $ - |
| Total | $ - | $ - | $ - |
| Total | $ 1,500,083 | $ 230,971 | $ 2,134,416 |

| Robert S. Mareburger | Termination Upon Death, Disability or Retirement | Termination Without Cause | Qualifying Termination Following a Change in Control |
|---|---|---|---|
| Cash Severance | $ - | $ - | $ 75,000 |
| Equity | | | |
| Restricted Stock/Units | $ 138,367 | $ 138,367 | $ 271,803 |
| Performance Shares/Units | $ 627,247 | $ - | $ 848,691 |
| Total | $ 765,614 | $ 138,367 | $ 1,120,494 |
| Other Benefits | | | |
| Health & Welfare | $ - | $ - | $ - |
| SERP Enhancement | $ - | $ - | $ - |
| Excise Tax Gross-up | $ - | $ - | $ - |
| Total | $ - | $ - | $ - |
| Total | $ 765,614 | $ 138,367 | $ 1,195,494 |

## ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

### Holdings of Major Unitholders

The following table sets forth the beneficial owners of 5 percent or more of our common units and Class B units known to us at February 1, 2011. Other than as set forth below, no person is known to us to beneficially own more than 5 percent of our common units or Class B units.

| Name and Address of Beneficial Owner | Common Units | | Percent of Common Units | | Class B Units | Percent of Class B Units | Percent of All Units | |
|---|---|---|---|---|---|---|---|---|
| ONEOK, Inc. and affiliates<br>100 West Fifth Street<br>Tulsa, OK 74103-4298 | 5,900,000 | | 9.0% | | 36,494,126 | 100% | 41.6% | (1) |
| Tortoise Capital Advisors, L.L.C.<br>11550 Ash Street, Suite 300<br>Leawood, Kansas 66211 | 3,285,613 | (2) | 5.0% | (2) | - | - | 3.2% | |

(1) Does not reflect the general partner's 2 percent interest, which is wholly-owned by ONEOK.

(2) Based upon the Schedule 13G filed with the Securities and Exchange Commission on February 11, 2011, in which Tortoise Capital Advisors, L.L.C. reported that, as of December 31, 2010, it beneficially owned 3,285,613 common units over which it had shared dispositive power and 3,078,442 shares of our common units over which it had shared voting power.

**Holdings of Officers and Directors**

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, 2011, 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.

| 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 | 17,500 | * | - | - | * | 168,982 | (3) | * |
| Curtis L. Dinan** | 10,000 | * | - | - | * | 32,160 | (4) | * |
| Robert F. Martinovich** | 144 | * | - | - | * | 6,621 | (5) | * |
| Terry K. Spencer | - | - | - | - | - | 34,868 | (6) | * |
| Sheridan C. Swords | - | - | - | - | - | 7,042 | (7) | * |
| Gary N. Petersen | 11,392 | * | - | - | * | - | | * |
| Gerald B. Smith | - | - | - | - | - | 750 | | * |
| Gil J. Van Lunsen | 2,000 | * | - | - | * | - | | - |
| Julie H. Edwards | - | - | - | - | - | 12,584 | | * |
| Jim W. Mogg | 1,000 | * | - | - | * | - | | - |
| Shelby E. Odell | 1,000 | * | - | - | * | - | | - |
| Craig F. Strehl | 4,700 | * | - | - | * | - | | - |
| All directors and executive officers as a group | 47,736 | * | - | - | * | 263,007 | | * |

* Less than 1 percent

**Effective March 1, 2011, Mr. Martinovich will succeed Mr. Dinan as Senior Vice President, Chief Financial Officer and Treasurer and as a member of our Board of Directors.

(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, 2011, upon exercise of stock options granted under the ONEOK Long-Term Incentive Plan.

(3) Includes options for 30,009 shares exercisable within 60 days of February 1, 2011. Excludes 41,391 shares, the receipt of which was deferred upon vesting in January 2010 and 49,275 shares, the receipt of which was defered upon vesting in January 2011, in each case under the deferral provisions of the ONEOK Equity Compensation Plan, and which shares will be issued to Mr. Gibson on July 17, 2013 and 2014, respectively.

(4) Excludes 12,565 shares, the receipt of which was deferred upon vesting in January 2010 and 13,797 shares, thre receipt of which was deferred upon vesting in January 2011, in each case under the deferral provisions of the ONEOK Equity Compensation Plan, and which shares will be issued to Mr. Dinan upon his separation of services from the company.

(5) Excludes 5,709 shares, the receipt of which was deferred upon vesting in January 2011, under the deferral provisions of the ONEOK Equity Compensation Plan, and which shares will be issued to Mr. Martinovich upon his separation of services from the company.

(6) Includes options for 5,500 shares exercisable within 60 days of February 1, 2011.

(7) Excludes 1,385 shares, the receipt of which was deferred upon vesting in January 2010 and 5,706 shares, the receipt of which was deferred upon veseting in January 2011, in each case under 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 the best interest of the Partnership 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 member of their immediate family have a direct or indirect material interest, the transaction is presented to our Audit Committee and, if warranted, our Conflicts Committee for review to determine if the transaction creates a conflict of interest and is otherwise fair and reasonable to the Partnership. In determining whether a particular transaction creates a conflict of interest and, if so, is fair and reasonable to the Partnership, our Audit Committee and, if warranted, our Conflicts Committee consider the specific facts and circumstances applicable to each such transaction, including: the parties to the transaction; their relationship to the Partnership and nature of their interest in the transaction; the nature of the transaction; the aggregate value of the transaction; the length of the transaction; whether the transaction occurs in the normal course of our business; the benefits to the Partnership provided by the transaction; if applicable, the availability of other sources of comparable products or services; and, if applicable, whether the terms of the transaction, including price or other consideration, are the same or substantially the same as those available to the Partnership if the transaction were entered into with an unrelated party.

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 appoints members of our Board of Directors and our Audit and Conflicts Committees. 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 42.8-percent ownership interest in us at December 31, 2010. In 2010, our general partner declared total cash distributions to ONEOK of $563 million, which included $103.5 million related to its incentive distribution rights. Additional information about our cash distribution policy is included in Item 5, Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities.

**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 provides to us similar 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 financial services, employee benefits provided through ONEOK's benefit plans, legal and 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 company, but which has no direct basis for allocation, is allocated by the modified Distrigas method, a widely recognized method of allocating cost which uses a combination of ratios that include gross plant and investment, operating income and payroll expense. All costs directly charged or allocated to us are reflected in our Consolidated Statements of Income.

In 2010, the aggregate amount charged by ONEOK, NBP Services and their affiliates to us for their services was approximately $207.3 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** - ONEOK Energy Services Company ("OES"), a subsidiary of ONEOK, became an affiliate of Northern Border Pipeline in November 2004 in connection with ONEOK's purchase of the controlling interest in ONEOK Partners GP. We own 50 percent of Northern Border Pipeline, but do not serve as its operator. In 2010, 1.0 percent of Northern Border Pipeline's design capacity was contracted on a firm basis with OES. Revenue from OES for 2010 was $4.1 million. As of January 31, 2011, 1.0 percent of Northern Border Pipeline's design capacity was contracted on a firm basis with OES for 2011.

Our Natural Gas Gathering and Processing segment sold $347.9 million of natural gas to ONEOK and its subsidiaries during 2010. Of our Natural Gas Pipelines segment's revenues, $109.8 million were from ONEOK and its subsidiaries during 2010 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 2010, the aggregate amount charged by ONEOK and its affiliates to us for their services was approximately $53.1 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 2010, the aggregate amount charged by ONEOK and its affiliates related to the Bushton Plant was approximately $9.2 million.

**Derivative Contracts** - OES, a subsidiary 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 C 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 an affiliate of 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, which is the parent company of our general partner, appoints the members of our Board of Directors and our Audit and Conflicts Committees and may change the composition or size of our Board and the Board's committees at its discretion.

ONEOK 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;
- 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; and
- The limited liability company agreement of Overland Pass Pipeline Company provides that members and their respective affiliates may engage, directly or indirectly, without the consent of the other members or Overland Pass Pipeline Company, in other business opportunities, transactions, ventures or other arrangements of any nature which may be competitive with or the same as or similar to the business of Overland Pass Pipeline Company, regardless of the geographic location of such business, and without any duty or obligation to account to the other members or Overland Pass Pipeline Company.

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 2010 and 2009 fiscal years included integrated audits of our consolidated financial statements and internal control over financial reporting, audits of the financial statements of certain of our affiliates, review of our quarterly financial statements, consents, and review of documents filed with the SEC.

The following table presents fees billed for services rendered by PricewaterhouseCoopers LLP for the years ended December 31, 2010 and 2009:

| | | **2010** | | **2009** |
|---|---|---|---|---|
| | | *(Thousands of dollars)* | | |
| Audit fees | **$** | **1,362.6** | $ | 1,423.7 |
| Audit-related fees | | **-** | | - |
| Tax fees (1) | | **819.5** | | 842.5 |
| All other fees (2) | | **1.0** | | 0.8 |
| Total | **$** | **2,183.1** | $ | 2,267.0 |

(1) Tax fees consisted of fees for tax compliance, tax planning or tax services, including preparation of our annual 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 2010 audit, a plan was submitted to and approved by the Audit Committee setting forth the services expected to be rendered during 2010 for each of the following four categories:

(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 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 has adopted a policy that provides that fees for services that are not included in the independent auditor's annual services plan, and for services for which fees are not determinable on an annual basis, are pre-approved if the fees for such services will not exceed $75,000. In addition, the policy provides that 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 Not used.

4.2 Not used.

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 Not used.

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 Not used.

10.5 Form of Termination Agreement with ONEOK, Inc. dated as of January 5, 2005 (incorporated by reference to Exhibit 99.1 to Northern Border Partners, L.P.'s Form 8-K filed on January 11, 2005 (File No. 1-12202)).

10.6 Amended and Restated Limited Liability Company Agreement of Overland Pass Pipeline Company LLC entered into between ONEOK Overland Pass Holdings, L.L.C. and Williams Field Services Company, LLC dated May 31, 2006 (incorporated by reference to Exhibit 10.6 to ONEOK Partners, L.P.'s Form 10-Q for the period ended June 30, 2006, filed on August 4, 2006 (File No. 1-12202)).

10.7 Processing and Gathering Services Agreement between ONEOK Field Services Company, L.L.C, ONEOK, Inc. and ONEOK Bushton Processing, Inc. dated April 6, 2006 (incorporated by reference to Exhibit 10.7 to ONEOK Partners, L.P.'s Form 10-Q for the period ended June 30, 2006, filed on August 4, 2006 (File No. 1-12202)).

10.8 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 Not used.

10.14 Not used.

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).

10.16 Commercial Paper Dealer Agreement between ONEOK Partners, L.P. and Citigroup Global Markets Inc. dated as of June 16, 2010 (incorporated by reference to Exhibit 10.1 to ONEOK Partners, L.P.'s Current Report on Form 8-K filed on June 22, 2010).

10.17 Commercial Paper Dealer Agreement between ONEOK Partners, L.P. and Banc of America Securities LLC dated as of June 16, 2010 (incorporated by reference to Exhibit 10.2 to ONEOK Partners, L.P.'s Current Report on Form 8-K filed on June 22, 2010).

12 Computation of Ratio of Earnings to Fixed Charges for the years ended December 31, 2010, 2009, 2008, 2007 and 2006.

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 Not used.

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)).

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.

Attached as Exhibit 101 to this Annual Report are the following documents formatted in XBRL: (i) Document and Entity Information; (ii) Consolidated Statements of Income for the years ended December 31, 2010, 2009 and 2008; (iii) Consolidated Balance Sheets at December 31, 2010 and 2009; (iv) Consolidated Statements of Cash Flows for the years ended December 31, 2010, 2009 and 2008; (v) Consolidated Statement of Changes in Equity for the years ended December 31, 2010, 2009 and 2008; (vi) Consolidated Statements of Comprehensive Income for the years ended December 31, 2010, 2009 and 2008; and (vii) Notes to Consolidated Financial Statements.

Users of this data are advised pursuant to Rule 401 of Regulation S-T that the information contained in the XBRL documents is unaudited, and these XBRL documents are not the official publicly filed consolidated financial statements of ONEOK Partners, L.P. The purpose of submitting these XBRL formatted documents is to test the related format and technology, and as a result, investors should continue to rely on the official filed version of the furnished documents and not rely on this information in making investment decisions.

In accordance with Rule 402 of Regulation S-T, the XBRL related information in Exhibit 101 to this Annual Report 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. We also make available on our website the Interactive Data Files submitted as Exhibit 101 to this Annual Report.

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 22, 2011

By: /s/ Curtis L. Dinan
Curtis L. Dinan
Senior 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 22nd day of February 2011.

/s/ John W. Gibson
John W. Gibson
Chairman of the Board, President and
Chief Executive Officer

/s/ Curtis L. Dinan
Curtis L. Dinan
Director, Senior 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

## 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, ethane/propane mix, propane, iso-butane, 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 commodity-price, interest-rate and throughput volatility, as well as disruptions in the operations of the company's assets.

**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.

ONEOK Partners is listed on the New York Stock Exchange under the symbol OKS.

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 involved in natural gas distribution and energy services.

ONEOK owns 42.8 percent of the partnership.

**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**
Wells Fargo Shareowner Services
P.O. Box 64854
St. Paul, MN 55164-0854
Phone toll free: 866-605-8639
Website: www.shareowneronline.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 Website**
ONEOK Partners business and financial information is available at www.oneokpartners.com.

## NON-GAAP (GENERALLY ACCEPTED ACCOUNTING PRINCIPLES) FINANCIAL MEASURE

ONEOK Partners has disclosed in this annual report anticipated earnings before interest, taxes, depreciation and amortization (EBITDA) that is a non-GAAP financial measure. EBITDA is used as a measure of the partnership's financial performance. EBITDA is defined as net income adjusted for interest expense, depreciation and amortization, income taxes and allowance for equity funds used during construction. The partnership believes the non-GAAP financial measure described above is useful to investors because this measurement is used by many companies in its industry as a measurement of financial performance and is commonly employed by financial analysts and others to evaluate the financial performance of the partnership and to compare the financial performance of the partnership with the performance of other publicly traded partnerships within its industry. EBITDA should not be considered an alternative to net income, earnings per unit or any other measure of financial performance presented in accordance with GAAP. This non-GAAP financial measure excludes some, but not all, items that affect net income. Additionally, these calculations may not be comparable with similarly titled measures of other companies.

## FORWARD-LOOKING STATEMENT

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 the ONEOK Partners, L.P. Annual Report on Form 10-K for the year ended December 31, 2010, included in this annual report.

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