As filed with the Securities and Exchange Commission on June 27, 2007

Registration No. 333-

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

FORM S-1

REGISTRATION STATEMENT
UNDER THE SECURITIES ACT OF 1933

OGE ENOGEX PARTNERS L.P.

(Exact name of registrant as specified in its charter)

Delaware	**4922**	**26-0320188**
(State or jurisdiction of incorporation or organization)	(Primary Standard Industrial Classification Code Number)	(I.R.S. Employer Identification No.)

600 Central Park Two, 515 Central Park Drive
Oklahoma City, Oklahoma 73124
(405) 525-7788
(Address, including zip code, and telephone number, including area code, of registrant's principal executive offices)

James R. Hatfield
Senior Vice President and Chief Financial Officer
321 North Harvey
Oklahoma City, Oklahoma 73101-0321
(405) 553-3000
(Name, address, including zip code, and telephone number, including area code, of agent for service)

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		(713) 758-2222

Approximate date of commencement of proposed sale to the public:
As soon as practicable after this Registration Statement becomes effective.

If any of the securities being registered on this Form are to be offered on a delayed or continuous basis pursuant to Rule 415 under the Securities Act of 1933, check the following box. ☐

If this Form is filed to register additional securities for an offering pursuant to rule 462(b) under the Securities Act, please check the following box and list the Securities Act registration statement number of the earlier effective registration statement for the same offering. ☐

If this Form is a post-effective amendment filed pursuant to Rule 462(c) under the Securities Act, check the following box and list the Securities Act registration statement number of the earlier effective registration statement for the same offering. ☐

If this Form is a post-effective amendment filed pursuant to Rule 462(d) under the Securities Act, check the following box and list the Securities Act registration statement number of the earlier effective registration statement for the same offering. ☐

CALCULATION OF REGISTRATION FEE

Title of Each Class of Securities to Be Registered	Proposed Maximum Aggregate Offering Price(1)(2)	Amount of Registration Fee
Common units representing limited partner interests . .	$181,125,000	$5,561

(1) Includes common units issuable upon exercise of the Underwriters' over-allotment option.

(2) Estimated solely for the purpose of calculating the registration fee pursuant to Rule 457(o).

The Registrant hereby amends this Registration Statement on such date or dates as may be necessary to delay its effective date until the Registrant shall file a further amendment which specifically states that this Registration Statement shall thereafter become effective in accordance with Section 8(a) of the Securities Act of 1933 or until the Registration Statement shall become effective on such date as the Securities and Exchange Commission, acting pursuant to Section 8(a), may determine.

PROSPECTUS

OGE ENOGEX PARTNERS L.P.
7,500,000 Common Units
Representing Limited Partner Interests

This is the initial public offering of our common units. All of the common units are being sold by us. We currently estimate that the initial public offering price will be between $ and $ per common unit. Prior to this offering, there has been no public market for our common units. We intend to apply to list our common units on the New York Stock Exchange under the symbol "OGP." After this offering, we will own a 25% interest in Enogex LLC and OGE Energy Corp. will own the remaining 75% interest.

Investing in our common units involves risks. Please see "Risk Factors" beginning on page 18.

These risks include the following:

- Because our interest in Enogex LLC currently represents our only cash-generating asset, our cash flows initially will depend completely on Enogex LLC's ability to make distributions to its members, including us.
- We may not have sufficient cash from operations to enable us to pay the minimum quarterly distribution on our common units or to increase distributions.
- Natural gas, natural gas liquids and other commodity prices are volatile, and changes in these prices could adversely affect our and Enogex LLC's revenue and cash available for distribution.
- Because of the natural decline in production from existing wells connected to Enogex LLC's systems, Enogex LLC's success depends on its ability to gather new sources of natural gas, which depends on certain factors beyond its or our control. Any decrease in supplies of natural gas could adversely affect our and Enogex LLC's business and results of operations and cash available for distribution.
- Enogex LLC depends on certain key natural gas producer customers for a significant portion of its supply of natural gas and natural gas liquids. The loss of, or reduction in volumes from, any of these customers could result in a decline in our and Enogex LLC's cash available for distribution.
- Enogex LLC depends on two customers for a significant portion of its firm intrastate transportation and storage services. The loss of, or reduction in volumes from, either of these customers could result in a decline in Enogex LLC's transportation and storage services and our and Enogex LLC's cash available for distribution.
- If third-party pipelines and other facilities interconnected to Enogex LLC's gathering or transportation facilities become partially or fully unavailable, our and Enogex LLC's revenues and cash available for distribution could be adversely affected.
- OGE Energy Corp. controls our general partner, which has sole responsibility for conducting our business and managing our operations. Our general partner and its affiliates, including OGE Energy Corp., may have conflicts of interest and may favor their own interests to your detriment.
- Although we control Enogex LLC through our ownership of its managing member, Enogex LLC's managing member owes fiduciary duties to Enogex LLC and its non-managing member, which may conflict with the interests of us and our unitholders.
- After this offering, we will own a 25% interest in Enogex LLC and OGE Energy Corp. will own the remaining 75% interest. OGE Energy Corp. is not obligated to offer us the remaining 75% interest in Enogex LLC.
- OGE Energy Corp. and certain of its affiliates are not limited in their ability to compete with us, which could cause conflicts of interest and limit our ability to acquire additional assets or businesses, which in turn could adversely affect our results of operations and cash available for distribution to our unitholders.
- Holders of our common units have limited voting rights and are not entitled to elect our general partner or its directors.
- Following the completion of this offering, an affiliate of our general partner will own a sufficient number of our common units to allow it to block any attempt to remove our general partner.
- You will experience immediate and substantial dilution of $10.46 in tangible net book value per common unit.
- 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 treats us as a corporation or we become subject to a material amount of additional entity-level taxation for state tax purposes, then our cash available for distribution to our unitholders would be substantially reduced.
- You may be required to pay taxes on your share of our income even if you do not receive any cash distributions from us.

	Per Common Unit	Total
Initial public offering price	$	$
Underwriting discount(1)	$	$
Proceeds, before expenses, to OGE Enogex Partners L.P.	$	$

(1) Excludes structuring fee of $ payable to UBS Securities LLC.

We have granted the underwriters a 30-day option to purchase up to an additional 1,125,000 common units from us on the same terms and conditions as set forth above if the underwriters sell more than 7,500,000 common units in this offering.

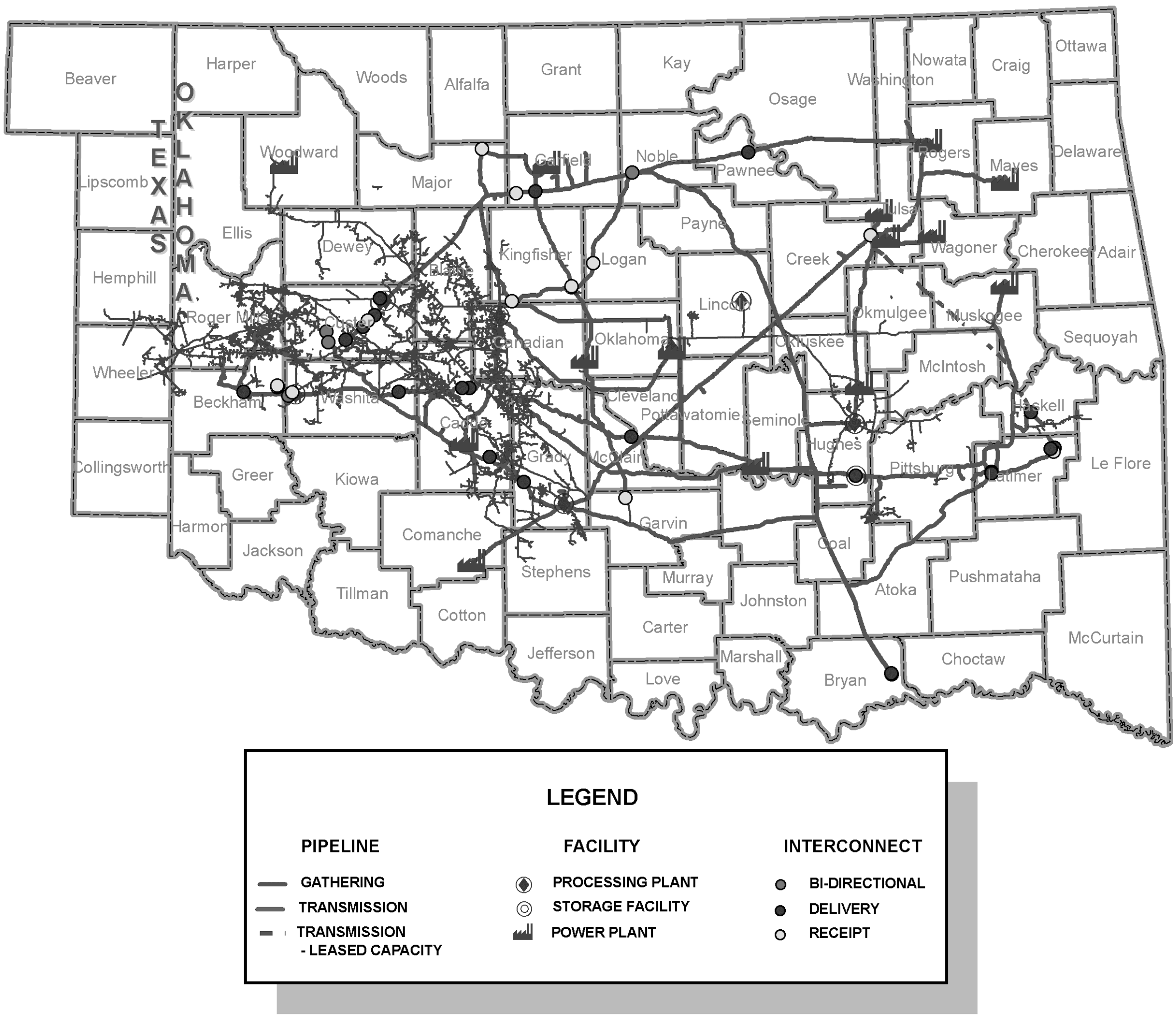
Neither the Securities and Exchange Commission nor any state securities commission has approved or disapproved of these securities or passed upon the adequacy or accuracy of this prospectus. Any representation to the contrary is a criminal offense.

The underwriters expect to deliver the common units on or about , 2007.

UBS Investment Bank **Lehman Brothers**

, 2007

OGE ENOGEX PARTNERS L.P.



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You should rely only on the information contained in this prospectus. We have not, and the underwriters have not, authorized anyone to provide you with different information. If anyone provides you with different or inconsistent information, you should not rely on it. We are not, and the underwriters are not, making an offer to sell these securities in any jurisdiction where an offer or sale is not permitted. You should assume that the information appearing in this prospectus is accurate as of the date on the front cover of this prospectus. Our business, financial condition, results of operations and prospects may have changed since that date.

Until   , 2007 (25 days after the date of this prospectus), all dealers that buy, sell or trade our common units, whether or not participating in this offering, may be required to deliver a prospectus. This is in addition to the dealers' obligation to deliver a prospectus when acting as underwriters and with respect to their unsold allotments or subscriptions.

SUMMARY

This summary provides a brief overview of information contained elsewhere in this prospectus. Because it is abbreviated, this summary may not contain all of the information that you should consider before investing in our common units. You should read the entire prospectus carefully, including the historical and pro forma consolidated financial statements and the notes to those financial statements. Unless indicated otherwise, the information presented in this prospectus assumes (1) an initial public offering price of $20.00 per common unit and (2) that the underwriters do not exercise their option to purchase additional common units. You should read "Risk Factors" beginning on page 18 for more information about important risks that you should consider carefully before investing in our common units. We include a glossary of some of the terms used in this prospectus as Appendix B.

Except as otherwise set forth in the prospectus, all references in this prospectus to "our," "we," "us" and "the partnership" refer to OGE Enogex Partners L.P. and its subsidiaries, including its interest in Enogex LLC, or "Enogex," after giving effect to the formation transactions described below, including the conversion of Enogex Inc. to Enogex LLC, a Delaware limited liability company. All references in this prospectus to "Enogex Predecessor" or to "Enogex" when used in a historical context refer to Enogex Inc. and its subsidiaries. All references in this prospectus to "Enogex" when used in the present tense or prospectively refer to Enogex LLC and its subsidiaries, collectively, or to Enogex LLC individually, as the context may require. Upon the completion of this offering, a wholly owned subsidiary of OGE Enogex Partners L.P. will own a 25% membership interest in Enogex and serve as its managing member. A wholly owned subsidiary of OGE Energy Corp. will own the remaining 75% membership interest and will be a non-managing member.

OGE Enogex Partners L.P.

Our Business

We are a provider of integrated natural gas midstream services. We were formed by OGE Energy Corp. (NYSE: OGE), or OGE Energy, to further develop its natural gas midstream assets and operations. OGE Energy is the parent company of Oklahoma Gas and Electric Company, or OG&E, a regulated electric utility, and Enogex Inc., an integrated natural gas midstream services provider. In connection with this offering, Enogex Inc. will convert to Enogex LLC, a Delaware limited liability company. Upon the completion of this offering, a wholly owned subsidiary of OGE Energy will own a 63.9% limited partner interest in us and a 2% general partner interest in us through its ownership of OGE Enogex GP LLC, our general partner. Our wholly owned subsidiary will own a 25% membership interest in Enogex, will be its managing member and will control its assets and operations. A wholly owned subsidiary of OGE Energy will own the remaining 75% membership interest in Enogex and will be a non-managing member.

Enogex's natural gas gathering, processing, transportation and storage assets are strategically located primarily in the Arkoma and Anadarko basins of Oklahoma and the Texas Panhandle. Enogex's transportation pipelines are connected to 11 other major pipelines at approximately 64 pipeline interconnect points providing access to markets in the western United States, the Midwest, Northeast and Gulf Coast in addition to Oklahoma and adjoining states. Through Enogex's gathering and processing assets, Enogex aggregates gas supplies for its markets and also for those markets accessible via its numerous intrastate and interstate pipeline connections. In addition, we believe that current and planned expansion projects will allow Enogex to take advantage of the increasing need for midstream services resulting from significant new natural gas production in the Woodford Shale play in southeastern Oklahoma and in various plays in western Oklahoma and the Texas Panhandle, including the Granite Wash play. As a result, we believe that Enogex's assets are situated in a key geographic region in the United States, with sufficient capacity to provide crosshaul transportation and storage services to (i) a variety of utility and industrial customers that need to access mid-continent natural gas supply and (ii) suppliers from other regions seeking to provide gas to markets that Enogex serves.

Enogex's current operations are organized into three businesses: (1) natural gas transportation and storage, (2) natural gas gathering and processing and (3) natural gas marketing.

- *Transportation and Storage.* Enogex owns and operates approximately 2,283 miles of intrastate natural gas transportation pipelines with approximately 1.44 trillion British thermal units per day, or TBtu/d, of current throughput. Enogex's transportation pipelines are directly connected to 11 third-party natural gas pipelines at 64 interconnect points and to 27 end-user customers, including 15 natural gas-fired electric generation facilities in Oklahoma. Enogex provides fee-based intrastate transportation services on a firm and interruptible basis and, pursuant to Section 311 of the Natural Gas Policy Act of 1978, or the NGPA, provides interstate transportation services on an interruptible basis.

  Enogex owns and operates two natural gas storage facilities, the Wetumka Storage Facility and the Stuart Storage Facility, with approximately 23 billion cubic feet, or Bcf, of aggregate working gas capacity. The storage facilities have approximately 650 million cubic feet per day, or MMcf/d, of maximum withdrawal capacity and approximately 650 MMcf/d of injection capacity. Enogex provides fee-based firm and interruptible storage services to third parties at market-based rates. For the year ended December 31, 2006, Enogex's transportation and storage business generated approximately $126 million of its gross margin on revenues, which is revenues minus cost of goods sold and is referred to herein as gross margin.

- *Gathering and Processing.* Enogex owns and operates approximately 5,474 miles of natural gas gathering pipelines with approximately 0.98 TBtu/d of current throughput and six natural gas processing plants with approximately 720 MMcf/d of aggregate inlet capacity. Enogex provides well connect, gathering, measurement, treating, dehydration, compression and processing services to its producer customers primarily in the Arkoma and Anadarko basins, including those operating in the Granite Wash play in western Oklahoma and the Texas Panhandle and the Woodford Shale play in southeastern Oklahoma. For the year ended December 31, 2006, Enogex processed approximately 0.54 TBtu/d of natural gas and extracted and sold approximately 371 million gallons of natural gas liquids, or NGLs. For the year ended December 31, 2006, Enogex's gathering and processing business generated approximately $168 million of its gross margin.

- *Marketing.* Enogex also conducts certain natural gas marketing activities, primarily in support of its transportation and storage and gathering and processing businesses. For the year ended December 31, 2006, Enogex's marketing business generated approximately $14 million of its gross margin.

Business Strategies

Our primary business objective is to increase our cash distributions per unit over time. We intend to accomplish this objective by executing the following business strategies:

- *Capturing growth opportunities through expansion projects, increasing utilization of existing assets and strategic acquisitions.* Enogex intends to expand its existing operations through organic growth projects, including expanding gathering capacity in western Oklahoma and the Texas Panhandle and the Woodford Shale play in southeastern Oklahoma and participating in the Midcontinent Express pipeline project and the Gulf Crossing pipeline project. We also intend to pursue strategic acquisitions, including acquiring additional interests in Enogex from OGE Energy as well as third-party acquisitions.

- *Maintaining strong customer relationships based upon high quality service, reliability and efficiency of Enogex's existing assets and operations.* Enogex intends to maximize the profitability of its existing assets by adding new volumes of natural gas by providing a comprehensive package of midstream services to customers, reducing project cycle times and providing access to high value markets and a large number of suppliers. Enogex also intends to deliver superior operational performance by engaging in strong safety and responsible environmental practices, fostering strong technical capabilities and focusing on reliability, efficiency and flexibility.
- *Maintaining sound financial practices.* Enogex intends to manage its commodity price exposure and to maintain its commitment to disciplined financial analyses and a balanced capital structure.

Competitive Strengths

We believe that we are well positioned to execute our business strategies successfully because of the following competitive strengths:

- Enogex's assets are strategically located.
- Enogex has transportation and processing flexibility.
- We have a management team and board of directors with significant experience in the natural gas midstream industry.
- Enogex has operated for more than 50 years in the natural gas midstream industry.
- We have the financial flexibility to pursue growth opportunities.
- We focus on operational efficiencies in our business.

Our Relationship with OGE Energy

One of our principal strengths is our relationship with OGE Energy, an energy and energy services provider offering physical delivery and related services for both electricity and natural gas primarily in the south central United States. Since its inception, Enogex has been the transporter of natural gas to OG&E's natural gas-fired electric generation facilities. Enogex's current contract with OG&E provides for no-notice load following transportation services and storage services. For the years ended December 31, 2004, 2005 and 2006, OG&E paid Enogex approximately $49.6 million, $47.6 million and $47.6 million, respectively, under the contract. We believe Enogex also benefits from a higher credit rating due to its relationship with OGE Energy.

In connection with this offering, OGE Energy will contribute a 25% membership interest in Enogex to our wholly owned subsidiary, and a wholly owned subsidiary of OGE Energy will own the remaining 75% membership interest and will own and control our general partner. Following this offering, the subsidiary of OGE Energy will also own an aggregate of approximately 65.2% of our common and subordinated units. OGE Energy has indicated that it intends to use our partnership to manage and further develop its natural gas midstream assets. In addition, OGE Energy has indicated that it intends to offer us the opportunity to purchase all of the remaining ownership interests in Enogex in the future, although OGE Energy is not obligated to do so. While we believe that it will be in OGE Energy's best interest to sell the remaining ownership interest in Enogex to us given its significant ownership interest in us, OGE Energy may elect to acquire, construct or dispose of midstream assets, including its interest in Enogex, in the future without offering us the opportunity to purchase or construct those assets. OGE Energy retained this flexibility because it believes that it is in the best interest of its shareholders to do so. We cannot say with any certainty that we will have the opportunity to acquire the remaining ownership interests in Enogex.

Through our relationship with OGE Energy, we expect to have access to a significant pool of management talent and access to OGE Energy's broad technical, risk management and administrative infrastructure. Please see "Certain Relationships and Related Party Transactions—Omnibus Agreement."

Recent System Expansions

Over the past several years, Enogex has executed on multiple organic growth projects. Currently, Enogex's organic growth capital expenditures are focused on three primary areas:

- upgrades to Enogex's existing transportation system due to increased volumes as a result of the broader shift of gas flow from the Rocky Mountains and the mid-continent to markets in the northeast and southeast United States;
- expansions on the east side of Enogex's gathering system, primarily in the Woodford Shale play in southeastern Oklahoma; and
- expansions on the west side of Enogex's gathering system, primarily in the Granite Wash play in the Wheeler County, Texas area, which is located in the Texas Panhandle.

Pipeline Lease Projects. On December 15, 2006, Enogex announced that it had entered into a firm capacity lease agreement with Midcontinent Express Pipeline, LLC for a primary term of 10 years (subject to possible extension) for capacity on Enogex's system. The leased capacity provided for in this agreement is up to 500 MMcf/d and is dependent on the shipper volumes that commit to the project.

In March 2007, Enogex also entered into a firm capacity lease agreement with Gulf Crossing Pipeline Company LLC, or Gulf Crossing, for a primary term of seven years (subject to a possible extension) for capacity on Enogex's system. The leased capacity provided for in this agreement is up to 165 MMcf/d and is dependent on the shipper volumes that commit to the project.

Southeastern Oklahoma / East Side Expansions. Enogex is expanding in the Woodford Shale play and has several projects either completed or scheduled for completion in 2007 and 2008. For example, in December 2006, Enogex entered into a joint venture arrangement with Pablo Gathering, a subsidiary of Pablo Energy II, LLC, a Texas-based exploration and production company. The joint venture, Atoka Midstream LLC, is constructing and will own and operate a gathering system and processing plant and related facilities relating to production in certain areas in southeastern Oklahoma. Enogex will own a 50% membership interest in Atoka Midstream LLC and act as the managing member and operator of the facilities owned by the joint venture.

Texas Panhandle / West Side Expansions. In August 2006, Enogex completed a project to expand its gathering pipeline capacity in the Granite Wash play in the Wheeler County, Texas area of the Texas Panhandle that has allowed Enogex to benefit from growth opportunities in that marketplace. This project included the addition of a 20-inch gathering header that is intended to be used to collect gas from producers and deliver the gas to multiple outlets and processing plants. Enogex continues to review growth opportunities to expand this project and has recently begun several additional new projects to continue expansion on the west side of its system.

Summary of Risk Factors

An investment in our common units involves risks associated with our business, regulatory and legal matters, our limited partnership structure and the tax characteristics of our common units. Please see the risks described under "Risk Factors."

Formation Transactions and Partnership Structure

Formation Transactions

Prior to the closing of this offering, Enogex Inc., which is currently an Oklahoma corporation, will reincorporate under the laws of the State of Delaware and convert to Enogex LLC, a Delaware limited liability company. In addition, two wholly owned subsidiaries of Enogex, OGE Energy Resources, Inc., or OERI, and Enogex Products Corporation, will convert from Oklahoma corporations to Oklahoma limited liability companies.

At the closing of this offering, the following transactions will occur:

- OGE Energy will contribute to our wholly owned subsidiary a membership interest in Enogex;
- we will issue to OGE Enogex Holdings LLC, a wholly owned subsidiary of OGE Energy, 3,280,605 common units and 10,780,605 subordinated units, collectively representing a 63.9% limited partner interest in us;
- we will issue to OGE Enogex GP LLC, our general partner and a subsidiary of OGE Energy, a 2% general partner interest in us and all of our incentive distribution rights, which will entitle our general partner to increasing percentages of the cash we distribute in excess of $0.3881 per unit per quarter;
- we will enter into an omnibus agreement with our general partner and OGE Energy and certain of its affiliates which will address, among other things, our and Enogex's reimbursement of expenses to OGE Energy for the payment of certain operating expenses and the provision of various general and administrative services in connection with this offering and the indemnification of us and Enogex by OGE Energy for certain matters;
- we will issue 7,500,000 common units to the public in this offering, representing a 34.1% limited partner interest in us, and will use the proceeds as described under the caption "Use of Proceeds"; and
- we will contribute approximately $137 million to Enogex in exchange for an additional membership interest in Enogex, bringing our total interest in Enogex to 25% following the closing of this offering.

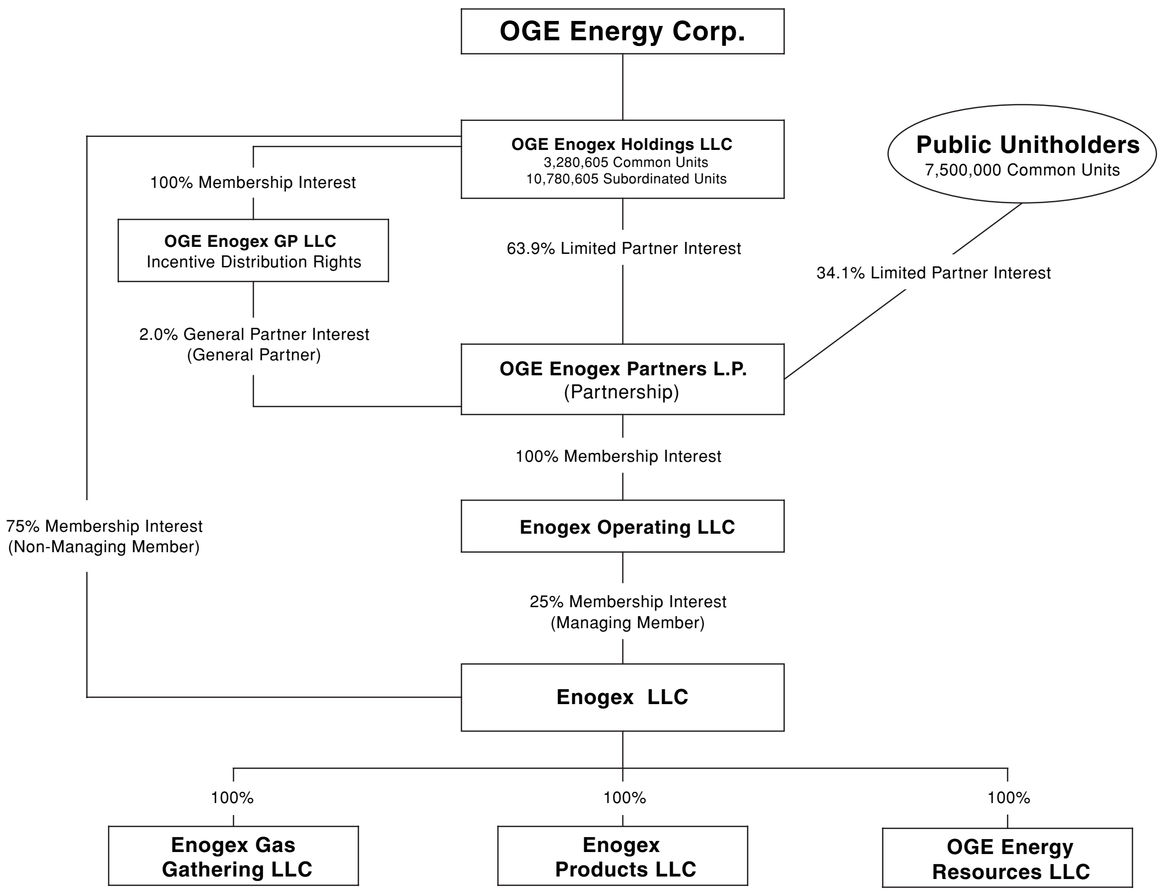
At the closing of this offering, Enogex expects to enter into a $250 million credit facility for working capital, capital expenditures and other corporate purposes, including acquisitions. We do not believe that there will be any outstanding borrowings under this facility at the closing of this offering. Enogex also currently expects to refinance its $400 million 8.125% senior notes due 2010, including the payment of a make-whole premium of approximately $30 million, with a combination of $300 million of new long-term debt and approximately $130 million of the proceeds of this offering that we expect to contribute to Enogex for the anticipated repayment of that debt.

Organizational Structure After the Formation Transactions

As is common with publicly traded partnerships and in order to maximize operational flexibility, we will conduct our operations through our subsidiaries. We will initially have one direct subsidiary, Enogex Operating LLC, a limited liability company, that will conduct business through its subsidiaries. Enogex Operating LLC will hold our 25% interest in Enogex.

The following diagram depicts our organization and ownership after giving effect to the offering and the related formation transactions described above.

Public Common Units	34.1%
OGE Energy Corp. and Its Affiliates Common Units	14.9%
OGE Energy Corp. and Its Affiliates Subordinated Units	49.0%
General Partner Interest	2.0%
Total	100.0%



Management of OGE Enogex Partners L.P.

OGE Enogex GP LLC, our general partner, will manage our business and operations. The board of directors and executive officers of our general partner will oversee our operations and make decisions on our behalf. Some of the executive officers and directors of OGE Energy also serve as executive officers or directors of our general partner.

Unlike shareholders in a publicly traded corporation, our common unitholders will not be entitled to elect our general partner or its directors. OGE Energy will elect all seven members to the board of directors of our general partner, and our general partner will have three directors who are independent as defined under the independence standards established by the New York Stock Exchange. For more information about our management, please see "Management—Directors and Executive Officers of OGE Enogex GP LLC."

Summary of Conflicts of Interest and Fiduciary Duties

General

OGE Enogex GP LLC, our general partner, has a legal duty to manage us in a manner beneficial to our unitholders. This legal duty originates in statutes and judicial decisions and is commonly referred to as a "fiduciary duty." However, because our general partner is indirectly owned by OGE Energy, the officers and directors of our general partner also have fiduciary duties to manage our general partner in a manner beneficial to OGE Energy.

We will control Enogex's business and operations as Enogex's managing member. We have a fiduciary duty to manage Enogex in a manner beneficial to us and to Enogex's non-managing member. The board of directors of our general partner may resolve any conflict between the interests of us and our unitholders, on the one hand, and OGE Energy and its affiliates, on the other hand, and has broad latitude to consider the interests of all parties to the conflict. The resolution of these conflicts may not always be in the best interest of us or our unitholders.

As a result of these relationships, conflicts of interest may arise in the future between us and our unitholders, on the one hand, and our general partner and its affiliates, including OGE Energy and Enogex, on the other hand. For example, our general partner will be entitled to make determinations that affect our ability to make cash distributions, including determinations related to:

- the manner in which our business is operated;
- the level and amount of our borrowings;
- the method and level of hedging activity we will undertake to mitigate Enogex's commodity price risk exposures;
- the amount, nature and timing of our capital expenditures;
- asset purchases and sales and other acquisitions and dispositions; and
- the amount of cash reserves necessary or appropriate to satisfy general, administrative and other expenses and debt service requirements, and otherwise provide for the proper conduct of our business.

These determinations will have an effect on the amount of cash distributions we make to the holders of common units which in turn will have an effect on whether our general partner receives incentive cash distributions as discussed below.

Partnership Agreement Modifications to Fiduciary Duties

Our partnership agreement limits our general partner's fiduciary duties to our unitholders and restricts the remedies available to our unitholders for actions taken by our general partner that might otherwise constitute breaches of its fiduciary duties owed to our unitholders. Our partnership agreement also provides that OGE Energy and its affiliates (other than our general partner) are not limited in their ability to compete with us. By purchasing a common unit, the purchaser agrees to be bound by the terms of our partnership agreement and, pursuant to the terms of our partnership agreement, each holder of common units consents to various actions contemplated in our partnership agreement and conflicts of interest that might otherwise be considered a breach of fiduciary or other duties under applicable state law.

For a more detailed description of the conflicts of interest and fiduciary duties of our general partner, please see "Conflicts of Interest and Fiduciary Duties."

Principal Executive Offices and Internet Address

Our principal executive offices are located at 600 Central Park Two, 515 Central Park Drive, Oklahoma City, Oklahoma 73124, and our telephone number is (405) 525-7788. Upon completion of this offering, our website will be located at http://www.enogexpartners.com. We expect to make our periodic reports and other information filed with or furnished to the Securities and Exchange Commission, or the SEC, available, free of charge, on our website, as soon as reasonably practicable after those reports and other information are electronically filed with or furnished to the SEC. Information on our website or any other website is not incorporated by reference into this prospectus and does not constitute a part of this prospectus.

The Offering

Common units offered to the public	7,500,000 common units or 8,625,000 common units if the underwriters exercise in full their option to purchase additional common units.
Units outstanding after this offering	10,780,605 common units and 10,780,605 subordinated units, representing 49.0% and 49.0%, respectively, limited partner interests in us (11,905,605 common units and 10,780,605 subordinated units, representing 51.4% and 46.6%, respectively, limited partner interests in us if the underwriters exercise in full their option to purchase additional common units).
Use of proceeds	We expect to receive net proceeds from this offering of approximately $139.5 million, after deducting underwriting discounts and commissions and a structuring fee. We base this amount on an assumed initial public offering price of $20.00 per common unit and assuming no exercise of the underwriters' option to purchase additional common units. We anticipate contributing the aggregate net proceeds of this offering to Enogex in order to: • pay approximately $2.5 million of expenses associated with the offering and related formation transactions; • apply approximately $130 million to the anticipated repayment by Enogex of a portion of its existing $400 million 8.125% senior notes that are scheduled to mature on January 15, 2010, including the payment of a make-whole premium of approximately $30 million; • pay approximately $5.5 million in fees and expenses related to Enogex's new credit facility and an issuance of up to $300 million of new long-term debt; and • apply the remaining proceeds to fund future capital expenditures, working capital and other corporate purposes. If the underwriters' option to purchase additional common units is exercised, we intend to apply the additional net proceeds to fund future capital expenditures and ordinary business expenses.

Cash distributions	We will make an initial quarterly distribution of \$0.3375 per common unit (\$1.35 per common unit on an annualized basis) to the extent we have sufficient cash from operations after establishment of cash reserves and payment of fees and expenses, including payments to our general partner and its affiliates. Our ability to pay cash distributions at this initial distribution rate is subject to various restrictions and other factors described in more detail under the caption "Cash Distribution Policy and Restrictions on Distributions."

Our partnership agreement requires us to distribute all of our cash on hand at the end of each quarter, less reserves established by our general partner. We refer to this cash as "available cash," and we define its meaning in our partnership agreement and in the glossary of terms attached as Appendix B. Our partnership agreement requires that we distribute all of our available cash from operating surplus each quarter in the following manner:

- first, 98% to the holders of common units and 2% to our general partner, until each common unit has received a minimum quarterly distribution of \$0.3375 plus any arrearages from prior quarters;
- second, 98% to the holders of subordinated units and 2% to our general partner, until each subordinated unit has received a minimum quarterly distribution of \$0.3375; and
- third, 98% to all unitholders, pro rata, and 2% to our general partner, until each unit has received a total distribution of \$0.3881.

If cash distributions to our unitholders exceed \$0.3881 per common unit in any quarter, our general partner will receive, in addition to distributions on its 2% general partner interest, increasing percentages, up to 48%, of the cash we distribute in excess of that amount. We refer to these distributions as "incentive distributions." Please see "Provisions of Our Partnership Agreement Relating to Cash Distributions."

	Assuming the underwriters exercise their option to purchase additional common units, the amount of our estimated pro forma cash available for distribution generated during the year ended December 31, 2006 and the twelve months ended March 31, 2007 would have been sufficient to allow us to pay the full minimum quarterly distribution on all of our common units and subordinated units for the year ended December 31, 2006 and the full minimum quarterly distribution on all of our common units and 86.6% of the minimum quarterly distribution on our subordinated units for the twelve months ended March 31, 2007. Please see "Cash Distribution Policy and Restrictions on Distributions." We believe that, based on the Statement of Estimated Cash Available for Distribution for the Forecasted Twelve Months Ending September 30, 2008 included under the caption "Cash Distribution Policy and Restrictions on Distributions," we will have sufficient cash available for distribution to make cash distributions for the four quarters ending September 30, 2008 at the initial distribution rate of $0.3375 per common unit per quarter ($1.35 per common unit on an annualized basis) on all common units and subordinated units.
Subordinated units	OGE Energy, through a wholly owned subsidiary, will initially own all of our subordinated units. The principal difference between our common units and subordinated units is that in any quarter during the subordination period, holders of the subordinated units are entitled to receive the minimum quarterly distribution of $0.3375 per unit only after the common units have received the minimum quarterly distribution plus any arrearages in the payment of the minimum quarterly distribution from prior quarters. Subordinated units will not accrue arrearages.
Subordination period	The subordination period will end on the first day after we have earned and paid at least $1.35 (the minimum quarterly distribution on an annualized basis) on each outstanding limited partner unit and made the corresponding distribution on the 2% general partner interest for any three consecutive, non-overlapping four-quarter periods ending on or after September 30, 2010. Alternatively, the subordination period will end on the first day after we have earned and paid at least $0.50625 (150% of the minimum quarterly distribution) on each outstanding limited partner unit and made the corresponding distribution on the 2% general partner interest for each quarter for four consecutive quarters.

In addition, the subordination period will end upon the removal of our general partner other than for cause if the units held by our general partner and its affiliates are not voted in favor of such removal.

When the subordination period ends, all remaining subordinated units will convert into common units on a one-for-one basis, and the common units will no longer be entitled to arrearages. Please see "Provisions of Our Partnership Agreement Relating to Cash Distributions—Subordination Period."

General partner's right to reset the target distribution levels . . . .

Our general partner has the right, at a time when there are no subordinated units outstanding and it has received incentive distributions at the highest level to which it is entitled (48%) for each of the prior four consecutive quarters, to reset the initial cash target distribution levels at higher levels based on the distribution at the time of the exercise of the reset election. Following a reset election by our general partner, the minimum quarterly distribution amount will be reset to an amount equal to the average cash distribution amount per common unit for the two quarters immediately preceding the reset election, referred to herein as the "reset minimum quarterly distribution," and the target distribution levels will be reset to correspondingly higher levels based on the same percentage increases above the reset minimum quarterly distribution amount as in our current target distribution levels.

In connection with resetting these target distribution levels, our general partner will be entitled to receive Class B units. The Class B units will be entitled to the same cash distributions per unit as our common units and will be convertible at any time into an equal number of common units. The number of Class B units to be issued will be equal to that number of common units whose aggregate quarterly cash distributions equaled the average of the distributions to our general partner on the incentive distribution rights in the prior two quarters. For a more detailed description of our general partner's right to reset the target distribution levels upon which the incentive distribution payments are based and the concurrent right of our general partner to receive Class B units in connection with this reset, please see "Provisions of Our Partnership Agreement Relating to Cash Distributions—General Partner's Right to Reset Incentive Distribution Levels."

Issuance of additional units	We can issue an unlimited number of units without the consent of our unitholders. Please see "Units Eligible for Future Sale" and "The Partnership Agreement—Issuance of Additional Securities."
Limited voting rights	Our general partner will manage and operate us. Unlike the holders of common stock in a corporation, limited partners will have only limited voting rights on matters affecting our business. Limited partners will have no right to elect our general partner or its directors on an annual or other continuing basis. Our general partner may not be removed except by a vote of the holders of at least 66⅔% of the outstanding units, including any units owned by our general partner and its affiliates, voting together as a single class. Upon consummation of this offering, an affiliate of our general partner will own an aggregate of 65.2% of our common and subordinated units. This will give our general partner the ability to prevent its involuntary removal. Please see "The Partnership Agreement—Voting Rights."
Limited call right	If at any time our general partner and its affiliates own more than 80% of the outstanding common units, our general partner has the right, but not the obligation, to purchase all of the remaining common units at a price not less than the then-current market price of the common units.
Estimated ratio of taxable income to distributions	We estimate that if you own the common units you purchase in this offering through the record date for distributions for the period ending December 31, 2010, you will be allocated, on a cumulative basis, an amount of federal taxable income for that period that will be % or less of the cash distributed to you with respect to that period. For example, if you receive an annual distribution of $1.35 per unit, we estimate that your average allocable federal taxable income per year will be no more than $ per unit. Please see "Material Tax Consequences—Tax Consequences of Unit Ownership—Ratio of Taxable Income to Distributions."
Material tax consequences	For a discussion of other material federal income tax consequences that may be relevant to prospective unitholders who are individual citizens or residents of the United States, please see "Material Tax Consequences."
Exchange listing	We intend to apply to list the common units on the New York Stock Exchange under the symbol "OGP."

Summary Historical and Pro Forma Financial and Operating Data

OGE Enogex Partners L.P. was formed on May 30, 2007 and does not have any historical financial statements prior to its formation. The following tables set forth, for the periods and at the dates indicated, the summary historical financial and operating data of Enogex Predecessor, which is derived from the books and records of Enogex Predecessor, and the pro forma financial and operating data of OGE Enogex Partners L.P.

The summary historical financial and operating data for the years ended December 31, 2006, 2005 and 2004 and balance sheet data at December 31, 2006 and 2005 is derived from and should be read in conjunction with the audited historical consolidated financial statements of Enogex Predecessor included elsewhere in this prospectus beginning on page F-10. The summary historical financial and operating data for the three months ended March 31, 2007 and 2006 and balance sheet data at March 31, 2007 is derived from and should be read in conjunction with the unaudited historical condensed consolidated financial statements of Enogex Predecessor included elsewhere in this prospectus beginning on page F-60. In each case, the summary historical financial and operating data reflects 100% of Enogex's operations, but following the contribution of a 25% membership interest in Enogex by OGE Energy to our wholly owned subsidiary (and as reflected in the pro forma financial and operating data), we will own only a 25% interest in Enogex. The operating data for all periods is unaudited. The summary unaudited pro forma financial and operating data is derived from and should be read in conjunction with the unaudited pro forma consolidated financial statements of OGE Enogex Partners L.P. included in this prospectus beginning on page F-2. The pro forma adjustments have been prepared as if certain transactions to be effected at the closing of this offering had taken place on March 31, 2007, in the case of the pro forma balance sheet data, and as of January 1, 2006 in the case of the pro forma statements of income for the year ended December 31, 2006 and the three months ended March 31, 2007. These transactions include:

- the conversion of Enogex Inc. to a Delaware limited liability company;
- the conversion of outstanding intercompany loans from Enogex to OGE Energy to a dividend to OGE Energy;
- the contribution by OGE Energy of a 25% membership interest in Enogex to our wholly owned subsidiary;
- the issuance by us of common units to the public;
- the payment of underwriting discounts and commissions, the structuring fee and other offering expenses;
- the contribution by us of proceeds of this offering to Enogex to allow for the anticipated repayment by Enogex of a portion of its existing $400 million 8.125% senior notes due 2010 and the refinancing by Enogex of those senior notes; and
- expected interest expense under Enogex's new credit facility.

The following tables include the financial measure of Adjusted EBITDA, which is calculated and presented not in accordance with generally accepted accounting principles in the United States, or GAAP. We define Adjusted EBITDA as net income from continuing operations before non-controlling interest, interest, income taxes and depreciation and amortization expense. For a reconciliation of Adjusted EBITDA to its most directly comparable financial measures calculated and presented in accordance with GAAP, please see "—Non-GAAP Financial Measures."

The following table presents the summary historical financial and operating data of Enogex Predecessor and our summary unaudited pro forma financial and operating data for the annual periods indicated:

	Enogex Predecessor					OGE Enogex Partners L.P.	
	Year Ended December 31,			Three Months Ended March 31,		Year Ended December 31, 2006	Three Months Ended March 31, 2007
	2004	2005	2006	2006	2007	Pro Forma	Pro Forma
	(in millions, except per unit and operating data)						
Results of Operations Data:							
Operating revenues	$3,372.2	$4,340.1	$2,367.8	$ 763.2	$ 557.8	$2,367.8	$ 557.8
Cost of goods sold	3,118.2	4,090.4	2,060.4	678.0	484.0	2,060.4	484.0
Gross margin on revenues	254.0	249.7	307.4	85.2	73.8	307.4	73.8
Other operation and maintenance	93.5	96.6	110.0	28.6	27.8	114.0	28.4
Depreciation	41.1	40.4	42.3	10.2	11.3	42.3	11.3
Impairment of assets	7.8	—	0.3	—	—	0.3	—
Taxes other than income	16.0	15.4	16.0	4.3	4.5	16.0	4.5
Operating income	95.6	97.3	138.8	42.1	30.2	134.8	29.6
Interest income	3.2	2.9	11.1	2.5	2.6	2.8	0.1
Other income	4.5	0.8	7.7	6.0	0.3	7.7	0.3
Other expense	0.3	0.3	0.3	—	0.1	0.3	0.1
Interest expense(1)	32.2	32.6	31.8	8.1	8.1	23.5	5.7
Income tax expense	26.4	23.4	48.0	16.3	9.4	—	—
Income from continuing operations	44.4	44.7	77.5	26.2	15.5	121.5	24.2
Income from discontinued operations	11.6	49.8	36.0	0.8	—	—	—
Income before non-controlling interest	56.0	94.5	113.5	27.0	15.5	121.5	24.2
Non-controlling interest	—	—	—	—	—	(92.6)	(18.3)
Net income	$ 56.0	$ 94.5	$ 113.5	$ 27.0	$ 15.5	$ 28.9	$ 5.9
General partner's interest in net income						$ 0.6	$ 0.1
Limited partners' interest in net income						$ 28.3	$ 5.8
Number of outstanding limited partner units						21.6	21.6
Basic and diluted earnings per limited partner unit						$ 1.31	$ 0.27
Balance Sheet Data (at period end):							
Property, plant and equipment, net(2)	$1,016.5	$ 875.9	$ 865.7	$ 885.6	$ 879.9		$ 879.9
Total assets	1,719.7	1,652.6	1,319.8	1,406.6	1,304.7		1,132.6
Long-term debt	477.8	407.6	403.7	407.4	403.5		301.0
Net owner equity	491.0	440.4	400.0	466.9	400.7		216.5
Other Financial Data:							
Net cash flows provided by (used in):							
Operating activities	$ 118.2	$ 235.2	$ 131.6	$ 49.8	$ 49.7		
Investing activities	(22.5)	(34.5)	(65.1)	(19.3)	(25.4)		
Financing activities	(118.6)	(304.0)	(139.4)	(31.4)	(21.2)		
Adjusted EBITDA	$ 140.9	$ 138.2	$ 188.5	$ 58.3	$ 41.7	$ 184.5	$ 41.1

	Enogex Predecessor					OGE Enogex Partners L.P.	
	Year Ended December 31,			Three Months Ended March 31,		Year Ended December 31, 2006	Three Months Ended March 31, 2007
	2004	2005	2006	2006	2007	Pro Forma	Pro Forma
	(in millions, except per unit and operating data)						
Operating Data (excludes discontinued operations):							
New well connects(3)	—	—	362	77	99	362	99
New well connects(4)	192	223	206	52	46	206	46
Gathered volumes—TBtu/d	0.84	0.92	0.98	0.96	0.99	0.98	0.99
Incremental transportation volumes—TBtu/d	0.39	0.39	0.46	0.41	0.39	0.46	0.39
Total throughput volumes—TBtu/d	1.23	1.31	1.44	1.37	1.38	1.44	1.38
Natural gas processed—TBtu/d	0.50	0.52	0.54	0.52	0.52	0.54	0.52
Natural gas liquids sold (keep-whole)—million gallons	185	219	244	52	51	244	51
Natural gas liquids sold (purchased for resale)—million gallons	78	77	113	22	27	113	27
Natural gas liquids sold (percent-of-liquids)—million gallons	16	15	14	3	4	14	4
Total natural gas liquids sold—million gallons	279	311	371	77	82	371	82
Average sales price per gallon	$ 0.720	$ 0.847	$ 0.901	$ 0.912	$ 0.858	$ 0.901	$ 0.858

(1) Under the provisions of Enogex's senior notes currently expected to be repaid in connection with this offering, a make-whole premium of approximately $30 million will be paid and funded with a portion of the proceeds from this offering contributed by us to Enogex. As this item does not have a continuing impact, no adjustment for this item is provided in the accompanying unaudited pro forma consolidated statements of income.

(2) Includes net property, plant and equipment related to discontinued operations of approximately $169.3 million and $34.9 million during 2004 and 2005, respectively, and approximately $34.5 million during the three months ended March 31, 2006.

(3) Includes wells behind central receipt points (as reported to us by third parties). A central receipt point is a single receipt point into a gathering line where a producer aggregates the volumes from more than one well and delivers them into the gathering system at a single meter site. This information is not available for years prior to 2006 as Enogex Predecessor's books and records were not maintained in a manner to provide this information for years prior to 2006.

(4) Excludes wells behind central receipt points.

Non-GAAP Financial Measures

We include in this prospectus the non-GAAP financial measure Adjusted EBITDA. We provide reconciliation of Adjusted EBITDA to its most directly comparable financial measures as calculated and presented in accordance with GAAP.

We define Adjusted EBITDA as net income from continuing operations before non-controlling interest, interest, income taxes and depreciation and amortization expense. Adjusted EBITDA is used as a supplemental financial measure by external users of our financial statements such as investors, commercial banks and others, to assess:

- the financial performance of Enogex's assets without regard to financing methods, capital structure or historical cost basis;
- Enogex's operating performance and return on capital as compared to other companies in the midstream energy sector, without regard to financing or capital structure; and
- the viability of acquisitions and capital expenditure projects and the overall rates of return on alternative investment opportunities.

The economic substance behind the use of Adjusted EBITDA is to measure the ability of Enogex's assets to generate cash sufficient to pay interest costs, support indebtedness and make distributions to its members.

The GAAP measures most directly comparable to Adjusted EBITDA are net cash provided by operating activities and net income from continuing operations. The non-GAAP financial measure of Adjusted EBITDA should not be considered as an alternative to GAAP net cash provided by operating activities and GAAP net income from continuing operations. Adjusted EBITDA is not a presentation made in accordance with GAAP and has important limitations as an analytical tool. You should not consider Adjusted EBITDA in isolation or as a substitute for analysis of our results as reported under GAAP. Because Adjusted EBITDA excludes some, but not all, items that affect net income and net cash provided by operating activities and is defined differently by different companies in our industry, our definition of Adjusted EBITDA may not be comparable to similarly titled measures of other companies.

To compensate for the limitations of Adjusted EBITDA as an analytical tool, we believe it is important to review the comparable GAAP measures and understand the differences between the measures.

	Enogex Predecessor					OGE Enogex Partners L.P.	
	Year Ended December 31,			Three Months Ended March 31,		Year Ended December 31, 2006	Three Months Ended March 31, 2007
	2004	2005	2006	2006	2007	Pro Forma	Pro Forma
	(in millions)						
Reconciliation of "Adjusted EBITDA" to net cash provided by operating activities:							
Net cash provided by operating activities	$118.2	$235.2	$131.6	$ 49.8	$ 49.7	$ 193.8	$ 78.6
Interest expense, net	29.0	29.7	20.7	5.6	5.5	20.7	5.6
Changes in operating working capital which provided (used) cash:							
Accounts receivable	169.4	60.3	(236.9)	(241.6)	(24.5)	(236.9)	(24.5)
Accounts payable	(151.2)	(84.6)	222.7	228.9	19.5	196.4	0.4
Other, including changes in noncurrent assets and liabilities	(24.5)	(102.4)	50.4	15.6	(8.5)	10.5	(19.0)
Adjusted EBITDA	$140.9	$138.2	$188.5	$ 58.3	$ 41.7	$ 184.5	$ 41.1
Reconciliation of "Adjusted EBITDA" to net income:							
Net income	$ 56.0	$ 94.5	$113.5	$ 27.0	$ 15.5	$ 28.9	$ 5.9
Add:							
Interest expense, net	29.0	29.7	20.7	5.6	5.5	20.7	5.6
Income tax expense	26.4	23.4	48.0	16.3	9.4	—	—
Depreciation expense	41.1	40.4	42.3	10.2	11.3	42.3	11.3
Discontinued operations, net income	(11.6)	(49.8)	(36.0)	(0.8)	—	—	—
Non-controlling interest	—	—	—	—	—	92.6	18.3
Adjusted EBITDA	$140.9	$138.2	$188.5	$ 58.3	$ 41.7	$ 184.5	$ 41.1

RISK FACTORS

Limited partner interests are inherently different from capital stock of a corporation, although many of the business risks to which we are subject are similar to those that would be faced by a corporation engaged in similar businesses. You should consider carefully the following risk factors together with all of the other information included in this prospectus in evaluating an investment in our common units.

If any of the following risks were actually to occur, our business, financial condition or results of operations could be materially adversely affected. In that case, we might not be able to pay the minimum quarterly distribution on our common units, the trading price of our common units could decline and you could lose all or part of your investment.

Risks Related to Our Business

Because our interest in Enogex currently represents our only cash-generating asset, our cash flows initially will depend completely on Enogex's ability to make distributions to its members, including us.

Our cash flows initially will depend completely on Enogex's distributions to us as one of its members. The amount of cash Enogex can distribute to its members will principally depend upon the amount of cash it generates from its operations, which may fluctuate from quarter to quarter based on, among other things:

- the fees Enogex charges and the margins Enogex realizes for its services;
- the prices of, levels of production of, and demand for natural gas;
- the volume of natural gas Enogex purchases, gathers, treats, compresses, processes, transports, stores and sells;
- the relationship between natural gas and NGL prices;
- cash calls and settlements of hedging positions;
- margin requirements on open price risk management assets and liabilities;
- the level of competition from other midstream energy companies;
- the level of Enogex's other operation and maintenance expenses and general and administrative costs; and
- prevailing economic conditions.

In addition, the actual amount of cash Enogex will have available for distribution to its members, including us, will depend on other factors, including:

- the level of capital expenditures it makes;
- its ability to make borrowings under its credit facility to pay distributions;
- the cost of acquisitions;
- its debt service requirements and other liabilities;
- fluctuations in its working capital needs;
- Enogex's ability to borrow funds and access capital markets;
- restrictions contained in Enogex's debt agreements; and
- the amount of Enogex's cash reserves established to fund its operations.

Some of these factors are beyond our and Enogex's control. For a description of additional restrictions and factors that may affect our ability to make cash distributions, please see "Cash Distribution Policy and Restrictions on Distributions."

Enogex's limited liability company agreement provides that it will distribute its available cash to its members on a monthly basis. Enogex's available cash includes cash on hand less any reserves that may be appropriate for operating its business. The amount of Enogex's monthly distributions, including the amount of cash reserves not distributed, will be determined by the board of directors of our general partner.

We may not have sufficient cash from operations to enable us to pay the minimum quarterly distribution on our common units or to increase distributions.

The source of our earnings and cash flow initially will consist exclusively of cash distributions from Enogex. Therefore, the amount of distributions we are able to make to our unitholders will fluctuate, initially, based on the level of distributions made by Enogex to its members, including us, and, in the future, based on the level of distributions made by Enogex and any subsidiaries through which we later conduct operations. Neither Enogex nor any such operating subsidiaries may make quarterly distributions at a level that will permit us to make distributions to our common unitholders at the minimum quarterly distribution level or to increase our quarterly distributions in the future. In addition, while we would expect to increase or decrease distributions to our unitholders if Enogex increases or decreases distributions to us, the timing and amount of any such increased or decreased distributions will not necessarily be comparable to the timing and amount of the increase or decrease in distributions made by Enogex to us.

Our ability to distribute to our unitholders any cash we may receive from Enogex or any future operating subsidiaries is or may be limited by a number of factors, including, among others:

- our debt service requirements and other liabilities;
- our ability to make borrowings under our debt agreements to pay distributions;
- restrictions on distributions contained in any of our debt agreements;
- fees and expenses of our general partner and its affiliates we are required to reimburse; and
- the amount of cash reserves established by our general partner.

Many of these factors will reduce the amount of cash we may otherwise have available for distribution. We may not be able to pay distributions, and any distributions we do make may not be at or above our minimum quarterly distribution. The amount of our pro forma cash available for distribution generated during the twelve months ended March 31, 2007 would have been sufficient to allow us to pay the full minimum quarterly distribution on all of our common units but would not have been sufficient to allow us to pay the minimum quarterly distribution on all of our subordinated units during such period. For a calculation of our ability to make distributions to unitholders based on our pro forma results for the year ended December 31, 2006 and the twelve months ended March 31, 2007 please see "Cash Distribution Policy and Restrictions on Distributions." The actual amount of cash that is available for distribution to our unitholders will depend on several factors, many of which are beyond the control of us or our general partner.

The amount of cash we have available for distribution to our unitholders depends primarily on our and Enogex's cash flows and not solely on profitability.

The amount of cash we have available for distribution depends primarily upon our and Enogex's cash flows and not solely on profitability, which will be affected by non-cash items. As a result, we may make cash distributions during periods when we record losses for financial accounting purposes and may not make cash distributions during periods when we record net earnings for financial accounting purposes.

The assumptions underlying our estimate of cash available for distribution included under the caption "Cash Distribution Policy and Restrictions on Distributions" are inherently uncertain and are subject to significant business, economic, financial, regulatory and competitive risks and uncertainties that could cause actual results to differ materially from those forecasted.

Our estimate of cash available for distribution set forth in "Cash Distribution Policy and Restrictions on Distributions" includes our forecasted results of operations, Adjusted EBITDA and cash available for distribution for the twelve months ending September 30, 2008. Our estimate and related assumptions have been prepared by, and are the responsibility of, management, and we have not received an opinion or report on it from our or any other independent auditor. The assumptions underlying the forecast are inherently uncertain and are subject to significant business, economic, financial, regulatory and competitive risks and uncertainties that could cause actual results to differ materially from those forecasted. If we do not achieve the forecasted results, we may not be able to pay the full minimum quarterly distribution or any amount on our common units or subordinated units, in which event the market price of our common units may decline materially.

Natural gas, NGLs and other commodity prices are volatile, and changes in these prices could adversely affect our and Enogex's revenue and cash available for distribution.

Enogex is subject to risks due to frequent and often substantial fluctuations in commodity prices. Our and Enogex's results of operations and cash available for distribution could be adversely affected by volatility in natural gas and NGL prices. In the past, the prices of natural gas and NGLs have been extremely volatile, and we expect this volatility to continue. With respect to natural gas, the mid-continent prices for natural gas, as represented by the Inside FERC monthly index posting for Panhandle Eastern Pipe Line Co., Texas, Oklahoma, for the forward month contract in 2006 ranged from a high of $8.76 per million British thermal unit, or MMBtu, to a low of $3.54 per MMBtu. In the first five months of 2007, the same index ranged from a high of $6.65 per MMBtu to a low of $5.52 per MMBtu. Natural gas prices reached relatively high levels in late 2005 due to the impact of Hurricanes Katrina and Rita but have returned to the near $6.00 per MMBtu level experienced over most of the period since 2004. With respect to NGLs, the mid-continent prices for propane, for example, as represented by the average of the Oil Price Information Service daily average posting at the Conway, Kansas market, in 2006 ranged from a high of $1.14 per gallon to a low of $0.90 per gallon. In the first five months of 2007, the same index ranged from a high of $1.13 per gallon to a low of $0.87 per gallon.

Our and Enogex's future revenue and cash flows may be materially adversely affected if the midstream industry experiences significant, prolonged deterioration below general price levels experienced in recent years.

The markets and prices for natural gas and NGLs depend upon factors beyond our and Enogex's control. These factors include demand for these commodities, which fluctuates with changes in market and economic conditions and other factors, including:

- the impact of seasonality and weather;
- general economic conditions;
- the level of domestic and offshore natural gas production and consumption;
- the availability of imported natural gas, liquified natural gas and NGLs;
- actions taken by foreign oil and gas producing nations;

- the availability of local, intrastate and interstate transportation systems;
- the availability and marketing of competitive fuels;
- the impact of energy conservation efforts; and
- the extent of governmental regulation and taxation.

Enogex's "keep-whole" arrangements and "percent-of-proceeds" and "percent-of-liquids" natural gas processing agreements expose it to fluctuations of natural gas prices.

Enogex's keep-whole natural gas processing arrangements, which constituted approximately 23% of its gross margin and accounted for approximately 73% of its natural gas processed volumes in 2006, expose it to fluctuations in the pricing spreads between NGL prices and natural gas prices. Keep-whole processing arrangements generally require a processor of natural gas to keep its shippers whole on a Btu basis by replacing the Btu's of the NGLs extracted from the production stream with Btu's of natural gas. Therefore, if natural gas prices increase and NGL prices do not increase by a corresponding amount, the processor has to replace the Btu's of natural gas at higher prices and processing margins are negatively affected. For information regarding Enogex's hedging activities, please see "Management's Discussion and Analysis of Financial Condition and Results of Operation—Quantitative and Qualitative Disclosures About Market Risk—Commodity Price Risk—Non-Trading Activities."

Enogex's percent-of-proceeds and percent-of-liquids natural gas processing agreements constituted approximately 4% of its gross margin and accounted for approximately 23% of its natural gas processed volumes in 2006. Under these arrangements, Enogex generally gathers raw natural gas from producers at the wellhead, transports the gas through its gathering system, processes the gas and sells the processed gas and/or NGLs at prices based on published index prices. The price paid to producers is based on an agreed percentage of the proceeds of the sale of processed natural gas, NGLs or both or the expected proceeds based on an index price. We refer to contracts in which Enogex shares in specified percentages of the proceeds from the sale of natural gas and NGLs as percent-of-proceeds arrangements and in which Enogex receives proceeds from the sale of NGLs or the NGLs themselves as compensation for its processing services as percent-of-liquids arrangements. These arrangements expose Enogex to risks associated with the price of natural gas and NGLs.

At any given time, Enogex's overall portfolio of processing contracts may reflect a net short position in natural gas (meaning that Enogex was a net buyer of natural gas) and a net long position in NGLs (meaning that Enogex was a net seller of NGLs). As a result, Enogex's margins could be negatively impacted to the extent the price of NGLs decreases in relation to the price of natural gas.

Because of the natural decline in production from existing wells connected to Enogex's systems, Enogex's success depends on its ability to gather new sources of natural gas, which depends on certain factors beyond its or our control. Any decrease in supplies of natural gas could adversely affect our and Enogex's business and results of operations and cash available for distribution.

Enogex's gathering and transportation systems are connected to or dependent on the level of production from natural gas wells, from which production will naturally decline over time. As a result, Enogex's cash flows associated with these wells will also decline over time. To maintain or increase throughput levels on its gathering and transportation systems and the asset utilization rates at its natural gas processing plants, Enogex must continually obtain new natural gas supplies. The primary factors affecting Enogex's ability to obtain new supplies of natural gas and attract new customers to its assets depends in part on the level of successful drilling activity near these systems, Enogex's ability to compete for volumes from successful new wells and Enogex's ability to expand capacity as needed.

Neither we nor Enogex have control over the level of drilling activity in the areas of Enogex's operations, the amount of reserves associated with the wells or the rate at which production from a well will decline. The primary factor that impacts drilling decisions is natural gas prices. Natural gas prices reached relatively high levels in late 2005 due to the impact of Hurricanes Katrina and Rita but have returned to the near $6.00 per MMBtu level experienced over most of the period since 2004. A sustained decline in natural gas prices could result in a decrease in exploration and development activities in the fields served by Enogex's gathering, processing and transportation facilities, which would lead to reduced utilization of these assets. Other factors that impact production decisions include producers' capital budgets, the ability of producers to obtain necessary drilling and other governmental permits, costs of steel and other commodities, geological considerations, demand for hydrocarbons, the level of reserves, other production and development costs and regulatory changes.

In addition, neither we nor Enogex have control over the Btu content of the natural gas that producers in Enogex's areas of operations discover. The majority of Enogex's fees are invoiced on a "per Btu" basis rather than on a "per Mcf" basis. A sustained decrease in the Btu content of the gas that is received on Enogex's system will decrease the amount of revenues Enogex receives to provide its services.

Because of these factors, even if new natural gas reserves are discovered in areas served by Enogex's assets, producers may choose not to develop those reserves. If Enogex is not able to obtain new supplies of natural gas to replace the natural decline in volumes from existing wells due to reductions in drilling activity or competition, throughput on its gathering, processing and transportation facilities would decline, which could have a material adverse effect on our and its business, results of operations, financial condition and ability to make cash distributions.

Enogex engages in commodity hedging activities to minimize the impact of commodity price risk, which may have a volatile effect on its earnings and cash flows and its ability to make distributions to its members, including us.

Enogex is exposed to changes in commodity prices in its operations. To minimize the risk of commodity prices, Enogex may enter into physical forward sales or financial derivative contracts to hedge purchase and sale commitments, fuel requirements and inventories of natural gas. However, financial derivative contracts do not eliminate the risk of market supply shortages, which could result in Enogex's inability to fulfill contractual obligations and incurrence of significantly higher energy or fuel costs relative to corresponding sales contracts.

Enogex marks its energy trading portfolio to estimated fair market value on a daily basis (mark-to-market accounting), which causes earnings variability. When available, market prices are utilized in determining the value of natural gas and related derivative commodity instruments. For longer-term positions, which are limited to a maximum of 60 months, and certain short-term positions for which market prices are not available, models based on forward price curves are utilized. These models incorporate estimates and assumptions as to a variety of factors such as pricing relationships between various energy commodities and geographic locations. Actual experience can vary significantly from these estimates and assumptions.

Enogex engages in cash flow hedge transactions to manage commodity risk. Hedges of anticipated transactions are documented as cash flow hedges pursuant to Statement of Financial Accounting Standard, or SFAS, No. 133, "Accounting for Derivative Instruments and Hedging Activities," and are executed based upon management-established price targets. Enogex utilizes hedge accounting under SFAS No. 133 to manage commodity exposure for contractual length and storage natural gas, percent-of-liquids and keep-whole natural gas, natural gas liquid hedges and certain transportation hedges. Hedges are evaluated prior to execution with respect to the impact on the volatility of forecasted earnings and are evaluated at least quarterly after execution for the impact on earnings. For derivatives that are designated and qualify as a cash flow hedge, the effective portion of the change in fair value of the derivative instrument is reported as a component of Accumulated Other Comprehensive Income and recognized into earnings in the same period during which the hedged transaction affects earnings. The ineffective portion of a derivative's change in fair value is recognized currently in earnings. Forecasted transactions designated as the hedged item in a cash flow hedge are regularly evaluated to assess whether they continue to be probable of occurring. If the forecasted transactions are no longer probable of occurring, hedge accounting will cease on a prospective basis and all future changes in the fair value of the derivative will be recognized directly in earnings. If the forecasted transactions are no longer reasonably possible of occurring, any associated amounts recorded in Accumulated Other Comprehensive Income will also be recognized directly in earnings.

As a result of the factors discussed above, Enogex's hedging activities may not be as effective as intended in reducing the volatility of its cash flows, which could adversely affect its ability to make distributions to its members, including us. In addition, these activities can result in substantial losses. Such losses could occur under various circumstances, including if a counterparty does not perform its obligations under the applicable hedging arrangement, the hedging arrangement is imperfect or ineffective or the hedging policies and procedures are not properly followed or do not work as planned. The steps taken to monitor Enogex's hedging activities may not detect and prevent violations of our risk management policies and procedures, particularly if deception or other intentional misconduct is involved. For additional information regarding Enogex's hedging activities, please see "Management's Discussion and Analysis of Financial Condition and Results of Operation—Quantitative and Qualitative Disclosures About Market Risk—Commodity Price Risk."

Enogex's results of operations and cash flows may be adversely affected by risks associated with its hedging activities.

Enogex has instituted a hedging program that is intended to reduce the commodity price risk associated with Enogex's keep-whole and percent-of-liquids arrangements and has hedged approximately 33% of its expected non-ethane NGL volumes attributable to these arrangements, along with the natural gas MMBtu equivalent, for 2007 and approximately 35% of its expected non-ethane NGL volumes attributable to these arrangements, along with the natural gas MMBtu equivalent, for 2008, 2009 and 2010. Enogex has not hedged ethane because Enogex can reject ethane if processing it is not economical. Enogex anticipates hedging additional non-ethane NGL volumes attributable to these arrangements through swaps, options or other mechanisms. Ethane accounted for approximately 40% of Enogex's total NGL volumes attributable to these arrangements during both the year ended December 31, 2006 and the three months ended March 31, 2007.

For periods after 2010, management will evaluate whether to enter into any new hedging arrangements, and there can be no assurance that Enogex will enter into any new hedging arrangements. Also, Enogex may seek in the future to further limit its exposure to changes in natural gas and NGL commodity prices and interest rates by using financial derivative instruments and other hedging mechanisms. To the extent Enogex hedges its commodity price and interest rate exposures, we and Enogex will forego the benefits that otherwise would be experienced if commodity prices or interest rates were to change in Enogex's favor. In addition, even though management monitors Enogex's hedging activities, these activities can result in substantial losses. Such losses could occur under various circumstances, including if a counterparty does not perform its obligations under the applicable hedging arrangement, the hedging arrangement is imperfect or ineffective, or the hedging policies and procedures are not followed or do not work as planned.

Enogex typically does not obtain independent evaluations of natural gas reserves dedicated to its gathering and transportation systems; therefore, volumes of natural gas on its systems in the future could be less than anticipated.

Enogex typically does not obtain independent evaluations of natural gas reserves connected to its systems due to the unwillingness of producers to provide reserve information as well as the cost of such evaluations. Accordingly, Enogex does not have independent estimates of total reserves dedicated to its systems or the anticipated life of such reserves. If the total reserves or estimated life of the reserves connected to its gathering systems is less than Enogex anticipates and Enogex is unable to secure additional sources of natural gas, then the volumes of natural gas on Enogex's systems in the future could be less than Enogex anticipates. A decline in the volumes of natural gas on Enogex's systems could have a material adverse effect on our and Enogex's business, results of operations, financial condition and cash available for distribution.

Enogex depends on certain key natural gas producer customers for a significant portion of its supply of natural gas and NGLs. The loss of, or reduction in volumes from, any of these customers could result in a decline in our and Enogex's cash available for distribution.

Enogex relies on certain key natural gas producer customers for a significant portion of its natural gas and NGL supply. During 2006 and the first three months of 2007, Enogex's top five natural gas producer customers accounted for approximately 51% and 52%, respectively, of Enogex's natural gas and NGL supply. The loss of the natural gas and NGL volumes supplied by these customers, the failure to extend or replace these contracts or the extension or replacement of these contracts on less favorable terms, as a result of competition or otherwise, could have a material adverse effect on our and Enogex's business, results of operations, financial condition and cash available for distribution.

Enogex depends on two customers for a significant portion of its firm intrastate transportation and storage services. The loss of, or reduction in volumes from, either of these customers could result in a decline in Enogex's transportation and storage services and our and Enogex's cash available for distribution.

Enogex provides firm intrastate transportation and storage services to several customers on its system. Enogex's major customers are OG&E, the largest electric utility in Oklahoma which serves the Oklahoma City market, and Public Service Company of Oklahoma, or PSO, which is the second largest electric utility in Oklahoma and serves the Tulsa market. As part of the no-notice load following contract with OG&E, Enogex provides natural gas storage services for OG&E. Enogex has been providing natural gas storage services to OG&E since August 2002 when it acquired the Stuart Storage Facility. Enogex provides gas transmission delivery services to all of PSO's natural gas-fired electric generation facilities in Oklahoma under a firm intrastate transportation contract. During 2006, 2005 and 2004, revenues from Enogex's firm intrastate transportation and storage contracts were approximately $98.1 million, $95.0 million and $95.6 million, respectively, of which $47.6 million, $47.6 million and $49.6 million was attributed to OG&E and $13.3 million in each of these years was attributed to PSO. Enogex's current contract with OG&E expires in April 2009. OG&E has indicated to us that it currently intends to consider competitive bids for gas transportation and storage services prior to the termination of Enogex's current agreement with OG&E, but it is not obligated to do so. Enogex's current contract with PSO expires in January 2013. Even though OG&E is a subsidiary of OGE Energy, there can be no assurance that the current contract with OG&E will be extended or replaced on similar terms or at all. Please see "Certain Relationships and Related Party Transactions—Contracts with Affiliates—Transportation and Storage Agreement with OG&E." The loss of all or even a portion of the intrastate transportation and storage services for either of these customers, the failure to extend or replace these contracts or the extension or replacement of these contracts on less favorable terms, as a result of competition or otherwise, could have a material adverse effect on our and Enogex's business, results of operations, financial condition and cash available for distribution.

Enogex may not be successful in balancing its purchases and sales of natural gas and NGLs, which would increase its exposure to commodity price risk.

In the normal course of business, Enogex purchases or retains from producers and other customers some of the natural gas and NGLs that flow through its natural gas gathering, processing and transportation systems for resale to third parties, including natural gas marketers and end-users. Enogex may not be successful in balancing its purchases and sales. A producer or supplier could fail to deliver contracted volumes or deliver in excess of contracted volumes, or a purchaser could purchase less than contracted volumes. Any of these actions could cause Enogex's purchases and sales to be unbalanced. If Enogex's purchases and sales are unbalanced, it will face increased exposure to commodity price risk and we and Enogex could have increased volatility in our and its operating income and cash flows.

If third-party pipelines and other facilities interconnected to Enogex's gathering or transportation facilities become partially or fully unavailable, our and Enogex's revenues and cash available for distribution could be adversely affected.

Enogex depends upon third-party natural gas pipelines to deliver gas to, and take gas from, its transportation system. Enogex also depends on third-party facilities to transport and fractionate NGLs that it delivers to the third party at the tailgates of its processing plants. Fractionation is the separation of the heterogeneous mixture of extracted NGLs into individual components for end-use sale. Since Enogex does not own or operate any of these third-party pipelines or other facilities, their continuing operation is not within our or Enogex's control. If any of these third-party pipelines or other facilities become partially or fully unavailable, our and Enogex's revenues and cash available for distribution could be adversely affected.

Enogex is exposed to the credit risk of its key customers, and any material nonpayment or nonperformance by its key customers could adversely affect our and Enogex's financial results and cash available for distribution.

Enogex is exposed to credit risks in its operations. Credit risk includes the risk that counterparties that owe Enogex money will breach their obligations. If the counterparties to these arrangements fail to perform, Enogex may be forced to enter into alternative arrangements. In that event, our and Enogex's financial results and cash available for distribution could be adversely affected.

Enogex faces certain human resource risks associated with the availability of trained and qualified labor to meet its future staffing requirements.

Workforce demographic issues challenge employers nationwide and are of particular concern to the natural gas pipeline industry. The median age of natural gas pipeline workers is significantly higher than the national average. Over the next three years, approximately 22% of Enogex's current employees will be eligible to retire with full pension benefits. Failure to hire and adequately train replacement employees, including the transfer of significant internal historical knowledge and expertise to the new employees, may adversely affect our and Enogex's ability to manage and operate our and its business.

Enogex will reimburse OGE Energy for costs associated with OGE Energy's defined benefit retirement plans, health care plans and other employee-related benefits related to Enogex's employees. Costs associated with these plans and benefits have been increasing and Enogex's reimbursement obligations may adversely affect our and Enogex's results of operations, financial condition or liquidity.

OGE Energy has defined benefit retirement and postretirement plans that cover substantially all of Enogex's employees. Enogex expects to continue to participate in these plans following completion of this offering. OGE Energy's assumptions related to future costs, returns on investments and interest rates and other actuarial assumptions with respect to these defined benefit retirement and postretirement plans have a significant impact on our and Enogex's earnings and funding requirements. Based on OGE Energy's assumptions at December 31, 2006, we expect that OGE Energy will continue to make future contributions to maintain required funding levels. A portion of these contributions is expected to be allocated to Enogex. Historically, OGE Energy has made voluntary contributions to maintain more prudent funding levels than minimally required. These amounts are estimates and may change based on actual stock market performance, changes in interest rates and any changes in governmental regulations.

In addition to the costs of OGE Energy's retirement plans, the costs of providing health care benefits to Enogex's employees and retirees have increased substantially in recent years. We believe that Enogex's employee benefit costs, including costs related to health care plans for Enogex's employees and former employees, will continue to rise. The increasing costs and funding requirements under the defined benefit retirement plan, health care plans and other employee benefits may adversely affect our and Enogex's results of operations, financial condition or liquidity.

All of OGE Energy's employees, including employees of Enogex, hired prior to February 1, 2000 participate in defined benefit and postretirement plans. If these employees retire when they become eligible for retirement over the next several years, or if OGE Energy's plan experiences adverse market returns on its investments, or if interest rates materially fall, OGE Energy's pension expense and contributions to the plans could rise substantially over historical levels. A portion of the expense and contributions is expected to be allocated to Enogex. The timing and number of employees retiring and selecting the lump-sum payment option could result in pension settlement charges that could materially affect our and Enogex's results of operations. In addition, assumptions related to future costs, returns on investments, interest rates and other actuarial assumptions, including projected retirements, have a significant impact on our and Enogex's results of operations and consolidated financial condition. Those assumptions are outside of our control.

Our industry is highly competitive, and increased competitive pressure could adversely affect our business and operating results.

Enogex competes with similar enterprises in its respective areas of operation. Some of these competitors are large oil, natural gas and petrochemical companies that have greater financial resources and access to supplies of natural gas and NGLs than Enogex or us. Some of these competitors may expand or construct gathering, processing, transportation and storage systems that would create additional competition for the services Enogex provides to its customers. In addition, Enogex's customers who are significant producers of natural gas may develop their own gathering, processing, transportation and storage systems in lieu of using Enogex's. Enogex's ability to renew or replace existing contracts with its customers at rates sufficient to maintain current revenues and cash flows could be adversely affected by the activities of its competitors and customers. All of these competitive pressures could have a material adverse effect on our and Enogex's business, results of operations, financial condition and ability to make cash distributions.

A change in the jurisdictional characterization of some of Enogex's assets by federal, state or local regulatory agencies or a change in policy by those agencies may result in increased regulation of its assets, which may cause its revenues to decline and operating expenses to increase.

Enogex's natural gas gathering and intrastate transportation operations are generally exempt from the jurisdiction of the Federal Energy Regulatory Commission, or the FERC, under the Natural Gas Act of 1938, but FERC regulation may indirectly impact these businesses and the markets for products derived from these businesses. The FERC's policies and practices across the range of its oil and natural gas regulatory activities, including, for example, its policies on interstate open access transportation, ratemaking and capacity release and its promotion of market centers, may indirectly affect intrastate markets. In recent years, the FERC has aggressively pursued pro-competitive policies in its regulation of interstate oil and natural gas pipelines. However, we cannot assure you that the FERC will continue to pursue these same objectives as it considers matters such as pipeline rates and rules and policies that may indirectly affect intrastate natural gas transportation business. For more information regarding regulation of Enogex's operations, please see "Business—Our Business—Transportation and Storage—Regulation."

Enogex's natural gas transportation and storage operations are subject to regulation by the FERC pursuant to Section 311 of the NGPA, which could have an adverse impact on its ability to establish transportation and storage rates that would allow it to recover the full cost of operating its transportation and storage facilities, including a reasonable return, and cash available for distribution.

The FERC has jurisdiction over transportation rates charged by Enogex for transporting natural gas in interstate commerce under Section 311 of the NGPA. Rates to provide such service must be "fair and equitable" under the NGPA and are subject to review and approval by the FERC at least once every three years. Enogex is currently charging rates for its Section 311 transportation services that were deemed fair and equitable under a rate settlement approved by the FERC for the period January 1, 2005 to December 31, 2007. Enogex must make its next triennial filing no later than October 1, 2007, to be effective January 1, 2008, at which time the rates, terms and conditions for its Section 311 transportation services may be subject to change. For more information regarding regulation of Enogex's operations, please see "Business—Our Business—Transportation and Storage—Regulation."

Enogex's natural gas transportation, storage and gathering operations are subject to regulation by agencies in Texas and Oklahoma, and that regulation could have an adverse impact on its ability to establish rates that would allow it to recover the full cost of operating its facilities, including a reasonable return, and our cash available for distribution.

State regulation of natural gas transportation, storage and gathering facilities generally focuses on various safety, environmental and, in some circumstances, nondiscriminatory access requirements and complaint-based rate regulation. Natural gas gathering may receive greater regulatory scrutiny at the state level; therefore, Enogex's natural gas gathering operations could be adversely affected should they become subject to the application of state regulation of rates and services. Enogex's gathering operations also may be or become subject to safety and operational regulations relating to the integrity, design, installation, testing, construction, operation, replacement and management of gathering facilities. Additional rules and legislation pertaining to these matters are considered and, in some instances, adopted from time to time. We cannot predict what effect, if any, such changes might have on Enogex's operations, but the industry could be required to incur additional capital expenditures and increased costs depending on future legislative and regulatory changes. Other state and local regulations also may affect Enogex's business.

Recent events that are beyond our control have increased the level of public and regulatory scrutiny of our industry. Governmental and market reactions to these events may have negative impacts on our and Enogex's business, financial condition, access to capital and cash available for distribution.

As a result of accounting irregularities at public companies in general, and energy companies in particular, and investigations by governmental authorities into energy trading activities, public companies, including those in the regulated and unregulated utility business, have been under an increased amount of public and regulatory scrutiny and suspicion. The accounting irregularities have caused regulators and legislators to review current accounting practices, financial disclosures and relationships between companies and their independent auditors. The capital markets and rating agencies also have increased their level of scrutiny. We believe that we and Enogex are complying with all applicable laws and accounting standards, but it is difficult or impossible to predict or control what effect these types of events may have on our or Enogex's business, financial condition, access to the capital markets or cash available for distribution. It is unclear what additional laws or regulations may develop, and we cannot predict the ultimate impact of any future changes in accounting regulations or practices in general with respect to public companies, the energy industry or Enogex's operations specifically. Any new accounting standards could affect the way we and Enogex are required to record revenues, expenses, assets, liabilities and equity. These changes in accounting standards could lead to negative impacts on reported earnings, decreases in assets or increases in liabilities that could, in turn, affect our and Enogex's results of operations and cash available for distribution.

We and Enogex may incur significant costs and liabilities in the future resulting from a failure to comply with new or existing environmental regulations or an accidental release of hazardous substances or hydrocarbons into the environment.

Enogex's operations are, and operations of any of our future subsidiaries may be, subject to stringent and complex federal, state and local environmental laws and regulations. These include, for example, (1) the federal Clean Air Act and comparable state laws and regulations that impose obligations related to air emissions, (2) the federal Resource Conservation and Recovery Act of 1976, or RCRA, and comparable state laws that impose requirements for the handling, storage, treatment and disposal of hazardous and solid waste from our facilities and (3) the Comprehensive Environmental Response, Compensation, and Liability Act of 1980, or CERCLA, also known as "Superfund," and comparable state laws that regulate and impose liability for the cleanup of hazardous substances that may have been released at properties currently or previously owned or operated by Enogex or locations to which Enogex has sent waste for disposal. Enogex may incur substantial costs in order to conduct its operations in compliance with these laws and regulations. For instance, Enogex may be required to obtain and maintain permits and approvals issued by various governmental authorities, limit or prevent releases of materials from its operations in accordance with these permits, or incur substantial liabilities for any pollution or contamination that may result from its operations. Failure to comply with these laws and regulations or newly adopted laws or regulations may trigger a variety of administrative, civil and criminal enforcement measures, including the assessment of monetary penalties, the imposition of remedial requirements, and the issuance of orders enjoining operations. Certain environmental regulations, including CERCLA and analogous state laws and regulations, impose strict, joint and several liability for costs required to clean up and restore sites where hazardous substances or hydrocarbons have been disposed or otherwise released. Moreover, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the release of hazardous substances, hydrocarbons or other waste products into the environment.

There is inherent risk of the incurrence of environmental costs and liabilities in Enogex's operations due to its handling of natural gas, air emissions related to its operations and historical industry operations and waste disposal practices. For example, an accidental release from one of Enogex's facilities could subject it to substantial liabilities arising from environmental cleanup and restoration costs, claims made by neighboring landowners and other third parties for personal injury and property damage and fines or penalties for related violations of environmental laws or regulations. Moreover, the possibility exists that stricter laws, regulations or enforcement policies could significantly increase compliance costs and the cost of any remediation that may become necessary. Neither we nor Enogex may be able to recover these costs from insurance or from indemnification from OGE Energy. Please see "Business—Environmental Matters."

We and Enogex may incur significant costs and liabilities resulting from pipeline integrity programs and related repairs.

Pursuant to the Pipeline Safety Improvement Act of 2002, the U.S. Department of Transportation, or the DOT, has adopted regulations requiring pipeline operators to develop integrity management programs for transportation pipelines. The regulations require operators to:

- identify potential threats to the public or environment, including "high consequence areas" on covered pipeline segments where a leak or rupture could do the most harm;
- develop a baseline plan to prioritize the assessment of a covered pipeline segment;
- gather data and identify and characterize applicable threats that could impact a covered pipeline segment;
- discover, evaluate and remediate problems in accordance with the program requirements;
- continuously improve all elements of the integrity program;
- continuously perform preventative and mitigation actions;
- maintain a quality assurance process and management-of-change process; and
- establish a communication plan that addresses safety concerns raised by the DOT and state agencies, including the periodic submission of performance documents to the DOT.

We currently estimate that Enogex will incur capital expenditures and operating costs of approximately $38.1 million between 2007 and 2011 to implement its pipeline integrity management program along certain segments of its natural gas pipelines. This includes Enogex's estimates for the repair, remediation, prevention or other mitigation that may be determined to be necessary as a result of the testing program. At this time, we cannot predict the ultimate costs of compliance with this regulation because those costs will depend on the number and extent of any repairs found to be necessary as a result of the pipeline integrity testing that is required by the rule. Enogex will continue its pipeline integrity testing programs to assess and maintain the integrity of its pipelines. The results of these tests could cause Enogex to incur significant and unanticipated capital and operating expenditures for repairs or upgrades deemed necessary to ensure the continued safe and reliable operations of its pipelines.

Construction of new assets or modifications to existing systems may not result in revenue or cash flow increases and is subject to regulatory, environmental, political, legal and economic risks, which could adversely affect our and Enogex's results of operations, financial condition and ability to make cash distributions.

One of the ways we and Enogex intend to grow is through the construction of new midstream assets. The construction of additions or modifications to existing systems, and the construction of new midstream assets, involves numerous regulatory, environmental, political and legal uncertainties beyond our and Enogex's control and may require the expenditure of significant amounts of capital. These projects, once undertaken, may not be completed on schedule or at the budgeted cost, or at all. Moreover, our and Enogex's revenues and cash flows may not increase immediately upon the expenditure of funds on a particular project. For instance, if Enogex expands a new pipeline, the construction may occur over an extended period of time, and Enogex will not receive any material increases in revenues or cash flows until the project is completed. In addition, we or Enogex may construct facilities to capture anticipated future growth in production in a region in which such growth does not materialize. Since neither we nor Enogex is engaged in the exploration for and development of natural gas, we and Enogex often do not have access to third-party estimates of potential reserves in areas to be developed prior to constructing facilities in those areas. To the extent we or Enogex rely on estimates of future production in deciding to construct additions to systems, those estimates may prove to be inaccurate because there are numerous uncertainties inherent in estimating quantities of future production. As a result, new facilities may not be able to attract enough throughput to achieve expected investment return, which could adversely affect our and Enogex's results of operations, financial condition and cash available for distribution. In addition, the construction of additions to existing gathering and transportation assets may require new rights-of-way prior to constructing new pipelines. Those rights-of-way to connect new natural gas supplies to existing gathering lines may be unavailable and we and Enogex may not be able to capitalize on attractive expansion opportunities. Additionally, it may become more expensive to obtain new rights-of-way or to renew existing rights-of-way. If the cost of renewing or obtaining new rights-of-way increases, our and Enogex's cash flows could be adversely affected.

Our ability to grow is dependent on our ability to access external expansion capital.

We expect that Enogex will distribute all of its available cash to its members, including us, and we will distribute all of our available cash to our unitholders. As a result, we expect that we and Enogex will rely primarily upon external financing sources, including commercial bank borrowings and the issuance of debt and equity securities, to fund acquisitions and expansion capital expenditures. As a result, to the extent we or Enogex are unable to finance growth externally, our and Enogex's cash distribution policy will significantly impair our and Enogex's ability to grow. In addition, because we and Enogex distribute all available cash, our and Enogex's growth may not be as fast as businesses that reinvest their available cash to expand ongoing operations. To the extent we issue additional units in connection with any acquisitions or expansion capital expenditures, the payment of distributions on those additional units may increase the risk that we will be unable to maintain or increase our per unit distribution level, which in turn may impact the available cash that we have to distribute on each unit. There are no limitations in our partnership agreement on our ability to issue additional units, including units ranking senior to the common units. The incurrence of additional commercial borrowings or other debt by us or Enogex to finance our growth strategy would result in increased interest expense, which in turn may impact the available cash that Enogex has to distribute to its members, including us, and that we have to distribute to our unitholders.

If we or Enogex do not make acquisitions or are unable to make acquisitions on economically acceptable terms, our and Enogex's future growth will be limited.

Our and Enogex's ability to grow depends, in part, on the ability to make acquisitions that result in an increase in our cash generated from operations per common unit. If we or Enogex are unable to make these accretive acquisitions either because: (1) we or Enogex are unable to identify attractive acquisitions or we are unable to negotiate purchase contracts on acceptable terms, (2) we or Enogex are unable to obtain financing on economically acceptable terms, or (3) we or Enogex are outbid by competitors, then our and Enogex's future growth and ability to increase distributions will be limited. Furthermore, even if we and Enogex do make acquisitions that we believe will be accretive, these acquisitions may nevertheless result in a decrease in our cash generated from operations per common unit.

Any acquisition involves potential risks, including, among other things:

- mistaken assumptions about volumes, revenues and costs, including synergies;
- an inability to integrate successfully the businesses that are acquired;
- a decrease in liquidity as a result of using a significant portion of available cash or borrowing capacity to finance the acquisitions;

- a significant increase in interest expense or financial leverage if additional debt is incurred to finance the acquisitions;
- the assumption of unknown liabilities for which we or Enogex are not indemnified or are indemnified inadequately;
- limitations on rights to indemnity from the seller;
- mistaken assumptions about the overall costs of equity or debt;
- the diversion of management's and employees' time and attention from other business concerns;
- unforeseen difficulties operating in new product areas or new geographic areas; and
- customer or key employee losses at the acquired businesses.

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

Enogex does not own all of the land on which its pipelines and facilities are located, which could disrupt its operations.

Enogex does not own all of the land on which its pipelines and facilities have been constructed, and it is therefore subject to the possibility of more onerous terms and/or increased costs to retain necessary land use if it does not have valid rights of way or if such rights of way lapse or terminate. Enogex obtains the rights to construct and operate its pipelines on land owned by third parties and governmental agencies sometimes for a specific period of time. A loss of these rights, through Enogex's inability to renew right-of-way contracts or otherwise, could cause Enogex to cease operations temporarily or permanently on the affected land, increase costs related to continuing operations elsewhere, reduce our and its revenue and impair our and its ability to make cash distributions.

Gathering, processing, transporting and storing natural gas involves many hazards and operational risks, some of which may not be fully covered by insurance. If a significant accident or event occurs that is not fully insured, our and Enogex's operations and financial results could be adversely affected.

Gathering, processing, transporting and storing natural gas involves many hazards and operational risks, including:

- damage to pipelines and plants, related equipment and surrounding properties caused by tornadoes, floods, earthquakes, fires and other natural disasters and acts of terrorism;
- inadvertent damage from third parties, including construction, farm and utility equipment;
- leaks of natural gas, NGLs and other hydrocarbons or losses of natural gas or NGLs as a result of the malfunction of equipment or facilities;
- fires and explosions; and
- other hazards that could also result in personal injury and loss of life, pollution and suspension of operations.

These risks could result in substantial losses due to personal injury and loss of life, severe damage to and destruction of property and equipment and pollution or other environmental damage and may result in curtailment or suspension of our or Enogex's related operations. A natural disaster or other hazard affecting the areas in which Enogex operates or in which we may operate in the future could have a material adverse effect on our or Enogex's operations. Enogex's insurance is currently provided under OGE Energy's insurance programs. Enogex is not fully insured against all risks inherent to its business. Enogex is not insured against all environmental accidents that might occur, which may include toxic tort claims, other than those considered to be sudden and accidental. If a significant accident or event occurs that is not fully insured, it could adversely affect our or Enogex's operations and financial condition. In addition, we or Enogex may not be able to maintain or obtain insurance of the type and amount desired at reasonable rates. Moreover, in some instances, significant claims by OGE Energy may limit or eliminate the amount of insurance proceeds available to us or Enogex. As a result of market conditions, premiums and deductibles for certain of Enogex's insurance policies have increased substantially, and could escalate further. In some instances, insurance could become unavailable or available only for reduced amounts of coverage.

Our and Enogex's debt levels may limit our and its flexibility in obtaining additional financing and in pursuing other business opportunities.

At the closing of this offering, Enogex expects to enter into up to a $250 million credit facility for working capital, capital expenditures and other corporate purposes, including acquisitions. We do not believe that there will be any outstanding borrowings under this facility at the closing of this offering. Following this offering, we and Enogex will continue to have the ability to incur additional debt, subject to limitations in Enogex's credit facility. Enogex also currently expects to refinance its $400 million 8.125% senior notes due 2010, including the payment of a make-whole premium of approximately $30 million, with a combination of $300 million of new long-term debt and approximately $130 million of the proceeds of this offering that we expect to contribute to Enogex for the anticipated repayment of that debt.

The levels of our and Enogex's debt could have important consequences, including the following:

- the ability to obtain additional financing, if necessary, for working capital, capital expenditures, acquisitions or other purposes may be impaired or the financing may not be available on favorable terms;
- a portion of cash flows will be required to make interest payments on the debt, reducing the funds that would otherwise be available for operations, future business opportunities and distributions;
- our and Enogex's debt level will make us more vulnerable to competitive pressures or a downturn in our business or the economy generally; and
- our and Enogex's debt level may limit our flexibility in responding to changing business and economic conditions.

Our and Enogex's ability to service our and its debt will depend upon, among other things, Enogex's future financial and operating performance, which will be affected by prevailing economic conditions and financial, business, regulatory and other factors, some of which are beyond our and Enogex's control. If operating results are not sufficient to service our or its current or future indebtedness, we and Enogex may be forced to take actions such as reducing distributions, reducing or delaying business activities, acquisitions, investments or capital expenditures, selling assets, restructuring or refinancing debt, or seeking additional equity capital. These actions may not be effected on satisfactory terms, or at all. Please see "Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources."

Enogex's new credit facility is expected to contain operating and financial restrictions, including covenants and restrictions that may be affected by events beyond our or Enogex's control, that may limit Enogex's business and financing activities.

Enogex's new credit facility is expected to contain operating and financial restrictions that may limit its ability, under specified circumstances, to:

- make distributions in certain circumstances, such as if any default or event of default occurs;
- incur additional indebtedness;
- grant liens;
- make acquisitions, certain loans or investments or dispositions and engage in transactions with affiliates;
- make any material change to the nature of Enogex's business, including consolidation, liquidations and dissolutions; or
- enter into a merger, consolidation, sale and leaseback transaction or sale of assets.

Additionally, Enogex's credit facility is expected to contain covenants requiring it to maintain specified financial ratios and tests. Any subsequent replacement of Enogex's credit facility or any future financing agreements could have similar or greater restrictions. These restrictions and covenants may restrict Enogex's ability to finance future operations or capital needs or to expand or pursue business activities.

Enogex's ability to comply with the covenants and restrictions contained in its credit facility may be affected by events beyond our or Enogex's control, including prevailing economic, financial and industry conditions. If market or other economic conditions deteriorate, Enogex's ability to comply with these covenants may be impaired. If Enogex violates any of the restrictions, covenants, ratios or tests in its credit facility, a significant portion of Enogex's indebtedness may become immediately due and payable, and Enogex's lenders' commitment to make further loans to Enogex may be suspended or terminate. Enogex might not have, or be able to obtain, sufficient funds to make these accelerated payments. Please see "Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources."

Restrictions in Enogex's new credit facility are expected to limit its ability to make distributions upon the occurrence of certain events.

Enogex's payment of principal and interest on its debt will reduce cash available for distributions to its members, including us. Enogex's new credit facility is expected to limit its ability to make distributions upon the occurrence of the following events, among others:

- failure to pay any principal, interest, fees, expenses or other amounts due under the credit facility when due;
- failure of any representation or warranty to be true and correct in any material respect;
- failure to perform or otherwise comply with specified covenants in the credit facility;
- failure to pay any other material debt;
- a bankruptcy or insolvency event involving Enogex or any of its material subsidiaries;
- the entry of, and failure to pay, one or more adverse judgments in excess of a specified amount against which enforcement proceedings are brought or that are not stayed pending appeal;
- a change in control of Enogex; and

- the occurrence of specified events with respect to employee benefit plans subject to the Employee Retirement Income Security Act of 1974, or ERISA.

Any subsequent refinancing of Enogex's current debt or any new debt could have similar or more restrictive provisions.

Due to Enogex's lack of asset and geographic diversification, adverse developments in its operations or operating areas would reduce our and its ability to make cash distributions.

We and Enogex rely on revenues generated from Enogex's gathering, processing, transportation and storage facilities and related assets. Enogex's assets are primarily located in Oklahoma. Due to this lack of diversification in industry type and geographic location, an adverse development in Enogex's operations or operating areas would have a significantly greater impact on our and its financial condition and results of operations than if Enogex's assets were more geographically diverse.

If our general partner fails to develop or maintain an effective system of internal controls, then we may not be able to accurately report our financial results or prevent fraud. As a result, current and potential unitholders could lose confidence in our financial reporting, which would harm our business and the trading price of our common units.

Our general partner has sole responsibility for conducting our business and for managing our operations. Effective internal controls are necessary for our general partner, on our behalf, to provide reliable financial reports, prevent fraud and operate us successfully as a public company. If our general partner's efforts to maintain its internal controls are not successful, it is unable to maintain adequate controls over our financial processes and reporting in the future or it is unable to assist us in complying with our obligations under Section 404 of the Sarbanes-Oxley Act of 2002, our operating results could be harmed or we may fail to meet our reporting obligations. Ineffective internal controls also could cause investors to lose confidence in our reported financial information, which would likely have a negative effect on the trading price of our common units.

We rely on executive officers of our general partner and employees of OGE Energy and Enogex for the success of our and our subsidiaries' businesses.

The executive officers of our general partner are employees of OGE Energy. Upon the closing of this offering, we intend to enter into an omnibus agreement with OGE Energy pursuant to which OGE Energy will perform administrative services for us such as legal, accounting, treasury, finance, investor relations, insurance administration and claims processing, risk management, health, safety and environmental, information technology, human resources, credit, payroll, internal audit, taxes, facilities, fleet management and media services. Affiliates of OGE Energy conduct businesses and activities of their own in which we have no economic interest, including businesses and activities relating to OG&E. As a result, there could be material competition for the time and effort of the executive officers and employees who provide services to our general partner, OGE Energy and Enogex. If the executive officers of our general partner and the employees of OGE Energy and Enogex do not devote sufficient attention to the management and operation of our and Enogex's business, our and Enogex's financial results may suffer and our and Enogex's ability to make cash distributions may be impaired.

Terrorist attacks, and the threat of terrorist attacks, have resulted in increased costs to our and Enogex's business. Continued hostilities in the Middle East or other sustained military campaigns may adversely impact our and Enogex's results of operations and ability to make cash distributions.

The long-term impact of terrorist attacks, such as the attacks that occurred on September 11, 2001, and the threat of future terrorist attacks on our industry in general, and on us and Enogex in particular, cannot be known. Increased security measures taken as a precaution against possible terrorist attacks have resulted in increased costs to our and Enogex's business. Uncertainty surrounding continued hostilities in the Middle East or other sustained military campaigns may affect our and Enogex's operations in unpredictable ways, including disruptions of supplies and markets for Enogex's products, and the possibility that infrastructure facilities could be direct targets of, or indirect casualties of, an act of terror.

Changes in the insurance markets attributable to terrorist attacks may make certain types of insurance more difficult for us or Enogex to obtain. Moreover, the insurance that may be available to us and Enogex may be significantly more expensive than existing insurance coverage. Instability in the financial markets as a result of terrorism or war could also affect our and Enogex's ability to raise capital.

Risks Related to an Investment in Us

OGE Energy controls our general partner, which has sole responsibility for conducting our business and managing our operations. Our general partner and its affiliates, including OGE Energy, may have conflicts of interest and may favor their own interests to your detriment.

Following this offering, OGE Energy will indirectly own and control our general partner. Some of our general partner's directors and executive officers are directors or officers of OGE Energy. Therefore, conflicts of interest may arise between OGE Energy and its affiliates, including our general partner, on the one hand, and us and our unitholders, on the other hand. In resolving these conflicts of interest, our general partner may favor its own interests and the interests of its affiliates over the interests of our unitholders. These conflicts include, among others, the following situations:

- neither our partnership agreement nor any other agreement requires OGE Energy and its affiliates (other than our general partner) to pursue a business strategy that favors us. OGE Energy's directors and officers have a fiduciary duty to make decisions in the best interests of the owners of OGE Energy, which may be contrary to our interests;
- our general partner is allowed to take into account the interests of parties other than us, such as OGE Energy and its affiliates, in resolving conflicts of interest;
- OGE Energy and its affiliates (other than our general partner) are not limited in their ability to compete with us. Please see "—OGE Energy and certain of its affiliates are not limited in their ability to compete with us, which could cause conflicts of interest and limit our ability to acquire additional assets or businesses, which in turn could adversely affect our results of operations and cash available for distribution to our unitholders" below;
- some officers of OGE Energy who provide services to us also will devote significant time to the business of OGE Energy and will be compensated by OGE Energy for the services rendered to it;
- our general partner has limited its liability and reduced its fiduciary duties and has also restricted the remedies available to our unitholders for actions that, without the limitations, might constitute breaches of fiduciary duty. Please see "—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 duties owed to our unitholders" below;
- our general partner determines the amount and timing of asset purchases and sales, borrowings, issuance of additional partnership securities and the creation, reduction or increase of reserves, each of which can affect the amount of cash that is distributed to our unitholders;
- in some instances, 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 a

distribution on the subordinated units or to make incentive distributions or to accelerate the expiration of the subordination period;

- our general partner determines the amount and timing of any capital expenditures and whether a capital expenditure is a maintenance capital expenditure, which reduces operating surplus, or an expansion capital expenditure, which does not reduce operating surplus. This determination can affect the amount of cash that is distributed to our unitholders and the ability of the subordinated units to convert to common units;
- our general partner determines which costs incurred by it and its affiliates are reimbursable by us;
- our partnership agreement does not restrict our general partner from causing us to pay it 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 intends to limit its liability regarding our contractual and other obligations and, in some circumstances, is entitled to be indemnified by us;
- our general partner may exercise its limited right to call and purchase common units if it and its affiliates own more than 80% of the common units;
- our general partner controls the enforcement of obligations owed to us by our general partner and its affiliates; and
- our general partner decides whether to retain separate counsel, accountants or others to perform services for us.

Please see "Conflicts of Interest and Fiduciary Duties."

Although we control Enogex through our ownership of its managing member, Enogex's managing member owes fiduciary duties to Enogex and Enogex's non-managing member, OGE Enogex Holdings LLC, which may conflict with the interests of us and our unitholders.

Conflicts of interest may arise as a result of the relationships between us and our unitholders, on the one hand, and Enogex and its members, particularly its non-managing member, OGE Enogex Holdings LLC, on the other hand. OGE Enogex Holdings LLC owns a 75% membership interest in Enogex and controls our general partner. Enogex's managing member has fiduciary duties to manage Enogex in a manner beneficial to us, as such managing member's owner. At the same time, Enogex's managing member has a fiduciary duty to manage Enogex in a manner beneficial to Enogex's non-managing member, OGE Enogex Holdings LLC. The resolution of these conflicts of interest may not always be in the best interest of us or our unitholders.

For example, conflicts of interest may arise in the following situations:

- the allocation of shared overhead expenses to Enogex and us;
- the interpretation and enforcement of contractual obligations between us and our affiliates, on the one hand, and Enogex or its subsidiaries, on the other hand;
- the determination and timing of the amount of cash to be distributed to Enogex's members and the amount of cash to be reserved for the future conduct of Enogex's business;
- the decision as to whether Enogex should make asset or business acquisitions or dispositions, and on what terms;
- the determination of the amount and timing of Enogex's capital expenditures;

- the determination of whether Enogex should use cash on hand, borrow or issue equity to raise cash to finance maintenance or expansion capital projects, repay indebtedness, meet working capital needs or otherwise; and
- any decision we make to engage in business activities independent of, or in competition with, Enogex.

Cost reimbursements owed to our general partner and its affiliates for services provided, which will be determined by our general partner, will be substantial and will reduce our cash available for distribution to our unitholders.

Pursuant to an omnibus agreement we will enter into with OGE Energy, our general partner and certain of their affiliates upon the closing of this offering, we and Enogex will reimburse OGE Energy for the payment of operating expenses related to our and Enogex's operations and for the provision of various general and administrative services for our benefit. Payments for these services will be substantial and will reduce the amount of cash available for distribution to our unitholders. Please see "Certain Relationships and Related Party Transactions—Omnibus Agreement." Our general partner and its affiliates will be entitled to reimbursement for any other expenses they incur on our behalf and any other necessary or appropriate expenses allocable to us or reasonably incurred by our general partner and its affiliates in connection with operating our business to the extent not otherwise covered by the omnibus agreement. In addition, under Delaware law, our general partner 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. To the extent our general partner incurs obligations on our behalf, we are obligated to reimburse or indemnify it. If we are unable or unwilling to reimburse or indemnify our general partner, our general partner may take actions to cause us to make payments of these obligations and liabilities. Any such payments would reduce the amount of cash otherwise available for distribution to our unitholders.

We will be required to deduct estimated maintenance capital expenditures from operating surplus, which may result in less cash available for distribution to unitholders than if actual maintenance capital expenditures were deducted.

Our partnership agreement requires us to deduct estimated, rather than actual, maintenance capital expenditures from operating surplus. The amount of estimated maintenance capital expenditures deducted from operating surplus will be subject to review and change by the conflicts committee of our general partner at least once a year. In years when our estimated maintenance capital expenditures are higher than actual maintenance capital expenditures, the amount of cash available for distribution to unitholders will be lower than if actual maintenance capital expenditures were deducted from operating surplus. If we underestimate the appropriate level of estimated maintenance capital expenditures, we may have less cash available for distribution in future periods when actual capital expenditures begin to exceed our previous estimates. Over time, if we do not set aside sufficient cash reserves or have available sufficient sources of financing and make sufficient expenditures to maintain our asset base, we will be unable to pay distributions at the anticipated level and could be required to reduce our distributions.

After this offering, our wholly owned subsidiary will own a 25% membership interest in Enogex, and a wholly owned subsidiary of OGE Energy will own the remaining 75% membership interest. OGE Energy is not obligated to offer to us the remaining 75% interest in Enogex.

After this offering, our wholly owned subsidiary will own a 25% membership interest in Enogex, and OGE Energy will retain, through a wholly owned subsidiary, the remaining 75% membership interest. OGE Energy is under no obligation to offer to us the opportunity to purchase over time the remaining 75% interest in Enogex. The board of directors of OGE Energy owes fiduciary duties to its shareholders, and not our unitholders, in making any decision to offer us this opportunity. Furthermore, the execution of any purchase agreement with respect to any interest in Enogex will be subject to the approval of the conflicts committee of our general partner. The consummation of any such purchase will also be conditioned upon, among other things, our ability to finance the purchase and our obtaining all necessary consents. Please see "Conflicts of Interest and Fiduciary Duties."

OGE Energy and certain of its affiliates are not limited in their ability to compete with us, which could cause conflicts of interest and limit our ability to acquire additional assets or businesses, which in turn could adversely affect our results of operations and cash available for distribution to our unitholders.

Neither our partnership agreement nor the omnibus agreement between us, our general partner and OGE Energy and certain of its affiliates will prohibit OGE Energy and its affiliates (other than our general partner) from owning assets or engaging in businesses that compete directly or indirectly with us. In addition, OGE Energy 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. OGE Energy is a large, established participant in the energy business, and has significantly greater resources than we have, which factors may make it more difficult for us to compete with OGE Energy with respect to commercial activities as well as for acquisition candidates. As a result, competition from OGE Energy or its affiliates could adversely impact our results of operations and cash available for distribution to our unitholders. Please see "Conflicts of Interest and Fiduciary Duties."

Any reductions in Enogex's credit ratings could increase Enogex's financing costs and the cost of maintaining certain contractual relationships.

We cannot assure that any credit ratings of our subsidiaries, including Enogex, 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. Any future downgrade could increase the cost of short-term borrowings. Any downgrade could also lead to higher borrowing costs and, if below investment grade, could require us or our subsidiaries to post cash collateral or letters of credit.

The credit and business risk profile of our general partner and its owners could adversely affect our credit ratings and profile.

The credit and business risk profiles of our general partner and its owners may be factors in credit evaluations of a master limited partnership. This is because our general partner can exercise significant influence over our business activities, including our cash distribution and acquisition strategy and business risk profile. Another factor that may be considered is the financial condition of our general partner and its owners, including the degree of their financial leverage and their dependence on cash flows from us to service their indebtedness.

OGE Energy, which indirectly owns our general partner, has indebtedness outstanding and is partially dependent on the cash distributions from its general partner and limited partner interests in us to service such indebtedness and pay dividends on its common stock. Any distributions by us to such entities will be made only after satisfying our then-current obligations to our creditors. Our credit ratings and business risk profile could be adversely affected if the ratings and risk profiles of the entities that control our general partner were viewed as substantially lower or more risky than ours.

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 duties owed to our unitholders.

Although our general partner has a fiduciary duty to manage us in a manner beneficial to us and our unitholders, the directors and executive officers of our general partner have a fiduciary duty to manage our general partner in a manner beneficial to OGE Energy, its ultimate parent. Our partnership agreement contains provisions that reduce the standards to which our general partner would otherwise be held by state fiduciary duty laws and also contains provisions that restrict the remedies available to unitholders for actions taken by our general partner that might otherwise constitute breaches of fiduciary duties. 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 in such cases it has no duty or obligation to give any consideration to any interest of, or factors affecting, us, our affiliates or our unitholders. Decisions made by our general partner in its individual capacity will be made by OGE Energy and not by the board of directors of our general partner. Examples include the exercise of its limited call right, its rights to vote or transfer common units that it owns, its registration rights and the determination of whether to consent to any merger or consolidation of the partnership;
- provides that our general partner will not have any liability to us or our unitholders for decisions made in its capacity as a general partner so long as it acted in good faith;
- generally provides that affiliated transactions and resolutions of conflicts of interest not approved by the conflicts committee of the board of directors of our general partner 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 must 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;
- provides that our general partner and its executive officers and directors will not be liable for monetary damages to us or our limited partners for any acts or omissions unless there has been a final and non-appealable judgment entered by a court of competent jurisdiction determining that our general partner or those other persons acted in bad faith or engaged in fraud or willful misconduct or, in the case of a criminal matter, acted with knowledge that the conduct was criminal; and
- provides that in resolving conflicts of interest, it will be presumed that in making its decision that our general partner acted in good faith, and in any proceeding brought by or on behalf of any limited partner or us, the person bringing or prosecuting such proceeding will have the burden of overcoming such presumption.

By purchasing a common unit, a common unitholder will agree to become bound by the provisions in our partnership agreement, including the provisions discussed above. Please see "Conflicts of Interest and Fiduciary Duties—Fiduciary Duties."

Our general partner may elect to cause us to issue Class B units to it in connection with a resetting of the target distribution levels related to our general partner's incentive distribution rights without the approval of the conflicts committee of our general partner or our unitholders. This may result in lower distributions to our unitholders in certain situations.

Our general partner has the right, at a time when there are no subordinated units outstanding and it has received incentive distributions at the highest level to which it is entitled (48%) for each of the prior four consecutive quarters, to reset the initial cash target distribution levels at higher levels based on the distribution at the time of the exercise of the reset election. Following a reset election by our general partner, the minimum quarterly distribution amount will be reset to an amount equal to the average cash distribution amount per common unit for the two quarters immediately preceding the reset election (such amount is referred to herein as the "reset minimum quarterly distribution") and the target distribution levels will be reset to correspondingly higher levels based on percentage increases above the reset minimum quarterly distribution amount.

In connection with resetting these target distribution levels, our general partner will be entitled to receive a number of Class B units. The Class B units will be entitled to the same cash distributions per unit as our common units and will be convertible into an equal number of common units. The number of Class B units to be issued will be equal to that number of common units whose aggregate quarterly cash distributions equaled the average of the distributions to our general partner on the incentive distribution rights in the prior two quarters. We anticipate that our general partner would exercise this reset right in order to facilitate acquisitions or internal growth projects that would not be sufficiently accretive to cash distributions per common unit without such conversion; however, it is possible that our general partner could exercise this reset election at a time when it is experiencing, or may be expected to experience, declines in the cash distributions it receives related to its incentive distribution rights and may therefore desire to be issued our Class B units, which are entitled to receive cash distributions from us on the same priority as our common units, rather than retain the right to receive incentive distributions based on the initial target distribution levels. As a result, a reset election may cause our common unitholders to experience dilution in the amount of cash distributions that they would have otherwise received had we not issued new Class B units to our general partner in connection with resetting the target distribution levels related to our general partner incentive distribution rights. Please see "Provisions of Our Partnership Agreement Relating to Cash Distributions—General Partner Interest and Incentive Distribution Rights."

Holders of our common units have limited voting rights and are not entitled to elect our general partner or its directors.

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 will not elect our general partner or its board of directors, and will have no right to elect our general partner or its board of directors on an annual or other continuing basis. Because OGE Energy indirectly owns 100% of our general partner, the board of directors of our general partner will be chosen by OGE Energy. Furthermore, if the unitholders were dissatisfied with the performance of our general partner, they will have little ability to remove our general partner. Please see "—Following the completion of this offering, an affiliate of our general partner will own a sufficient number of our common units to allow it to block any attempt to remove our general partner." As a result of these limitations, the price at which the common units will trade could be diminished because of the absence or reduction of a takeover premium in the trading price.

Following the completion of this offering, an affiliate of our general partner will own a sufficient number of our common units to allow it to block any attempt to remove our general partner.

The unitholders will be unable initially to remove our general partner without its consent because an affiliate of our general partner will own sufficient units upon completion of this offering to be able to prevent its removal. The vote of the holders of at least 66⅔% of all outstanding units voting together as a single class is required to remove our general partner. Following the closing of this offering, an affiliate of our general partner will own 65.2% of our aggregate outstanding common and subordinated units. Also, if our general partner is removed without cause during the subordination period and units held by our general partner and its affiliates are not voted in favor of that removal, all remaining subordinated units will automatically convert into common units and any existing arrearages on our common units will be extinguished. A removal of our general partner under these circumstances would adversely affect our common units by prematurely eliminating their distribution and liquidation preference over our subordinated units, which would otherwise have continued until we had met certain distribution and performance tests. "Cause" is narrowly defined under our partnership agreement to mean that a court of competent jurisdiction has entered a final, non-appealable judgment finding our general partner liable for actual fraud or willful or wanton misconduct in its capacity as our general partner. "Cause" does not include most cases of charges of poor management of the business, so the removal of our general partner because of the unitholder's dissatisfaction with our general partner's performance in managing us will most likely result in the termination of the subordination period and conversion of all subordinated units to common units.

Our partnership agreement restricts the voting rights of unitholders owning 20% or more of our common units.

Unitholders' voting rights are further restricted by our partnership agreement provision providing that any units held by a person that owns 20% or more of any class of units then outstanding, other than our general partner, its affiliates, their transferees and persons who acquired such units with the prior approval of the board of directors of our general partner, cannot vote on any matter. Our partnership agreement also contains provisions limiting the ability of unitholders to call meetings or to acquire information about our operations, as well as other provisions limiting the unitholders' ability to influence the manner or direction of management.

Our general partner's interest in us and control of our general partner may be transferred to a third party without unitholder consent.

Our general partner may transfer its general partner interest to a third party in a merger or in a sale of all or substantially all of its assets without the consent of the unitholders. Furthermore, our partnership agreement does not restrict the ability of the owners of our general partner from transferring all or a portion of their respective membership interest in our general partner to a third party. The new owners of our general partner would then be in a position to replace the board of directors and executive officers of our general partner with its own choices and thereby influence the decisions taken by the board of directors and executive officers.

If we cease to control Enogex, we may be deemed to be an investment company under the Investment Company Act of 1940.

If we cease to manage and control Enogex and are deemed to be an investment company under the Investment Company Act of 1940 because of our wholly owned subsidiary's ownership of Enogex membership interests, we would either have to register as an investment company under the Investment Company Act, obtain exemptive relief from the SEC or modify our organizational structure or our contract rights to fall outside the definition of an investment company. Registering as an investment company could, among other things, materially limit our ability to engage in transactions with affiliates, including the purchase and sale of certain securities or other property to or from our affiliates, restrict our ability to borrow funds or engage in other transactions involving leverage, and require us to add additional directors who are independent of us or our affiliates.

You will experience immediate and substantial dilution of $10.46 in tangible net book value per common unit.

The assumed initial public offering price of $20.00 per unit exceeds our pro forma net tangible book value of $9.54 per unit. Based on the assumed initial public offering price of $20.00 per unit, you will incur immediate and substantial dilution of $10.46 per common unit. This dilution results primarily because the assets contributed by our general partner and its affiliates are recorded in accordance with GAAP at their historical cost, and not their fair value. Please see "Dilution."

We may issue additional units without your approval, which would dilute your existing ownership interests.

Our partnership agreement does not limit the number of additional limited partner interests that we may issue at any time without the approval of our unitholders. 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 amount of cash available for distribution on each unit may decrease;
- because a lower percentage of total outstanding units will be subordinated units, the risk that a shortfall in the payment of the minimum quarterly distribution will be borne by our common unitholders will increase;
- the ratio of taxable income to distributions may increase;
- the relative voting strength of each previously outstanding unit may be diminished; and
- the market price of the common units may decline.

Affiliates of our general partner may sell common units in the public markets, which could have an adverse impact on the trading price of the common units.

After the sale of the common units offered hereby, a subsidiary of OGE Energy will hold an aggregate of 3,280,605 common units and 10,780,605 subordinated units. Management of our general partner may also purchase common units in the offering. All of the subordinated units will convert into common units at the end of the subordination period and some may convert earlier. The sale of these units in the public markets could have an adverse impact on the price of the common units.

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

If at any time our general partner and its affiliates own more than 80% of the common units, our general partner will have the right, but not the obligation, which it may assign to any of its affiliates or to us, to acquire all, but not less than all, of the common units held by unaffiliated persons at a price not less than their then-current market price. As a result, you may be required to sell your common units at an undesirable time or price and may not receive any return on your investment. You may also incur a tax liability upon a sale of your units. Upon the completion of this offering and assuming no exercise of the underwriters' option to purchase additional common units, an affiliate of our general partner will own approximately 30.4% of our outstanding common units. At the end of the subordination period, assuming no additional issuances of common units, an affiliate of our general partner will own approximately 65.2% of our aggregate outstanding common units. Affiliates of our general partner may acquire additional common units from us in connection with future transactions or through open-market or negotiated purchases. For additional information about this right, please see "The Partnership Agreement—Limited Call Right."

Your liability may not be limited if a court finds that unitholder action constitutes control of our business.

A general partner of a partnership generally has unlimited liability for the obligations of the partnership, except for those contractual obligations of the partnership that are expressly made without recourse to the general partner. Our partnership is organized under Delaware law, and we conduct business in Oklahoma and Texas. 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 other states in which we may do business. You could be liable for any and all of our obligations as if you were a general partner if:

- a court or government agency determined that we were conducting business in a state but had not complied with that particular state's partnership statute; or
- your right to act with other unitholders to remove or replace our general partner, to approve some amendments to our partnership agreement or to take other actions under our partnership agreement constitute "control" of our business.

For a discussion of the implications of the limitations of liability on a unitholder, please see "The Partnership Agreement—Limited Liability."

Unitholders may have liability to repay distributions that were wrongfully distributed to them.

Under certain circumstances, unitholders may have to repay amounts wrongfully returned or distributed to them. Under Section 17-607 of the Delaware Revised Uniform Limited Partnership Act, which we refer to herein as the Delaware Act, we may not make a distribution to you if the distribution would cause our liabilities to exceed the fair value of our assets. Delaware law provides that for a period of three years from the date of the impermissible distribution, limited partners who received the distribution and who knew at the time of the distribution that it violated Delaware law will be liable to the limited partnership for the distribution amount. Substituted limited partners are liable for the obligations of the assignor to make contributions to the partnership that are known to the substituted limited partner at the time it became a limited partner and for unknown obligations if the liabilities could be determined from the partnership agreement. Liabilities to partners on account of their partnership interest and liabilities that are non-recourse to the partnership are not counted for purposes of determining whether a distribution is permitted.

Increases in interest rates could adversely impact the price of our common units.

As with other yield-oriented securities, the market price of our common units is impacted by the level of our cash distributions and implied distribution yield. The distribution yield is often used by investors to compare and rank related yield-oriented securities for investment making decision purposes. Therefore, changes in interest rates may affect the yield requirements of investors who invest in our units, and a rising interest rate environment could have an adverse impact on the price of our common units and our ability to issue additional equity to make acquisitions or for other purposes.

There is no existing market for our common units, and a trading market that will provide you with adequate liquidity may not develop. The price of our common units may fluctuate significantly, and you could lose all or part of your investment.

Prior to the offering, there has been no public market for the common units. After the offering, there will be only 7,500,000 publicly traded common units, assuming no exercise of the underwriters' option to purchase additional units. We do not know the extent to which investor interest will lead to the development of a trading market or how liquid that market might be. You may not be able to resell your common units at or above the initial public offering price. Additionally, the lack of liquidity may result in wide bid-ask spreads, contribute to significant fluctuations in the market price of the common units and limit the number of investors who are able to buy the common units.

The initial public offering price for the common units will be determined by negotiations between us and the representatives of the underwriters and may not be indicative of the market price of the common units that will prevail in the trading market. The market price of our common units may decline below the initial public offering price. The market price of our common units may also be influenced by many factors, some of which are beyond our control, including:

- our quarterly distributions;
- our quarterly or annual earnings or those of other companies in our industry;
- loss of a large customer;
- announcements by us, Enogex or competitors of significant contracts or acquisitions;
- changes in accounting standards, policies, guidance, interpretations or principles;
- general economic conditions;
- the failure of securities analysts to cover our common units after this offering or changes in financial estimates by analysts;
- future sales of our common units; and
- other factors described in these "Risk Factors."

We will incur increased costs as a result of being a publicly traded partnership.

We have no history operating as a publicly traded partnership. As a publicly traded partnership, we will incur significant legal, accounting and other expenses that we did not incur as a private company. In addition, the Sarbanes-Oxley Act of 2002, as well as rules subsequently implemented by the SEC and the New York Stock Exchange, have required changes in corporate governance practices of publicly traded companies. We expect these rules and regulations to increase our legal and financial compliance costs and to make activities more time-consuming and costly. For example, as a result of becoming a publicly traded partnership, we are required to have at least three independent directors, create additional board committees and adopt policies regarding internal controls and disclosure controls and procedures, including the preparation of reports on internal control over financial reporting. In addition, we will incur additional costs associated with our publicly traded company reporting requirements. We also expect these new rules and regulations to make it more difficult and more expensive for our general partner to obtain director and officer liability insurance, and it may be required to accept reduced policy limits and coverage or incur substantially higher costs to obtain the same or similar coverage. As a result, it may be more difficult for our general partner to attract and retain qualified persons to serve on its board of directors or as executive officers. We have included $4.0 million of estimated incremental costs per year, some of which will be allocated to us by OGE Energy and its affiliates, associated with being a publicly traded partnership for purposes of our financial forecast included elsewhere in this prospectus; however, it is possible that our actual incremental costs of being a publicly traded partnership will be higher than we currently estimate.

Tax Risks to Common Unitholders

In addition to reading the following risk factors, you should read the information under the caption "Material Tax Consequences" for a more complete discussion of the expected material federal income tax consequences of owning and disposing of our common units.

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 treats us as a corporation or we become subject to a material amount of additional entity-level taxation for state tax purposes, then our cash available for distribution to our unitholders would be substantially reduced.

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

If we were treated as a corporation for federal income tax purposes, we would pay federal income tax on our income at the corporate tax rate, which is currently a maximum of 35%, and would likely pay state income tax 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 you. Because a tax would be imposed upon us as a corporation, our cash available for distribution to our unitholders would be substantially reduced. Therefore, our treatment as a corporation would result in a material reduction in the anticipated cash flows and after-tax return to our unitholders, likely causing a substantial reduction in the value of our common units.

Current law may change so as to cause us to be treated as a corporation for federal income tax purposes or otherwise subject us to entity-level taxation. In addition, 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, we will be subject to a new entity-level tax, the Texas margin tax, at an effective rate of up to 0.7% on the portion of our gross income that is apportioned to Texas. Imposition of such a tax on us by Texas or any other state, will reduce the cash available for distribution to you. 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 entity-level taxation for federal, state or local income tax purposes, the minimum quarterly distribution amount and the target distribution amounts will be adjusted to reflect the impact of that law on us.

An IRS contest of the federal income tax positions we take may adversely affect the market for our common units, and the cost of any IRS contest will 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 or any other matter affecting us. The IRS may adopt positions that differ from the conclusions of our counsel expressed in this prospectus or from the positions we take. It may be necessary to resort to administrative or court proceedings to sustain some or all of our counsel's conclusions or the positions we take. A court may not agree with some or all of our counsel's conclusions or positions we take. Any contest with the IRS may materially and adversely impact the market for our common units and the price at which they trade. In addition, our costs of any contest with the IRS will be borne indirectly by our unitholders and our general partner because the costs will reduce our cash available for distribution to our unitholders.

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

Tax gain or loss on the disposition of our common units could be more or less than expected.

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

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

Investment in our common units by tax-exempt entities, such as individual retirement accounts (known as IRAs), other retirement plans, and non-U.S. persons raises issues unique to them. For example, virtually all of our income allocated to organizations that are exempt from federal income tax, including IRAs and other retirement plans, will be unrelated business taxable income and will be taxable to them. Distributions to non-U.S. persons will be reduced by withholding taxes at the highest applicable effective tax rate, and non-U.S. persons will be required to file U.S. federal income tax returns and pay tax on their share of our taxable income. If you are a tax-exempt entity or a foreign person, you should consult your tax advisor before investing in our common units.

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

Because we cannot match transferors and transferees of common units, we will take depreciation and amortization positions that may not conform with all aspects of existing Treasury regulations. A successful IRS challenge to those positions could adversely affect the amount of tax benefits available to you. It also could affect the timing of these tax benefits or the amount of gain from the sale of common units and could have a negative impact on the value of our common units or result in audit adjustments to your tax returns. For a further discussion of the effect of the depreciation and amortization positions we will adopt, please see "Material Tax Consequences—Tax Consequences of Unit Ownership—Section 754 Election."

We may adopt certain valuation methodologies that could result in a shift of income, gain, loss and deduction between our general partner and our 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 will 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 our general partner, which may be unfavorable to such unitholders. Moreover, under such 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 our 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.

You will likely be subject to state and local taxes and return filing requirements where you do not live as a result of investing in our common units.

In addition to federal income taxes, you will likely be subject to other taxes, such as state and local income taxes, unincorporated business taxes and estate, inheritance or intangible taxes that are imposed by the various jurisdictions in which we do business or own property, now or in the future, even if you do not live in any of those jurisdictions. You likely will be required to file state and local income tax returns and pay state and local income taxes in some or all of these various jurisdictions. Further, you may be subject to penalties for failure to comply with those requirements. We will initially own property and conduct business in Oklahoma and Texas. Currently, Texas does not impose a personal income tax on individuals. As we make acquisitions or expand our business, we may own assets or do business in additional states that impose a personal income tax. It is your responsibility to file all U.S. federal, foreign, state and local tax returns. Our counsel has not rendered an opinion on the foreign, state or local tax consequences of an investment in our common units.

The sale or exchange of 50% or more of our capital and profits interests within a twelve-month period will result in the termination of our partnership for federal income tax purposes.

We will be considered to have terminated for federal income tax purposes if there is a sale or exchange of 50% or more of the total interests in our capital and profits within a twelve-month period. Our termination would, among other things, result in the closing of our taxable year for all unitholders, which could result in a deferral of depreciation and amortization deductions allowable in computing our taxable income. Please see "Material Tax Consequences—Disposition of Common Units—Constructive Termination" for a discussion of the consequences of our termination for federal income tax purposes.

USE OF PROCEEDS

We expect to receive net proceeds from this offering of approximately $139.5 million, after deducting underwriting discounts and commissions and a structuring fee but before paying offering expenses. We base this amount on an assumed initial public offering price of $20.00 per common unit and assuming no exercise of the underwriters' option to purchase additional common units. We intend to contribute the net proceeds of this offering to Enogex in order to:

- pay approximately $2.5 million of expenses associated with the offering and related formation transactions;
- apply approximately $130 million to the anticipated repayment by Enogex of a portion of its existing $400 million 8.125% senior notes that are scheduled to mature on January 15, 2010, including the payment of a make-whole premium of approximately $30 million;
- pay approximately $5.5 million in fees and expenses related to Enogex's new credit facility and an issuance of up to $300 million of new long-term debt; and
- apply the remaining proceeds to fund future capital expenditures, working capital and other corporate purposes.

The structuring fee of approximately $ will be paid to UBS Securities LLC for evaluation, analysis and structuring of our partnership.

If the underwriters' option to purchase additional common units is exercised, we intend to apply the additional net proceeds to fund future capital expenditures and ordinary business expenses. If the underwriters exercise in full their option to purchase additional common units, the ownership interest of the public unitholders will increase to 8,625,000 common units, representing an aggregate 37.3% limited partner interest in us, and our general partner will retain its 2% general partner interest in us.

An increase or decrease in the assumed public offering price of $1.00 per common unit would cause the net proceeds from the offering, after deducting underwriting discounts and commissions, the structuring fee and offering expenses payable by us, to increase or decrease by approximately $7.0 million.

CAPITALIZATION

The following table shows:

- the capitalization of Enogex Predecessor as of March 31, 2007; and
- our pro forma capitalization as of March 31, 2007, adjusted to reflect this offering, the other transactions described under the caption "Summary—Formation Transactions and Partnership Structure" and the application of the net proceeds from this offering as described under the caption "Use of Proceeds."

We derived this table from, and it should be read in conjunction with and is qualified in its entirety by reference to, the historical and pro forma consolidated financial statements and the accompanying notes included elsewhere in this prospectus. For a description of the pro forma adjustments, please see our unaudited pro forma consolidated financial statements and accompanying notes included elsewhere in this prospectus beginning on page F-2. You should also read this table in conjunction with "Management's Discussion and Analysis of Financial Condition and Results of Operations."

	As of March 31, 2007	
	Historical	Pro Forma
	(in millions)	
Cash	$ 179.4 (a)	$ 4.6
Non-controlling interest	—	354.6
Long-term debt	403.5	301.0
Equity:		
Owner's equity	409.4	—
Held by public:		
Common units	—	137.0
Held by affiliates of OGE Energy:		
Common units	—	19.9
Subordinated units	—	65.6
General partner interest	—	2.7
Accumulated other comprehensive loss	(8.7)	(8.7)
Total equity	400.7	216.5
Total capitalization	$ 804.2	$516.5

(a) Includes outstanding intercompany loans from Enogex to OGE Energy of approximately $176.3 million. In connection with this offering, these loans will be converted to a dividend to OGE Energy.

DILUTION

Dilution is the difference between the offering price paid by the purchasers of common units sold in this offering and the pro forma net tangible book value per unit after the offering. Assuming an initial public offering price of $20.00, on a pro forma basis as of March 31, 2007, after giving effect to the offering of common units and the application of the related net proceeds, our net tangible book value was $209.9 million, or $9.54 per common unit. Net tangible book value excludes $6.6 million of net intangible assets. Purchasers of common units in this offering will experience an immediate dilution in net tangible book value per common unit for financial accounting purposes, as illustrated in the following table:

Assumed initial public offering price per common unit		$20.00
Pro forma net tangible book value per common unit before the offering(1)	7.77	
Increase in pro forma net tangible book value per common unit attributable to purchasers in the offering	1.77	
Less:		
Pro forma net tangible book value per common unit after the offering(2)		9.54
Immediate dilution in pro forma tangible net book value per common unit to new investors(3)		$10.46

(1) Determined by dividing the number of units (3,280,605 common units, 10,780,605 subordinated units and the 2% general partner interest, which has a dilutive effect equivalent to 440,025 units) to be issued to affiliates of OGE Energy for the contribution of a 25% membership interest in Enogex to our wholly owned subsidiary in connection with this offering into the net tangible book value of the contributed assets and liabilities.

(2) Determined by dividing the total number of units to be outstanding after the offering (10,780,605 common units, 10,780,605 subordinated units and the 2% general partner interest, which has a dilutive effect equivalent to 440,025 units) into our pro forma net tangible book value, after giving effect to the application of the expected net proceeds of the offering.

(3) If the initial public offering price were to increase or decrease by $1.00 per common unit, immediate dilution in tangible net book value per common unit would not change after giving effect to the corresponding change in our pro forma use of proceeds.

The following table sets forth the number of units that we will issue and the total consideration contributed to us by affiliates of OGE Energy (including our general partner) and by the purchasers of our common units in this offering upon consummation of the transactions contemplated by this prospectus:

	Units Acquired		Total Consideration	
	Number	Percent	Amount	Percent
Affiliates of OGE Energy(1)(2)	14,501,235	65.9%	$ 88,200,000	37.0%
New investors	7,500,000	34.1%	$150,000,000	63.0%
Total	22,001,235	100.0%	$238,200,000	100.0%

(1) Upon completion of the transactions contemplated by this prospectus, our general partner and its affiliates will own 3,280,605 common units, 10,780,605 subordinated units and the 2% general partner interest, which has a dilutive effect equivalent to 440,025 units.

(2) The assets and liabilities contributed by affiliates of OGE Energy were recorded at historical cost in accordance with GAAP. The net investment of OGE Energy, as of March 31, 2007, after giving effect to the application of the net proceeds of this offering, are set forth in the following table:

	(in millions)
Book value of net assets contributed	$118.2
Distribution to Enogex	$(30.0)
Total consideration	$ 88.2

CASH DISTRIBUTION POLICY AND RESTRICTIONS ON DISTRIBUTIONS

You should read the following discussion of our cash distribution policy in conjunction with specific assumptions included in this section. For more detailed information regarding the factors and assumptions upon which our cash distribution policy is based, please see "Assumptions and Considerations" below. In addition, you should read "Forward-Looking Statements" and "Risk Factors" for information regarding statements that do not relate strictly to historical or current facts and certain risks inherent in our business.

For additional information regarding our historical and pro forma operating results, you should refer to our historical and pro forma consolidated financial statements included elsewhere in this prospectus.

General

Rationale for Our Cash Distribution Policy

Our partnership agreement requires us to distribute all of our available cash quarterly. Our available cash is our cash on hand, including cash from borrowings, at the end of a quarter after the payment of our expenses and the establishment of reserves for future capital expenditures, hedging activities and operational needs. We intend to fund a portion of our capital expenditures with borrowings or issuances of additional units. We may also borrow to make distributions to unitholders, for example, in circumstances where we believe that the distribution level is sustainable over the long term, but short-term factors have caused available cash from operations to be insufficient to pay the distribution at the current level. Our cash distribution policy reflects a basic judgment that our unitholders will be better served by our distributing rather than retaining our available cash.

Limitations on Cash Distributions and Our Ability to Change Our Cash Distribution Policy

There is no guarantee that unitholders will receive quarterly distributions from us. Our distribution policy is subject to certain restrictions and may be changed at any time, including:

- Our cash flow initially will depend completely on Enogex's distributions to us as one of its members. We have the authority, as Enogex's managing member, to determine the amount of Enogex's monthly distributions, including the amount of cash reserves not distributed. We have a fiduciary duty to make decisions with respect to Enogex in the best interest of its members, including its non-managing member, OGE Enogex Holdings LLC. Our decision to make distributions, if any, and the amount of those distributions, if any, could result in a reduction in cash distributions to our unitholders from levels we currently anticipate pursuant to our stated distribution policy.
- Our distribution policy may be affected by restrictions on distributions under the credit facility that Enogex expects to enter into at the closing of this offering. That credit facility is expected to contain covenants requiring it to maintain certain financial ratios and tests. Should Enogex be unable to satisfy these restrictions or if Enogex is otherwise in default under the credit facility, it would be prohibited from making cash distributions to us, which would materially hinder our ability to make cash distributions to our unitholders, notwithstanding our stated cash distribution policy.
- The board of directors of our general partner will have the authority to establish reserves for the prudent conduct of our business and for future cash distributions to our unitholders, and the establishment of those reserves could result in a reduction in cash distributions to our unitholders from levels we currently anticipate.
- While our partnership agreement requires us to distribute all of our available cash, our partnership agreement, including provisions requiring us to make cash distributions contained therein, may be amended. Although during the subordination period, with certain exceptions, our partnership agreement may not be amended without the consent of our general partner and the approval of the public common unitholders, our partnership agreement can be amended with

the approval of a majority of the outstanding common units (including common units held by affiliates of OGE Energy) and Class B units issued upon the reset of incentive distribution rights, if any, after the subordination period has ended, voting as a class. At the closing of this offering, a wholly owned subsidiary of OGE Energy will own our general partner and approximately 65.2% of our outstanding common units and subordinated units.

- Even if our cash distribution policy is not modified or revoked, the amount of distributions we pay under our cash distribution policy and the decision to make any distribution is determined by our general partner, taking into consideration the terms of our partnership agreement.
- Under Section 17-607 of the Delaware Act, we may not make a distribution to our unitholders if the distribution would cause our liabilities to exceed the fair value of our assets.
- We may lack sufficient cash to pay distributions to our unitholders due to increases in our or Enogex's operating or general and administrative expense, principal and interest payments on our or Enogex's outstanding debt, tax expenses, working capital requirements and anticipated cash needs.

Our ability to make distributions to our unitholders depends on the performance of Enogex and its ability to distribute funds to us. Upon the closing of this offering, our 25% interest in Enogex will be our only cash-generating asset. The ability of Enogex to make distributions to us may be restricted by, among other things, the provisions of existing and future indebtedness, applicable limited liability company laws and other laws and regulations.

Our Ability to Grow is Dependent on Our Ability to Access External Expansion Capital

We expect that Enogex will distribute all of its available cash to its members, including us, and we will distribute all of our available cash to our unitholders. As a result, we expect that we and Enogex will rely primarily upon external financing sources, including commercial bank borrowings and the issuance of debt and equity securities, to fund acquisitions and expansion capital expenditures. As a result, to the extent we or Enogex are unable to finance growth externally, our and Enogex's cash distribution policy will significantly impair our and Enogex's ability to grow. In addition, because we and Enogex distribute all of our available cash, our and Enogex's growth may not be as fast as businesses that reinvest their available cash to expand ongoing operations. To the extent we issue additional units in connection with any acquisitions or expansion capital expenditures, the payment of distributions on those additional units may increase the risk that we will be unable to maintain or increase our per unit distribution level, which in turn may impact the available cash that we have to distribute on each unit. There are no limitations in our partnership agreement on our ability to issue additional units, including units ranking senior to the common units. The incurrence of additional commercial borrowings or other debt by us or Enogex to finance our growth strategy would result in increased interest expense, which in turn may impact the available cash that Enogex has to distribute to its members, including us, and that we have to distribute to our unitholders.

Our Initial Distribution Rate

Upon completion of this offering, the board of directors of our general partner will adopt a policy pursuant to which we will declare an initial quarterly distribution of $0.3375 per unit per complete quarter, or $1.35 per unit on an annualized basis, to be paid no later than 45 days after the end of each fiscal quarter through September 30, 2008. This equates to an aggregate cash distribution of $7.4 million per quarter or $29.7 million per year, in each case based on the number of common units, subordinated units and the 2% general partner interest to be outstanding immediately after completion of this offering. If the underwriters' option to purchase additional common units is exercised in full, the ownership interest of the public unitholders will increase to 8,625,000 common units representing an aggregate 37.3% limited partner interest in us and our aggregate cash distribution would be $7.8 million per quarter or $31.3 million per year. Our ability to make cash distributions at the initial distribution rate pursuant to this policy will be subject to the factors described above under the caption "—General—Limitations on Cash Distributions and Our Ability to Change Our Cash Distribution Policy."

As of the date of this offering, our general partner will be entitled to 2% of all distributions that we make prior to our liquidation. Our general partner's initial 2% interest in these distributions may be reduced if we issue additional units in the future and our general partner does not contribute a proportionate amount of capital to us to maintain its initial 2% general partner interest. However, if the underwriters' option is exercised in the transaction and additional common units are issued, our general partner will maintain its initial 2% interest and will not be required to make a capital contribution to us.

The table below sets forth the assumed number of outstanding common units (assuming no exercise and full exercise of the underwriters' option to purchase additional common units) and subordinated units and the general partner interest upon the closing of this offering and the aggregate distribution amounts payable during the year following the closing of this offering at our initial distribution rate of $0.3375 per common unit per quarter ($1.35 per common unit on an annualized basis).

	No Exercise of the Underwriters' Option to Purchase Additional Units			Full Exercise of the Underwriters' Option to Purchase Additional Units		
		Distributions			Distributions	
	Number of Units	One Quarter	Four Quarters	Number of Units	One Quarter	Four Quarters
Publicly held common units	7,500,000	$2,531,250	$10,125,000	8,625,000	$2,910,938	$11,643,750
Common units held by an affiliate of OGE Energy	3,280,605	$1,107,204	$ 4,428,817	3,280,605	$1,107,204	$ 4,428,817
Subordinated units held by an affiliate of OGE Energy	10,780,605	$3,638,455	$14,553,817	10,780,605	$3,638,454	$14,553,817
General partner interest held by an affiliate of OGE Energy(1)	440,025	$ 148,508	$ 594,033	462,984	$ 156,257	$ 625,028
Total	**22,001,235**	**$7,425,417**	**$29,701,667**	**23,149,194**	**$7,812,853**	**$31,251,412**

(1) The number of general partner units is determined by multiplying the total number of units deemed to be outstanding (*i.e.*, the total number of common and subordinated units outstanding divided by 98%) by the general partner's 2% general partner interest.

The subordination period generally will end if we have earned and paid at least $1.35 on each outstanding unit and made the corresponding distribution on the 2% general partner interest for any three consecutive, non-overlapping four-quarter periods ending on or after September 30, 2010. If we have earned and paid at least $0.50625 (150% of the minimum quarterly distribution) on each outstanding common unit and subordinated unit and made the corresponding distribution on the 2% general partner interest for each quarter for four consecutive quarters, the subordination period will terminate automatically and all of the subordinated units will convert into an equal number of common units. Please see "Provisions of Our Partnership Agreement Relating to Cash Distributions—Subordination Period."

We do not have a legal obligation to pay distributions at our initial distribution rate or at any other rate except as provided in our partnership agreement. Our partnership agreement requires that we distribute all of our available cash quarterly. Under our partnership agreement, available cash is defined to generally mean, for each fiscal quarter, cash generated from our business in excess of expenses and the amount of reserves our general partner determines is necessary or appropriate to provide for the conduct of our business, comply with applicable law, comply with any of our debt instruments or other agreements or provide for future distributions to our unitholders for any one or more of the upcoming four quarters. Please see "Provisions of Our Partnership Agreement Relating to Cash Distributions." The actual amount of our cash distributions for any quarter is subject to fluctuations based on the amount of cash Enogex generates from its business and distributes to its members, including us.

If distributions on our common units are not paid with respect to any fiscal quarter at the initial distribution rate, our unitholders will not be entitled to receive such payments in the future except that, to the extent we have available cash in any future quarter during the subordination period in excess of the amount necessary to make cash distributions to holders of our common units at the initial distribution rate, we will use this excess available cash to pay these deficiencies related to prior quarters before any cash distribution is made to holders of subordinated units. Please see "Provisions of Our Partnership Agreement Relating to Cash Distributions—Subordination Period."

Our partnership agreement provides that any determination made by our general partner in its capacity as our general partner must be made in good faith and that any such determination will not be subject to any other standard imposed by our partnership agreement, the Delaware Act or any other law, rule or regulation or at equity. Holders of our common units may pursue judicial action to enforce provisions of our partnership agreement, including these related to requirements to make cash distributions as described above; however, our partnership agreement provides that our general partner is entitled to make the determinations described above without regard to any standard other than the requirements to act in good faith.

Our cash distribution policy, as expressed in our partnership agreement, may not be modified or repealed without amending our partnership agreement.

We will pay our distributions on or about the 15th of each of February, May, August and November to holders of record on or about the 1st of each such month. If the distribution date does not fall on a business day, we will make the distribution on the business day immediately preceding the indicated distribution date. We will adjust the quarterly distribution for the period from the closing of this offering through December 31, 2007 based on the actual length of the period.

Pro Forma and Forecasted Results of Operations

We present below a financial forecast of the expected results of operations for OGE Enogex Partners L.P. for the twelve months ending September 30, 2008. Our financial forecast presents, to the best of our knowledge and belief, our expected results of operations for the forecast period. We also present the unaudited pro forma consolidated results of operations for the year ended December 31, 2006 and the twelve months ended March 31, 2007.

Our financial forecast reflects our judgment as of the date of this prospectus of conditions we expect to exist and the course of action we expect to take during the twelve months ending September 30, 2008. The assumptions disclosed in Note 3 below are those that we believe are significant to our financial forecast. We believe our actual results of operations will approximate those reflected in our financial forecast, but we can give you no assurance that our forecast results will be achieved. There will likely be differences between our forecast and the actual results and those differences could be material. If the forecast is not achieved, we may not be able to pay cash distributions on our common units at the initial distribution rate stated in our cash distribution policy or at all.

Our financial forecast is a forward-looking statement and should be read together with the historical consolidated financial statements and the accompanying notes included elsewhere in this prospectus and together with "Management's Discussion and Analysis of Financial Condition and Results of Operations." The financial forecast has been prepared by and is the responsibility of our management. Neither Ernst & Young LLP, our independent registered public accounting firm, nor any other independent accountants have compiled, examined or performed any procedures with respect to the forecasted financial information contained herein, nor have they expressed any opinion or given any other form of assurance on such information or its achievability, and they assume no responsibility for, and disclaim any association with, the forecasted financial information. Ernst & Young LLP reports included in this prospectus relate to the historical financial information of Enogex Predecessor. Those reports do not extend to the financial forecast information and should not be read to do so.

When considering our financial forecast, you should keep in mind the risk factors and other cautionary statements under the heading “Risk Factors” elsewhere in this prospectus. Any of the risks discussed in this prospectus could cause our actual results of operations to vary significantly from the financial forecast.

We are providing the financial forecast to supplement our historical and pro forma consolidated financial statements in support of our belief that we will have sufficient cash available to allow us to pay cash distributions on all of our outstanding common and subordinated units for each quarter in the twelve month period ending September 30, 2008 at our stated initial distribution rate. Please see “Note 3. Significant Forecast Assumptions” for further information as to the assumptions we have made for the financial forecast.

We do not undertake any obligation to release publicly the results of any future revisions we may make to the financial forecast or to update the financial forecast to reflect events or circumstances after the date of this prospectus. Therefore, we caution you not to place undue reliance on this information.

The unaudited pro forma consolidated results of operations for the year ended December 31, 2006 and the twelve months ended March 31, 2007 are presented to illustrate the assumed effects of the following:

- the conversion of Enogex Inc. to a Delaware limited liability company;
- the conversion of outstanding intercompany loans from Enogex to OGE Energy to a dividend to OGE Energy;
- the contribution by OGE Energy of a 25% membership interest in Enogex to our wholly owned subsidiary;
- the issuance by us of common units to the public assuming the underwriters exercise in full their option to purchase additional common units;
- the payment of underwriting discounts and commissions, the structuring fee and other offering expenses;
- the contribution by us of the proceeds of this offering to Enogex to allow for the anticipated repayment by Enogex of a portion of its existing $400 million 8.125% senior notes due 2010 and the refinancing by Enogex of those senior notes; and
- expected interest expense under Enogex’s new credit facility.

Under the provisions of Enogex’s senior notes currently expected to be extinguished in connection with this offering, a make-whole premium of approximately $30 million will be paid and funded with a portion of the proceeds from this offering contributed by us to Enogex. As this item does not have a continuing impact, no adjustment for this item is provided in the Pro Forma and Forecasted Results of Operations.

The pro forma data included herein are not indicative of forecasted financial results nor do they represent comparable results of operations.

The unaudited pro forma consolidated results of operations for the year ended December 31, 2006 are based on the audited historical consolidated financial statements of Enogex Predecessor included elsewhere in this prospectus, as adjusted to illustrate the estimated pro forma effects of the transactions described above. The unaudited pro forma consolidated financial statements should be read together with “Selected Historical and Pro Forma Financial and Operating Data” and “Management’s Discussion and Analysis of Financial Condition and Results of Operations.” The unaudited pro forma consolidated results of operations for the twelve months ended March 31, 2007 are based in part on the unaudited historical condensed consolidated financial statements of Enogex Predecessor included elsewhere in this prospectus.

OGE Enogex Partners L.P.
Pro Forma and Forecasted Results of Operations

(unaudited)	Pro Forma — Year Ended December 31, 2006	Pro Forma — Twelve Months Ended March 31, 2007	Forecasted — Twelve Months Ending September 30, 2008
	(in millions, except per unit data)		
Revenues	$2,367.8	$2,162.4	$2,491.7
Cost of goods sold	2,060.4	1,866.4	2,138.1
Segment gross margin on revenues:			
Gathering and processing segment	167.6	171.3	199.9
Transportation and storage segment	125.6	114.8	138.8
Marketing segment	14.2	9.9	14.9
Total segment gross margin on revenues	307.4	296.0	353.6
Expenses:			
Other operation and maintenance	114.0	113.3	126.1
Depreciation	42.3	43.4	49.5
Impairment of assets	0.3	0.3	—
Taxes other than income	16.0	16.1	19.7
Total expenses	172.6	173.1	195.3
Operating income	134.8	122.9	158.3
Interest income	2.8	2.7	—
Other income	7.7	2.0	—
Other expense	0.3	0.3	4.5
Interest expense(1)	23.5	23.2	23.9
Income from continuing operations before non-controlling interest	121.5	104.1	129.9
Non-controlling interest	(92.6)	(79.6)	(98.8)
Net income	28.9	24.5	31.1
General partner's interest in net income	0.6	0.5	0.6
Limited partners' interest in net income:			
Common units held by public	10.8	9.1	11.6
Common units held by an affiliate of OGE Energy	4.1	3.5	4.4
Subordinated units held by an affiliate of OGE Energy	13.4	11.4	14.5
Basic weighted-average limited partner units outstanding			
Common units held by public	8.6	8.6	8.6
Common units held by an affiliate of OGE Energy	3.3	3.3	3.3
Subordinated units held by an affiliate of OGE Energy	10.8	10.8	10.8
Basic and diluted net income per limited partner unit outstanding	$ 1.25	$ 1.06	$ 1.34

(1) Under the provisions of Enogex's senior notes currently expected to be repaid in connection with this offering, a make-whole premium of approximately $30 million will be paid and funded with a portion of the proceeds from this offering contributed by us to Enogex. As this item does not have a continuing impact, no adjustment for this item is provided in the accompanying unaudited pro forma and forecasted consolidated statements of income.

Summary of Significant Accounting Policies and Forecast Assumptions

Note 1. Basis of Presentation

The accompanying financial forecast and related notes of OGE Enogex Partners L.P. present the forecasted financial results of operations of OGE Enogex Partners L.P. for the twelve months ending September 30, 2008 based on the assumptions that, as of the closing of the offering contemplated by this prospectus, Enogex will be converted to a limited liability company and a 25% member interest in Enogex will be contributed to our wholly owned subsidiary by OGE Energy. Upon the closing of this offering, we will issue common units and subordinated units to OGE Enogex Holdings LLC, a 2% general partner interest and incentive distribution rights to OGE Enogex GP LLC and common units representing limited partner interests to the public through the underwriters. For purposes of this presentation, we assume that the underwriters will exercise in full their option to purchase additional common units.

The unaudited pro forma consolidated financial statements do not purport to present our results of operations had the offering and related transactions to be effected in connection with the offering actually been completed at the dates indicated. In addition, they do not project our results of operations for any future period.

Note 2. Summary of Significant Accounting Policies

Organization and Business Operations. OGE Enogex Partners L.P. is a Delaware limited partnership formed on May 30, 2007 to acquire a 25% interest in Enogex from OGE Energy. Our general partner is OGE Enogex GP LLC, an indirect wholly owned subsidiary of OGE Energy.

Principles of Consolidation. The financial forecast includes our accounts and those of our wholly owned subsidiaries and partially-owned subsidiaries we control, including Enogex. All significant intercompany transactions have been eliminated in consolidation.

Use of Estimates. In preparing the consolidated financial statements, management is required to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and contingent liabilities at the date of the consolidated financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Cash and Cash Equivalents. For purposes of the consolidated financial statements, we consider all highly liquid debt instruments purchased with an original maturity of three months or less to be cash equivalents. These investments are carried at cost, which approximates fair value.

Allowance for Uncollectible Accounts Receivable. The allowance for uncollectible accounts receivable is calculated based on outstanding accounts receivable balances over 180 days old. In addition, other outstanding accounts receivable balances less than 180 days old are reserved on a case-by-case basis when Enogex believes the required payment of specific amounts owed is unlikely to occur.

Credit risk is the risk of financial loss to Enogex if counterparties fail to perform their contractual obligations. Enogex maintains credit policies with regard to its counterparties that management believes minimize overall credit risk. These policies include the evaluation of a potential counterparty's financial condition (including credit rating), collateral requirements under certain circumstances and the use of standardized agreements which provide for the netting of cash flows associated with a single counterparty. Enogex also monitors the financial condition of existing counterparties on an ongoing basis.

Property, Plant and Equipment. All property, plant and equipment are recorded at cost. Newly constructed plant is added to plant balances at cost, which includes contracted services, direct labor, materials, overhead, transportation costs and capitalized interest. Replacements of units of property are capitalized as plant. For assets that belong to a common plant account, the replaced plant is removed from plant balances and charged to accumulated depreciation. For assets that do not belong to a common plant account, the replaced plant is removed from plant balances with the related accumulated depreciation and the remaining balance is recorded as a loss in the consolidated statements of income as other expense. Repair and removal costs are included in the consolidated statements of income as other operation and maintenance expenses.

Enogex assesses potential impairments of assets or asset groups when there is evidence that events or changes in circumstances require an analysis of the recoverability of an asset or asset group. For purposes of recognition and measurement of an impairment loss, a long-lived asset or assets will be grouped with other assets and liabilities at the lowest level for which identifiable cash flows are largely independent of the cash flows of other assets and liabilities. Estimates of future cash flows used to test the recoverability of a long-lived asset or asset group will include only the future cash flows (cash inflows less associated cash outflows) that are directly associated with and that are expected to arise as a direct result of the use and eventual disposition of the asset or asset group. The fair value of these assets is based on third-party evaluations, prices for similar assets, historical data and projected cash flow. An impairment loss is recognized when the sum of the expected future net cash flows is less than the carrying amount of the asset. The amount of any recognized impairment is based on the estimated fair value of the asset subject to impairment compared to the carrying amount of such asset.

Depreciation. Depreciation is computed principally on the straight-line method using estimated useful lives of three to 83 years for transportation and storage assets, three to 30 years for gathering and processing assets and three to 10 years for marketing assets. Amortization of intangibles other than debt costs is computed using the straight-line method over the respective lives of the intangibles ranging up to 20 years.

Natural Gas Inventories. Natural gas inventory is held by Enogex to provide operational support for its pipeline deliveries and to facilitate its ongoing gas storage and marketing businesses. As part of its recurring buy and sell activity, OERI injects and withdraws natural gas in to and out of inventory under the terms of its storage capacity contracts. All natural gas inventory held by Enogex is recorded at the lower of cost or market.

Gas Imbalances. Gas imbalances occur when the actual amounts of natural gas delivered from or received by Enogex's pipeline system differ from the amounts scheduled to be delivered or received. Imbalances are due to or due from shippers and operators and can be settled in cash or made up in-kind. Enogex values all imbalances at an average of current market indices applicable to Enogex's operations, not to exceed net realizable value. Also included in gas imbalances on the consolidated balance sheets are planned or managed imbalances related to natural gas storage transactions.

Revenue Recognition. Operating revenues for transportation, storage, gathering and processing services are recorded each month based on the current month's estimated volumes, contracted prices (considering current commodity prices), historical seasonal fluctuations and any known adjustments. The estimates are reversed in the following month and customers are billed on actual volumes and contracted prices. Gas sales are calculated on current month nominations and contracted prices. Operating revenues associated with the production of natural gas liquids are estimated based on current month estimated production and contracted prices. These amounts are reversed in the following month and the customers are billed on actual production and contracted prices. Estimates for gas purchases are based on sales volumes and contracted purchase prices.

Enogex recognizes revenue from natural gas gathering, processing, transportation and storage services to third parties as services are provided. Revenue associated with natural gas liquids is recognized when the production is sold. Substantially all of the natural gas contracts related to Enogex's marketing business qualify as derivatives and, therefore, are accounted for at fair value as prescribed in SFAS No. 133.

Accrued Vacation. Enogex accrues vacation pay by establishing a liability for vacation earned during the current year, but not payable until the following year.

Environmental Costs. Accruals for environmental costs are recognized when it is probable that a liability has been incurred and the amount of the liability can be reasonably estimated. Costs are charged to expense if they relate to the remediation of conditions caused by past operations or if they are not expected to mitigate or prevent contamination from future operations. Where environmental expenditures relate to facilities currently in use, such as pollution control equipment, the costs may be capitalized and depreciated over the future service periods. Estimated remediation costs are recorded at undiscounted amounts, independent of any insurance, based on prior experience, assessments and current technology. Accrued obligations are regularly adjusted as environmental assessments and estimates are revised, and remediation efforts proceed. For sites where Enogex has been designated as one of several potentially responsible parties, the amount accrued represents Enogex's estimated share of the cost.

Price Risk Management Activities—Non-Trading Activities. Enogex periodically utilizes derivative contracts to manage the exposure of its assets to unfavorable changes in commodity prices, as well as to reduce exposure to adverse interest rate fluctuations. In accordance with SFAS No. 133, Enogex recognizes its non-exchange traded derivative instruments as price risk management assets or liabilities in the consolidated balance sheets at fair value with such amounts classified as current or long-term based on their anticipated settlement. Exchange-traded transactions are settled on a net basis daily through margin accounts with a clearing broker and, therefore, are recorded at fair value on a net basis in other current assets in the consolidated balance sheets. The accounting for changes in the fair value of a derivative depends on the intended use of the derivative and resulting designation. For derivative instruments that are designated and qualify as a fair value hedge, the gain or loss on the derivative instrument is recognized in current earnings on the same line item as the gain or loss recorded for the change in the fair value of the hedged item. For derivatives that are designated and qualify as a cash flow hedge, the effective portion of the change in fair value of the derivative instrument is reported as a component of accumulated other comprehensive income and recognized into earnings in the same period during which the hedged transaction affects earnings. The ineffective portion of a derivative's change in fair value is recognized currently in earnings. Forecasted transactions designated as the hedged item in a cash flow hedge are regularly evaluated to assess whether they continue to be probable of occurring. If the forecasted transactions are no longer probable of occurring, hedge accounting will cease on a prospective basis and all future changes in the fair value of the derivative will be recognized directly in earnings. If the forecasted transactions are no longer reasonably possible of occurring, any associated amounts recorded in accumulated other comprehensive income will also be recognized directly in earnings.

Enogex may designate certain derivative instruments for the purchase or sale of physical commodities as normal purchases and normal sales contracts under the provisions of SFAS No. 133. Normal purchases and normal sales contracts are not recorded in price risk management assets or liabilities in the consolidated balance sheets and earnings recognition is recorded in the period in which physical delivery of the commodity occurs. Enogex applies normal purchases and normal sales to: (i) commodity contracts for the purchase and sale of natural gas by its subsidiaries; and (ii) commodity contracts for the sale of natural gas liquids produced by Enogex Products Corporation.

Price Risk Management Activities—Trading Activities. Enogex, through a subsidiary, engages in energy trading activities primarily related to the purchase and sale of natural gas. Contracts utilized in these activities generally include forward swap contracts as well as over-the-counter and exchange traded futures and options. Energy trading activities are accounted for in accordance with SFAS No. 133 and Emerging Issues Task Force, or EITF, Issue No. 02-3, "Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Involved in Energy Trading and Risk Management Activities." In accordance with SFAS No. 133, financial instruments that qualify as derivatives are reflected at fair value with the resulting unrealized gains and losses recorded as price risk management assets or liabilities in the consolidated balance sheets, classified as current or long-term based on their anticipated settlement or against the brokerage deposits in other current assets. Unrealized gains and losses from changes in the market value of open contracts are included in operating revenues in the consolidated statements of income. Energy trading contracts resulting in delivery of a commodity that meet the requirements of EITF Issue No. 99-19, "Reporting Revenues Gross as a Principal or Net as an Agent," are included as sales or purchases in the consolidated statements of income depending on whether the contract relates to the sale or purchase of the commodity.

In accordance with Financial Accounting Standards Board, or FASB, Interpretation No. 39 (As Amended), "Offsetting of Amounts Related to Certain Contracts an interpretation of APB Opinion No. 10 and FASB Statement No. 105," fair value amounts recognized for forward, interest rate swap, currency swap, option and other conditional or exchange contracts executed with the same counterparty under a master netting arrangement may be offset. The reporting entity's choice to offset or not must be applied consistently. A master netting arrangement exists if the reporting entity has multiple contracts, whether for the same type of conditional or exchange contract or for different types of contracts, with a single counterparty that are subject to a contractual agreement that provides for the net settlement of all contracts through a single payment in a single currency in the event of default on or termination of any one contract. Offsetting the fair values recognized for forward, interest rate swap, currency swap, option and other conditional or exchange contracts outstanding with a single counterparty results in the net fair value of the transactions being reported as an asset or a liability in the consolidated balance sheet. Enogex has presented the fair values of its contracts under master netting agreements using a net fair value presentation.

Maintenance Costs. Maintenance costs are expensed as incurred.

Benefits. Enogex adopted certain provisions of SFAS No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans, an amendment of FASB Statements No. 87, 88, 106 and 132R," effective December 31, 2006, which requires Enogex to separately disclose the items that have not yet been recognized as components of net periodic pension cost including, net loss, prior service cost and net transition obligation at December 31, 2006.

All eligible employees of Enogex are covered by a non-contributory defined benefit pension plan sponsored by OGE Energy. For employees hired on or after February 1, 2000, the pension plan is a cash balance plan, under which OGE Energy annually will credit to the employee's account an amount equal to five percent of the employee's annual compensation plus accrued interest. Employees hired prior to February 1, 2000 will receive the greater of the cash balance benefit or a benefit based primarily on years of service and the average of the five highest consecutive years of compensation during an employee's last 10 years prior to retirement, with reductions in benefits for each year prior to age 62 unless the employee's age and years of credited service equal or exceed 80.

It is OGE Energy's policy to fund the plan on a current basis based on the net periodic SFAS No. 87, "Employers' Accounting for Pensions," pension expense as determined by OGE Energy's actuarial consultants. Additional amounts may be contributed from time to time to increase the funded status of the plan. In April 2007, OGE Energy contributed approximately $20.0 million to its pension plan, of which approximately $1.7 million was allocated to Enogex. During the remainder of 2007, OGE Energy may contribute up to an additional $30.0 million to the pension plan, of which approximately $2.6 million is expected to be allocated to Enogex.

OGE Energy provides a restoration of retirement income plan to those participants in OGE Energy's pension plan whose benefits are subject to certain limitations under the Internal Revenue Code. The benefits payable under this restoration of retirement income plan are equivalent to the amounts that would have been payable under the pension plan but for these limitations. The restoration of retirement income plan is intended to be an unfunded plan.

In addition to providing pension benefits, OGE Energy provides certain medical and life insurance benefits for eligible retired employees, referred to herein as postretirement benefits. Regular, full-time, active employees hired prior to February 1, 2000, whose age and years of credited service total or exceed 80 or have attained age 55 with 10 years of vesting service at the time of retirement are entitled to these postretirement benefits. Employees hired on or after February 1, 2000, are not entitled to postretirement medical benefits but are entitled to postretirement life insurance benefits. Eligible retirees must contribute such amount as OGE Energy specifies from time to time toward the cost of coverage for postretirement benefits. The benefits are subject to deductibles, co-payment provisions and other limitations. Enogex charges to expense the SFAS No. 106, "Employers' Accounting for Postretirement Benefits other than Pensions," costs.

Income Taxes. We do not provide in our accounts for federal or state income taxes as such taxes are a liability of our partners.

Note 3. Significant Forecast Assumptions

The following discussion refers to 100% of Enogex, of which OGE Enogex Partners L.P. will own a 25% interest upon completion of this offering. The subheading "Non-Controlling Interest in Net Income" describes the portion of income that is attributable to the 75% non-controlling interest.

All comparisons below are made to historical periods which have been adjusted on a pro forma basis. The forecast has been prepared assuming full exercise of the underwriters' over-allotment option.

We forecast Enogex's consolidated gross margin to be approximately $353.6 million for the twelve months ending September 30, 2008 compared to $307.4 million and $296.0 million for the year ended December 31, 2006 and the twelve months ended March 31, 2007, respectively. Segment detail on the forecasted gross margin is provided below.

Transportation and Storage Gross Margin

We forecast gross margin for Enogex's transportation and storage business to be approximately $138.8 million for the twelve months ending September 30, 2008 compared to $125.6 million and $114.8 million for the year ended December 31, 2006 and twelve months ended March 31, 2007, respectively. Key factors impacting the forecasted increase in transportation and storage gross margin are:

- Approximately $99.6 million of the total transportation and storage gross margin is fixed fee based and is related to demand fees. The forecasted amount of $99.6 million is compared to $92.6 million and $94.5 million for the year ended December 31, 2006 and twelve months ended March 31, 2007, respectively. This increase is related to favorable contract renewals.
- Additionally, forecasted gross margin includes $19.7 million of low-pressure and high-pressure gas transportation fees associated with bundled gathering and transportation contracts and $5.1 million of interruptible and daily crosshaul transportation fees. The remaining $14.4 million of gross margin is associated with other transportation and storage services.

- The increase in forecasted gross margin over the prior periods is partially due to an $8.3 million lower-of-cost or market write-down in 2006 which is not included in the forecast period.

Gathering and Processing Gross Margin

We forecast gross margin for Enogex's gathering and processing business to be approximately $199.9 million for the twelve months ending September 30, 2008 compared to $167.6 million and $171.3 million for the year ended December 31, 2006 and the twelve months ended March 31, 2007, respectively. Key factors impacting the forecasted increase in gathering and processing gross margin are:

- An increase in gathered volumes to 1.18 TBtu/d of natural gas for the twelve months ending September 30, 2008 as compared to gathered volumes of 0.98 TBtu/d and 0.99 TBtu/d for the year ended December 31, 2006 and the twelve months ended March 31, 2007, respectively. This increase is being driven by recent and anticipated new well connects and gathering system expansions in the Woodford Shale play in southeastern Oklahoma and the Granite Wash play in western Oklahoma and the Texas Panhandle.

- Fee-based gathering revenues account for $69.6 million, or 35% of the total segment gross margin of $199.9 million for the twelve months ending September 30, 2008. This compares to 34% of the total $167.6 million of gross margin for the year ended December 31, 2006 and 34% of the total gross margin of $171.3 million for the twelve months ended March 31, 2007, respectively.

- We forecast Enogex's total processing inlet volumes to be 0.62 TBtu/d for the twelve months ending September 30, 2008 as compared to inlet volumes of 0.54 TBtu/d and 0.54 TBtu/d for the year ended December 31, 2006 and the twelve months ended March 31, 2007, respectively. This increase is being driven by anticipated increased gathered volumes as a result of system expansions in the Woodford Shale play in southeastern Oklahoma and the Granite Wash play in western Oklahoma and the Texas Panhandle.

- Of the total forecasted processing volumes, Enogex's expected processing mix is forecasted to be approximately 22.6% percent-of-liquids and percent-of-proceeds, 39.0% keep-whole subject to a default processing fee, 31.9% "lean" keep-whole (natural gas which has a Btu content less than 1,080 per cubic foot) and 6.5% fixed fee, which approximates Enogex's current mix of processing contracts.

- We forecast sales of Enogex's equity portion of NGLs attributable to percent-of-liquids arrangements sold to be 16.3 million gallons for the twelve months ending September 30, 2008 compared to 14.2 million gallons and 15.2 million gallons for the year ended December 31, 2006 and the twelve months ended March 31, 2007, respectively. The increase during the forecast period is due to a forecasted increase in percent-of-liquid volumes.

- We forecast sales of Enogex's equity portion of NGLs attributable to keep-whole arrangements sold to be 259.6 million gallons for the twelve months ending September 30, 2008 compared to 243.9 million gallons and 298.5 million gallons for the year ended December 31, 2006 and the twelve months ended March 31, 2007, respectively. The decrease in the forecast period compared to the twelve months ended March 31, 2007 relates to expected leaner keep-whole gas being processed.

- We utilize a forecast based upon expected prices in Enogex's areas of operations. The weighted-average natural gas price for the regions in which Enogex operates is forecasted to be $7.31 per MMBtu for the twelve months ending September 30, 2008. Our forecasted weighted-average natural gas price for the twelve months ending September 30, 2008 represents a 21.5% and 26.7% increase over average historical gas prices for the year ended December 31, 2006 and the twelve months ended March 31, 2007, respectively. The forward price as of June 18, 2007 was 5.4% above the forecasted price.

- Weighted-average NGL prices are forecasted to be $0.977 per gallon for the twelve months ending September 30, 2008. Our forecasted weighted-average NGL prices for the twelve months ending September 30, 2008 represent a 4.5% and 5.1% increase over average historical NGL prices for the year ended December 31, 2006 and the twelve months ended March 31, 2007, respectively. The forward prices of NGLs as of June 18, 2007 averaged 3.5% above the forecasted prices.

- The result of our forecasted natural gas price and NGL price is a forecasted commodity spread of $3.71 per MMBtu for the twelve months ending September 30, 2008 as compared to $4.56 per MMBtu for the year ended December 31, 2006 and $4.65 per MMBtu for the twelve months ended March 31, 2007.

- Processing gross margin sensitivity due to commodity prices is not expected to be linear due to factors such as ethane rejection, hedges in place and the absolute prices of the commodities that comprise the commodity spread. The table below reflects the effects on Enogex's gross margin and cash available for distribution of a 10% and 20% increase and decrease from the forecasted commodity spread.

	Forecasted Amount	Incremental Change to Forecasted Amount			
		+10%	-10%	+20%	-20%
	(in millions, except commodity spread)				
Commodity spread	$ 3.71	$0.37	$(0.37)	$0.74	$ (0.74)
Gross margin	$ 353.6	$ 6.9	$ (5.7)	$13.2	$ (13.3)
Cash available for distribution	$ 35.9	$ 1.7	$ (1.4)	$ 3.3	$ (3.3)
Minimum quarterly cash distribution for the forecast period	$ 31.3				

- Approximately 30% of Enogex's total processing commodity exposure is currently hedged. This 30% represents hedges on approximately 32% of Enogex's total expected keep-whole related processing volumes and approximately 30% of its expected percent-of-liquid volumes. These volumes are hedged as follows:

  - The following hedges were placed for the three months ending December 31, 2007 and are comprised of swaps and forwards. The NGL hedges are net short positions and natural gas hedges are net long positions.

	Three Months Ending December 31, 2007	
Commodity	Volume	Weighted-Average Price
Ethane	25,200,000 gallons	Indexed to natural gas
Propane	12,600,000 gallons	$ 1.146 / gallon
Normal butane	3,780,000 gallons	$ 1.300 / gallon
Iso-butane	1,260,000 gallons	$ 1.420 / gallon
Natural gasoline	1,890,000 gallons	$ 1.787 / gallon
Natural gas	1,635,694 MMBtu	$7.670 / MMBtu

- The following hedges were placed for the nine months ending September 30, 2008 and are comprised of swaps and forwards. The NGL hedges are net short positions and natural gas hedges are net long positions.

	Nine Months Ending September 30, 2008	
Commodity	Volume	Weighted-Average Price
Propane	1,398,600 gallons	$ 1.080 / gallon
Normal butane	491,400 gallons	$ 1.240 / gallon
Iso-butane	207,900 gallons	$ 1.280 / gallon
Natural gasoline	415,800 gallons	$ 1.583 / gallon
Natural gas	3,870,000 MMBtu	$7.830 / MMBtu

- The following hedges were placed for the nine months ending September 30, 2008 and are comprised of purchased put options.

	Nine Months Ending September 30, 2008	
Commodity	Volume	Weighted-Average Price
Propane	21,924,000 gallons	$0.966 / gallon
Normal butane	6,426,000 gallons	$1.091 / gallon
Iso-butane	4,158,000 gallons	$1.143 / gallon
Natural gasoline	8,694,000 gallons	$1.387 / gallon

- Enogex anticipates hedging additional non-ethane NGL volumes attributable to its keep-whole and percent-of-liquids arrangements through swaps, options or other mechanisms.

Marketing Gross Margin

We forecast gross margin for Enogex's marketing business to be approximately $14.9 million for the twelve months ending September 30, 2008 compared to $14.2 million and $9.9 million for the year ended December 31, 2006 and the twelve months ended March 31, 2007, respectively. Key factors impacting the forecasted gross margin for Enogex's marketing business include:

- Of the total $14.9 million of gross margin for the forecast period, $8.9 million relates to margin due to favorable transportation positions as compared to $4.3 million in the year ended December 31, 2006 and a negative $5.3 million during the twelve months ended March 31, 2007.
- Additionally, for the forecast period, $3.6 million of gross margin relates to favorable storage positions as compared to $6.6 million in the year ended December 31, 2006 and $10.1 million during the twelve months ended March 31, 2007.

Operation and Maintenance Expenses

We forecast Enogex's consolidated operation and maintenance expenses to be approximately $126.1 million for the twelve months ending September 30, 2008 compared to $114.0 million and $113.3 million for the year ended December 31, 2006 and the twelve months ended March 31, 2007, respectively, based on the following significant assumptions:

- Increased salary and wage expense due to new positions in response to increased business activity.
- We estimate that we will incur additional expenses of $4.0 million associated with being a publicly traded partnership, including but not limited to fees associated with annual and quarterly reports to unitholders, tax returns and Schedule K-1 preparation and distribution, investor relations, registrar and transfer agent fees, incremental insurance costs, accounting,

auditing and legal services and independent director compensation, of which $2.0 million will be incurred by us and $2.0 million will be incurred by Enogex.

Depreciation and Amortization Expense

We forecast Enogex's depreciation and amortization expense to be approximately $49.5 million for the twelve months ending September 30, 2008 compared to $42.3 million and $43.4 million in depreciation and amortization expense for the year ended December 31, 2006 and the twelve months ended March 31, 2007, respectively. The increase is primarily due to increased investment in Enogex's assets located in the Texas Panhandle, western Oklahoma and southeastern Oklahoma areas.

Taxes Other than Income

We forecast Enogex's taxes other than income to be approximately $19.7 million for the twelve months ending September 30, 2008 compared to $16.0 million and $16.1 million for the year ended December 31, 2006 and the twelve months ended March 31, 2007, respectively. The increase is primarily due to increased investment in Enogex's assets located in the Texas Panhandle, western Oklahoma and southeastern Oklahoma areas.

Other Expense

We forecast Enogex's other expense to be approximately $4.5 million for the twelve months ending September 30, 2008 compared to a gain of $7.4 million and a gain of $1.6 million for the year ended December 31, 2006 and the twelve months ended March 31, 2007, respectively. The forecasted other expense is primarily attributable to the non-controlling interest of the partner of the Atoka joint venture.

Non-Controlling Interest in Net Income

We forecast Enogex's non-controlling interest in net income to be approximately $98.8 million for the twelve months ending September 30, 2008 compared to $92.6 million and $80.3 million on a pro forma basis for the year ended December 31, 2006 and the twelve months ended March 31, 2007, respectively. The non-controlling interest is based on OGE Energy's initial 75% indirect ownership of Enogex.

Capital Expenditures

We forecast total capital expenditures for the twelve months ending September 30, 2008 to be $147.1 million based on the following assumptions:

- Maintenance capital expenditures are forecasted to be approximately $34.8 million. These forecasted expenditures include:

(in millions)	
Well connects on Enogex's existing system	$14.3
Environmental	0.7
Facilities and fleet	2.7
Regulatory compliance	2.2
Reliability (including pipeline integrity)	8.1
Technology improvements	6.5
Other	0.3
Total maintenance capital expenditures	$34.8

- Expansion capital expenditures during the forecast period are forecasted to be approximately $112.3 million. These forecasted expenditures include:

(in millions)	
Mid-Continent Express	$ 37.5
Woodford Shale expansion projects	40.4
Texas Panhandle expansion projects	2.6
Western Oklahoma expansion	20.3
Processing upgrades	7.8
Expansion and other	3.7
Total expansion capital expenditures	$112.3

Financing

Our forecast for the twelve months ending September 30, 2008 is based on the following significant financing assumptions:

- Enogex refinances all of its 8.125% senior notes due 2010 currently outstanding in an aggregate principal amount of $400 million.
- Enogex funds the refinancing, including payment of a $30 million make-whole premium, with a combination of proceeds from the issuance of $300 million in aggregate principal amount of senior notes and a contribution from us of $130 million of net proceeds from this offering.
- Enogex's interest expense is forecasted to be $24.0 million compared to $23.2 million and $23.2 million on a pro forma basis for the year ended December 31, 2006 and the twelve months ended March 31, 2007, respectively, assuming borrowings during the forecast period of $103.5 million under Enogex's new credit facility using an annual interest rate of 6.25% and the issuance of $300 million aggregate principal amount of senior notes with an assumed annual interest rate of 7.0%. A 1.0% increase or decrease in the assumed annual interest rate with respect to Enogex's new credit facility would cause forecasted interest expense to increase or decrease by $0.4 million. A 1.0% increase or decrease in the assumed annual interest rate with respect to the new senior notes would cause forecasted interest expense to increase or decrease by $3.0 million.
- Enogex will finance expected expansion capital expenditures using cash on hand as well as available capacity on its revolving credit facility. Enogex is expected to have $146.5 million of available borrowing capacity as of September 30, 2008.

Payments of Distributions to Non-Controlling Interest

We forecast that distributions to OGE Energy's indirect 75% non-controlling interest in Enogex will be approximately $113.2 million for the twelve months ending September 30, 2008.

Payments of Distributions on Common Units, Subordinated Units and the 2% General Partner Interest

We forecast that distributions on common units, subordinated units and on the 2% general partner interest for the twelve months ending September 30, 2008 will be approximately $31.3 million in the aggregate, which includes distributions for the period beginning October 1, 2007 and ending September 30, 2008.

Regulatory, Industry and Economic Factors

We forecast for the twelve months ending September 30, 2008 based on the following significant assumptions related to regulatory, industry and economic factors:

- No material nonperformance or credit-related defaults by suppliers, customers or vendors will occur. There will not be any new federal, state or local regulation of the portions of the energy industry in which Enogex operates or any interpretation of existing regulation that in either case will be materially adverse to Enogex's business.
- No material accidents, releases, weather-related incidents, unscheduled downtime or similar unanticipated and material events will occur.
- There will not be any major adverse change in the midstream sector of the energy industry or in general economic conditions.
- Market, regulatory, insurance and overall economic conditions will not change substantially.

Pro Forma and Forecasted Cash Available for Distribution

The following table illustrates, on a pro forma basis, for the year ended December 31, 2006 and for the twelve months ended March 31, 2007, the amount of cash available for distribution that would have been available for distributions to our unitholders, assuming that this offering and the related transactions had been consummated on January 1, 2006.

If we had completed the transactions contemplated in this prospectus on January 1, 2006, our estimated pro forma cash available for distribution generated during the year ended December 31, 2006 and the twelve months ended March 31, 2007 would have been approximately $32.9 million and $29.3 million, respectively. Assuming the underwriters exercise in full their option to purchase additional common units, this amount would have been sufficient to make aggregate cash distributions equal to 100.0% of the minimum quarterly distribution of $0.3375 per unit per quarter (or $1.35 per unit on an annualized basis) on our common units and subordinated units for the year ended December 31, 2006 and 100.0% of the minimum quarterly distribution of $0.3375 per unit per quarter ($1.35 per unit on an annualized basis) on our common units and 86.6% of the minimum quarterly distribution on our subordinated units for the twelve months ended March 31, 2007.

The table below also sets forth our calculation of forecasted cash available for distribution to our unitholders and general partner based on the forecasted results of operations set forth above. Based on the financial forecast and related assumptions, we forecast that our cash available for distribution generated during the twelve months ending September 30, 2008 will be approximately $35.9 million. Assuming the underwriters exercise in full their option to purchase additional common units, this amount would be sufficient to pay the minimum quarterly distribution of $0.3375 per unit on all of our common units and subordinated units for the four quarters ending September 30, 2008.

Unaudited pro forma cash available for distribution includes direct, incremental general and administrative expense that will result from operating as a separate publicly held limited partnership. These direct, incremental general and administrative expenses are expected to be approximately $4.0 million annually, are not subject to the cap contained in the omnibus agreement and include costs associated with annual and quarterly reports to unitholders, tax return and Schedule K-1 preparation and distribution, incremental independent auditor fees, registrar and transfer agent fees and independent director compensation. These direct, incremental general and administrative expenditures are not reflected in the historical consolidated financial statements of Enogex Predecessor or our pro forma consolidated financial statements.

We based the pro forma adjustments upon currently available information and specific estimates and assumptions. The pro forma amounts below do not purport to present our results of operations had the transactions contemplated in this prospectus actually been completed as of the dates indicated. In addition, cash available to pay distributions is primarily a cash accounting concept, while our pro forma consolidated financial statements have been prepared on an accrual basis. As a result, you should view the amount of pro forma available cash only as a general indication of the amount of cash available to pay distributions that we might have generated had we been formed in earlier periods.

You should read "Note 3. Significant Forecast Assumptions" included as part of the financial forecast for a discussion of the material assumptions underlying our forecast of Adjusted EBITDA that is included in the table below. Our forecast is based on those material assumptions and reflects our judgment of conditions we expect to exist and the course of action we expect to take. The assumptions disclosed in our financial forecast are those that we believe are significant to our ability to generate the forecasted Adjusted EBITDA. If our estimate is not achieved, we may not be able to pay distributions on the common units at the initial distribution rate of $0.3375 per unit per quarter ($1.35 per unit on an annualized basis). Our financial forecast and the forecast of cash available for distribution set forth below have been prepared by our management.

Our independent auditors have not examined, compiled, or otherwise applied procedures to our financial forecast and the forecast of cash available for distribution set forth below and, accordingly, do not express an opinion or any other form of assurance on it.

When considering our forecast of cash available for distribution for the twelve months ending September 30, 2008, you should keep in mind the risk factors and other cautionary statements under the heading "Risk Factors" and elsewhere in this prospectus. Any of these factors or the other risks discussed in this prospectus could cause our financial condition and consolidated results of operations to vary significantly from those set forth in financial forecast and the forecast of cash available for distribution set forth below.

OGE Enogex Partners L.P.
Statement of Estimated Cash Available for Distribution

(unaudited)	Pro Forma Year Ended December 31, 2006	Pro Forma Twelve Months Ended March 31, 2007	Forecasted Twelve Months Ending September 30, 2008
	(in millions, except per unit data)		
Net income	$ 28.9	$ 24.5	$ 31.1
Adjustments to reconcile net income to estimated Adjusted EBITDA:			
Add:			
Depreciation and amortization expense	42.3	43.4	49.5
Interest expense, net(1)	20.7	20.5	23.9
Option premium amortization	—	—	4.2
Non-controlling interest(2)	92.6	79.6	98.8
Estimated Adjusted EBITDA(3)	$184.5	$168.0	$207.5
Adjustments to reconcile estimated Adjusted EBITDA to estimated cash available for distribution:			
Less:			
Cash interest expense	20.7	20.5	23.6
Maintenance capital expenditures(4)	26.0	24.3	34.8
Expansion capital expenditures	41.1	48.3	112.3
Add:			
Share of public partnership expenses(5)	2.0	2.0	2.0
Borrowings to fund expansion capital expenditures	41.1	48.3	112.3
Cash available for distribution from Enogex	139.8	125.2	151.1
Less:			
Non-controlling interest(2)	104.9	93.9	113.2
Share of public partnership expenses(5)	2.0	2.0	2.0
Estimated cash available for distribution	$ 32.9	$ 29.3	$ 35.9
Annual minimum distributions to:			
Publicly held common units	$ 11.7	$ 11.7	$ 11.7
Common units held by an affiliate of OGE Energy	4.4	4.4	4.4
Subordinated units held by an affiliate of OGE Energy	14.6	14.6	14.6
General partner interest	0.6	0.6	0.6
Total minimum annual cash distributions	$ 31.3	$ 31.3	$ 31.3

(1) Under the provisions of Enogex's senior notes currently expected to be repaid in connection with this offering, a make-whole premium of approximately $30 million will be paid and funded with a portion of the proceeds from this offering contributed by us to Enogex. As this item does not have a continuing impact, no adjustment for this item is provided in the accompanying unaudited pro forma and forecasted consolidated statements of income.

(2) Represents OGE Energy's 75% indirect ownership of Enogex.

(3) Adjusted EBITDA is defined as net income from continuing operations before non-controlling interest, interest, income taxes and depreciation and amortization expense. Adjusted EBITDA is used as a supplemental financial measure by external users of our financial statements such as investors, commercial banks and others, to assess the financial performance of Enogex's assets without regard to financing methods, capital structure or historical cost basis; Enogex's operating performance and return on capital as compared to other companies in the midstream energy sector, without regard to financing or capital structure; and the viability of acquisitions and capital expenditure projects and the overall rates of return on alternative investment opportunities.

The economic substance behind the use of Adjusted EBITDA is to measure the ability of Enogex's assets to generate cash sufficient to pay interest costs, support indebtedness and make distributions to its members.

The GAAP measures most directly comparable to Adjusted EBITDA are net cash provided by operating activities and net income from continuing operations. The non-GAAP financial measure of Adjusted EBITDA should not be considered as an alternative to GAAP net cash provided by operating activities and GAAP net income from continuing operations. Adjusted EBITDA is not a presentation made in accordance with GAAP and has important limitations as an analytical tool. You should not consider Adjusted EBITDA in isolation or as a substitute for analysis of our results as reported under GAAP. Because Adjusted EBITDA excludes some, but not all, items that affect net income and net cash provided by operating activities and is defined differently by different companies in our industry, our definition of Adjusted EBITDA may not be comparable to similarly titled measures of other companies.

To compensate for the limitations of Adjusted EBITDA as an analytical tool, we believe that it is important to review the comparable GAAP measures and understand the differences between the measures.

(4) The $34.8 million of maintenance capital expenditures for the forecast period represents estimated maintenance capital expenditures as defined in our partnership agreement. The $26.0 million and $24.3 million for the year ended December 31, 2006 and twelve months ended March 31, 2007, respectively, represent actual maintenance capital expenditures during those periods. Our partnership agreement requires that an estimate of the maintenance capital expenditures necessary to maintain our asset base be subtracted from operating surplus each quarter as opposed to amounts actually spent. Due to the expected decline rate of the wells currently connected to Enogex's assets and those that we expect will be connected in the future, we expect that as our asset base grows the expenditures we will incur in the future to maintain our larger asset base will increase above the level estimated herein. The amount of estimated maintenance capital expenditures deducted from operating surplus is subject to review and change by the board of directors of our general partner at least once a year, provided that any change must be approved by the conflicts committee.

(5) We estimate that we will incur additional expenses of $4.0 million associated with being a publicly traded partnership, including but not limited to fees associated with annual and quarterly reports to unitholders, tax returns and Schedule K-1 preparation and distribution, investor relations, registrar and transfer agent fees, incremental insurance costs, accounting, auditing and legal services and independent director compensation, of which $2.0 million will be incurred by us and $2.0 million will be incurred by Enogex.

PROVISIONS OF OUR PARTNERSHIP AGREEMENT RELATING TO CASH DISTRIBUTIONS

Following completion of this offering, OGE Enogex Holdings LLC, a wholly owned subsidiary of OGE Energy, will own 3,280,605 common units and 10,780,605 subordinated units. In addition, OGE Enogex Holdings LLC will hold all of the membership interests in our general partner, and consequently will be entitled to all of the distributions that we make to OGE Enogex GP LLC, subject to the terms of the limited liability company agreement of OGE Enogex GP LLC and relevant legal restrictions.

Set forth below is a summary of the significant provisions of our partnership agreement that relate to cash distributions.

Distributions of Available Cash

General

Our partnership agreement requires that, no later than 45 days after the end of each quarter, beginning with the quarter ending December 31, 2007, we distribute all of our available cash to unitholders of record on the applicable record date.

Definition of Available Cash

We define available cash in the partnership agreement, and it generally means, for each fiscal quarter, the sum of all cash and cash equivalents on hand at the end of the quarter (including our proportionate share of cash on hand of certain subsidiaries we do not wholly own, including Enogex) plus all additional cash and cash equivalents on hand on the date of determination of available cash for the quarter (including our proportionate share of cash on hand of certain subsidiaries we do not wholly own, including Enogex) resulting from working capital borrowings made after the end of the quarter, less the amount of cash reserves (including our proportionate share of cash reserves of certain subsidiaries we do not wholly own, including Enogex) established by our general partner to:

- provide for the proper conduct of our business (including reserves for future capital expenditures and for future credit needs of us and our subsidiaries);
- comply with applicable law, any of our debt instruments or other agreements; or
- provide funds for distributions to our unitholders and to our general partner for any one or more of the next four quarters (provided that our general partner may not establish cash reserves for subordinated units unless it determines that the establishment of reserves will not prevent us from distributing the minimum quarterly distribution on all common units and any cumulative arrearages for the next four quarters).

Working capital borrowings are generally borrowings that are made under a credit facility, commercial paper facility or similar financing arrangement, and in all cases are used solely for working capital purposes or to pay distributions to partners.

Minimum Quarterly Distribution

We intend to distribute to the holders of common units and subordinated units on a quarterly basis at least the minimum quarterly distribution of $0.3375 per unit, or $1.35 on an annualized basis, to the extent we have sufficient cash from operations after establishment of cash reserves and payment of fees and expenses, including payments to our general partner and its affiliates. However, there is no guarantee that we will pay the minimum quarterly distribution on the units in any quarter. Even if our cash distribution policy is not modified or revoked, the amount of distributions paid under our policy and the decision to make any distribution is determined by our general partner, taking into consideration the terms of our partnership agreement.

General Partner Interest and Incentive Distribution Rights

Initially, our general partner will be entitled to 2% of all quarterly distributions since inception that we make prior to our liquidation. Our general partner's 2% interest in us is represented by unit equivalents for allocation and distribution purposes. This general partner interest will be represented by 440,025 units equivalents (or 462,984 units equivalents if the underwriters exercise in full their option to purchase additional common units). Our general partner has the right, but not the obligation, to contribute a proportionate amount of capital to us to maintain its current general partner interest if we issue additional units. Our general partner's initial 2% interest in these distributions may be reduced if we issue additional units in the future and our general partner does not contribute a proportionate amount of capital to us to maintain its 2% general partner interest.

Our general partner also currently holds incentive distribution rights that entitle it to receive increasing percentages, up to a maximum of 50%, of the cash we distribute from operating surplus (as defined below) in excess of $0.3881 per unit per quarter. The maximum distribution of 50% includes distributions paid to our general partner on its 2% general partner interest and assumes that our general partner maintains its general partner interest at 2%. The maximum distribution of 50% does not include any distributions that our general partner may receive on common units or subordinated units that it owns.

Operating Surplus and Capital Surplus

General

All cash distributed to unitholders will be characterized as either "operating surplus" or "capital surplus." Our partnership agreement requires that we distribute available cash from operating surplus differently than available cash from capital surplus.

Operating Surplus

We define operating surplus in the partnership agreement, and for any period it generally means:

- an amount equal to two times the amount needed for any one quarter for us to pay a distribution on all of our units (including the general partner interest) and the incentive distribution rights at the same per-unit amount as was distributed in the immediately preceding quarter; plus
- all cash receipts of us and our subsidiaries (including our proportionate share of cash receipts for certain subsidiaries we do not wholly own, including Enogex) after the closing of this offering, excluding cash from interim capital transactions, which include:
  - borrowings that are not working capital borrowings;
  - sales of equity and debt securities;
  - sales or other dispositions of assets outside the ordinary course of business;
  - capital contributions received; or
  - corporate reorganizations or restructurings,

  provided the cash receipts from the termination of a commodity hedge or interest rate swap prior to its specified termination date shall be included in operating surplus in equal quarterly installments over the remaining scheduled life of such commodity hedge or interest rate swap; plus
- working capital borrowings (including our proportionate share of working capital borrowings for certain subsidiaries we do not wholly own, including Enogex) made after the end of a quarter but on or before the date of determination of operating surplus for the quarter; plus

- cash distributions paid on equity issued in connection with the construction or development of a capital improvement or replacement asset during the period beginning on the date that we enter into a binding commitment to commence the construction or development of such capital improvement or replacement asset and ending on the earlier to occur of the date the capital improvement or replacement asset is placed into service and the date that it is abandoned or disposed of; less
- all operating expenditures of us and our subsidiaries (including our proportionate share of operating expenditures of certain subsidiaries we do not wholly own, including Enogex) after the closing of this offering; less
- estimated maintenance capital expenditures; less
- the amount of cash reserves (including our proportionate share of cash reserves of certain subsidiaries we do not wholly own, including Enogex) established by our general partner to provide funds for future operating expenditures; less
- all working capital borrowings (including our proportionate share of working capital borrowings for certain subsidiaries we do not wholly own, including Enogex) not repaid within twelve months after having been incurred or repaid within such twelve-month period with the proceeds of additional working capital borrowings.

If a working capital borrowing, which increases operating surplus, is not repaid during the twelve-month period following the borrowing, it will be deemed repaid at the end of such period, thus decreasing operating surplus at such time. When such working capital borrowing is in fact repaid, it will not be treated as a reduction in operating surplus because operating surplus will have been previously reduced by the deemed repayment.

We define operating expenditures in the partnership agreement, and it generally means all of our cash expenditures (including our proportionate share of cash expenditures of certain subsidiaries we do not wholly own, including Enogex), including, but not limited to, taxes, reimbursements of expenses to our general partner, repayment of working capital borrowings, debt service payments and estimated maintenance capital expenditures, provided that operating expenditures will not include:

- repayment of working capital borrowings deducted from operating surplus pursuant to the last bullet point of the definition of operating surplus above when such repayment actually occurs;
- payments (including prepayments and prepayment penalties) of principal and premium on indebtedness other than working capital borrowing;
- actual maintenance capital expenditures;
- expansion capital expenditures;
- investment capital expenditures;
- payment of transaction expenses relating to interim capital transactions; or
- distributions to partners.

For purposes of determining operating surplus, maintenance capital expenditures are those capital expenditures required to maintain over the long term the operating capacity or revenues of us and our subsidiaries, and expansion capital expenditures are those capital expenditures that increase the operating capacity or revenues generated by capital assets. Examples of maintenance capital expenditures include expenditures required to maintain equipment reliability, storage and pipeline integrity and safety and to address environmental regulations. Maintenance capital expenditures will also include interest (and related fees) on debt incurred and distributions on equity issued to finance all or any portion of the construction or development of a replacement asset that is paid in respect of the period that begins when we enter into a binding obligation to commence constructing or developing the replacement asset and ending on the earlier to occur of the date of any such replacement asset commences commercial service or the date that it is abandoned or disposed of. Capital expenditures made solely for investment purposes will not be considered maintenance capital expenditures.

Because our maintenance capital expenditures can be very large and vary significantly in timing, the amount of our actual maintenance capital expenditures may differ substantially from period to period, which could cause similar fluctuations in the amounts of operating surplus, adjusted operating surplus and cash available for distribution to our unitholders if we subtracted actual maintenance capital expenditures from operating surplus each quarter. Accordingly, to eliminate the effect on operating surplus of these fluctuations, our partnership agreement will require that an amount equal to an estimate of the average quarterly maintenance capital expenditures necessary to maintain the operating capacity of the revenue generated by our capital assets over the long term be subtracted from operating surplus each quarter, as opposed to the actual amounts spent. The amount of estimated maintenance capital expenditures deducted from operating surplus is subject to review and change by the board of directors of our general partner at least once a year, provided that any change must be approved by the board's conflicts committee. The estimate will be made at least annually and whenever an event occurs that is likely to result in a material adjustment to the amount of our maintenance capital expenditures, such as a major acquisition. For purposes of calculating operating surplus, any adjustment to this estimate will be prospective only. For a discussion of the amounts we have allocated toward estimated maintenance capital expenditures, please see "Cash Distribution Policy and Restrictions on Distributions."

The use of estimated maintenance capital expenditures in calculating operating surplus will have the following effects:

- it will reduce the risk that maintenance capital expenditures in any one quarter will be large enough to render operating surplus less than the minimum quarterly distribution to be paid on all the units for the quarter and subsequent quarters;
- it will increase our ability to distribute as operating surplus cash we receive from non-operating sources; and
- it will be more difficult for us to raise our distribution above the minimum quarterly distribution and pay incentive distributions on the incentive distribution rights held by our general partner.

Expansion capital expenditures are those capital expenditures that we expect will increase our operating capacity or operating income. Examples of expansion capital expenditures include the acquisition of equipment and the construction, development or acquisition of additional pipeline or processing capacity, to the extent such capital expenditures are expected to expand, for a period of longer than the short term, either our operating capacity or operating income. Expansion capital expenditures will also include interest (and related fees) on debt incurred and distributions on equity issued to finance all or any portion of the construction of such capital improvement during the period that commences when we enter into a binding obligation to commence construction of a capital improvement and ending on the date any such capital improvement commences commercial service or the date that it is abandoned or disposed of. Capital expenditures made solely for investment purposes will not be considered expansion capital expenditures.

As described below, none of investment capital expenditures or expansion capital expenditures are subtracted from operating surplus. Because investment capital expenditures and expansion capital expenditures include interest payments (and related fees) on debt incurred and distributions on equity issued to finance all of the portion of the construction, replacement or improvement of a capital asset (such as gathering pipelines or processing facilities) during the period that begins when we enter into a binding obligation to commence construction of a capital improvement and ending on the earlier to occur of the date any such capital asset commences commercial service or the date that it is abandoned or disposed of, such interest payments and equity distributions are also not subtracted from operating surplus (except, in the case of maintenance capital expenditures, to the extent such interest payments and distributions are included in estimated maintenance capital expenditures).

Investment capital expenditures are those capital expenditures that are neither maintenance capital expenditures nor expansion capital expenditures.

Capital expenditures that are made in part for maintenance capital purposes and in part for investment capital or expansion capital purposes will be allocated as maintenance capital expenditures, investment capital expenditures or expansion capital expenditure by our general partner, with the concurrence of the conflicts committee of our general partner.

Capital Surplus

Capital surplus generally consists of:

- borrowings other than working capital borrowings;
- sales of our equity and debt securities;
- sales or other dispositions of assets for cash, other than inventory, accounts receivable and other current assets sold in the ordinary course of business or as part of normal retirement or replacement of assets;
- capital contributions received; and
- corporate reorganizations or restructurings.

Characterization of Cash Distributions

Our partnership agreement requires that we treat all available cash distributed as coming from operating surplus until the sum of all available cash distributed since the closing of this offering equals the operating surplus from the closing of this offering through the end of the quarter immediately preceding that distribution. Our partnership agreement requires that we treat any amount distributed in excess of operating surplus, regardless of its source, as capital surplus. As reflected above, operating surplus includes an amount equal to two times the amount needed for any one quarter for us to pay a distribution on all of our units (including the general partner interest) and the incentive distribution rights at the same per-unit amount as was distributed in the immediately preceding quarter. This amount, which initially equals approximately $15.0 million, does not reflect actual cash on hand that is available for distribution to our unitholders. Rather, it is a provision that will enable us, if we choose, to distribute as operating surplus up to this amount of cash we receive in the future from non-operating sources, such as asset sales, issuances of securities and long-term borrowings, that would otherwise be distributed as capital surplus. We do not anticipate that we will make any distributions from capital surplus.

Subordination Period

General

Our partnership agreement provides that, during the subordination period (which we define below and in Appendix B), the common units will have the right to receive distributions of available cash from operating surplus each quarter in an amount equal to $0.3375 per common unit, which amount is defined in our partnership agreement as the minimum quarterly distribution, plus any arrearages in the payment of the minimum quarterly distribution on the common units from prior quarters, before any distributions of available cash from operating surplus may be made on the subordinated units. These units are deemed "subordinated" because for a period of time, referred to herein as the subordination period, the subordinated units will not be entitled to receive any distributions until the common units have received the minimum quarterly distribution plus any arrearages from prior quarters. Furthermore, no arrearages will be paid on the subordinated units. The practical effect of the subordinated units is to increase the likelihood that during the subordination period there will be available cash to be distributed on the common units.

Subordination Period

The subordination period will extend until the first day of any quarter beginning after September 30, 2010 that each of the following tests are met:

- distributions of available cash from operating surplus on each of the outstanding common units and subordinated units and the corresponding distributions on the 2% general partner interest equaled or exceeded the minimum quarterly distribution for each of the three consecutive, non-overlapping four-quarter periods immediately preceding that date;
- the "adjusted operating surplus" (as defined below) generated during each of the three consecutive, non-overlapping four-quarter periods immediately preceding that date equaled or exceeded the sum of the minimum quarterly distributions on all of the outstanding common units and subordinated units and the corresponding distributions on the 2% general partner interest during those periods on a fully diluted basis during those periods; and
- there are no arrearages in payment of the minimum quarterly distribution on the common units.

Alternatively, the subordination period will end the first day after the following tests are met:

- distributions of available cash from operating surplus on each of the outstanding common units and subordinated units and the corresponding distributions on the 2% general partner interest equaled or exceeded $0.50625 (150% of the minimum quarterly distribution) for each quarter for four consecutive quarters;
- the "adjusted operating surplus" (as defined below) generated during the four consecutive, non-overlapping quarters immediately preceding the date equaled or exceeded $0.50625 (150% of the minimum quarterly distribution) on each of the outstanding common units, subordinated units and the corresponding distributions on the 2% general partner interest during those periods; and
- there are no arrearages in payment of the minimum quarterly distributions on the common units.

When the subordination period expires, each outstanding subordinated unit will convert into one common unit and will then participate pro rata with the other common units in distributions of available cash. In addition, if the unitholders remove our general partner other than for cause and units held by our general partner and its affiliates are not voted in favor of such removal:

- the subordination period will end and each subordinated unit will immediately convert into one common unit;
- any existing arrearages in payment of the minimum quarterly distribution on the common units will be extinguished; and
- our general partner will have the right to convert its general partner interest and its incentive distribution rights into common units or receive cash in exchange for those interests.

Adjusted Operating Surplus

Adjusted operating surplus is intended to reflect the cash generated from operations during a particular period and therefore excludes net drawdowns of reserves of cash generated in prior periods. Adjusted operating surplus consists of:

- operating surplus generated with respect to that period (excluding any amounts attributable to the items described in the first bullet point under "—Operating Surplus and Capital Surplus—Operating Surplus" above); less
- any net increase in working capital borrowings (including our proportionate share of any net increase of certain subsidiaries we do not wholly own, including Enogex) with respect to that period; less
- any net decrease made in subsequent periods in cash reserves for operating expenditures (including our proportionate share of any net decreases of certain subsidiaries we do not wholly own, including Enogex) with respect to that period; less
- any net decrease in cash reserves for operating expenditures (including our proportionate share of any net decreases of certain subsidiaries we do not wholly own, including Enogex) with respect to that period not relating to an operating expenditure made with respect to that period; plus
- any net decrease in working capital borrowings (including our proportionate share of any net decrease of certain subsidiaries we do not wholly own, including Enogex) with respect to that period; plus
- any net increase in cash reserves for operating expenditures (including our proportionate share of any net increases of certain subsidiaries we do not wholly own, including Enogex) with respect to that period required by any debt instrument for the repayment of principal, interest or premium.

Distributions of Available Cash from Operating Surplus During the Subordination Period

Our partnership agreement requires that we make distributions of available cash from operating surplus for any quarter during the subordination period in the following manner:

- first, 98% to the common unitholders, pro rata, and 2% to the general partner, until we distribute for each outstanding common unit an amount equal to the minimum quarterly distribution for that quarter;
- second, 98% to the common unitholders, pro rata, and 2% to the general partner, until we distribute for each outstanding common unit an amount equal to any arrearages in payment of the minimum quarterly distribution on the common units for any prior quarters during the subordination period;
- third, 98% to the subordinated unitholders, pro rata, and 2% to the general partner, until we distribute for each subordinated unit an amount equal to the minimum quarterly distribution for that quarter; and
- thereafter, in the manner described in "—General Partner Interest and Incentive Distribution Rights" below.

The preceding discussion is based on the assumptions that our general partner maintains its 2% general partner interest and that we do not issue additional classes of equity securities.

Distributions of Available Cash from Operating Surplus After the Subordination Period

Our partnership agreement requires that we make distributions of available cash from operating surplus for any quarter after the subordination period in the following manner:

- first, 98% to all unitholders, pro rata, and 2% to the general partner, until we distribute for each outstanding unit an amount equal to the minimum quarterly distribution for that quarter; and
- thereafter, in the manner described in "—General Partner Interest and Incentive Distribution Rights" below.

The preceding discussion is based on the assumptions that our general partner maintains its 2% general partner interest and that we do not issue additional classes of equity securities.

General Partner Interest and Incentive Distribution Rights

Our partnership agreement provides that our general partner initially will be entitled to 2% of all distributions that we make prior to our liquidation. Our general partner has the right, but not the obligation, to contribute a proportionate amount of capital to us to maintain its 2% general partner interest if we issue additional units. Our general partner's 2% interest, and the percentage of our cash distributions to which it is entitled, will be proportionately reduced if we issue additional units in the future and our general partner does not contribute a proportionate amount of capital to us in order to maintain its 2% general partner interest. Our general partner will be entitled to make a capital contribution in order to maintain its 2% general partner interest in the form of the contribution to us of common units based on the current market value of the contributed common units.

Incentive distribution rights represent the right to receive an increasing percentage (13%, 23% and 48%) of quarterly distributions of available cash from operating surplus after the minimum quarterly distribution and the target distribution levels have been achieved. Our general partner currently holds the incentive distribution rights, but may transfer these rights separately from its general partner interest, subject to restrictions in our partnership agreement.

The following discussion assumes that our general partner maintains its 2% general partner interest and continues to own the incentive distribution rights.

If for any quarter:

- we have distributed available cash from operating surplus to the common and subordinated unitholders in an amount equal to the minimum quarterly distribution; and
- we have distributed available cash from operating surplus on outstanding common units in an amount necessary to eliminate any cumulative arrearages in payment of the minimum quarterly distribution;

then, our partnership agreement requires that we distribute any additional available cash from operating surplus for that quarter among our unitholders and our general partner in the following manner:

- first, 98% to all unitholders, pro rata, and 2% to the general partner, until each unitholder receives a total of $0.3881 per unit for that quarter (the "first target distribution");
- second, 85% to all unitholders, pro rata, and 15% to the general partner, until each unitholder receives a total of $0.4219 per unit for that quarter (the "second target distribution");
- third, 75% to all unitholders, pro rata, and 25% to the general partner, until each unitholder receives a total of $0.50625 per unit for that quarter (the "third target distribution"); and
- thereafter, 50% to all unitholders, pro rata, and 50% to the general partner.

Percentage Allocations of Available Cash from Operating Surplus

The following table illustrates the percentage allocations of available cash from operating surplus between our unitholders and our general partner based on the specified target distribution levels. The amounts set forth under "Marginal Percentage Interest in Distributions" are the percentage interests of our general partner and the unitholders in any available cash from operating surplus we distribute up to and including the corresponding amount in the column "Total Quarterly Distribution Per Unit," until available cash from operating surplus we distribute reaches the next target distribution level, if any. The percentage interests shown for our unitholders and our general partner for the minimum quarterly distribution are also applicable to quarterly distribution amounts that are less than the minimum quarterly distribution. The percentage interests set forth below for our general partner include its 2% general partner interest and assume our general partner has contributed any additional capital to maintain its 2% general partner interest and has not transferred its incentive distribution rights.

	Total Quarterly Distribution Per Unit	Marginal Percentage Interest in Distributions	
	Target Amount	Unitholders	General Partner
Minimum Quarterly Distribution	$0.3375	98%	2%
First Target Distribution	up to $0.3881	98%	2%
Second Target Distribution	above $0.3881 up to $0.4219	85%	15%
Third Target Distribution	above $0.4219 up to $0.50625	75%	25%
Thereafter	above $0.50625	50%	50%

General Partner's Right to Reset Incentive Distribution Levels

Our general partner, as the holder of our incentive distribution rights, has the right under our partnership agreement to elect to relinquish the right to receive incentive distribution payments based on the initial cash target distribution levels and to reset, at higher levels, the minimum quarterly distribution amount and cash target distribution levels upon which the incentive distribution payments to our general partner would be set. Our general partner's right to reset the minimum quarterly distribution amount and the target distribution levels upon which the incentive distributions payable to our general partner are based may be exercised, without approval of our unitholders or the conflicts committee of our general partner, at any time when there are no subordinated units outstanding and we have made cash distributions to the holders of the incentive distribution rights at the highest level of incentive distribution for each of the prior four consecutive quarters. The reset minimum quarterly distribution amount and target distribution levels will be higher than the minimum quarterly distribution amount and the target distribution levels prior to the reset such that our general partner will not receive any incentive distributions under the reset target distribution levels until cash distributions per unit following this event increase as described below. We anticipate that our general partner would exercise this reset right in order to facilitate acquisitions or internal growth projects that would otherwise not be sufficiently accretive to cash distributions per common unit, taking into account the existing levels of incentive distribution payments being made to our general partner.

In connection with the resetting of the minimum quarterly distribution amount and the target distribution levels and the corresponding relinquishment by our general partner of incentive distribution payments based on the target cash distributions prior to the reset, our general partner will be entitled to receive a number of newly issued Class B units based on a predetermined formula described below that takes into account the "cash parity" value of the average cash distributions related to the incentive distribution rights received by our general partner for the two quarters prior to the reset event as compared to the average cash distributions per common unit during that period.

The number of Class B units that our general partner would be entitled to receive from us in connection with a resetting of the minimum quarterly distribution amount and the target distribution levels then in effect would be equal to (1) the average amount of cash distributions received by our general partner in respect of its incentive distribution rights during the two consecutive quarters ended immediately prior to the date of such reset election divided by (2) the average of the amount of cash distributed per common unit during each of those two quarters. Each Class B unit will be convertible into one common unit at the election of the holder of the Class B unit at any time following the first anniversary of the issuance of these Class B units.

Following a reset election by our general partner, the minimum quarterly distribution amount will be reset to an amount equal to the average cash distribution amount per common unit for the two quarters immediately preceding the reset election (such amount is referred to herein as the "reset minimum quarterly distribution") and the target distribution levels will be reset to be correspondingly higher such that we would distribute all of our available cash from operating surplus for each quarter thereafter as follows:

- first, 98% to all unitholders, pro rata, and 2% to the general partner, until each unitholder receives an amount equal to 115% of the reset minimum quarter distribution for that quarter;
- second, 85% to all unitholders, pro rata, and 15% to the general partner, until each unitholder receives an amount per unit equal to 125% of the reset minimum quarterly distribution for that quarter;
- third, 75% to all unitholders, pro rata, and 25% to the general partner, until each unitholder receives an amount per unit equal to 150% of the reset minimum quarterly distribution for that quarter; and
- thereafter, 50% to all unitholders, pro rata, and 50% to the general partner.

The following table illustrates the percentage allocation of available cash from operating surplus between our unitholders and our general partner at various levels of cash distribution levels pursuant to the cash distribution provision of our partnership agreement in effect at the closing of this offering as well as following a hypothetical reset of the minimum quarterly distribution and target distribution levels based on the assumption that the average quarterly cash distribution amount per common unit during the two quarters immediately preceding the reset election was $0.60.

		Marginal Percentage Interest in Distributions		
	Quarterly Distribution per Unit Prior to Reset	Unitholders	General Partner	Quarterly Distribution per Unit Following Hypothetical Reset
Minimum Quarterly Distribution	$0.3375	98%	2%	$0.6000
First Target Distribution	up to $0.3881	98%	2%	up to $0.6900(1)
Second Target Distribution	above $0.3881 up to $0.4219	85%	15%	above $0.6900 up to $0.7500(2)
Third Target Distribution	above $0.4219 up to $0.50625	75%	25%	above $0.7500 up to $0.9000(3)
Thereafter	above $0.50625	50%	50%	above $0.9000(3)

(1) This amount is 115% of the hypothetical reset minimum quarterly distribution.

(2) This amount is 125% of the hypothetical reset minimum quarterly distribution.

(3) This amount is 150% of the hypothetical reset minimum quarterly distribution.

The following table illustrates the total amount of available cash from operating surplus that would be distributed to our unitholders and our general partner, including in respect of incentive distribution rights, based on an average of the amounts distributed for a quarter for the two quarters immediately prior to the reset. The table assumes that the underwriters exercise in full their option to purchase additional common units, that there are 22,686,210 common units and 462,984 unit equivalents representing the 2% general partner interest outstanding and that the average distribution to each common unit is $0.60 for each of the two quarters prior to the reset. The assumed number of outstanding units assumes the underwriters exercise in full their option to purchase additional common units, the conversion of all subordinated units into common units and no additional unit issuances.

	Quarterly Distribution Per Unit Prior to Reset	Common Unitholders Cash Distributions Prior to Reset	General Partner Cash Distributions Prior to Reset				Total Distributions
			Class B Units	2% General Partner Interest	Incentive Distribution Rights	Total	
Minimum Quarterly Distribution	$0.3375	$ 7,656,596	$ —	$156,257	$ —	$ 156,257	$ 7,812,853
First Target Distribution	up to $0.3881	1,148,489	—	23,439	—	23,439	1,171,928
Second Target Distribution	above $0.3881 up to $0.4219	765,660	—	18,016	117,100	135,116	900,776
Third Target Distribution	above $0.4219 up to $0.50625	1,914,149	—	51,044	587,006	638,050	2,552,199
Thereafter	above $0.50625	2,126,832	—	85,073	2,041,759	2,126,832	4,253,664
		$13,611,726	$ —	$333,829	$2,745,865	$3,079,694	$16,691,420

The following table illustrates the total amount of available cash from operating surplus that would be distributed to our unitholders and our general partner with respect to the quarter in which the reset occurs. The table reflects that as a result of the reset there are 22,686,210 common units, 4,576,442 Class B units and 556,382 unit equivalents representing the 2% general partner interest outstanding, and that the average distribution to each common unit is $0.60. The number of Class B units was calculated by dividing (1) the $2,745,865 received by our general partner in respect of its incentive distribution rights per quarter for the two quarters prior to the reset as shown in the table above by (2) the $0.60 of available cash from operating surplus distributed to each common unit as the average distributed per common unit per quarter for each of the two quarters prior to the reset.

	Quarterly Distribution per Unit After Reset	Common Unitholders Cash Distributions After Reset	General Partner Cash Distributions After Reset				Total Distributions
			Class B Units	2% General Partner Interest	Incentive Distribution Rights	Total	
Minimum Quarterly Distribution	$0.6000	$13,611,726	$2,745,865	$333,829	$ —	$ 3,079,694	$16,691,420
First Target Distribution(1)	up to $0.6900						
Second Target Distribution(2)	above $0.6900 up to $0.7500						
Third Target Distribution(3)	above $0.7500 up to $0.9000						
Thereafter	above $0.9000						
		$13,611,726	$2,745,865	$333,829	$ —	$ 3,079,694	$16,691,420

(1) This amount is 115% of the hypothetical reset minimum quarterly distribution.

(2) This amount is 125% of the hypothetical reset minimum quarterly distribution.

(3) This amount is 150% of the hypothetical reset minimum quarterly distribution.

Our general partner will be entitled to cause the minimum quarterly distribution amount and the target distribution levels to be reset on more than one occasion, provided that it may not make a reset election except at a time when it has received incentive distributions for the prior four consecutive quarters based on the highest level of incentive distributions that it is entitled to receive under our partnership agreement.

Distributions from Capital Surplus

How Distributions from Capital Surplus will be Made

Our partnership agreement requires that we make distributions of available cash from capital surplus, if any, in the following manner:

- first, 98% to all unitholders, pro rata, and 2% to the general partner, until we distribute for each common unit that was issued in this offering, an amount of available cash from capital surplus equal to the initial public offering price;
- second, 98% to the common unitholders, pro rata, and 2% to the general partner, until we distribute for each common unit, an amount of available cash from capital surplus equal to any unpaid arrearages in payment of the minimum quarterly distribution on the common units; and
- thereafter, we will make all distributions of available cash from capital surplus as if they were from operating surplus.

The preceding paragraph assumes that our general partner maintains its 2% general partner interest and that we do not issue additional classes of equity securities.

Effect of a Distribution from Capital Surplus

Our partnership agreement treats a distribution of capital surplus as the repayment of the initial unit price from this initial public offering, which is a return of capital. The initial public offering price less any distributions of capital surplus per unit is referred to herein as the "unrecovered initial unit price." Each time a distribution of capital surplus is made, the minimum quarterly distribution and the target distribution levels will be reduced in the same proportion as the corresponding reduction in the unrecovered initial unit price. Because distributions of capital surplus will reduce the minimum quarterly distribution, after any of these distributions are made, it may be easier for our general partner to receive incentive distributions and for the subordinated units to convert into common units. However, any distribution of capital surplus before the unrecovered initial unit price is reduced to zero cannot be applied to the payment of the minimum quarterly distribution or any arrearages.

Once we distribute capital surplus on a unit issued in this offering in an amount equal to the initial unit price, our partnership agreement specifies that the minimum quarterly distribution and the target distribution levels will be reduced to zero. Our partnership agreement specifies that we then make all future distributions from operating surplus, with 50% being paid to the holders of units and 50% to the general partner. The percentage interests shown for our general partner include its 2% general partner interest and assume our general partner maintains its 2% general partner interest and has not transferred the incentive distribution rights.

Adjustment to the Minimum Quarterly Distribution and Target Distribution Levels

In addition to adjusting the minimum quarterly distribution and target distribution levels to reflect a distribution of capital surplus, if we combine our units into fewer units or subdivide our units into a greater number of units, our partnership agreement specifies that the following items will be proportionately adjusted:

- the minimum quarterly distribution;
- target distribution levels;
- the unrecovered initial unit price; and
- the number of common units into which a subordinated unit is convertible.

For example, if a two-for-one split of the common units should occur, the minimum quarterly distribution, the target distribution levels and the unrecovered initial unit price would each be reduced to 50% of its initial level, and each subordinated unit would be convertible into two common units. Our partnership agreement provides that we not make any adjustment by reason of the issuance of additional units for cash or property.

In addition, if legislation is enacted or if existing law is modified or interpreted by a governmental taxing authority, so that we become taxable as a corporation or otherwise subject to taxation as an entity for federal, state or local income tax purposes, our partnership agreement specifies that our general partner may reduce the minimum quarterly distribution and the target distribution levels for each quarter by multiplying each distribution level by a fraction, the numerator of which is available cash for that quarter and the denominator of which is the sum of available cash for that quarter plus our general partner's estimate of our aggregate liability for the quarter for such income taxes payable by reason of such legislation or interpretation. To the extent that the actual tax liability differs from the estimated tax liability for any quarter, the difference will be accounted for in subsequent quarters.

Distributions of Cash Upon Liquidation

General

If we dissolve in accordance with our partnership agreement, we will sell or otherwise dispose of our assets in a process called liquidation. We will first apply the proceeds of liquidation to the payment of our creditors. We will distribute any remaining proceeds to our unitholders and our general partner, in accordance with their capital account balances, as adjusted to reflect any gain or loss upon the sale or other disposition of our assets in liquidation.

The allocations of gain and loss upon liquidation are intended, to the extent possible, to entitle the holders of outstanding common units to a preference over the holders of outstanding subordinated units upon our liquidation, to the extent required to permit common unitholders to receive their unrecovered initial unit price plus the minimum quarterly distribution for the quarter during which liquidation occurs plus any unpaid arrearages in payment of the minimum quarterly distribution on the common units. However, there may not be sufficient gain upon our liquidation to enable the holders of common units to fully recover all of these amounts, even though there may be cash available for distribution to the holders of subordinated units. Any further net gain recognized upon liquidation will be allocated in a manner that takes into account the incentive distribution rights of our general partner.

Manner of Adjustments for Gain

The manner of the adjustment for gain is set forth in our partnership agreement. If our liquidation occurs before the end of the subordination period, we will allocate any gain to the partners in the following manner:

- first, to the general partner and the holders of units who have negative balances in their capital accounts to the extent of and in proportion to those negative balances;
- second, 98% to the common unitholders, pro rata, and 2% to the general partner, until the capital account for each common unit is equal to the sum of: (1) the unrecovered initial unit price; (2) the amount of the minimum quarterly distribution for the quarter during which our liquidation occurs; and (3) any unpaid arrearages in payment of the minimum quarterly distribution;
- third, 98% to the subordinated unitholders, pro rata, and 2% to the general partner until the capital account for each subordinated unit is equal to the sum of: (1) the unrecovered initial unit price; and (2) the amount of the minimum quarterly distribution for the quarter during which our liquidation occurs;

- fourth, 98% to all unitholders, pro rata, and 2% to the general partner, until we allocate under this paragraph an amount per unit equal to: (1) the sum of the excess of the first target distribution per unit over the minimum quarterly distribution per unit for each quarter of our existence; less (2) the cumulative amount per unit of any distributions of available cash from operating surplus in excess of the minimum quarterly distribution per unit that we distributed 98% to the unitholders, pro rata, and 2% to the general partner, for each quarter of our existence;
- fifth, 85% to all unitholders, pro rata, and 15% to the general partner, until we allocate under this paragraph an amount per unit equal to: (1) the sum of the excess of the second target distribution per unit over the first target distribution per unit for each quarter of our existence; less (2) the cumulative amount per unit of any distributions of available cash from operating surplus in excess of the first target distribution per unit that we distributed 85% to the unitholders, pro rata, and 15% to the general partner for each quarter of our existence;
- sixth, 75% to all unitholders, pro rata, and 25% to the general partner, until we allocate under this paragraph an amount per unit equal to: (1) the sum of the excess of the third target distribution per unit over the second target distribution per unit for each quarter of our existence; less (2) the cumulative amount per unit of any distributions of available cash from operating surplus in excess of the second target distribution per unit that we distributed 75% to the unitholders, pro rata, and 25% to the general partner for each quarter of our existence; and
- thereafter, 50% to all unitholders, pro rata, and 50% to the general partner.

The percentage interests set forth above for our general partner include its 2% general partner interest and assume our general partner has not transferred the incentive distribution rights.

If the liquidation occurs after the end of the subordination period, the distinction between common units and subordinated units will disappear, so that clause (3) of the second bullet point above and all of the third bullet point above will no longer be applicable.

Manner of Adjustments for Losses

If our liquidation occurs before the end of the subordination period, we will generally allocate any loss to the general partner and the unitholders in the following manner:

- first, 98% to holders of subordinated units in proportion to the positive balances in their capital accounts and 2% to the general partner, until the capital accounts of the subordinated unitholders have been reduced to zero;
- second, 98% to the holders of common units in proportion to the positive balances in their capital accounts and 2% to the general partner, until the capital accounts of the common unitholders have been reduced to zero; and
- thereafter, 100% to the general partner.

If the liquidation occurs after the end of the subordination period, the distinction between common units and subordinated units will disappear, so that all of the first bullet point above will no longer be applicable.

Adjustments to Capital Accounts

Our partnership agreement requires that we make adjustments to capital accounts upon the issuance of additional units. In this regard, our partnership agreement specifies that we allocate any unrealized and, for tax purposes, unrecognized gain or loss resulting from the adjustments to the unitholders and the general partner in the same manner as we allocate gain or loss upon liquidation. In the event that we make positive adjustments to the capital accounts upon the issuance of additional units, our partnership agreement requires that we allocate any later negative adjustments to the capital accounts resulting from the issuance of additional units or upon our liquidation in a manner which results, to the extent possible, in the general partner's capital account balances equaling the amount which they would have been if no earlier positive adjustments to the capital accounts had been made.

SELECTED HISTORICAL AND PRO FORMA FINANCIAL AND OPERATING DATA

OGE Enogex Partners L.P. was formed on May 30, 2007 and does not have any historical consolidated financial statements prior to its formation. The following tables set forth, for the periods and at the dates indicated, the selected historical financial and operating data of Enogex Predecessor, which is derived from the books and records of Enogex Predecessor, and the pro forma financial and operating data of OGE Enogex Partners L.P.

The selected historical financial and operating data for the years ended December 31, 2006, 2005 and 2004 and balance sheet data at December 31, 2006 and 2005 is derived from and should be read in conjunction with the audited historical consolidated financial statements of Enogex Predecessor included elsewhere in this prospectus beginning on page F-10. The selected historical financial and operating data for the years ended December 31, 2003 and 2002 and balance sheet data at December 31, 2004, 2003 and 2002 is derived from the audited historical consolidated financial statements of Enogex Predecessor. The selected historical financial and operating data for the three months ended March 31, 2007 and 2006 and balance sheet data at March 31, 2007 is derived from and should be read in conjunction with the unaudited historical condensed consolidated financial statements of Enogex Predecessor included elsewhere in this prospectus beginning on page F-60. In each case, the selected historical financial and operating data reflects 100% of Enogex's operations, but following the contribution of a 25% membership interest in Enogex by OGE Energy to our wholly owned subsidiary (and as reflected in the pro forma financial and operating data), we will own only a 25% interest in Enogex. The operating data for all periods is unaudited. The selected unaudited pro forma financial and operating data is derived from and should be read in conjunction with the unaudited pro forma consolidated financial statements of OGE Enogex Partners L.P. included in this prospectus beginning on page F-2. The pro forma adjustments have been prepared as if certain transactions to be effected at the closing of this offering had taken place on March 31, 2007, in the case of the pro forma balance sheet data, or as of January 1, 2006, in the case of the pro forma statements of income for the year ended December 31, 2006 and the three months ended March 31, 2007. These transactions include:

- the conversion of Enogex Inc. to a Delaware limited liability company;
- the conversion of outstanding intercompany loans from Enogex to OGE Energy to a dividend to OGE Energy;
- the contribution by OGE Energy of a 25% membership interest in Enogex to our wholly owned subsidiary;
- the issuance by us of common units to the public;
- the payment of underwriting discounts and commissions, the structuring fee and other offering expenses;
- the contribution by us of proceeds of this offering to Enogex to allow for the anticipated repayment by Enogex of a portion of its existing $400 million 8.125% senior notes due 2010 and the refinancing by Enogex of those senior notes; and
- expected interest expense under Enogex's new credit facility.

The following tables include the financial measure of Adjusted EBITDA, which is a non-GAAP financial measure. We define Adjusted EBITDA as net income from continuing operations before non-controlling interest, interest, income taxes and depreciation and amortization expense. For a reconciliation of Adjusted EBITDA to its most directly comparable financial measures calculated and presented in accordance with GAAP, please see "Summary—Non-GAAP Financial Measures."

The following table presents the selected historical financial and operating data of Enogex Predecessor and our selected unaudited pro forma financial and operating data for the periods indicated:

	Enogex Predecessor							OGE Enogex Partners L.P.	
	Year Ended December 31,					Three Months Ended March 31,		Year Ended December 31, 2006	Three Months Ended March 31, 2007
	2002	2003	2004	2005	2006	2006	2007	Pro Forma	Pro Forma
	(in millions, except per unit and operating data)								
Results of Operations Data:									
Operating revenues	$1,652.0	$2,306.2	$3,372.2	$4,340.1	$2,367.8	$ 763.2	$ 557.8	$ 2,367.8	$ 557.8
Cost of goods sold	1,458.2	2,070.2	3,118.2	4,090.4	2,060.4	678.0	484.0	2,060.4	484.0
Gross margin on revenues	193.8	236.0	254.0	249.7	307.4	85.2	73.8	307.4	73.8
Other operation and maintenance	97.2	87.4	93.5	96.6	110.0	28.6	27.8	114.0	28.4
Depreciation	45.8	40.9	41.1	40.4	42.3	10.2	11.3	42.3	11.3
Impairment of assets	48.3	9.2	7.8	—	0.3	—	—	0.3	—
Taxes other than income	14.6	16.4	16.0	15.4	16.0	4.3	4.5	16.0	4.5
Operating income (loss)	(12.1)	82.1	95.6	97.3	138.8	42.1	30.2	134.8	29.6
Interest income	1.0	0.8	3.2	2.9	11.1	2.5	2.6	2.8	0.1
Other income	0.9	0.7	4.5	0.8	7.7	6.0	0.3	7.7	0.3
Other expense	0.2	1.6	0.3	0.3	0.3	—	0.1	0.3	0.1
Interest expense(1)	43.9	34.1	32.2	32.6	31.8	8.1	8.1	23.5	5.7
Income tax expense (benefit)	(20.6)	19.8	26.4	23.4	48.0	16.3	9.4	—	—
Income (loss) from continuing operations	(33.7)	28.1	44.4	44.7	77.5	26.2	15.5	121.5	24.2
Income from discontinued operations(2)	12.1	4.7	11.6	49.8	36.0	0.8	—	—	—
Cumulative effect of change in accounting principle	—	(5.9)	—	—	—	—	—	—	—
Income (loss) before non-controlling interest	(21.6)	26.9	56.0	94.5	113.5	27.0	15.5	121.5	24.2
Non-controlling interest	—	—	—	—	—	—	—	(92.6)	(18.3)
Net income (loss)	$ (21.6)	$ 26.9	$ 56.0	$ 94.5	$ 113.5	$ 27.0	$ 15.5	$ 28.9	$ 5.9
General partner's interest in net income								$ 0.6	$ 0.1
Limited partners' interest in net income								$ 28.3	$ 5.8
Number of outstanding limited partner units								21.6	21.6
Basic and diluted earnings per limited partner unit								$ 1.31	$ 0.27

	Enogex Predecessor							OGE Enogex Partners L.P.	
	Year Ended December 31,					Three Months Ended March 31,		Year Ended December 31, 2006	Three Months Ended March 31, 2007
	2002	2003	2004	2005	2006	2006	2007	Pro Forma	Pro Forma
	(in millions, except per unit and operating data)								
Balance Sheet Data (at period end):									
Property, plant and equipment, net(3)	$1,137.4	$1,043.2	$1,016.5	$ 875.9	$ 865.7	$ 885.6	$ 879.9		$ 879.9
Total assets	1,532.6	1,554.5	1,719.7	1,652.6	1,319.8	1,406.6	1,304.7		1,132.6
Long-term debt	591.4	522.7	477.8	407.6	403.7	407.4	403.5		301.0
Net owner's equity	429.6	449.8	491.0	440.4	400.0	466.9	400.7		216.5
Other Financial Data:									
Net cash flows provided by (used in):									
Operating activities	$ 60.8	$ 10.6	$ 118.2	$ 235.2	$ 131.6	$ 49.8	$ 49.7		
Investing activities	(20.3)	(25.9)	(22.5)	(34.5)	(65.1)	(19.3)	(25.4)		
Financing activities	(97.5)	(27.0)	(118.6)	(304.0)	(139.4)	(31.4)	(21.2)		
Adjusted EBITDA(4)	34.3	116.3	140.9	138.2	188.5	58.3	41.7	184.5	41.1
Operating Data (excludes discontinued operations):									
New well connects(5)	—	—	—	—	362	77	99	362	99
New well connects(6)	166	200	192	223	206	52	46	206	46
Gathered volumes—TBtu/d	1.00	0.95	0.84	0.92	0.98	0.96	0.99	0.98	0.99
Incremental transportation volumes—TBtu/d	0.38	0.36	0.39	0.39	0.46	0.41	0.39	0.46	0.39
Total throughput volumes—TBtu/d	1.38	1.31	1.23	1.31	1.44	1.37	1.38	1.44	1.38
Natural gas processed—TBtu/d	0.45	0.41	0.50	0.52	0.54	0.52	0.52	0.54	0.52
Natural gas liquids sold (keep-whole)—million gallons	285	207	185	219	244	52	51	244	51
Natural gas liquids sold (purchased for resale)—million gallons	—	—	78	77	113	22	27	113	27
Natural gas liquids sold (percentage of liquids)—million gallons	22	18	16	15	14	3	4	14	4
Total natural gas liquids sold—million gallons	307	225	279	311	371	77	82	371	82
Average sales price per gallon	$ 0.406	$ 0.595	$ 0.720	$ 0.847	$ 0.901	$ 0.912	$ 0.858	$0.901	$ 0.858

(1) Under the provisions of Enogex's senior notes currently expected to be repaid in connection with this offering, a make-whole premium of approximately $30 million will be paid and funded with a portion of the proceeds from this offering contributed by us to Enogex. As this item does not have a continuing impact, no adjustment for this item is provided in the accompanying unaudited pro forma consolidated statements of income.

(2) Amounts for 2005 and 2004 were restated for discontinued operations related to the sale of Enogex assets in May 2006, as discussed in Note 6 of Notes to Consolidated Financial Statements. Amounts for years 2003 and 2002 have not been restated for discontinued operations since this information is not available as Enogex Predecessor's financial records were not maintained in a manner to provide this information for years prior to 2004.

(3) Includes net property, plant and equipment related to discontinued operations of approximately $180.7 million, $166.9 million, $169.3 million and $34.9 million during the years ended December 31, 2002, 2003, 2004 and 2005, respectively. Includes net property, plant and equipment related to discontinued operations of approximately $34.5 million during the first quarter of 2006.

(4) We define Adjusted EBITDA as net income from continuing operations before non-controlling interest, interest, income taxes and depreciation and amortization expense. Adjusted EBITDA is used as a supplemental financial measure by external users of our financial statements such as investors, commercial banks and others, to assess:

- the financial performance of Enogex's assets without regard to financing methods, capital structure or historical cost basis;
- Enogex's operating performance and return on capital as compared to other companies in the midstream energy sector, without regard to financing or capital structure; and

- the viability of acquisitions and capital expenditure projects and the overall rates of return on alternative investment opportunities.

The economic substance behind the use of Adjusted EBITDA is to measure the ability of Enogex's assets to generate cash sufficient to pay interest costs, support indebtedness, and make distributions to its members.

The GAAP measures most directly comparable to Adjusted EBITDA are net cash provided by operating activities and net income from continuing operations. The non-GAAP financial measure of Adjusted EBITDA should not be considered as an alternative to GAAP net cash provided by operating activities and GAAP net income from continuing operations. Adjusted EBITDA is not a presentation made in accordance with GAAP and has important limitations as an analytical tool. You should not consider Adjusted EBITDA in isolation or as a substitute for analysis of our results as reported under GAAP. Because Adjusted EBITDA excludes some, but not all, items that affect net income and net cash provided by operating activities and is defined differently by different companies in our industry, our definition of Adjusted EBITDA may not be comparable to similarly titled measures of other companies.

To compensate for the limitations of Adjusted EBITDA as an analytical tool, we believe it is important to review the comparable GAAP measures and understand the differences between the measures.

(5) Includes wells behind central receipt points (as reported to us by third parties). This information is not available for years prior to 2006 as Enogex Predecessor's books and records were not maintained in a manner to provide this information for years prior to 2006.

(6) Excludes wells behind central receipt points.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The historical financial statements included in this prospectus reflect the assets, liabilities and operations of Enogex Predecessor. The following discussion analyzes the financial condition and results of operations of Enogex Predecessor, which reflects ownership of 100% of the assets of Enogex, but following the contribution of a 25% membership interest in Enogex by OGE Energy, we will own only a 25% interest in these assets and OGE Energy will retain the remaining 75% interest. You should read the following discussion of the financial condition and results of operations for Enogex Predecessor in conjunction with the audited historical consolidated financial statements and accompanying notes of Enogex Predecessor and the unaudited pro forma consolidated financial statements and accompanying notes for OGE Enogex Partners L.P. included elsewhere in this prospectus.

All references in this Management's Discussion and Analysis of Financial Condition and Results of Operations to "our," "we," "us" and "the partnership" refer to OGE Enogex Partners L.P. and its subsidiaries, including its interest in Enogex LLC, or "Enogex," after giving effect to the formation transactions described herein, including the conversion of Enogex Inc. to Enogex LLC, a Delaware limited liability company. All references in this Management's Discussion and Analysis of Financial Condition and Results of Operations to "Enogex Predecessor" or to "Enogex" when used in a historical context refer to Enogex Inc. and its subsidiaries. All references in this Management's Discussion and Analysis of Financial Condition and Results of Operations to "Enogex" when used in the present tense or prospectively refer to Enogex LLC and its subsidiaries, collectively, or to Enogex LLC individually, as the context may require.

Our Business

We are a provider of integrated natural gas midstream services. We were formed by OGE Energy to further develop its natural gas midstream assets and operations. OGE Energy is the parent company of OG&E, a regulated electric utility, and Enogex Inc., an integrated natural gas midstream services provider. In connection with this offering, Enogex Inc. will convert to Enogex LLC, a Delaware limited liability company. Upon the completion of this offering, a wholly owned subsidiary of OGE Energy will own a 63.9% limited partner interest in us and a 2% general partner interest in us through its ownership of OGE Enogex GP LLC, our general partner. Our wholly owned subsidiary will own a 25% membership interest in Enogex, will be its managing member and will control the assets and operations of Enogex. A wholly owned subsidiary of OGE Energy will own the remaining 75% membership interest in Enogex and will be a non-managing member. Upon the completion of this offering, our interest in Enogex will be our only cash-generating asset.

Operations

Enogex's current operations are organized into three businesses: (1) natural gas transportation and storage, (2) natural gas gathering and processing and (3) natural gas marketing.

- *Transportation and Storage*. Enogex owns and operates approximately 2,283 miles of intrastate natural gas transportation pipelines with approximately 1.44 TBtu/d of current throughput. Enogex's transportation pipelines are directly connected to 11 third-party natural gas pipelines at 64 interconnect points and to 27 end-user customers, including 15 natural gas-fired electric generation facilities in Oklahoma. Enogex provides fee-based intrastate transportation services on a firm and interruptible basis and interstate transportation services pursuant to Section 311 of the NGPA on an interruptible basis only. Enogex owns and operates two natural gas storage facilities, the Wetumka Storage Facility and the Stuart Storage Facility, with approximately 23 Bcf of aggregate working gas capacity. The storage facilities have approximately 650 MMcf/d, of maximum withdrawal capacity and approximately 650 MMcf/d of injection capacity. Enogex provides fee-based firm and interruptible storage services to third parties at market-based rates.

- *Gathering and Processing*. Enogex owns and operates approximately 5,474 miles of natural gas gathering pipelines with approximately 0.98 TBtu/d of current throughput and six natural gas processing plants with approximately 720 MMcf/d of aggregate inlet capacity. Enogex provides well connect, gathering, measurement, treating, dehydration, compression and processing services to its producer customers primarily in the Arkoma and Anadarko basins, including those operating in the Granite Wash play in western Oklahoma and the Texas Panhandle and the Woodford Shale play in southeastern Oklahoma. For the year ended December 31, 2006, Enogex processed approximately 0.54 TBtu/d of natural gas and extracted and sold approximately 371 million gallons of natural gas liquids, or NGLs.
- *Marketing*. Enogex also conducts certain natural gas marketing activities, primarily in support of its gathering and processing and transportation and storage businesses. Enogex's marketing business provides risk management services to assist Enogex in managing its exposure to commodity price risk as well as real time and longer term price discovery and valuation of natural gas and NGLs associated with Enogex's assets. Enogex's subsidiary, OERI also purchases and sells natural gas to support the daily operational activities of Enogex's combined position of its businesses.

In May 2006, Enogex's gathering business sold certain gas gathering assets in the Kinta, Oklahoma area, which have been reported as discontinued operations in Enogex's consolidated financial statements. Please see "—Results of Operations—Discontinued Operations" below for a further discussion.

Factors That Significantly Affect Our and Enogex's Results

Transportation and Storage

Results of operations from the transportation and storage business are determined primarily by the volumes of natural gas transported on Enogex's intrastate pipeline system, volumes of natural gas stored at Enogex's storage facilities and the level of fees charged to Enogex's customers for such services. Enogex generates a majority of its revenues and margins for its pipeline business under fee-based transportation contracts that are directly related to the volume of natural gas capacity reserved on its system. The margin Enogex earns from its transportation activities is not directly dependent on commodity prices. To the extent a sustained decline in commodity prices results in a decline in volumes, Enogex's revenues from these arrangements would be reduced.

Generally, Enogex provides to shippers two types of fee-based transportation services under its intrastate transportation contracts:

- *Firm Transportation*. Enogex's obligation to provide firm transportation service means that it is obligated to transport natural gas nominated by the shipper up to the maximum daily quantity specified in the contract. In exchange for that obligation on Enogex's part, the shipper pays a specified demand or reservation charge, whether or not it utilizes the capacity. In most cases, the shipper also pays a transportation or commodity charge with respect to quantities actually transported by Enogex.
- *Interruptible Transportation*. Enogex's obligation to provide interruptible transportation service means that it is only obligated to transport natural gas nominated by the shipper to the extent that it has available capacity. For this service, the shipper pays no demand or reservation charge but pays a transportation or commodity charge for quantities actually shipped.

Enogex also provides interstate transportation services on an interruptible basis pursuant to Section 311 of the NGPA at rates approved by the FERC.

Enogex offers both firm and interruptible storage services to third parties. Services offered under Section 311 of the NGPA are pursuant to the terms and conditions specified in Enogex's Statement of Operating Conditions for gas storage and at market-based rates negotiated with each customer. Enogex's customers include end-users, local distribution companies, producers and marketers, which contract for a majority of Enogex's storage services. Factors that impact Enogex's storage margins include, among other things, changes in the price or availability of natural gas or other forms of energy, seasonal and locational (basis) spreads, hourly load swings for power generators, weather, avoidance of costly imbalances and overrun penalties.

Two key contracts for Enogex's transportation and storage business are its contracts with OG&E, the largest electric utility in Oklahoma which serves the Oklahoma City market, and PSO, the second largest utility in Oklahoma, serving the Tulsa market. As part of the no-notice load following contract with OG&E, Enogex provides natural gas storage services for OG&E. Enogex has been providing natural gas storage services to OG&E since August 2002 when it acquired the Stuart Storage Facility. Enogex provides gas transmission delivery services to all of PSO's natural gas-fired electric generation facilities in Oklahoma under a firm intrastate transportation contract. The PSO contract, which expires January 1, 2013, and the OG&E contract, which expires April 30, 2009, provide for a monthly demand charge plus variable transportation charges (including fuel). During 2006, 2005 and 2004, revenues from Enogex's firm intrastate transportation and storage contracts were approximately $98.1 million, $95.0 million and $95.6 million, respectively, of which $47.6 million, $47.6 million and $49.6 million was attributed to OG&E and $13.3 million in each of these years was attributed to PSO.

Gathering and Processing

Results of operations from the gathering and processing business are determined primarily by the volumes of natural gas Enogex gathers and processes, its current contract portfolio and natural gas and NGL prices.

Enogex gathers and processes natural gas pursuant to a variety of arrangements generally categorized as "fee-based" arrangements, "percent-of-proceeds" and "percent-of-liquids" arrangements and "keep-whole" arrangements. Under fee-based arrangements, Enogex earns cash fees for the services that it renders. Under the latter types of arrangements, Enogex generally purchases raw natural gas and sells processed natural gas and NGLs or receives NGLs.

Percent-of-proceeds, percent-of-liquids and keep-whole arrangements involve commodity price risk to Enogex because Enogex's margin is based in part on natural gas and NGL prices. Enogex seeks to minimize its exposure to fluctuations in commodity prices in several ways, including managing its contract portfolio. In managing its contract portfolio, Enogex classifies its gathering and processing contracts according to the nature of commodity risk implicit in the settlement structure of those contracts.

- *Fee-Based Arrangements*. Under these arrangements, Enogex generally is paid a fixed cash fee for performing the gathering and processing service. This fee is directly related to the volume of natural gas that flows through Enogex's system and is not directly dependent on commodity prices. A sustained decline, however, in commodity prices could result in a decline in volumes and, thus, a decrease in Enogex's fee revenues. These arrangements provide stable cash flows, but minimal, if any, upside in higher commodity price environments. At March 31, 2007, these arrangements accounted for approximately 7% of Enogex's natural gas processed volumes.

- *Percent-of-Proceeds and Percent-of-Liquids Arrangements*. Under these arrangements, Enogex generally gathers raw natural gas from producers at the wellhead, transports the gas through its gathering system, processes the gas and sells the processed gas and/or NGLs at prices based on published index prices. These arrangements provide upside in high commodity price environments, but result in lower margins in low commodity price environments. The price paid to producers is based on an agreed percentage of the proceeds of the sale of processed natural gas, NGLs or both or the expected proceeds based on an index price. We refer to contracts in which Enogex shares in specified percentages of the proceeds from the sale of natural gas and NGLs as percent-of-proceeds arrangements and in which Enogex receives proceeds from the sale of NGLs or the NGLs themselves as compensation for its processing services as percent-of-liquids arrangements. Under percent-of-proceeds arrangements, Enogex's margin correlates directly with the prices of natural gas and NGLs. Under percent-of-liquids arrangements, Enogex's margin correlates directly with the prices of NGLs (although there is often a fee-based component to both of these forms of contracts in addition to the commodity sensitive component). At March 31, 2007, these arrangements accounted for approximately 23% of Enogex's natural gas processed volumes.

- *Keep-Whole Arrangements*. Under these arrangements, Enogex processes raw natural gas to extract NGLs and pays to the producer the full gas equivalent Btu value of raw natural gas received from the producer in the form of either processed gas or its cash equivalent. Enogex is generally entitled to retain the processed NGLs and to sell them for its own account. Accordingly, Enogex's margin is a function of the difference between the value of the NGLs produced and the cost of the processed gas used to replace the thermal equivalent of those NGLs. The profitability of these arrangements is subject not only to the commodity price risk of natural gas and NGLs but also to the price of natural gas relative to NGL prices. These arrangements can provide large profit margins in favorable commodity price environments, but also can be subject to losses if the cost of natural gas exceeds the value of its thermal equivalent of NGLs. Many of Enogex's keep-whole contracts include provisions that reduce its commodity price exposure, including (1) conditioning floors (such as the default processing fee described below) that require the keep-whole contract to convert to a fee-based arrangement if the NGLs have a lower value than their gas equivalent Btu value in natural gas, (2) embedded discounts to the applicable natural gas index price under which Enogex may reimburse the producer an amount in cash for the gas equivalent Btu value of raw natural gas acquired from the producer, or (3) fixed cash fees for ancillary services, such as gathering, treating and compressing. At March 31, 2007, these arrangements accounted for approximately 70% of Enogex's natural gas volumes.

In addition, as a seller of NGLs, Enogex is exposed to commodity price risk associated with downward movements in NGL prices. NGL prices have experienced volatility in recent years in response to changes in the supply and demand for NGLs and market uncertainty. In response to this volatility, in 2002, Enogex revised its Statement of Operating Conditions used as part of its typical natural gas processing arrangements and included language that requires a "default processing fee" in the event the gathered gas exceeds downstream interconnect specifications. Natural gas that is greater than 1,080 Btu per cubic foot coming out of wells must typically be processed before it can enter an interstate pipeline. The default processing fee stipulates a minimum fee to be paid to the processor if the market for NGLs is lower than the gas equivalent Btu value of the natural gas that is removed from the stream. The default processing fee helps to minimize the risk of processing gas that is greater than 1,080 Btu per cubic foot when the price of the NGLs to be extracted and sold is less than the Btu value of the natural gas that Enogex otherwise would be required to replace.

Additionally, Enogex instituted a hedging program that is intended to reduce the commodity price risk associated with Enogex's keep-whole and percent-of-liquids arrangements and has hedged approximately 33% of its expected non-ethane NGL volumes attributable to these arrangements, along with the natural gas MMBtu equivalent, for 2007 and approximately 35% of its expected non-ethane NGL volumes attributable to these arrangements, along with the natural gas MMBtu equivalent, for 2008, 2009 and 2010. Enogex has not hedged ethane because Enogex can reject ethane if processing it is not economical. Enogex anticipates hedging additional non-ethane NGL volumes attributable to these arrangements through swaps, options or other mechanisms. Ethane accounted for approximately 40% of Enogex's total NGL volumes attributable to these arrangements during both the year ended December 31, 2006 and the three months ended March 31, 2007. Enogex used a combination of forward sales, purchased put options and swaps in its hedging program. The default processing fee, coupled with Enogex's hedge program, is expected to reduce the risk of commodity price volatility. Where market conditions permit, Enogex intends to pursue the conversion of existing keep-whole contracts to fixed fee-based arrangements. Enogex continually monitors its hedging and contract portfolio and expects to continue to adjust its hedge position as conditions warrant.

Marketing

Enogex's marketing business is focused primarily on marketing natural gas. As a service to the producers on Enogex's system, Enogex's marketing business may agree to purchase the gas at the wellhead in conjunction with Enogex's gathering its gas for transportation to other markets. Enogex's marketing business also purchases and sells natural gas to support the daily operational activities of Enogex's combined position of its businesses pursuant to contracts with Enogex and its wholly owned subsidiary, Enogex Products Corporation, relating to its gathering, processing, transportation and storage assets. The gross margin of Enogex's marketing business is determined primarily by the differential between the price at which it purchases and the price at which it sells natural gas.

General Trends and Outlook

We expect Enogex's business to continue to be affected by the following key trends. Our expectations are based on assumptions made by us and information currently available to us. To the extent our underlying assumptions about or interpretations of available information prove to be incorrect, our and Enogex's actual results may vary materially from our and its expected results.

Natural Gas Supply, Demand and Outlook

Natural gas continues to be a critical component of energy consumption in the United States. According to the Energy Information Administration, or EIA, natural gas consumption in the United States is expected to grow from approximately 60.2 Bcf/d in 2005 to approximately 70.1 Bcf/d in 2017, or by approximately 1.3% per year. During the five years ended December 31, 2005, the United States on average consumed approximately 22.4 trillion cubic feet, or Tcf, per year, while total marketed domestic production averaged approximately 19.9 Tcf per year during the same period. The industrial and electricity generation sectors currently account for the largest usage of natural gas in the United States.

We believe that current natural gas prices and the existing strong demand for natural gas will continue to result in relatively high levels of natural gas-related drilling in the United States as producers seek to increase their level of natural gas production. Although the natural gas reserves in the United States have increased overall in recent years, a corresponding increase in production has not been realized. We believe that this lack of increased production is attributable to insufficient pipeline infrastructure, the continued depletion of existing wells and a tight labor and equipment market. We believe that an increase in U.S. natural gas production, additional sources of supply such as liquid natural gas, and imports of natural gas will be required for the natural gas industry to meet the expected increased demand for natural gas in the United States.

Many of the areas in which Enogex operates are experiencing significant drilling activity. Although we anticipate continued high levels of exploration and production activities in substantially all of the areas in which Enogex operates, fluctuations in energy prices can affect production rates over time and levels of investment by third parties in exploration for and development of new natural gas reserves.

Neither we nor Enogex have control over the level of natural gas exploration and development activity in the areas of Enogex's operations.

Gathering and Processing Margins

As of March 31, 2007, Enogex's overall portfolio of processing contracts reflected a net short position in natural gas of approximately 49,605 MMBtu/d (meaning that Enogex was a net buyer of natural gas) and a net long position in NGLs of approximately 14,661 barrels per day (meaning that Enogex was a net seller of NGLs). As a result, Enogex margins would be positively impacted to the extent the price of NGLs increased in relation to the price of natural gas and would be adversely impacted to the extent the price of NGLs declined in relation to the price of natural gas. We refer to the price of NGLs in relation to the price of natural gas as the fractionation spread. This portfolio performed well in response to favorable fractionation spreads during the three months ended March 31, 2007. Enogex has instituted a hedging program that is intended to reduce the commodity price risk associated with Enogex's keep-whole and percent-of-liquids arrangements and has hedged approximately 33% of its expected non-ethane NGL volumes attributable to these arrangements, along with the natural gas MMBtu equivalent, for 2007 and approximately 35% of its expected non-ethane NGL volumes attributable to these arrangements, along with the natural gas MMBtu equivalent, for 2008, 2009 and 2010. Enogex has not hedged ethane because Enogex can reject ethane if processing it is not economical. Enogex anticipates hedging additional non-ethane NGL volumes attributable to these arrangements through swaps, options or other mechanisms. Ethane accounted for approximately 40% of Enogex's total NGL volumes attributable to these arrangements during both the year ended December 31, 2006 and the three months ended March 31, 2007. For periods after 2010, management will evaluate whether to enter into any new hedging arrangements, and there can be no assurance that Enogex will enter into any new hedging arrangements.

Impact of Interest Rates and Inflation

The credit markets recently have experienced 50-year record lows in interest rates. If the overall economy continues to strengthen, we believe that it is likely that monetary policy may tighten further, resulting in higher interest rates to counter possible inflation. Interest rates on future credit facilities and debt offerings could be higher than current levels, causing our and Enogex's financing costs to increase accordingly. Although this could limit our and Enogex's ability to raise funds in the capital markets, we expect in this regard to remain competitive with respect to acquisitions and capital projects, as our competitors would face similar circumstances.

Inflation in the United States has been relatively low in recent years and did not have a material impact on Enogex's results of operations in 2006. Yet, the current high levels of natural gas exploration, development and production activities, both in the Arkoma and Anadarko basins and more broadly across the United States, is increasing competition for personnel and equipment. This increased competition is placing upward pressure on the prices Enogex pays for labor, supplies, property, plant and equipment. Enogex attempts to recover increased costs from its customers. To the extent Enogex is unable to procure necessary supplies or recover higher costs, our and Enogex's operating results will be negatively impacted.

Factors Affecting Comparability of Future Results

You should read the discussion of Enogex's financial condition and results of operations in conjunction with Enogex's historical and our pro forma financial statements included elsewhere in this prospectus. Our future results could differ materially from Enogex's historical results due to a variety of factors, including the following:

Partial Ownership of Operating Assets

After this offering, our wholly owned subsidiary will own a 25% membership interest in Enogex and a wholly owned subsidiary of OGE Energy will own the remaining 75% membership interest. Enogex's historical consolidated financial statements were prepared from Enogex Predecessor's books and records related to Enogex's operating assets. Accordingly, the discussion that follows includes 100% of the results of operations for Enogex's operating assets, but in the future the partnership will have only a 25% interest in those results.

Additional General and Administrative Expenses

We expect to incur approximately $4.0 million in incremental general and administrative expenses as a result of becoming a publicly traded entity. These costs include fees associated with annual and quarterly reports to unitholders, tax returns and Schedule K-1 preparation and distribution, investor relations, registrar and transfer agent fees, incremental insurance costs, accounting, auditing and legal services and independent director compensation. These costs also include estimated amounts payable to OGE Energy and its affiliates in connection with the omnibus agreement. For additional information regarding these administrative services, please see "Certain Relationships and Related Party Transactions—Omnibus Agreement."

Elimination of Tax Expenses as a Result of Converting to a Limited Liability Company

In connection with this offering, Enogex will convert to a limited liability company that will be treated as a partnership for tax purposes. Accordingly, Enogex will not be subject to corporate income taxes. Moreover, because we are a partnership, we are also not subject to corporate income taxes. Therefore, after this offering, our tax expenses should decrease from the levels experienced by Enogex historically. For a discussion of other material federal income tax consequences that may be relevant to prospective unitholders who are individual citizens or residents of the United States, please see "Material Tax Consequences."

How We Evaluate Our and Enogex's Operations

Management uses a variety of financial and operational measurements to analyze our and Enogex's performance. We view these measurements as important factors affecting our profitability and review these measurements on a monthly basis for consistency and trend analysis. The operating measurement used by management is volumes, and the financial measurements are gross margin on revenues (which is revenues minus cost of goods sold and is referred to herein as gross margin), operating income and other operation and maintenance expenses, each as reported in Enogex's consolidated financial statements.

- *Volumes*. Enogex must continually obtain new supplies of natural gas to maintain or increase throughput volumes on its gathering and processing and transportation and storage systems. Enogex's ability to maintain existing supplies of natural gas and obtain new supplies is impacted by (1) the level of workovers or recompletions of existing connected wells and successful drilling activity in areas currently dedicated to Enogex's pipelines, (2) Enogex's ability to compete for volumes from successful new wells in other areas and (3) Enogex's ability to obtain natural gas that has been released from other commitments. To increase throughput volumes on its intrastate pipelines of its transportation and storage business, Enogex must contract with shippers, including producers and marketers, for supplies of natural gas. Enogex routinely monitors producer activity in the areas served by its gathering and intrastate pipeline systems to pursue new supply opportunities. See "Business—Business Strategies—Expanding Enogex's operations through organic growth projects" for a description of significant opportunities currently being pursued by Enogex to increase the throughput volumes of its gathering and intrastate pipeline systems.

- *Gross margin*. We evaluate Enogex's consolidated and business segment performance based on gross margin as reported in Enogex's consolidated financial statements. We believe that it (either in total or by individual business segment) is an important performance measure of the core profitability of Enogex's operations. Senior management uses gross margin by business segment as the primary measure in deciding to allocate capital resources among the business segments.
- *Operating income*. We also evaluate consolidated performance and, to a lesser extent, business segment performance based on operating income as reported in the accompanying consolidated financial statements. This measure (which consists of gross margin less other operation and maintenance expenses, depreciation expense, impairment of assets and taxes other than income) is part of our monthly financial reports and indicates Enogex's ongoing profitability, excluding the cost of capital and income taxes. In our judgment, this measure is more useful at the consolidated level because operating income at the business segment level often is significantly affected by allocations among the business segments of other operation and maintenance expenses. See Note 1 of Notes to Consolidated Financial Statements for a further discussion.
- *Other operation and maintenance expenses*. Other operation and maintenance expenses are a separate measure that we use to evaluate performance of Enogex's field operations. Direct labor, insurance, property taxes, repairs and maintenance, utilities and contract services comprise the most significant portion of this item. These expenses are largely independent of the volumes through Enogex's systems but fluctuate depending on the activities performed during a specific period.

Results of Operations

The following discussion and analysis presents factors that affected Enogex's consolidated results of operations for the three months ended March 31, 2007 and 2006 and the years ended December 31, 2006, 2005 and 2004 and Enogex's consolidated financial condition at March 31, 2007 and December 31, 2006. The following information should be read in conjunction with the consolidated financial statements and notes thereto. Known trends and contingencies of a material nature are discussed to the extent considered relevant.

The following tables compare Enogex's operating results by reportable business segment for the three months ended March 31, 2007 and 2006 and the years ended December 31, 2006, 2005 and 2004.

Three Months Ended March 31, 2007	Transportation and Storage	Gathering and Processing	Marketing	Eliminations	Total
			(in millions)		
Operating revenues	$59.1	$165.6	$461.4	$(128.3)	$557.8
Cost of goods sold	29.1	123.7	459.5	(128.3)	484.0
Gross margin on revenues	30.0	41.9	1.9	—	73.8
Other operation and maintenance	10.4	16.0	1.4	—	27.8
Depreciation	4.4	6.9	—	—	11.3
Taxes other than income	3.4	0.9	0.2	—	4.5
Operating income	$11.8	$ 18.1	$ 0.3	$ —	$ 30.2

Three Months Ended March 31, 2006	Transportation and Storage	Gathering and Processing	Marketing	Eliminations	Total
			(in millions)		
Operating revenues	$64.6	$159.9	$677.1	$(138.4)	$763.2
Cost of goods sold	23.8	121.7	670.9	(138.4)	678.0
Gross margin on revenues	40.8	38.2	6.2	—	85.2
Other operation and maintenance	10.8	15.4	2.4	—	28.6
Depreciation	4.5	5.7	—	—	10.2
Taxes other than income	3.4	0.7	0.2	—	4.3
Operating income	$22.1	$ 16.4	$ 3.6	$ —	$ 42.1

Year Ended December 31, 2006	Transportation and Storage	Gathering and Processing	Marketing	Eliminations	Total
			(in millions)		
Operating revenues	$225.9	$704.3	$1,941.3	$(503.7)	$2,367.8
Cost of goods sold	100.3	536.7	1,927.1	(503.7)	2,060.4
Gross margin on revenues	125.6	167.6	14.2	—	307.4
Other operation and maintenance	41.2	59.5	9.3	—	110.0
Depreciation	17.9	24.2	0.2	—	42.3
Impairment of assets	—	0.3	—	—	0.3
Taxes other than income	11.8	3.8	0.4	—	16.0
Operating income	$ 54.7	$ 79.8	$ 4.3	$ —	$ 138.8

Year Ended December 31, 2005	Transportation and Storage	Gathering and Processing	Marketing	Eliminations	Total
			(in millions)		
Operating revenues	$246.4	$644.5	$4,003.0	$(553.8)	$4,340.1
Cost of goods sold	147.3	504.3	3,992.6	(553.8)	4,090.4
Gross margin on revenues	99.1	140.2	10.4	—	249.7
Other operation and maintenance	32.9	55.3	8.4	—	96.6
Depreciation	17.3	23.0	0.1	—	40.4
Taxes other than income	11.6	3.4	0.4	—	15.4
Operating income	$ 37.3	$ 58.5	$ 1.5	$ —	$ 97.3

Year Ended December 31, 2004	Transportation and Storage	Gathering and Processing	Marketing	Eliminations	Total
			(in millions)		
Operating revenues	$249.4	$524.7	$3,048.4	$(450.3)	$3,372.2
Cost of goods sold	134.9	401.3	3,032.3	(450.3)	3,118.2
Gross margin on revenues	114.5	123.4	16.1	—	254.0
Other operation and maintenance	29.9	51.3	12.3	—	93.5
Depreciation	17.1	22.6	1.4	—	41.1
Impairment of assets	8.8	(1.0)	—	—	7.8
Taxes other than income	11.6	3.8	0.6	—	16.0
Operating income	$ 47.1	$ 46.7	$ 1.8	$ —	$ 95.6

Statistical Data—Continuing Operations

	Three Months Ended March 31,	
	2007	2006
New well connects (includes wells behind central receipt points)(A)	99	77
New well connects (excludes wells behind central receipt points)	46	52
Gathered volumes—TBtu/d	0.99	0.96
Incremental transportation volumes—TBtu/d(B)	0.39	0.41
Total throughput volumes—TBtu/d	1.38	1.37
Natural gas processed—TBtu/d	0.52	0.52
Natural gas liquids sold (keep-whole)—million gallons	51	52
Natural gas liquids sold (purchased for resale)—million gallons	27	22
Natural gas liquids sold (percent-of-liquids)—million gallons	4	3
Total natural gas liquids sold—million gallons	82	77
Average sales price per gallon	$0.858	$0.912

(A) Includes wells behind central receipt points (as reported to management by third parties).

(B) Incremental transportation volumes (reported in trillion British thermal units per day) consist of natural gas moved only on the transportation pipeline.

	Year ended December 31,		
	2006	2005	2004
New well connects (includes wells behind central receipt points)(A)	362	—	—
New well connects (excludes wells behind central receipt points)	206	223	192
Gathered volumes—TBtu/d	0.98	0.92	0.84
Incremental transportation volumes—TBtu/d(B)	0.46	0.39	0.39
Total throughput volumes—TBtu/d	1.44	1.31	1.23
Natural gas processed—TBtu/d	0.54	0.52	0.50
Natural gas liquids sold (keep-whole)—million gallons	244	219	185
Natural gas liquids sold (purchased for resale)—million gallons	113	77	78
Natural gas liquids sold (percent-of-liquids)—million gallons	14	15	16
Total natural gas liquids sold—million gallons	371	311	279
Average sales price per gallon	$0.901	$0.847	$0.720

(A) Includes wells behind central receipt points (as reported to management by third parties). This information is not available for years prior to 2006 as Enogex Predecessor's books and records were not maintained in a manner to provide this information for years prior to 2006.

(B) Incremental transportation volumes (reported in trillion British thermal units per day) consist of natural gas moved only on the transportation pipeline.

Summary of Operating Results

Enogex reported net income of approximately $15.5 million in the three months ended March 31, 2007 as compared to approximately $27.0 million in the three months ended March 31, 2006. This decrease was primarily due to a lower gross margin in Enogex's transportation and storage business, largely as a result of increased imbalance expense, and lower gross margin in Enogex's marketing business, largely due to losses on hedges recorded at market value in the first quarter of 2007, which were only partially offset by higher gross margin in Enogex's gathering and processing business. Also contributing to the decrease in net income was higher depreciation expense and lower other income, which was partially offset by lower operation and maintenance expenses.

Enogex reported net income of approximately $113.5 million in 2006 as compared to approximately $94.5 million in 2005. This increase was primarily due to increased gross margin in each of its businesses largely as a result of higher commodity spreads and business growth in 2006 as compared to 2005. The increases in gross margin were partially offset by higher operation and maintenance expenses. Also contributing to the increase in net income were higher interest income and other income partially offset by lower net income from discontinued operations in 2006 as compared to 2005. Enogex reported net income of approximately $94.5 million in 2005 as compared to approximately $56.0 million in 2004. This increase was primarily due to higher net income from discontinued operations in 2005 as compared to 2004 and from an asset impairment charge recorded in 2004 with no similar item recorded in 2005. Enogex's consolidated gross margin for 2005 decreased approximately $4.3 million as compared to 2004 due to decreased gross margin in Enogex's marketing business and its transportation and storage business, which were only partially offset by increased gross margin in its gathering and processing business.

Three Months Ended March 31, 2007 Compared to Three Months Ended March 31, 2006

Enogex's consolidated operating revenues and cost of goods sold decreased approximately $205.4 million, or 26.9%, and $194.0 million, or 28.6%, respectively, during the three months ended March 31, 2007 as compared to the same period in 2006. These decreases were attributable primarily to lower revenues and related costs in Enogex's marketing business, reflecting a reduction in the trading activities of its marketing business.

Gross Margin

Enogex's consolidated gross margin decreased approximately $11.4 million during the quarter ended March 31, 2007 as compared to the quarter ended March 31, 2006. The decrease resulted from lower gross margin in the transportation and storage business ($10.8 million) and in the marketing business ($4.3 million), which was only partially offset by a $3.7 million increase in the gross margin in the gathering and processing business.

The transportation and storage business contributed approximately $30.0 million of Enogex's consolidated gross margin during the three months ended March 31, 2007 as compared to approximately $40.8 million during the same period in 2006, a decrease of approximately $10.8 million, or 26.5%. The gross margin decreased primarily due to:

- an imbalance expense of approximately $4.2 million during the first quarter of 2007 as the result of an increase in the net imbalance liability, as compared to the first quarter of 2006 in which the transportation and storage business recognized approximately a $5.9 million benefit from the reduction of the net imbalance liability, of which approximately $3.2 million was due to the transfer of certain imbalance liabilities to the gathering and processing business during the first quarter of 2006; and
- lower margins on natural gas sales from lower natural gas prices and lower volumes in 2007, which decreased the gross margin by approximately $1.2 million.

Gas imbalances occur when the actual amounts of natural gas delivered from or received by Enogex's pipeline system differ from the amounts scheduled to be delivered or received. Imbalances due to shippers by Enogex are shown on Enogex's consolidated balance sheets as a liability and imbalances due to Enogex from shippers are shown as an asset on Enogex's consolidated balance sheets. Exclusive of changes in the price of natural gas, increases in the amount of imbalances shown as an asset, or decreases in the amount of imbalances shown as a liability, on Enogex's consolidated balance sheets increase Enogex's gross margin, while decreases in the amount of imbalances shown as an asset, or increases in the amount of imbalances shown as a liability, on Enogex's consolidated balance sheets decrease gross margin.

These decreases in the transportation and storage gross margin were partially offset by a reduction in Enogex's over-recovered position under its FERC-approved fuel tracker in the East Zone in the first quarter of 2007 as compared to the first quarter of 2006, which increased the gross margin by approximately $1.3 million. See "Business—Our Business—Transportation and Storage—Regulation" for a discussion of the fuel tracker.

The gathering and processing business contributed approximately $41.9 million of Enogex's consolidated gross margin during the three months ended March 31, 2007 as compared to approximately $38.2 million during the same period in 2006, an increase of approximately $3.7 million, or 9.7%. The gathering and processing gross margin increased primarily due to:

- reduced imbalance expense resulting from the recognition in the first quarter of 2006 of approximately a $3.2 million imbalance liability upon the transfer of imbalances previously recognized in the transportation and storage business coupled with approximately a $0.2 million net imbalance liability increase in 2007 as compared to 2006;
- increased net keep-whole margins primarily due to higher commodity spreads in 2007 as compared to 2006, which increased the gross margin by approximately $1.5 million;

- new percent-of-liquids contracts in 2007, which increased the gross margin by approximately $0.8 million;
- increased compression fees relating to low pressure gathering wells due to new business growth in 2007, which increased the gross margin by approximately $0.7 million; and
- increased revenues relating to condensate liquids, which are a by-product of the gathering process and are sold on the open market, due to higher prices and increased production from colder temperatures in 2007, which increased the gross margin by approximately $0.6 million.

These increases in the gathering and processing gross margin were partially offset by a reduction in Enogex's over-recovered position of approximately $3.2 million in the first quarter of 2006 as compared to a reduction of approximately $0.1 million in the first quarter of 2007, which resulted in a decreased gross margin in the first quarter of 2007 of approximately $3.1 million as compared to 2006.

The marketing business contributed approximately $1.9 million of Enogex's consolidated gross margin during the three months ended March 31, 2007 as compared to approximately $6.2 million during the same period in 2006, a decrease of approximately $4.3 million, or 69.4%. The gross margin decreased primarily due to:

- losses on hedges associated with transportation contracts from recording these hedges at market value on March 31, 2007, which decreased the gross margin by approximately $13.4 million; and
- losses on hedges of natural gas storage inventory from recording these hedges at market value on March 31, 2007, which decreased the gross margin by approximately $4.9 million.

These decreases in the marketing gross margin were partially offset by:

- gains on physical storage activity partially offset by higher fees, which increased the gross margin by approximately $6.9 million;
- realized gains from physical activity on transportation contracts, which increased the gross margin by approximately $4.4 million; and
- a lower of cost or market adjustment related to natural gas in storage during the first quarter of 2006, which increased the 2007 gross margin by approximately $2.1 million.

Operating Income

As shown above, Enogex's operating income is calculated by subtracting from gross margin the following three items: (i) other operation and maintenance expenses, (ii) depreciation expense and (iii) taxes other than income. Enogex's consolidated operating income for the three months ended March 31, 2007 was $30.2 million, an $11.9 million decrease from its consolidated operating income for the quarter ended March 31, 2006. The $11.9 million decrease was attributable almost entirely to the $11.4 million decrease described above in consolidated gross margin, as the aggregate of other operation and maintenance expenses, depreciation expense and taxes other than income was only $0.5 million higher during the first quarter of 2007 as compared to the first quarter of 2006. The slight variances in depreciation expense and in taxes other than income on both a consolidated basis and by business reflect differing levels of depreciable plant in service and a slight increase in property taxes. The $0.8 million decrease in other operation and maintenance expenses on a consolidated basis was primarily due to lower outside service expenses related to delays in projects from inclement weather in the first quarter of 2007 and lower allocations of expense from OGE Energy partially offset by higher salaries, wages and other employee benefits.

Specifically, by segment, other operation and maintenance expenses for the transportation and storage business were approximately $0.4 million, or 3.7%, lower during the three months ended March 31, 2007 as compared to the same period in 2006 primarily due to lower outside services expense of approximately $1.5 million related to a delay in projects due to inclement weather in 2007 as well as the write-off of costs associated with a business development project in 2006. This decrease was only partially offset by higher salaries, wages and other employee benefits expense of approximately $1.1 million primarily due to higher incentive compensation costs and hiring additional employees to support business growth.

Other operation and maintenance expenses increased approximately $0.6 million, or 3.9%, for the gathering and processing business during the three months ended March 31, 2007 as compared to the same period in 2006. The increase reflected higher salaries, wages and other employee benefits expense of approximately $0.3 million primarily due to incentive compensation and hiring additional employees to support business growth and higher allocations from OGE Energy of approximately $0.3 million primarily due to a change in allocation methods. These increases were only partially offset by lower outside services expense of approximately $0.3 million primarily related to a delay in projects due to inclement weather in 2007.

Other operation and maintenance expenses for the marketing business were approximately $1.0 million, or 41.7%, lower during the three months ended March 31, 2007 as compared to the same period in 2006. The decrease was primarily due to lower allocations from OGE Energy of approximately $0.7 million primarily due to a change in allocation methods and from lower salaries, wages and other employee benefits expense of approximately $0.2 million primarily due to lower salaries and incentive compensation.

Consolidated Information

Other Income. Consolidated other income was approximately $0.3 million during the three months ended March 31, 2007 as compared to approximately $6.0 million during the same period in 2006, a decrease of approximately $5.7 million, or 95.0%, primarily due to a litigation settlement of approximately $5.2 million in 2006.

Income Tax Expense. Consolidated income tax expense was approximately $9.4 million during the three months ended March 31, 2007 as compared to approximately $16.3 million during the same period in 2006, a decrease of approximately $6.9 million, or 42.3%, primarily due to lower pre-tax income.

Net Income. For the three months ended March 31, 2007, Enogex's consolidated net income of approximately $15.5 million included a loss of approximately $4.1 million at OERI resulting from recording hedges associated with the Cheyenne Plains transportation contract at market value on March 31, 2007. The offsetting gains from physical utilization of the transportation capacity are expected to be realized during the remainder of 2007. Also, at March 31, 2007, Enogex recorded a loss of approximately $0.8 million resulting from recording storage hedges at market value. The offsetting gains from the sale of withdrawals from inventory are expected to be realized during the first quarter of 2008. During the three months ended March 31, 2007, Enogex had no items that it does not consider to be reflective of its ongoing performance.

For the three months ended March 31, 2006, Enogex's consolidated net income, including the discontinued operations discussed below under the caption "—Discontinued Operations," was approximately $27.0 million. During the three months ended March 31, 2006, Enogex had an increase in net income of approximately $4.3 million relating to various items that Enogex does not consider to be reflective of its ongoing performance. These increases in consolidated net income include:

- the approximately $3.2 million after-tax impact of a litigation settlement;
- income from discontinued operations of approximately $0.8 million; and
- an after-tax gain of approximately $0.3 million from the sale of a small gathering section of Enogex's pipeline.

2006 Compared to 2005

Enogex's consolidated operating revenues and cost of goods sold decreased in 2006 approximately $2.0 billion, or 45.4%, and $2.0 billion, or 49.6%, respectively, as compared to 2005 primarily due to lower revenues and related costs in Enogex's marketing business, reflecting a reduction in the trading activities of its marketing business.

Gross Margin

Enogex's consolidated gross margin increased approximately $57.7 million in 2006 as compared to 2005 primarily due to increased gross margin in each of its businesses largely as a result of higher commodity spreads and business growth in 2006 as compared to 2005.

The transportation and storage business contributed approximately $125.6 million of Enogex's consolidated gross margin in 2006 as compared to approximately $99.1 million in 2005, an increase of approximately $26.5 million, or 26.7%. The gross margin increased primarily due to:

- better management of gas pipeline imbalances as Enogex reduced its exposure to gas imbalances while taking advantage of favorable market price movement in 2006 and the transfer of certain imbalance liabilities previously carried by the transportation and storage business in 2005 to the gathering and processing business in 2006, which increased the gross margin by approximately $11.5 million in 2006;
- increased commodity, interruptible and low and high pressure revenues primarily due to higher volumes, which increased the gross margin by approximately $6.2 million;
- a change in Enogex's 2005 accounting estimate of the volume of natural gas in its natural gas storage inventory, which reduced the 2005 gross margin by approximately $5.7 million;
- improved recovery of fuel as Enogex transitioned to zonal fuel rates in 2006, which increased the gross margin by approximately $4.7 million;
- storage hedging gains, which increased the gross margin by approximately $3.5 million; and
- increased natural gas sales due to higher realized natural gas prices in 2006, which increased the gross margin by approximately $3.5 million.

These increases in the transportation and storage gross margin were partially offset by a lower of cost or market adjustment related to natural gas inventory used to operate Enogex's pipeline during 2006, which reduced the 2006 gross margin by approximately $8.3 million as there was no comparable item during 2005.

The gathering and processing business contributed approximately $167.6 million of Enogex's consolidated gross margin in 2006 as compared to approximately $140.2 million in 2005, an increase of approximately $27.4 million, or 19.5%. The gathering and processing gross margin increased primarily due to:

- increased net keep-whole margins primarily due to higher commodity spreads in 2006 as compared to 2005 and increased volumes due to business growth, which increased the gross margin by approximately $33.5 million;
- contractual fuel gains primarily due to higher natural gas prices in 2006, which increased the gross margin by approximately $4.9 million; and
- a reduction in Enogex's over-recovered fuel position as it transitioned to zonal fuel rates in 2006, which increased the gross margin by approximately $2.5 million.

These increases in the gathering and processing gross margin were partially offset by the recognition of imbalance expense in 2006 (previously carried by the transportation and storage business in 2005), which reduced the gross margin by approximately $13.8 million in 2006.

The marketing business contributed approximately $14.2 million of Enogex's consolidated gross margin in 2006 as compared to approximately $10.4 million in 2005, an increase of approximately $3.8 million, or 36.5%. The gross margin increased primarily due to:

- gains in storage activity due to timing, resulting from recording Enogex's storage hedges at market value at December 31, 2006 and an increase in storage capacity, which increased the gross margin by approximately $13.2 million; and
- more favorable market conditions on transportation contracts, which increased the gross margin by approximately $7.6 million.

These increases in the marketing gross margin were partially offset by:

- a lower of cost or market adjustment related to natural gas in storage during 2006, which reduced the 2006 gross margin by approximately $9.9 million; and
- lower gains in trading and park and loan activity due to a lower level of activity in Enogex's marketing business and less favorable market conditions, which reduced the gross margin by approximately $6.0 million.

Operating Income

Enogex's consolidated operating income increased $41.5 million in 2006 compared to 2005. This increase reflects the $57.7 million increase in gross margin on revenues discussed above, which was only partially offset by a $13.4 million increase (13.9%) in other operation and maintenance expenses, a $0.3 million impairment charge, and minor increases in depreciation expense of $1.9 million and taxes other than income of $0.6 million. The variances in depreciation expense and in taxes other than income on a consolidated basis and by business segment were attributable primarily to new assets placed into service and slightly higher property taxes. The increase in other operation and maintenance expenses on a consolidated basis was primarily due to:

- higher salaries, wages and other employee benefits of approximately $9.5 million primarily due to higher incentive compensation and hiring additional employees to support business growth; and
- higher materials and supplies costs of approximately $2.7 million primarily related to work performed to maintain the integrity and safety of Enogex's pipelines, higher cost of materials and increased material used at newly added facilities.

These same factors were the primary reasons for the increases in other operation and maintenance expenses by segment.

For the transportation and storage business, other operation and maintenance expenses in 2006 increased $14.8 million due to higher salaries, wages and other employee benefits, $3.2 million due to decreased capitalized labor and $1.7 million due to higher materials and supplies costs. These increases were only partially offset by a change in 2006 in Enogex's internal methods for allocating other operation and maintenance expenses, which lowered the allocations by OGE Energy to the transportation and storage business by $10.3 million. Other operation and maintenance expenses increased $4.2 million in the gathering and processing business in 2006 due to a $9.6 million increase resulting from the change in such allocation method and $1.0 million from higher costs for materials and supplies. Offsetting these increases were lower salaries, wages and other employee benefits of $5.7 million and a sales and use tax refund of $2.0 million pertaining to activity in prior years. In the marketing business, other operation and maintenance expenses in 2006 increased $0.9 million, of which $0.7 million was attributable to the change in allocation methods and $0.4 million to higher wages, salaries and other employee benefits.

Consolidated Information

Interest Income. Consolidated interest income was approximately $11.1 million in 2006 as compared to approximately $2.9 million in 2005, an increase of approximately $8.2 million primarily due to interest income on cash investments from interest earned on the cash proceeds from the sale of Enogex Arkansas Pipeline Corporation, or EAPC, in October 2005 and the sale of certain gas gathering assets in the Kinta, Oklahoma area, referred to herein as the Kinta Assets, in May 2006. See "—Discontinued Operations."

Other Income. Consolidated other income was approximately $7.7 million in 2006 as compared to approximately $0.8 million in 2005, an increase of approximately $6.9 million. The increase in other income was primarily due to:

- a litigation settlement of approximately $5.2 million in 2006;
- a pre-tax gain of approximately $1.0 million in the fourth quarter of 2006 from the sale of certain west Texas pipeline assets; and
- a pre-tax gain of approximately $0.5 million in the first quarter of 2006 from the sale of small gathering sections of Enogex's pipeline.

Income Tax Expense. Consolidated income tax expense was approximately $48.0 million in 2006 as compared to approximately $23.4 million in 2005, an increase of approximately $24.6 million primarily due to higher pre-tax income.

Net Income. For 2006, Enogex's consolidated net income, including the discontinued operations discussed below under the caption "—Discontinued Operations," was approximately $113.5 million. During 2006, Enogex had an increase in net income of approximately $41.2 million relating to various items that it does not consider to be reflective of the ongoing profitability of its business. These increases in net income include:

- an after-tax gain on the sale of the Kinta Assets in May 2006 of approximately $34.1 million;
- the approximately $3.2 million after-tax impact of a litigation settlement;
- income from discontinued operations of approximately $1.9 million;
- a sales and use tax refund related to activity in prior years of approximately $1.3 million;
- an after-tax gain of approximately $0.6 million related to the sale of certain west Texas pipeline assets; and
- an after-tax gain of approximately $0.3 million from the sale of a small gathering section of Enogex's pipeline.

These increases in net income were partially offset by a decrease in net income of approximately $0.2 million related to the impairment of certain long-lived assets.

For 2005, Enogex's consolidated net income, including the discontinued operations discussed below under the caption "—Discontinued Operations," was approximately $94.5 million. During 2005, Enogex had an increase in net income of approximately $50.0 million relating to various items that it does not consider to be reflective of the ongoing profitability of its business. These increases in net income include:

- an after-tax gain on the sale of EAPC in October 2005 of approximately $36.7 million;
- income from discontinued operations of approximately $11.3 million;
- an after-tax gain on the sale of Enerven in August 2005 of approximately $1.8 million; and

• income from a sales tax refund related to activity in prior years of approximately $0.2 million.

2005 Compared to 2004

Enogex's consolidated operating revenues and cost of goods sold increased in 2005 approximately $967.9 million, or 28.7%, and $972.2 million, or 31.2%, respectively, as compared to 2004 primarily due to higher commodity prices and higher revenues and related costs in Enogex's marketing business in 2005 as compared to 2004.

Gross Margin

Enogex's consolidated gross margin decreased approximately $4.3 million in 2005 as compared to 2004 primarily due to lower gross margins in its marketing and transportation and storage businesses, which were partially offset by a higher gross margin in its gathering and processing business. Factors affecting gross margin by business segment are explained below.

The transportation and storage business contributed approximately $99.1 million of Enogex's consolidated gross margin in 2005 as compared to approximately $114.5 million in 2004, a decrease of approximately $15.4 million, or 13.4%. The gross margin decreased primarily due to:

- losses of gas in Enogex's storage fields, increased costs associated with natural gas purchases and sales, increased costs from electric compression, reduced fuel recoveries due to timing and system fuel volumes previously recorded in Enogex's transportation and storage business which are now being recorded in its gathering and processing business, which collectively reduced the gross margin by approximately $20.5 million; and
- reduced demand fees due to fewer overrun service charges with OG&E and the loss of firm contracts, which reduced the gross margin by approximately $2.1 million.

These decreases in the transportation and storage gross margin were partially offset by:

- increased crosshaul prices and volumes, which increased the gross margin by approximately $5.3 million; and
- increased commodity and interruptible revenues, which increased the gross margin by approximately $1.5 million.

The gathering and processing business contributed approximately $140.2 million of Enogex's consolidated gross margin in 2005 as compared to approximately $123.4 million in 2004, an increase of approximately $16.8 million, or 13.6%. The gathering and processing gross margin increased primarily due to:

- contractual fuel gains primarily due to higher natural gas prices and renegotiated contracts, which increased the gross margin by approximately $7.2 million;
- increased fuel over recoveries due to higher natural gas prices, 2005 fuel reserve and system fuel volumes previously recorded in Enogex's transportation and storage business which is now being recorded in its gathering and processing business, which increased the gross margin by approximately $6.2 million;
- increased condensate liquid margins primarily due to higher condensate liquid prices, which increased the gross margin by approximately $3.0 million;
- higher volumes related to compression and dehydration, which increased the gross margin by approximately $2.5 million;
- higher volumes on the low pressure gathering systems, which increased the gross margin by approximately $2.2 million;

• increased percent-of-liquids margins primarily due to higher natural gas prices, which increased the gross margin by approximately $1.4 million; and

• higher margin on natural gas sales reflective of opportunities in the marketplace, which increased the gross margin by approximately $1.1 million.

These increases in the gathering and processing gross margin were partially offset by:

• decreased net keep-whole margins primarily due to higher natural gas prices, which reduced the gross margin by approximately $3.2 million;

• higher cost of electricity in 2005, which reduced the gross margin by approximately $3.0 million; and

• lower volumes on the high pressure gathering systems, which reduced the gross margin by approximately $1.0 million.

The marketing business contributed approximately $10.4 million of Enogex's consolidated gross margin in 2005 as compared to approximately $16.1 million in 2004, a decrease of approximately $5.7 million, or 35.4%. The gross margin decreased primarily due to:

• less favorable market conditions and trading activity, which reduced the gross margin by approximately $13.0 million; and

• losses incurred related to Enogex's position on the Cheyenne Plains' transportation agreement, which reduced the gross margin by approximately $3.6 million.

These decreases in the marketing gross margin were partially offset by:

• a correction to the accounting procedure for park and loan transactions in 2004, which reduced the 2004 gross margin by approximately $7.7 million;

• lower demand fees paid for storage services due to establishing new rates for the new storage season, which began April 1, 2004 and increased the gross margin by approximately $2.5 million; and

• gains in storage activity, which increased the gross margin by approximately $0.7 million.

Operating Income

Enogex's consolidated operating income was $97.3 million in 2005 as compared to $95.6 million in 2004, an increase of $1.7 million despite the lower consolidated gross margin in 2005. The 2005 increase in operating income was primarily due to a net asset impairment charge of $7.8 million in 2004, with no similar item recorded in 2005. The impairment charge related to certain pipeline assets in the transportation and storage business that served a particular customer's power plants pursuant to a transportation agreement that was terminated by the customer effective December 31, 2004. Other factors affecting consolidated operating income were slight decreases in depreciation expense of $0.7 million and in taxes other than income of $0.6 million. The changes in these two items, both on a consolidated and business segment basis, were attributable to variances in plant in service and slightly lower property taxes. The other factor affecting Enogex's consolidated operating income was an increase of $3.1 million (3.3%) in other operation and maintenance expenses, which was primarily due to:

• higher outside service costs related to business development projects in 2005, system software implementation in 2005 and work performed to maintain the integrity and safety of Enogex's pipeline of approximately $4.4 million; and

- expenses related to a pipeline rupture in the second quarter of 2005 of approximately $0.5 million.

These increases in other operation and maintenance expenses were partially offset by an uncollectible debt reserve of approximately $1.1 million recorded in 2004 with no similar reserve recorded in 2005. Each of the foregoing items pertained almost entirely to the transportation and storage business.

Other factors affecting other operation and maintenance expenses in the transportation and storage business were higher allocations from OGE Energy of approximately $2.7 million. These increases in other operation and maintenance expenses for the transportation and storage business were offset in part by increased capitalized labor of approximately $3.2 million, lower salaries, wages and other employee benefits of approximately $0.8 million primarily due to more employee costs being capitalized in 2005 and an uncollectible debt reserve of approximately $0.8 million recorded in 2004 with no similar reserve recorded in 2005.

For the gathering and processing business, other operation and maintenance expenses were approximately $55.3 million in 2005 as compared to approximately $51.3 million in 2004, an increase of approximately $4.0 million, or 7.8%. The increase was due to higher salaries, wages and other employee benefits of approximately $3.7 million primarily due to a change in allocation methods. In the marketing business, other operation and maintenance expenses decreased primarily due to lower allocations from OGE Energy of approximately $3.4 million due to a change in allocation rates, lower salaries, wages and other employee benefits of approximately $0.8 million primarily due to a reduction in incentive compensation in 2004 and an uncollectible debt reserve of approximately $0.3 million recorded in 2004 with no similar reserve recorded in 2005. These decreases in other operation and maintenance expenses were partially offset by higher outside service costs related to a capital allocation study and system software implementation in 2005 of approximately $0.3 million.

Consolidated Information

Interest Income. Consolidated interest income was approximately $2.9 million in 2005 as compared to approximately $3.2 million in 2004, a decrease of approximately $0.3 million, or 9.4%, primarily due to a decrease in interest income of approximately $1.9 million due to the interest portion of an income tax refund related to prior periods which was received in 2004 with no similar activity recorded in 2005 partially offset by an increase in interest income of approximately $1.1 million from parent due to funds received from the sale of EAPC in October 2005.

Other Income. Consolidated other income was approximately $0.8 million in 2005 as compared to approximately $4.5 million in 2004, a decrease of approximately $3.7 million, or 82.2%. The decrease in other income was primarily due to a gain in 2004 of approximately $3.0 million from the sale of certain of Enogex's compression and processing assets in 2004 in addition to approximately $0.8 million received related to a bankruptcy settlement from one of Enogex's customers during the third quarter of 2004.

Income Tax Expense. Consolidated income tax expense was approximately $23.4 million in 2005 as compared to approximately $26.4 million in 2004, a decrease of approximately $3.0 million, or 11.4%. The decrease in income tax expense was primarily due to:

- lower pre-tax income; and
- a reduction in excess deferred taxes of approximately $3.2 million in 2005.

These decreases in income tax expense were partially offset by a decrease in Oklahoma state income tax credits of approximately $1.6 million in 2005 as compared to 2004.

Net Income. For 2005, Enogex's consolidated net income, including the discontinued operations, discussed below under the caption "—Discontinued Operations," was approximately $94.5 million. During 2005, Enogex had an increase in net income of approximately $50.0 million relating to various items that Enogex does not consider to be reflective of the ongoing profitability of its business. These increases in net income include:

- a gain on the sale of EAPC in October 2005 of approximately $36.7 million;
- income from discontinued operations of approximately $11.3 million;
- a gain on the sale of Enerven in August 2005 of approximately $1.8 million; and
- income from a sales tax refund related to activity in prior years of approximately $0.2 million.

For 2004, Enogex's consolidated net income, including the discontinued operations, discussed below under the caption "—Discontinued Operations," was approximately $56.0 million. During 2004, Enogex had an increase in net income of approximately $10.9 million relating to various items that Enogex does not consider to be reflective of the ongoing profitability of its business. These increases in net income include:

- income from discontinued operations of approximately $11.7 million;
- authorized recovery of previously under-recovered fuel of approximately $3.8 million;
- a gain on the sale of Enogex's compression and processing assets of approximately $1.8 million;
- an imbalance settlement with a customer of approximately $1.6 million;
- a net Oklahoma investment tax credit of approximately $1.0 million; and
- a settlement related to a customer bankruptcy of approximately $0.5 million.

These increases to net income were partially offset by:

- a net impairment charge of approximately $4.8 million; and
- a correction to the accounting procedure for park and loan transactions in 2004 of approximately $4.7 million.

Discontinued Operations

In March 2006, Enogex announced that its wholly owned subsidiary, Enogex Gas Gathering, L.L.C., had entered into an agreement to sell the Kinta Assets, which included approximately 568 miles of gas gathering pipeline and 22 compressor units with current volumes of approximately 145 MMcf/d, all in eastern Oklahoma. The sale price was approximately $93 million. This transaction closed on May 1, 2006 and Enogex recorded an after tax gain of approximately $34.1 million during the second quarter of 2006. The proceeds from the sale were used, among other things, to reduce short-term debt levels and fund capital expenditures.

In September 2005, Enogex announced that it had entered into an agreement to sell its interest in EAPC, which held a 75% interest in the NOARK Pipeline System Limited Partnership. This sale was completed on October 31, 2005. Enogex received approximately $177.4 million in cash proceeds and recognized an after tax gain of approximately $36.7 million from the sale of this business in the fourth quarter of 2005. Enogex used approximately $31.9 million of the proceeds to repay principal and accrued interest on long-term debt and approximately $46.7 million to pay taxes associated with EAPC. The balance of the proceeds of approximately $98.8 million was used, among other things, to reduce short-term debt levels and fund capital expenditures.

In April 2005, Enogex Compression Company, LLC, or Enogex Compression, received an unsolicited offer to buy its interest in Enerven, a joint venture focused on the rental of natural gas compression assets. After evaluating this offer, Enogex Compression sold its interest in Enerven for approximately $7.3 million in August 2005. Enogex Compression recognized an after tax gain of approximately $1.8 million related to the sale of this business.

As a result of these sale transactions, the Kinta Assets have been reported as discontinued operations for the three months ended March 31, 2007 and 2006 and Enogex Compression's interest in Enerven, Enogex's interest in EAPC and the Kinta Assets have been reported as discontinued operations for the years ended December 31, 2006, 2005 and 2004 in the consolidated financial statements. Enogex Compression's sale of its Enerven interest and Enogex's sale of its EAPC interest were completed during 2005 and, therefore, there are no results of operations for these transactions during 2006. Results for these discontinued operations are summarized and discussed below.

	Three Months Ended March 31,		Year Ended December 31,		
	2007	2006	2006	2005	2004
			(in millions)		
Operating revenues	$ —	$ 6.6	$ 9.4	$106.0	$120.1
Cost of goods sold	—	4.1	4.9	69.5	80.0
Gross margin on revenues	—	2.5	4.5	36.5	40.1
Other operation and maintenance	—	0.8	1.0	7.5	7.9
Depreciation	—	0.3	0.3	5.8	6.5
Taxes other than income	—	0.1	0.1	1.3	1.5
Operating income	—	1.3	3.1	21.9	24.2
Interest income	—	—	—	0.2	0.3
Other income	—	—	56.0	66.2	—
Other expense	—	—	—	0.1	0.6
Interest expense	—	—	—	4.0	5.3
Income tax expense	—	0.5	23.1	34.4	7.0
Net income	$ —	$ 0.8	$36.0	$ 49.8	$ 11.6

Three Months Ended March 31, 2007 Compared to Three Months Ended March 31, 2006

Following the sale of the Kinta Assets in May 2006, no operations of the Kinta Assets are reflected in the consolidated financial statements.

2006 Compared to 2005

Gross margin decreased approximately $32.0 million, or 87.7%, in 2006 as compared to 2005 primarily due to the sale of EAPC in October 2005, the sale of the Kinta Assets in May 2006 and a decrease in natural gas purchases and sales due to a decrease in natural gas transported prior to these assets being sold.

Operation and maintenance expenses decreased approximately $6.5 million, or 86.7%, in 2006 as compared to 2005 primarily due to the sale of EAPC in October 2005 and the sale of the Kinta Assets in May 2006.

Depreciation expense decreased approximately $5.5 million, or 94.8%, in 2006 as compared to 2005 primarily due to the sale of EAPC in October 2005 and ceasing depreciation expense in January 2006 when the Kinta Assets were reported as a discontinued operation.

Taxes other than income decreased approximately $1.2 million, or 92.3%, in 2006 as compared to 2005 for ad valorem taxes primarily due to the sale of EAPC in October 2005.

Other income decreased approximately $10.2 million, or 15.4%, in 2006 as compared to 2005 due to the sale of the Kinta Assets in May 2006 partially offset by the sale of EAPC in October 2005 and the sale of Enerven in August 2005.

Interest expense decreased approximately $4.0 million, or 100.0%, in 2006 as compared to 2005 due to the sale of EAPC in October 2005 and the use of a portion of the sale proceeds to repay EAPC long-term debt.

Income tax expense increased approximately $11.3 million, or 32.8%, in 2006 as compared to 2005 primarily due to the sale of the Kinta Assets in May 2006 partially offset by the sale of EAPC in October 2005 and the sale of Enerven in August 2005.

2005 Compared to 2004

Gross margin decreased approximately $3.6 million, or 9.0%, in 2005 as compared to 2004 primarily due to the sale of EAPC in October 2005 and a decrease in natural gas purchases and sales due to a decrease in natural gas transported prior to these assets being sold.

Other income increased approximately $66.2 million in 2005 as compared to 2004 due to a pre-tax gain of approximately $63.3 million recognized in the fourth quarter of 2005 related to the sale of EAPC and a pre-tax gain of approximately $2.9 million recognized in the third quarter of 2005 related to the sale of Enerven.

Interest expense decreased approximately $1.3 million, or 24.5%, in 2005 as compared to 2004 due to the sale of EAPC in October 2005 and the use of a portion of the sale proceeds to repay EAPC long-term debt.

Income tax expense increased approximately $27.4 million in 2005 as compared to 2004 primarily due to the sale of the Kinta Assets in May 2006 partially offset by the sale of EAPC in October 2005 and the sale of Enerven in August 2005.

Financial Condition

March 31, 2007 Compared to December 31, 2006

The balance of Accounts Receivable, Net was approximately $182.3 million and $205.6 million at March 31, 2007 and December 31, 2006, respectively, a decrease of approximately $23.3 million, or 11.3%, primarily due to lower natural gas sales prices and volumes.

The balance of current Price Risk Management assets was approximately $5.9 million and $37.4 million at March 31, 2007 and December 31, 2006, respectively, a decrease of approximately $31.5 million, or 84.2%. The decrease was primarily due to lower natural gas prices associated with OERI's short-term physical natural gas purchase transactions and associated financial contracts. A reduction in the volume of OERI's short-term physical natural gas activity and associated financial contracts outstanding at March 31, 2007 from December 31, 2006 also contributed to the decrease.

December 31, 2006 Compared to December 31, 2005

The balance of Accounts Receivable, Net was approximately $205.6 million and $437.0 million at December 31, 2006 and 2005, respectively, a decrease of approximately $231.4 million, or 53.0%, primarily due to lower natural gas sales prices and volumes.

The balance of Advances to Parent was approximately $144.4 million and $125.5 million at December 31, 2006 and 2005, respectively, an increase of approximately $18.9 million, or 15.1%, primarily due to a reduction in income taxes payable to OGE Energy in 2006.

The balance of current Price Risk Management assets was approximately $37.4 million and $89.0 million at December 31, 2006 and 2005, respectively, a decrease of approximately $51.6 million, or 58.0%. The decrease was primarily due to lower natural gas prices associated with OERI short-term physical natural gas purchase transactions and associated financial contracts. A reduction in the volume of OERI's short-term physical natural gas activity and associated financial contracts outstanding at December 31, 2006 from December 31, 2005 also contributed to the decrease.

The balance of Gas Imbalance asset was approximately $2.8 million and $32.0 million at December 31, 2006 and 2005, respectively, a decrease of approximately $29.2 million, or 91.3%. The Gas Imbalance asset is comprised of planned or managed imbalances related to OERI's business, referred to herein as park and loan transactions, and pipeline and NGL imbalances, which are operational imbalances. Park and loan transactions were approximately $15.7 million at December 31, 2005 with no comparable balance at December 31, 2006. The decrease in park and loan transactions was due to the expiration of 2005 park and loan transactions in OERI's business activities. Operational imbalances were approximately $2.8 million and $16.3 million at December 31, 2006 and 2005, respectively, a decrease of approximately $13.5 million, or 82.8%. The decrease in operational imbalances was primarily due to Enogex beginning to manage imbalances related to its storage operations on a combined basis in 2006 for its two storage facilities, which resulted in a decrease in net imbalance volumes.

The balance of Accounts Payable was approximately $195.0 million and $391.3 million at December 31, 2006 and 2005, respectively, a decrease of approximately $196.3 million, or 50.2%, primarily due to lower natural gas prices and volumes in December 2006 as compared to December 2005.

The balance of current Price Risk Management liabilities was approximately $5.6 million and $81.9 million at December 31, 2006 and 2005, respectively, a decrease of approximately $76.3 million, or 93.2%. The decrease was primarily due to lower natural gas prices associated with OERI's short-term physical natural gas purchase transactions and associated financial contracts. A reduction in the volume of OERI's short-term physical natural gas activity and associated financial contracts outstanding at December 31, 2006 from December 31, 2005 also contributed to the decrease.

The balance of Gas Imbalance liability was approximately $11.1 million and $35.8 million at December 31, 2006 and 2005, respectively, a decrease of approximately $24.7 million, or 69.0%. The Gas Imbalance liability is comprised of park and loan transactions, and pipeline and NGLs imbalances, which are operational imbalances. Park and loan transactions were approximately $10.2 million at December 31, 2005 with no comparable balance at December 31, 2006. The decrease in park and loan transactions was due to the expiration of 2005 park and loan transactions in OERI's business activities. Operational imbalances were approximately $11.1 million and $25.6 million at December 31, 2006 and 2005, respectively, a decrease of approximately $14.5 million, or 56.6%. The decrease in operational imbalances was primarily due to Enogex beginning to manage imbalances related to its storage operations on a combined basis in 2006 for its two storage facilities, which resulted in a decrease in net imbalance volumes.

Off-Balance Sheet Arrangements

Off-balance sheet arrangements include any transactions, agreements or other contractual arrangements to which an unconsolidated entity is a party and under which we or Enogex have: (1) any obligation under a guarantee contract having specific characteristics as defined in FASB Interpretation No. 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect

Guarantees of Indebtedness of Others"; (2) a retained or contingent interest in assets transferred to an unconsolidated entity or similar arrangement that serves as credit, liquidity or market risk support to such entity for such assets; (3) any obligation, including a contingent obligation, under a contract that would be accounted for as a derivative instrument but is indexed to our own units and is classified in equity in our consolidated balance sheets; or (4) any obligation, including a contingent obligation, arising out of a variable interest as defined in FASB Interpretation No. 46, "Consolidation of Variable Interest Entities, an interpretation of Accounting Research Bulletin No. 51," in an unconsolidated entity that is held by, and material to, us or Enogex, where such entity provides financing, liquidity, market risk or credit risk support to, or engages in leasing, hedging or research and development services with, us or Enogex. Neither we nor Enogex currently have any off-balance sheet arrangements that have or are reasonably expected to have a material current or future effect on our or Enogex's financial condition, revenues, expenses, results of operations, liquidity, capital expenditures or capital resources.

Liquidity and Capital Resources

Historically, Enogex's sources of liquidity have included cash generated from operations, proceeds from the sale of assets and proceeds from the issuance of long-term debt. All cash flow in excess of operating expenses and capital expenditures was transferred to OGE Energy under an inter-company borrowing agreement and appears in the consolidated financial statements as "Advances to Parent." Enogex was paid market rates on its cash balances. There have been no borrowings by Enogex under this inter-company arrangement since October 2005.

In addition to the receipt of a contribution from us of a portion of the proceeds from this offering for working capital and other needs, Enogex expects its ongoing sources of liquidity to include cash generated from operations, Enogex's anticipated $250 million credit facility, long-term debt offerings and cash infusions from us out of proceeds from the issuance of additional limited partner units. We believe that cash generated from these sources will be sufficient to meet Enogex's short-term working capital requirements, long-term capital expenditures program and monthly cash distributions to its members, including us.

Cash Flows

	Three Months Ended March 31,		Year Ended December 31,		
Enogex Predecessor	**2007**	**2006**	**2006**	**2005**	**2004**
			(in millions)		
Net cash provided from operating activities	$ 49.7	$ 49.8	$ 131.6	$ 235.2	$ 118.2
Net cash used in investing activities	$(25.4)	$(19.3)	$ (65.1)	$ (34.5)	$ (22.5)
Net cash used in financing activities	$(21.2)	$(31.4)	$(139.4)	$(304.0)	$(118.6)

The reduction of approximately $0.1 million in net cash provided from operating activities during the three months ended March 31, 2007 as compared to the same period in 2006 was primarily related to changes to working capital, primarily due to changes in gas imbalance assets and liabilities, and lower levels of net income partially offset by changes to price risk management assets and liabilities. The reduction of approximately $103.6 million in net cash provided from operating activities in 2006 as compared to 2005 was primarily related to the $82.0 million decrease in changes to working capital, primarily due to changes in gas imbalance assets and liabilities, and changes to price risk management assets and liabilities partially offset by higher levels of net income and deferred taxes. The increase of approximately $117.0 million in net cash provided from operating activities in 2005 as compared to 2004 was primarily related to the $113.7 million increase in changes to working capital, primarily due to changes in gas imbalance assets and liabilities, as well as gain on asset sales of approximately $0.1 million as compared to a loss on asset sales in 2004 of approximately $3.3 million.

The increase in net cash used in investing activities of approximately $6.1 million during the three months ended March 31, 2007 as compared to the same period in 2006 related to higher levels of capital expenditures. The increase in net cash used in investing activities of approximately $30.6 million in 2006 as compared to 2005 related to higher levels of capital expenditures. The increase in net cash used in investing activities of approximately $12.0 million in 2005 as compared to 2004 related to higher levels of capital expenditures and lower proceeds from asset sales.

The decrease in net cash used in financing activities of approximately $10.2 million during the three months ended March 31, 2007 as compared to the same period in 2006 related primarily to lower levels of advances to parent and the repurchase of Enogex's common stock. The decrease in net cash used in financing activities of approximately $164.6 million in 2006 as compared to 2005 related primarily to lower levels of advances to parent and maturities of long-term debt. The increase in net cash used in financing activities of approximately $185.4 million in 2005 as compared to 2004 relates primarily to higher levels of dividends paid to OGE Energy on Enogex's common stock owned by OGE Energy and higher levels of advances to parent partially offset by lower maturities of long-term debt.

Capital Expenditures

Our businesses are capital-intensive and require investment to upgrade or enhance existing operations, connect new wells to the system, organically grow into new areas and comply with environmental and safety regulations. The capital investment for these businesses consists primarily of:

- maintenance capital expenditures, which are capital expenditures made to replace partially or fully depreciated assets in order to maintain the existing operating capacity of Enogex's assets and extend their useful lives, connect new wells to Enogex's system or comply with environmental or safety regulations; and
- expansion capital expenditures such as those to expand and upgrade plant or pipeline capacity and to construct new plants or pipelines.

We estimate that maintenance capital expenditures for Enogex's assets will be approximately $34.9 million for 2007, of which approximately $6.4 million has been spent through March 31, 2007.

We estimate that expansion capital expenditures for Enogex's assets will be approximately $136.3 million for 2007, of which approximately $19.1 million has been spent through March 31, 2007.

Below is a table showing expansion and maintenance capital expenditures for 2006 and forecasted expansion and maintenance capital expenditures for 2007 and the period October 2007 through September 2008.

	Actual	Forecasted	
	2006	2007	October 2007 through September 2008
Maintenance capital expenditures	$26.0	$ 34.9	$ 34.8
Expansion capital expenditures	41.1	136.3	112.3
Total	$67.1	$171.2	$147.1

Contractual Obligations

Enogex's future contractual obligations estimated for the next five years (*i.e.*, January 1, 2007 through December 31, 2011) and beyond were as follows:

	Total	Less than 1 year (2007)	1-3 years (2008-2009)	3-5 years (2010-2011)	More than 5 years
			(in millions)		
Maturities of long-term debt	$404.0	$ 3.0	$ 1.0	$ 400.0	—
Interest payments on long-term debt	96.3	31.8	63.2	1.3	—
Pension funding obligations	13.8	4.0	5.2	4.6	N/A
Total debt and pension obligations	514.1	38.8	69.4	405.9	—
Operating lease obligations					
Noncancellable operating leases	8.6	2.2	3.1	2.9	$ 0.4
Other purchase obligations and commitments	53.4	6.9	12.4	13.0	21.1
Total debt, pension and operating lease obligations and other purchase obligations and commitments	$576.1	$ 47.9	$ 84.9	$ 421.8	$ 21.5

N/A—Not available

2006 Capital Requirements and Financing Activities

Enogex's total capital requirements, consisting of capital expenditures, maturities of long-term debt, interest payments on long-term debt and pension funding obligations, were approximately $106.0 million and contractual obligations were approximately $10.7 million resulting in total capital requirements and contractual obligations of approximately $116.7 million in 2006. Approximately $41.1 million of the 2006 capital requirements were for expansion capital expenditures and approximately $26.0 million were for maintenance capital expenditures, including approximately $0.8 million to comply with environmental regulations. This compares to capital requirements of approximately $109.5 million and contractual obligations of approximately $4.3 million totaling approximately $113.8 million in 2005. Approximately $2.8 million of the 2005 capital requirements were for expansion capital expenditures and approximately $31.9 million were for maintenance capital expenditures, including approximately $2.5 million to comply with environmental regulations. During 2006, Enogex's sources of capital were internally generated funds from operating cash flows and proceeds from the sale of assets. Changes in working capital reflect the seasonal nature of Enogex's business and the revenue lag between billing and collection from customers. See "—Financial Condition" for a discussion of significant changes in net working capital requirements as it pertains to operating cash flows and liquidity.

Discontinued Operations

Also contributing to Enogex's liquidity has been the disposition of certain assets classified as discontinued operations in 2005 and 2006. During 2005 and 2006, these dispositions have generated net sales proceeds of approximately $277.7 million. Sales proceeds generated to date have been used to fund capital expenditures and as advances to OGE Energy.

Additional asset sales could further contribute to Enogex's liquidity.

Long-Term Debt Maturities

Maturities of Enogex's long-term debt during the next five years consist of $1.0 million in 2008 and $400.0 million in 2010. There are no remaining maturities of Enogex's long-term debt in years 2007, 2009 or 2011. The partnership does not have any long-term debt outstanding. In connection with this offering, Enogex currently expects to refinance the $400.0 million of long-term debt due in 2010. Proceeds from an issuance of up to $300 million of new long-term debt, with maturities ranging from two to 30 years, are expected to be utilized to fund a portion of the refinancing.

Pension and Postretirement Benefit Plans

All of Enogex's eligible employees are covered by a non-contributory defined benefit pension plan sponsored by OGE Energy. During 2006, actual asset returns for this defined benefit pension plan were positively affected by growth in the equity markets. At December 31, 2006, approximately 64% of the pension plan assets were invested in listed common stocks with the balance invested in corporate debt and U.S. Government securities. In 2006, asset returns on the pension plan were approximately 14.5% as compared to approximately 6.2% in 2005. During the same time, corporate bond yields, which are used in determining the discount rate for future pension obligations, have continued to decline.

OGE Energy's contributions to the pension plan increased from approximately $32.0 million in 2005, of which approximately $2.3 million was allocated to Enogex, to approximately $90.0 million in 2006, of which approximately $7.0 million was allocated to Enogex. This increase in pension plan contributions in 2006 was to maintain an adequate funded status. The level of funding is dependent on returns on plan assets and future discount rates. Higher returns on plan assets and increases in discount rates will reduce funding requirements to the plan. In August 2006, legislation was passed that changed the funding requirement for single- and multi-employer defined benefit pension plans as discussed below. In April 2007, OGE Energy contributed approximately $20.0 million to its pension plan, of which approximately $1.7 million was allocated to Enogex. During the remainder of 2007, OGE Energy may contribute up to an additional $30.0 million to the pension plan, of which approximately $2.6 million is expected to be allocated to Enogex.

In accordance with SFAS No. 88, "Employer's Accounting for Settlements and Curtailments of Defined Benefit Pension Plans and for Termination Benefits," a one-time settlement charge is required to be recorded by an organization when lump-sum payments or other settlements that relieve the organization from the responsibility for the pension benefit obligation during a plan year exceed the service cost and interest cost components of the organization's net periodic pension cost. During 2006, Enogex experienced an increase in both the number of employees electing to retire and the amount of lump-sum payments to be paid to such employees upon retirement in 2006. As a result, Enogex recorded a pension settlement charge for 2006 of approximately $0.8 million in the fourth quarter of 2006. The pension settlement charge did not require a cash outlay and did not increase Enogex's total pension expense over time, as the charge was an acceleration of costs that otherwise would have been recognized as pension expense in future periods.

As discussed in Note 11 of Notes to Consolidated Financial Statements, in 2000, OGE Energy made several changes to its pension plan, including the adoption of a cash balance benefit feature for employees hired after January 31, 2000. The cash balance plan may provide lower post-employment pension benefits to employees, which could result in less pension expense being recorded. Over the near term, Enogex's cash requirements for the plan are not expected to be materially different than the requirements existing prior to the plan changes. However, as the population of employees included in the cash balance plan feature increases, Enogex's cash requirements should decrease and will be much less sensitive to changes in discount rates.

At December 31, 2006, the projected benefit obligation and fair value of assets of Enogex's portion of OGE Energy's pension plan and restoration of retirement income plan was approximately

$41.7 million and $42.7 million, respectively, for an overfunded status of approximately $1.0 million. The above amounts have been recorded in Prepaid Pension and Benefit Obligations with the offset in Accumulated Other Comprehensive Income in the consolidated balance sheets. The entry did not impact the results of operations in 2006 and did not require a usage of cash and is therefore excluded from the consolidated statements of cash flows. The amounts in Accumulated Other Comprehensive Income represent a net periodic pension cost to be recognized in the consolidated statements of income in future periods.

During 2005, OGE Energy made contributions to the pension plan that exceeded amounts previously recognized as net periodic pension expense and recorded a net prepaid benefit obligation at December 31, 2005 of approximately $88.9 million, of which approximately $7.7 was allocated to Enogex. At December 31, 2005, Enogex's portion of the projected pension benefit obligation exceeded the fair value of the pension plan assets by approximately $4.1 million. As a result of recording a prepaid benefit obligation and having a funded status where the projected benefit obligations exceeded the fair value of plan assets, provisions of SFAS No. 87 required the recognition of an additional minimum liability in the amount of approximately $181.4 million for OGE Energy, of which approximately $0.1 million was allocated to Enogex at December 31, 2005. The offset of this entry was an intangible asset and Accumulated Other Comprehensive Income, net of a deferred tax asset; therefore, this adjustment did not impact the results of operations in 2005 and did not require a usage of cash and is therefore excluded from the consolidated statements of cash flows. The amount recorded as an intangible asset equaled the unrecognized prior service cost with the remainder recorded in Accumulated Other Comprehensive Income. The amount in Accumulated Other Comprehensive Income represents a net periodic pension cost to be recognized in the consolidated statements of income in future periods.

On August 17, 2006, President Bush signed The Pension Protection Act of 2006, or the Pension Protection Act, into law. The Pension Protection Act makes changes to important aspects of qualified retirement plans. Among other things, it introduces a new funding requirement for single- and multi-employer defined benefit pension plans, provides legal certainty on a prospective basis for cash balance and other hybrid plans and addresses contributions to defined contribution plans, deduction limits for contributions to retirement plans and investment advice provided to plan participants. Management is currently analyzing the impact of the Pension Protection Act on Enogex's pension plans.

Security Ratings

	Moody's	Standard & Poor's	Fitch's
Enogex Notes(1)	Baa3	BBB+	BBB

(1) Enogex currently expects to refinance its $400 million 8.125% senior notes due 2010, including the payment of a make-whole premium of approximately $30 million, with a combination of $300 million of new long-term debt and approximately $130 million of the proceeds of this offering that we expect to contribute to Enogex for the anticipated repayment of that debt.

A security rating is not a recommendation to buy, sell or hold securities. Such rating may be subject to revision or withdrawal at any time by the credit rating agency and each rating should be evaluated independently of any other rating.

Future financing requirements may be dependent, to varying degrees, upon numerous factors such as general economic conditions, commodity prices, levels of drilling activity, acquisitions of other businesses or development of projects, actions by rating agencies, inflation, changes in environmental laws or regulations and new legislation.

Future Sources of Financing

Management expects that internally generated funds, the issuance of long and short-term debt and proceeds from the sales of common units to the public or other offerings will be adequate over the next three years to meet anticipated cash needs. Historically, Enogex has utilized short-term borrowings (from OGE Energy) to satisfy temporary working capital needs and as an interim source of financing capital expenditures until permanent financing is arranged.

In connection with this offering, Enogex expects to enter into a $250 million credit facility for working capital, capital expenditures and other corporate purposes, including acquisitions. Although the terms of the new credit facility have not been finalized, we expect that the credit facility will contain customary operating restrictions that may limit Enogex's ability, under specified circumstances, to:

- make distributions in certain circumstances, such as if any default or event of default occurs;
- incur additional indebtedness;
- grant liens;
- make acquisitions, certain loans or investments or dispositions and engage in transactions with affiliates;
- make any material change to the nature of Enogex's business, including consolidation, liquidations and dissolutions; or
- enter into a merger, consolidation, sale and leaseback transaction or sale of assets.

Additionally, we expect Enogex's credit facility to contain customary covenants requiring it to maintain certain financial ratios and meet certain financial tests.

Critical Accounting Policies and Estimates

The consolidated financial statements and notes contain information that is pertinent to Management's Discussion and Analysis of Financial Condition and Results of Operations. In preparing the consolidated financial statements, management is required to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and contingent liabilities at the date of the consolidated financial statements and the reported amounts of revenues and expenses during the reporting period. Changes to these assumptions and estimates could have a material affect on the consolidated financial statements, particularly as they relate to pension expense and impairment estimates. However, management believes it has taken reasonable, but conservative, positions where assumptions and estimates are used in order to minimize the negative financial impact on us or Enogex that could result if actual results vary from the assumptions and estimates. In management's opinion, the areas where it exercises the most significant judgment are in the valuation of pension plan assumptions, impairment estimates, contingency reserves, fair value and cash flow hedges, operating revenues, natural gas purchases, the allowance for uncollectible accounts receivable and the valuation of energy purchase and sale contracts. The selection, application and disclosure of the following critical accounting estimates have been discussed with the audit committee of OGE Energy.

Pension and Postretirement Benefit Plans

OGE Energy has defined benefit retirement and postretirement plans that cover substantially all of Enogex's employees. Enogex expects to continue to participate in these plans following completion of this offering. Pension and other postretirement plan expenses and liabilities are determined on an actuarial basis and are affected by the market value of plan assets, estimates of the expected return on plan assets, assumed discount rates and the level of funding. These expectations and assumptions are made by management of OGE Energy. Actual changes in the fair market value of plan assets and differences between the actual return on plan assets and the expected return on plan assets could have a material effect on the amount of pension expense ultimately recognized. The pension plan rate assumptions are shown in Note 11 of Notes to Consolidated Financial Statements. The assumed return on plan assets is based on OGE Energy's expectation of the long-term return on the plan assets portfolio. The discount rate used to compute the present value of plan liabilities is based generally on rates of high-grade corporate bonds with maturities similar to the average period over which benefits will be paid. The level of funding is dependent on returns on plan assets and future discount rates. Higher returns on plan assets and an increase in discount rates will reduce funding requirements to the pension plan. The following table indicates the sensitivity of OGE Energy's pension plan funded status to these variables.

	Change	Impact on Funded Status	Portion of Impact Allocated to Enogex
Actual plan asset returns	+/- 5 percent	+/- $26.0 million	+/- $2.1 million
Discount rate	+/- 0.25 percent	+/- $19.5 million	+/- $1.7 million
Contributions	+ $10.0 million	+ $10.0 million	+ $10.0 million
Expected long-term return on plan assets	+/- 1 percent	None	None

Impairment of Assets

Management assesses potential impairments of assets or asset groups when there is evidence that events or changes in circumstances require an analysis of the recoverability of an asset or asset group. For purposes of recognition and measurement of an impairment loss, a long-lived asset or assets shall be grouped with other assets and liabilities at the lowest level for which identifiable cash flows are largely independent of the cash flows of other assets and liabilities. Estimates of future cash flows used to test the recoverability of a long-lived asset or asset group shall include only the future cash flows (cash inflows less associated cash outflows) that are directly associated with and that are expected to arise as a direct result of the use and eventual disposition of the asset or asset group. The fair value of these assets is based on third-party evaluations, prices for similar assets, historical data and projected cash flows. An impairment loss is recognized when the sum of the expected future net cash flows is less than the carrying amount of the asset. The amount of any recognized impairment is based on the estimated fair value of the asset subject to impairment compared to the carrying amount of such asset. Management expects to continue to evaluate the strategic fit and financial performance of each of Enogex's assets in an effort to ensure a proper economic allocation of resources. The magnitude and timing of any potential impairment or gain on the disposition of any assets have not been included in the 2007 assumptions and considerations.

Commitments and Contingencies

In the normal course of business, we and Enogex are confronted with issues or events that may result in a contingent liability. These generally relate to lawsuits, claims made by third parties, environmental actions or the action of various regulatory agencies and income tax related items. Management consults with legal counsel and other appropriate experts to assess the claim. If, in management's opinion, we or Enogex have incurred a probable loss as set forth by GAAP, an estimate is made of the loss and the appropriate accounting entries are reflected in the consolidated financial statements.

Except as disclosed otherwise in this prospectus, management, after consultation with legal counsel, does not currently anticipate that liabilities arising out of these pending or threatened lawsuits, claims and contingencies will have a material adverse effect on our or Enogex's consolidated financial condition, results of operations or cash flows. See Notes 13 and 14 of Notes to Consolidated Financial Statements and the information under the caption "Business—Legal Proceedings" below.

Hedging Policies

Enogex engages in cash flow hedge transactions to manage commodity risk. Enogex may hedge its forward exposure to manage the impact of changes in commodity prices. Hedges of anticipated transactions are documented as cash flow hedges pursuant to SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," and are executed based upon management-established price targets. During 2004 and 2005, Enogex utilized hedge accounting under SFAS No. 133 to manage commodity exposure for contractual length and operational storage natural gas, keep-whole natural gas and certain types of NGL hedges. During 2006, Enogex utilized hedge accounting under SFAS No. 133 to manage commodity exposure for contractual length and operational storage natural gas, keep-whole natural gas, NGL hedges and certain transportation hedges. Hedges are evaluated prior to execution with respect to the impact on the volatility of forecasted earnings and are evaluated at least quarterly after execution for the impact on earnings. Enogex engages in cash flow and fair value hedge transactions to modify the rate composition of the debt portfolio. During 2005 and 2006, Enogex did not enter into any interest rate swap agreements.

Operating Revenues

Operating revenues for gathering, processing, transportation and storage services are recorded each month based on the current month's estimated volumes, contracted prices (considering current commodity prices), historical seasonal fluctuations and any known adjustments. The estimates are reversed in the following month and customers are billed on actual volumes and contracted prices. Gas sales are calculated on current-month nominations and contracted prices. Operating revenues associated with the production of NGLs are estimated based on current-month estimated production and contracted prices. These amounts are reversed in the following month and the customers are billed on actual production and contracted prices. Estimated operating revenues are reflected in Accounts Receivable, Net on the consolidated balance sheets and in Operating Revenues on the consolidated statements of income.

Natural Gas Purchases

Estimates for gas purchases are based on sales volumes and contracted purchase prices. Estimated gas purchases are included in Accounts Payable on the consolidated balance sheets and in Cost of Goods Sold on the consolidated statements of income.

Energy Purchase and Sale Contracts

OERI's activities include the marketing and hedging of natural gas and NGLs. The vast majority of these contracts expire within three years, which is when the cash aspect of the transactions will be realized. A substantial portion of these contracts qualify as derivatives under SFAS No. 133 and are marked-to-market with offsetting gains and losses recorded in earnings. In nearly all cases, independent market prices are obtained and compared to the values used for this mark-to-market valuation, and an oversight group outside of the marketing organization monitors all modeling methodologies and assumptions. The recorded value of the energy contracts may change significantly in the future as the market price for the commodity changes, but the value is still subject to the risk loss limitations provided under our risk policies. Management utilizes models to estimate the fair value of energy contracts including derivatives that do not have an independent market price. At December 31, 2006, Enogex's unrealized mark-to-market gains were approximately $31.2 million, which included approximately $0.5 million of unrealized mark-to-market gains that were calculated utilizing models. At December 31, 2006, a price movement of 1.0% for prices verified by independent parties would result in changes in unrealized mark-to-market gains of less than $0.1 million and a price movement of 5.0% on model-based prices would result in changes in unrealized mark-to-market gains of approximately $0.1 million. Energy contracts are presented in Price Risk Management assets, liabilities or against the brokerage deposits in Other Current Assets on the consolidated balance sheets and in Operating Revenues on the consolidated statements of income.

Natural Gas Inventory

Natural gas inventory is held by the transportation and storage and marketing businesses. The transportation and storage business maintains natural gas inventory to provide operational support for Enogex's pipeline deliveries. In addition, as part of its recurring buy and sell activity, OERI injects and withdraws natural gas in to and out of inventory under the terms of its storage capacity contracts. In order to mitigate market price exposures, both businesses enter into contracts or hedging instruments to protect the cash flows associated with its inventory. During 2004, 2005 and 2006, OERI elected not to designate inventory hedging contracts as fair value or cash flow hedges under SFAS No. 133. The fair value of the hedging instruments is recorded on the books of OERI as Price Risk Management assets, liabilities or against the brokerage deposits in Other Current Assets with an offsetting gain or loss recorded in current earnings. All natural gas inventory held by Enogex is recorded at the lower of cost or market. During 2006, Enogex recorded write-downs to market value related to natural gas storage inventory of approximately $18.7 million. The amount of Enogex's natural gas inventory was approximately $35.9 million and $35.7 million at December 31, 2006 and 2005, respectively. Natural gas storage inventory is presented in Natural Gas Inventories on the consolidated balance sheets and in Cost of Goods Sold on the consolidated statements of income.

Allowance for Uncollectible Accounts Receivable

The allowance for uncollectible accounts receivable is calculated based on outstanding accounts receivable balances over 180 days old. In addition, other outstanding accounts receivable balances less than 180 days old are reserved on a case-by-case basis when management believes the required payment of specific amounts owed is unlikely to occur. The allowance for uncollectible accounts receivable is a reduction to Accounts Receivable, Net on the consolidated balance sheets and is included in Other Operation and Maintenance Expenses on the consolidated statements of income. The allowance for Enogex's uncollectible accounts receivable was approximately $1.1 million and $1.2 million at December 31, 2006 and 2005, respectively.

Accounting Pronouncements

See Notes 2 and 3 of Notes to Consolidated Financial Statements for a discussion of recent accounting pronouncements that are applicable to us and Enogex.

Quantitative and Qualitative Disclosures About Market Risk

Market risks are, in most cases, risks that are actively traded in a marketplace and have been well studied in regards to quantification. Market risks include, but are not limited to, changes in commodity prices, commodity price volatilities and interest rates. Enogex is exposed to commodity price and commodity price volatility risks in its operations. Enogex's exposure to changes in interest rates relates primarily to short-term variable-rate debt, interest rate swap agreements and commercial paper. Enogex engages in price risk management activities for both trading and non-trading purposes.

Risk Committee and Oversight

Management monitors market risks using a risk committee structure. The Risk Oversight Committee of the partnership's general partner, which consists primarily of corporate officers, is responsible for the overall development, implementation and enforcement of strategies and policies for all risk management activities. This committee's emphasis is a holistic perspective of risk measurement and policies targeting our overall financial performance. The Risk Oversight Committee is authorized by, and will report quarterly to, the audit committee of the partnership's general partner.

The partnership's general partner also has a Corporate Risk Management Department led by its Chief Risk Officer. This group, in conjunction with the aforementioned committees, is responsible for establishing and enforcing the risk policies.

Risk Policies

Management utilizes risk policies to control the amount of market risk exposure. These policies are designed to provide the audit committee and senior executives of the partnership's general partner with confidence that the risks taken on by our and Enogex's business activities are in accordance with their expectations for financial returns and that the approved policies and controls related to risk management are being followed. Some of the measures in these policies include value-at-risk, or VaR, limits, position limits, tenor limits and stop loss limits.

Enogex's price risk management assets and liabilities as of March 31, 2007 were as follows:

Trading	Commodity	Notional Volume (MMBtu)	Maturity	Fair Value
		(dollars in millions)		
Price Risk Management Assets				
Physical Purchases	Natural Gas	23.2	2007	$ 1.1
Physical Purchases	Natural Gas	2.5	2008	0.1
Total Physical Purchases				1.2
Physical Sales	Natural Gas	30.3	2007	2.8
Physical Sales	Natural Gas	4.8	2008	0.5
Total Physical Sales				3.3
Short Physical Options	Natural Gas	13.7	2007	0.8
Long Basis Positions	Natural Gas	3.3	2008	1.1
Long Basis Positions	Natural Gas	0.9	2009	0.2
Total Long Basis Positions				1.3
Short Basis Positions	Natural Gas	12.9	2007	0.8
Total Trading Price Risk Management Assets				$ 7.4
Trading				
Price Risk Management Liabilities				
Physical Purchases	Natural Gas	16.0	2007	$ 0.7
Physical Purchases	Natural Gas	1.0	2008	0.2
Total Physical Purchases				0.9
Physical Sales	Natural Gas	14.5	2007	1.4
Physical Sales	Natural Gas	2.6	2008	0.1
Total Physical Sales				1.5
Long Basis Positions	Natural Gas	10.4	2007	2.0
Short Basis Positions	Natural Gas	3.3	2007	0.2
Short Basis Positions	Natural Gas	3.3	2008	0.3
Short Basis Positions	Natural Gas	0.9	2009	0.3
Total Short Basis Positions				0.8
Total Trading Price Risk Management Liabilities				$ 5.2
Non-Trading				
Price Risk Management Liabilities				
Long Basis Positions	Natural Gas	0.4	2007	$ 0.1
Total Non-Trading Risk Management Liabilities	Natural Gas			$ 0.1

The valuation of Enogex's price risk management assets and liabilities were determined primarily based on quoted market prices. However, in certain instances where market quotes are not available, other valuation techniques or models are used to estimate market values. The valuation of instruments also considers the credit risk of the counterparties and the potential impact of liquidating the position in an orderly manner over a reasonable period of time.

Interest Rate Risk

The fair value of Enogex's long-term debt is based on quoted market prices and management's estimate of current rates available for similar issues with similar maturities. At March 31, 2007, neither we nor Enogex had outstanding variable-rate debt, commercial paper or interest rate swap agreements. The following table shows Enogex's long-term debt maturities and the weighted-average interest rates by maturity date.

	2007	2008	2009	2010	2011	Thereafter	Total	March 31, 2007 Fair Value
				(dollars in millions)				
Fixed-rate debt(A)								
Principal amount	$ 3.0(B)	$1.0	$—	$ 400.0(C)	$—	$ —	$404.0	$ 434.1
Weighted-average interest rate	8.28%	7.07%	—	8.13%	—	—	8.12%	—

(A) Prior to or when these debt obligations mature, Enogex may refinance all or a portion of such debt at then-existing market interest rates which may be more or less than the interest rates on the maturing debt.

(B) This long-term debt matured in April 2007.

(C) Enogex currently expects to refinance its $400 million 8.125% senior notes due 2010, including the payment of a make-whole premium of approximately $30 million, with a combination of $300 million of new long-term debt and approximately $130 million of the proceeds of this offering that we expect to contribute to Enogex for the anticipated repayment of that debt.

Commodity Price Risk

The market risks inherent in market risk sensitive instruments, positions and anticipated commodity transactions are the potential losses in value arising from adverse changes in the commodity prices to which Enogex is exposed. These market risks can be classified as trading, which includes transactions that are entered into voluntarily to capture subsequent changes in commodity prices, or non-trading, which includes the exposure some of Enogex's assets have to commodity prices.

Trading Activities

The trading activities are conducted throughout the year subject to daily and monthly trading stop loss limits set by the Risk Oversight Committee. Those trading stop loss limits currently are $2.5 million. The daily loss exposure from trading activities is measured primarily using VaR, which estimates the potential losses the trading activities could incur over a specified time horizon and confidence level. The VaR limit set by the Risk Oversight Committee for Enogex's trading activities, assuming a 95% confidence level, currently is $1.5 million. These limits are designed to mitigate the possibility of trading activities having a material adverse effect on Enogex's operating income.

A sensitivity analysis has been prepared to estimate Enogex's exposure to market risk created by trading activities. The value of trading positions is a summation of the fair values for each net commodity position based upon quoted market prices. Market risk is estimated as the potential loss in fair value resulting from a hypothetical 10% adverse change in quoted market prices over the next 12 months. The result of this analysis with respect to Enogex, which may differ from actual results, is as follows at March 31, 2007.

	Trading
	(in millions)
Commodity market risk, net	$ 0.2

Non-Trading Activities

The prices of natural gas, NGLs and NGLs processing spreads are subject to fluctuations resulting from changes in supply and demand. The changes in these prices have a direct effect on the compensation Enogex receives for operating some of its assets. To partially reduce non-trading commodity price risk, Enogex hedges, through the utilization of derivatives and other forward transactions, the effects these market fluctuations have on its operating income. Because the commodities covered by these hedges are substantially the same commodities that Enogex buys and sells in the physical market, no special studies other than monitoring the degree of correlation between the derivative and cash markets are deemed necessary.

A sensitivity analysis has been prepared to estimate Enogex's exposure to the market risk of its non-trading activities. Enogex's daily net commodity position consists of natural gas inventories, commodity purchase and sales contracts, financial and commodity derivative instruments and anticipated natural gas processing spreads and fuel recoveries. Quoted market prices are not available for all of Enogex's non-trading positions, therefore, the value of non-trading positions is a summation of the forecasted values calculated for each commodity based upon internally generated forecast prices. Market risk is estimated as the potential loss in fair value resulting from a hypothetical 10% adverse change in such prices over the next 12 months. The result of this analysis with respect to Enogex, which may differ from actual results, is as follows at March 31, 2007.

	Non-Trading
	(in millions)
Commodity market risk, net	$ 10.9

Management may designate certain derivative instruments for the purchase or sale of physical commodities as normal purchases and normal sales contracts under the provisions of SFAS No. 133. Normal purchases and normal sales contracts are not recorded in Price Risk Management assets or liabilities in the consolidated balance sheets and earnings recognition is recorded in the period in which physical delivery of the commodity occurs. Management applies normal purchases and normal sales to (1) commodity contracts for the purchase and sale of natural gas and (2) commodity contracts for the sale of NGLs produced by Enogex Products Corporation.

Credit Risk

Credit risk includes the risk that counterparties that owe us and Enogex money or energy will breach their obligations. If the counterparties to these arrangements fail to perform, we and Enogex may be forced to enter into alternative arrangements. In that event, our or Enogex's financial results could be adversely affected and we or Enogex could incur losses.

Management maintains credit policies with regard to our and Enogex's counterparties that management believes minimize overall credit risk. These policies include the evaluation of a potential counterparty's financial condition (including credit rating, if available), collateral requirements under certain circumstances and the use of standardized agreements that provide for the netting of cash flows associated with a single counterparty. Management also monitors the financial condition of existing counterparties on an ongoing basis.

BUSINESS

Our Partnership

We are a Delaware limited partnership recently formed by OGE Energy Corp. (NYSE: OGE), or OGE Energy, to further develop its natural gas midstream assets and operations. Upon the completion of this offering, a wholly owned subsidiary of OGE Energy will own a 63.9% limited partner interest in us and a 2% general partner interest in us through its ownership of OGE Enogex GP LLC, our general partner. Our wholly owned subsidiary will own a 25% membership interest in Enogex, will be its managing member and will control its assets and operations. A wholly owned subsidiary of OGE Energy will own the remaining 75% interest in Enogex and will be a non-managing member.

Upon the completion of this offering, our interest in Enogex will be our only cash-generating asset. Enogex is engaged in the business of gathering, processing, transporting, storing and marketing natural gas. The vast majority of Enogex's assets are located in the major natural gas producing basins of Oklahoma. Enogex's current operations are organized into three businesses: (1) natural gas transportation and storage, (2) natural gas gathering and processing and (3) natural gas marketing.

- *Transportation and Storage.* Enogex owns and operates approximately 2,283 miles of intrastate natural gas transportation pipelines with approximately 1.44 TBtu/d of current throughput. Enogex's transportation pipelines are directly connected to 11 third-party natural gas pipelines at 64 interconnect points and to 27 end-user customers, including 15 natural gas-fired electric generation facilities in Oklahoma. Enogex provides fee-based intrastate transportation services on a firm and interruptible basis and, pursuant to Section 311 of the NGPA provides interstate transportation services on an interruptible basis.

  Enogex owns and operates two natural gas storage facilities, the Wetumka Storage Facility and the Stuart Storage Facility, with approximately 23 Bcf of aggregate working gas capacity. The storage facilities have approximately 650 MMcf/d of maximum withdrawal capacity and approximately 650 MMcf/d of injection capacity. Enogex provides fee-based firm and interruptible storage services to third parties at market-based rates. For the year ended December 31, 2006, Enogex's transportation and storage business generated approximately $126 million of its gross margin.

- *Gathering and Processing.* Enogex owns and operates approximately 5,474 miles of natural gas gathering pipelines with approximately 0.98 TBtu/d of current throughput and six natural gas processing plants with approximately 720 MMcf/d of aggregate inlet capacity. Enogex provides well connect, gathering, measurement, treating, dehydration, compression and processing services to its producer customers primarily in the Arkoma and Anadarko basins, including those operating in the Granite Wash play in western Oklahoma and the Texas Panhandle and the Woodford Shale play in southeastern Oklahoma. For the year ended December 31, 2006, Enogex processed approximately 0.54 TBtu/d of natural gas and extracted and sold approximately 371 million gallons of natural gas liquids, or NGLs. For the year ended December 31, 2006, Enogex's gathering and processing business generated approximately $168 million of its gross margin.

- *Marketing.* Enogex conducts certain natural gas marketing activities, primarily in support of its transportation and storage and gathering and processing businesses. Enogex's marketing business helps to manage its exposure to commodity price risk as well as maximize the prices Enogex receives for the sale of natural gas and NGLs. The marketing business focuses on developing supplies and markets that can access Enogex's systems either directly or via interconnections with intrastate and interstate pipelines. For the year ended December 31, 2006, Enogex's marketing business generated approximately $14 million of its gross margin.

Business Strategies

Our primary business objective is to increase our cash distributions per unit over time. We intend to accomplish this objective by executing the strategies listed below. The key components of our strategy include (1) capturing growth opportunities through expansion projects, increasing utilization of existing assets and strategic acquisitions, (2) maintaining strong customer relationships based upon high quality service, reliability and efficiency of Enogex's existing assets and operations and (3) maintaining sound financial practices. Specifically, we will look to the following strategies to drive cash distribution growth:

Capturing growth opportunities through expansion projects, increasing utilization of existing assets and strategic acquisitions

- *Expanding Enogex's existing operations through organic growth projects*. Enogex plans to leverage its location and scale to expand its existing asset base to meet new or increased demand for midstream services. We believe that Enogex is well positioned to take advantage of the increasing need for midstream services in the areas that are experiencing high levels of drilling activity, such as the Granite Wash play in western Oklahoma and the Texas Panhandle and the Woodford Shale play in southeastern Oklahoma.

  In 2006 and 2007, Enogex initiated several major organic growth projects, including:

  - *Expanding gathering capacity in western Oklahoma and the Texas Panhandle*. Enogex has recently expanded its gathering pipeline capacity in western Oklahoma and the Texas Panhandle through installation of 42 miles of 20-inch gathering trunkline and three new compression stations. The 20-inch trunkline serves as a gathering "header" and provides Enogex with the ability to flow gas to multiple processing plants on a part of its system without having to shut-in the producers if a particular processing plant is shut down for maintenance.

  - *Expanding gathering capacity in the Woodford Shale play in southeastern Oklahoma*. Enogex has recently approved expansion plans regarding its gathering systems in the Woodford Shale play. Enogex has begun several near-term and longer-term expansion projects in this area, including gathering system, compression and processing capacity additions.

  - *Participating in the Midcontinent Express pipeline project*. Enogex has signed an agreement to provide lease capacity to Midcontinent Express Pipeline LLC. Enogex estimates that its capital expenditures related to this project during 2007 and 2008 will be between approximately $65 million and $100 million to expand and upgrade its system in exchange for a long-term, fixed-fee lease arrangement. Subject to regulatory approval, this project is scheduled to be on-line at the beginning of 2009.

  - *Participating in the Gulf Crossing pipeline project*. Enogex has signed an agreement to provide lease capacity to Gulf Crossing Pipeline Company LLC. Enogex plans to add approximately 4,000 horsepower of compression capability to its system as part of its commitment to the Gulf Crossing project. Subject to regulatory approval, the Gulf Crossing project is expected to have a commercial operation date in late 2008.

- *Pursuing strategic acquisitions, including acquiring additional interests in Enogex from OGE Energy.* OGE Energy has indicated that it intends to use our partnership to manage and further develop its natural gas midstream assets and we believe we are well positioned to acquire, over time, additional interests in Enogex. In addition, we will also consider strategic third-party acquisitions, including acquisitions outside of Enogex's current area of operations. When reviewing potential third-party acquisitions, we seek to identify:

- Assets that are complementary to Enogex's existing facilities and provide opportunities for Enogex to extract operational efficiencies and the potential to expand or increase the utilization of the acquired assets as well as Enogex's existing facilities;
- Acquisitions in areas in which Enogex does not currently operate that have significant natural gas reserves and are experiencing high levels of drilling activity; and
- Acquisitions of mature assets with excess capacity that will allow Enogex to capitalize on existing infrastructure, personnel and producer and customer relationships to provide an integrated package of services.

Maintaining strong customer relationships based upon high quality service, reliability and efficiency of Enogex's existing assets and operations

- *Maximize the profitability of Enogex's existing assets by adding new volumes of natural gas*. We intend to execute on this strategy by:
  - *Providing a comprehensive package of midstream services*. Enogex can provide its producer customers with a full range of midstream services, including gathering, treating, processing, transporting and storage of natural gas. We believe that Enogex's comprehensive package of services in the markets that it serves provides it with a competitive advantage in attracting new volumes.
  - *Reducing project cycle times*. Project cycle time is the amount of time it takes a service provider to complete a particular project, such as connecting a well or laying a gathering line. We believe Enogex is able to service its customers more efficiently than its competitors due to its experienced field managers, highly trained employees and access to one of the largest compressor fleets in the industry. We believe that continued improvement on cycle time will allow Enogex to capture additional volumes of natural gas.
  - *Providing access to high value markets and a large number of suppliers*. Enogex's transportation and storage assets provide its producer customers with access to high value local and interstate markets, which increases the producers' likelihood of receiving the highest price for its natural gas. Likewise, Enogex's assets provide natural gas purchasers with the ability to choose from a large number of suppliers, which increases the likelihood of the purchasers' receiving the lowest cost gas. This optionality provides direct benefits to Enogex's customers and therefore provides it a competitive advantage in its efforts to attract new volumes to its existing system.
- *Delivering superior operational performance*. We believe Enogex provides its customers with a high level of operational performance. Underlying Enogex's operational performance are robust safety and environmental policies and practices and strong technical capabilities. A technically proficient work force that operates safely and with regard for the environment allows Enogex to focus on the key business drivers of reliability, efficiency and flexibility. We believe focusing on these business drivers allows Enogex to provide a superior level of service while continuing to drive down costs. Specifically, we intend to execute on this strategy by:
  - *Engaging in strong safety and responsible environmental practices*. We believe sound safety and environmental practices are good business practices and protect the public, the environment and Enogex's employees. Enogex believes that strong performance in these areas is a good indication of its attention to the details of its business. Enogex was recognized in 2006 by

the Gas Processors Association and the Southern Gas Association for being ranked number one nationally in its peer group in safety performance.

- *Fostering strong technical capabilities*. Enogex's operations staff consists of individuals with high levels of experience and knowledge in their areas of expertise and is organized by technical discipline: Measurement, Compression, Pipeline, Processing, Optimization and Control and Employee Training and Development. We believe that by separating Enogex's staff by technical discipline, Enogex's system is able to operate in an efficient and technically sound manner.
- *Focusing on reliability*. Enogex's technical expertise and experience is used to develop programs and maintenance schedules to help ensure reliability of its operations. We believe that Enogex's customers perceive reliability as a key component of their choice of midstream services provider. By focusing on service reliability, Enogex helps ensure that it maintains strong customer relationships.
- *Focusing on efficiency*. Enogex is continually working on initiatives that are intended to increase value to its customers. These initiatives include programs to achieve industry-leading fuel rates and to minimize the total costs of Enogex's facilities. Enogex's fuel efficiency program incorporates efforts to optimize the flow of natural gas across Enogex's systems to minimize fuel costs and maximize profitability. Other fuel efficiency efforts focus on reducing fuel consumed and gas loss. These efforts are intended to lead to lower fuel rates for Enogex's customers and therefore increased value to its customers.
- *Focusing on flexibility*. We believe that Enogex's technical capabilities coupled with the flexibility of Enogex's system results in increased reliability and efficiency for its customers. For example, Enogex's automated gas control systems coupled with its gathering and transmission lines give Enogex the ability to optimize its processing plants by flowing gas to different locations at different times depending on the economic and operating conditions. On a daily basis, Enogex makes decisions regarding how to configure its plants in a manner intended to capture the most value for customers and for the company.

Maintaining sound financial practices

- *Managing commodity price risk exposure*. Enogex is continually seeking ways to reduce its exposure to commodity price risk. In 2002, Enogex instituted a "default processing fee" in its Statement of Operating Conditions that helps to minimize the risk of processing gas when the price of the NGLs to be extracted and sold is less than the Btu value of the natural gas that Enogex otherwise would be required to replace. Additionally, Enogex instituted a hedging program that is intended to reduce the commodity price risk associated with Enogex's keep-whole and percent-of-liquids arrangements and has hedged approximately 33% of its expected non-ethane NGL volumes attributable to these arrangements, along with the natural gas MMBtu equivalent, for 2007 and approximately 35% of its expected non-ethane NGL volumes attributable to these arrangements, along with the natural gas MMBtu equivalent, for 2008, 2009 and 2010. Enogex has not hedged ethane because Enogex can reject ethane if processing it is not economical. Enogex anticipates hedging additional non-ethane NGL volumes attributable to these arrangements through swaps, options or other mechanisms. Ethane accounted for approximately 40% of Enogex's total NGL volumes attributable to these arrangements during both the year ended December 31, 2006 and the three months ended March 31, 2007. Where market conditions permit, Enogex intends to pursue the conversion of existing keep-whole contracts to fixed fee-based arrangements.
- *Commitment to disciplined financial analyses and a balanced capital structure*. We will continue to analyze organic growth projects and strategic acquisitions using disciplined financial

practices and are also committed to maintaining a balanced capital structure. We believe maintaining this discipline will help us meet our objective of increasing cash distributions over time.

Through successful execution of these key components we believe Enogex will be able to differentiate itself from its competition and therefore be well positioned to maintain and enhance its existing business as well as capture growth opportunities.

Competitive Strengths

We believe that we are well positioned to execute our business strategies successfully because of the following competitive strengths:

- *Enogex's assets are strategically located*. Enogex's assets are strategically located in Oklahoma and the Texas Panhandle, two consistently strong areas of natural gas production. We believe that Enogex's assets are well positioned to allow it to capture gas flowing from west to east, south to north or north to south for customers within the State of Oklahoma or suppliers from other regions seeking to provide gas to on-system markets that Enogex serves. Enogex's system was also designed to serve natural gas-fired power plants in the state of Oklahoma. We believe that Enogex has a significant strategic advantage over its competition to serve these plants and that its competitors would need to make significant capital expenditures to duplicate the services Enogex provides to these large customers.

- *Enogex has transportation and processing flexibility*. Enogex operates its gathering system utilizing large diameter pipelines to provide flexibility to its processing plants. This gives Enogex increased volume capacity to allow it to continue to process and transport gas in the event a third-party facility or an alternate Enogex facility is unavailable. This flexibility helps to assure customers that their gas will flow continuously, even if one or more of Enogex's plants are out of service for a period of time.

- *We have a management team and board of directors with significant experience in the natural gas midstream industry*. Our senior management team and the board of directors of our general partner have extensive experience in the natural gas midstream industry and are committed to long-term operational excellence and strong financial performance. Additionally, our management team understands the service requirements of Enogex's customers and, equally important, we believe Enogex's assets are ideally suited to meet those requirements.

- *Enogex has operated for more than 50 years in the natural gas midstream industry*. Enogex and its predecessors have been engaged in the natural gas midstream business since 1948. Incorporated as Mustang Fuel Corporation, Enogex was created to deliver natural gas to OG&E's Mustang, Oklahoma power plant. Enogex currently delivers natural gas to 15 of the 27 natural gas fired power plants in Oklahoma and has grown, organically and through acquisitions, to become one of the largest pipeline companies in the mid-continent region. Enogex was acquired by OG&E in 1986. We believe that Enogex's operating experience in the markets that Enogex serves provides Enogex with a strategic advantage over its competition.

- *We have the financial flexibility to pursue growth opportunities*. Enogex expects to enter into a $250 million credit facility at the closing of this offering for working capital, capital expenditures and other corporate purposes, including acquisitions. We believe that Enogex's available capacity under this credit facility, combined with our expected ability to access the capital markets, will provide us with a flexible financial structure that will facilitate our expansion and strategic acquisition strategies.

- *We focus on operational efficiencies in our business*. Our focus on operational efficiencies has helped Enogex improve key operating and safety metrics, resulting in increased run time, operating efficiencies, lower expenses and added value to its customers. In addition, Enogex owns and operates one of the largest fleets of compression in the country, with over 400,000 horsepower of compression capability. Enogex also owns and operates its own state-of-the-art compression overhaul facility that provides repackaging services. We believe that Enogex's ability to service its own fleet of compression provides it with a strategic advantage over its competition.

Our Relationship with OGE Energy

One of our principal strengths is our relationship with OGE Energy. Since inception, Enogex has been the transporter of natural gas to OG&E's natural gas-fired electric generation facilities. Enogex's current contract with OG&E provides for no-notice load following transportation services and storage services. For the years ended December 31, 2004, 2005 and 2006, OG&E paid Enogex approximately $49.6 million, $47.6 million and $47.6 million, respectively, under the contract. We believe Enogex also benefits from a higher credit rating due to its relationship with OGE Energy.

In connection with this offering, OGE Energy will contribute a 25% membership interest in Enogex to our wholly owned subsidiary, and a wholly owned subsidiary of OGE Energy will own the remaining 75% membership interest and will own and control our general partner. Following this offering, the subsidiary of OGE Energy will also own an aggregate of 65.2% of our common and subordinated units. OGE Energy has indicated that it intends to use our partnership to manage and further develop its natural gas midstream assets. In addition, OGE Energy has indicated that it intends to offer us the opportunity to purchase all of the remaining ownership interests in Enogex in the future, although OGE Energy is not obligated to do so. While we believe that it will be in OGE Energy's best interest to sell the remaining ownership interest in Enogex to us given its significant ownership interest in us, OGE Energy may elect to acquire, construct or dispose of midstream assets, including its interest in Enogex, in the future without offering us the opportunity to purchase or construct those assets. OGE Energy retained this flexibility because it believes that it is in the best interest of its shareholders to do so. We cannot say with any certainty that we will have the opportunity to acquire the remaining ownership interests in Enogex.

Through our relationship with OGE Energy, we expect to have access to a significant pool of management talent and access to OGE Energy's broad technical, risk management and administrative infrastructure. Please see "Certain Relationships and Related Party Transactions—Omnibus Agreement."

Recent System Expansions

Over the past several years, Enogex has executed on multiple organic growth projects. Currently, Enogex's organic growth capital expenditures are focused on three primary areas:

- upgrades to Enogex's existing transportation system due to increased volumes as a result of the broader shift of gas flow from the Rocky Mountains and the mid-continent to markets in the northeast and southeast United States;
- expansions on the east side of Enogex's gathering system, primarily in the Woodford Shale play in southeastern Oklahoma; and
- expansions on the west side of Enogex's gathering system, primarily in the Granite Wash play in the Wheeler County, Texas area, which is located in the Texas Panhandle.

Pipeline Lease Projects. On December 15, 2006, Enogex announced that it had entered into a firm capacity lease agreement with Midcontinent Express Pipeline, LLC for a primary term of 10 years (subject to possible extension) for capacity on Enogex's system. The leased capacity provided for in this agreement is up to 500 MMcf/d and is dependent on the shipper volumes that commit to the project.

In addition to Enogex's leased capacity, the proposed joint venture includes a new pipeline originating near Bennington, Oklahoma and terminating in Butler, Alabama. Pending necessary regulatory approval, the MEP project is currently expected to be in service during the first quarter of 2009. Enogex estimates that its capital expenditures related to this project during 2007 and 2008 will be between approximately $65 million and $100 million. The lease agreement with MEP is subject to certain contingencies, including regulatory approval. Prior to such approval, Enogex may incur expenditures of between approximately $20 million and $40 million, with the majority being for commitments for materials that can be sold or used in normal operations in the event the MEP project does not proceed. The amount not recovered or utilized for such expenditures is not expected to be material.

In March 2007, Enogex also entered into a firm capacity lease agreement with Gulf Crossing Pipeline Company LLC, or Gulf Crossing, for a primary term of seven years (subject to a possible extension) for capacity on Enogex's system. The leased capacity provided for in this agreement is up to 165 MMcf/d and is dependent on the shipper volumes that commit to the project. Boardwalk Pipeline Partners, LP has announced plans to build the Gulf Crossing pipeline, which includes 355 miles of new interstate natural gas pipeline. The Gulf Grossing pipeline initially is expected to transport gas from the supply areas in Sherman, Texas, Bennington, Oklahoma and Paris, Texas to the Perryville, Louisiana hub. Enogex currently estimates that its capital expenditures related to this project during 2007 and 2008 will be between approximately $2 million and $5 million. The lease agreement with Gulf Crossing is subject to regulatory approval. Prior to that approval, Enogex may incur expenditures of up to $5 million primarily related to commitments for material that can be sold or used in normal operations in the event the Gulf Crossing project does not proceed. The amount not recovered or utilized for such expenditures is not expected to be material. Gulf Crossing filed applications with the FERC on June 19, 2007 requesting certificates of public convenience and necessity authorizing Gulf Crossing to construct, abandon and lease certain facilities relating to its Gulf Crossing pipeline. In a related application, Enogex filed its FERC application on June 20, 2007 for issuance of a limited-jurisdiction certificate authorizing its lease of intrastate pipeline capacity to Gulf Crossing. Both Enogex and Gulf Crossing have requested approval of the applications by November 2007. Subject to regulatory approval, the Gulf Crossing project is expected to have a commercial operation date in late 2008.

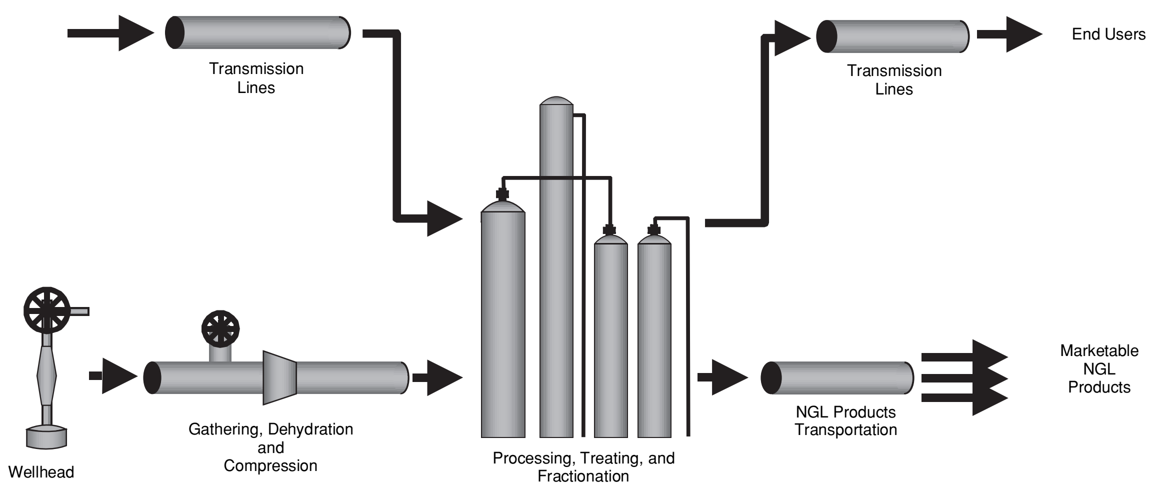
Southeastern Oklahoma / East Side Expansions. Enogex is expanding in the Woodford Shale play and has several projects either completed or scheduled for completion in 2007 and 2008. For example, in December 2006, Enogex entered into a joint venture arrangement with Pablo Gathering, a subsidiary of Pablo Energy II, LLC, a Texas-based exploration and production company. The joint venture, Atoka Midstream LLC, is constructing and will own and operate a gathering system and processing plant and related facilities relating to production in certain areas in southeastern Oklahoma. Enogex will own a 50% membership interest in Atoka Midstream and act as the managing member and operator of the facilities owned by the joint venture.

Texas Panhandle / West Side Expansions. In August 2006, Enogex completed a project to expand its gathering pipeline capacity in the Granite Wash play in the Wheeler County, Texas area of the Texas Panhandle that has allowed Enogex to benefit from growth opportunities in that marketplace. This project included the addition of a 20-inch gathering header that is intended to be used to collect gas from producers and deliver the gas to multiple outlets and processing plants. Enogex continues to review growth opportunities to expand this project and has recently begun several additional new projects to continue expansion on the west side of its system. In addition, Enogex is in the process of installing approximately 11.5 miles of 12-inch pipeline and adding approximately 5,400 horsepower of compression to its Billy Rose compressor station.

Industry Overview

General

Natural gas gathering and processing is a critical part of the natural gas value chain. Natural gas gathering and processing systems create value by collecting raw natural gas from the wellhead and separating dry gas (primarily methane) from NGLs such as ethane, propane, normal butane, isobutane and natural gasoline. Most natural gas produced at the wellhead contains NGLs. Natural gas produced in association with crude oil typically contains higher concentrations of NGLs than natural gas produced from gas wells. This high-content, or "rich," natural gas is generally not acceptable for transportation in the nation's transmission pipeline system or for commercial use. Processing plants extract the NGLs, leaving residual dry gas that meets transmission pipeline and commercial quality specifications. Furthermore, processing plants produce marketable NGLs, which, on an energy equivalent basis, usually have a greater economic value as a raw material for petrochemicals and motor gasolines than as a component of the natural gas stream.



Gathering

At the initial stages of the midstream value chain, a network of typically small diameter pipelines known as gathering systems directly connect to wellheads in the production area. These gathering systems transport raw natural gas to a central location for processing and treating. A large gathering system may involve thousands of miles of gathering lines connected to thousands of wells. Gathering systems are often designed to be highly flexible to allow gathering of natural gas at different pressures, flowing natural gas to multiple plants and quickly connecting new producers, and most importantly, scalable to allow for additional production without significant incremental capital expenditures. A by-product of the gathering process is the release of condensate liquids which are sold on the open market.

Compression

Since wells produce at progressively lower field pressures as they age, it becomes increasingly difficult to deliver the remaining production in the ground against a higher pressure that exists in the connecting gathering system. Natural gas compression is a mechanical process in which a volume of natural gas at an existing pressure is compressed to a desired higher pressure, allowing natural gas that no longer naturally flows into a higher-pressure downstream pipeline to be brought to market. Field compression is typically used to allow a gathering system to operate at a lower pressure or provide sufficient discharge pressure to deliver natural gas into a higher downstream pipeline. If field compression is not installed, then the remaining natural gas in the ground will not be produced because it cannot overcome the higher gathering system pressure. In contrast, if field compression is installed, then a well can continue delivering natural gas that otherwise would not be produced.

Treating and Dehydration

After gathering, the second process in the midstream value chain is treating and dehydration. Natural gas contains various contaminants, such as water vapor, carbon dioxide and hydrogen sulfide, that can cause significant damage to intrastate and interstate pipelines and therefore render the gas unacceptable for transmission on such pipelines. In addition, end-users will not purchase natural gas with a high level of these contaminants. To meet downstream pipeline and end-user natural gas quality standards, the natural gas is dehydrated to remove the saturated water and is chemically treated to separate the carbon dioxide and hydrogen sulfide from the gas stream.

Processing

Once the contaminants are removed, the next step involves the separation of pipeline quality residue gas from NGLs. Most decontaminated rich natural gas is not suitable for long-haul pipeline transportation or commercial use and must be processed to remove the heavier hydrocarbon components. The removal and separation of hydrocarbons during processing is possible because of the differences in physical properties between the components of the raw gas stream. There are four basic types of natural gas processing methods, including cryogenic expansion, lean oil absorption, straight refrigeration and dry bed absorption. Cryogenic expansion represents the latest generation of processing, incorporating extremely low temperatures and high pressures to provide the best processing and most economical extraction.

Natural gas is processed not only to remove NGLs that would interfere with pipeline transportation or the end use of the natural gas, but also to separate from the natural gas those hydrocarbon liquids that could have a higher value as NGLs than as natural gas. The principal components of residue gas are methane and ethane, but processors typically have the option either to recover ethane from the residue gas stream for processing into NGLs or reject ethane and leave it in the residue gas stream, depending on whether the ethane is more valuable being processed or left in the natural gas stream. The residue gas is sold to industrial, commercial and residential customers and electric utilities. We refer to the price of NGLs in relation to the price of natural gas as the fractionation spread. Because NGLs often serve as substitutes for products derived from crude oil, NGL prices tend to move in relation to crude oil prices.

Natural gas processing occurs under a contractual arrangement between the producer or owner of the raw natural gas stream and the processor. There are many forms of processing contracts that vary in the amount of commodity price risk they carry. The specific commodity exposure to natural gas or NGL prices is highly dependent on a company's contracts. Processing contracts can vary in length from one month to the ''life of the field.'' Three typical processing contract types are described below:

- *Fee-Based Arrangements*. Under these arrangements, the processor generally is paid a fixed cash fee for performing the gathering and processing service. This fee is directly related to the volume of natural gas that flows through the processor's systems and is not directly dependent on commodity prices. A sustained decline, however, in commodity prices could result in a decline in volumes and, thus, a decrease in the processor's fee revenues. These arrangements provide stable cash flows, but minimal, if any, upside in higher commodity price environments.
- *Percent-of-Proceeds and Percent-of-Liquids Arrangements*. Under these arrangements, the processor generally gathers raw natural gas from producers at the wellhead, transports the gas through its gathering system, processes the gas and sells the processed gas and/or NGLs at

prices based on published index prices. These arrangements provide upside in high commodity price environments, but result in lower margins in low commodity price environments. The price paid to producers is based on an agreed percentage of the proceeds of the sale of processed natural gas, NGLs or both or the expected proceeds based on an index price. We refer to contracts in which the processor shares in specified percentages of the proceeds from the sale of natural gas and NGLs as percent-of-proceeds arrangements and in which the processor receives proceeds from the sale or NGLs or the NGLs themselves as compensation for its processing services as percent-of-liquids arrangements. Under percent-of-proceeds arrangements, the processor's margin correlates directly with the prices of natural gas and NGLs. Under percent-of-liquids arrangements, the processor's margin correlates directly with the prices of NGLs (although there is often a fee-based component to both of these forms of contracts in addition to the commodity sensitive component).

- *Keep-Whole Arrangements*. Under these arrangements, the processor processes raw natural gas to extract NGLs and pays to the producer the gas equivalent Btu value of raw natural gas received from the producer in the form of either processed gas or its cash equivalent. The processor is generally entitled to retain the processed NGLs and to sell them for its own account. Accordingly, the processor's margin is a function of the difference between the value of the NGLs produced and the cost of the processed gas used to replace the gas equivalent Btu value of those NGLs. The profitability of these arrangements is subject not only to the commodity price risk of natural gas and NGLs, but also to the price of natural gas relative to NGL prices. These arrangements can provide large profit margins in favorable commodity price environments, but also can be subject to losses if the cost of natural gas exceeds the value of its thermal equivalent of NGLs. In order to mitigate the downside risk to the processor associated with the price spread between natural gas and NGLs, several companies, including Enogex, introduced a fee that stipulates a minimum amount to be paid to the processor if the market for downstream liquids is lower than the gas equivalent Btu value of the gas that is removed from the stream and that must be paid to the producer.

Fractionation

Fractionation is the separation of the heterogeneous mixture of extracted NGLs into individual components for end-use sale. Fractionation is accomplished by controlling the temperature of the stream of mixed liquids in order to take advantage of the difference in boiling points of separate products. As the temperature of the stream is increased, the lightest component boils off the top of the distillation tower as a gas where it then condenses into a purity liquid that is routed to storage. The heavier components in the mixture are routed to the next tower where the process is repeated until all components have been separated. A typical barrel of NGLs consists of ethane, propane, normal butane, isobutane and natural gasoline. Described below are the five basic NGL components and their typical uses:

- *Ethane*. Ethane is used primarily as feedstock in the production of ethylene, one of the basic building blocks for a wide range of plastics and other chemical products.
- *Propane*. Propane is used as heating fuel, engine fuel and industrial fuel, for agricultural burning and drying and as petrochemical feedstock for production of ethylene and propylene.
- *Normal Butane*. Normal butane is principally used for motor gasoline blending and as fuel gas, either alone or in a mixture with propane, and feedstock for the manufacture of ethylene and butadiene, a key ingredient of synthetic rubber. Normal butane is also used to derive isobutane.
- *Isobutane*. Isobutane is principally used by refiners to enhance the octane content of motor gasoline and in the production of specialty chemicals.

- *Natural Gasoline*. Natural gasoline is principally used as a motor gasoline blend stock or petrochemical feedstock.

Transportation and Storage

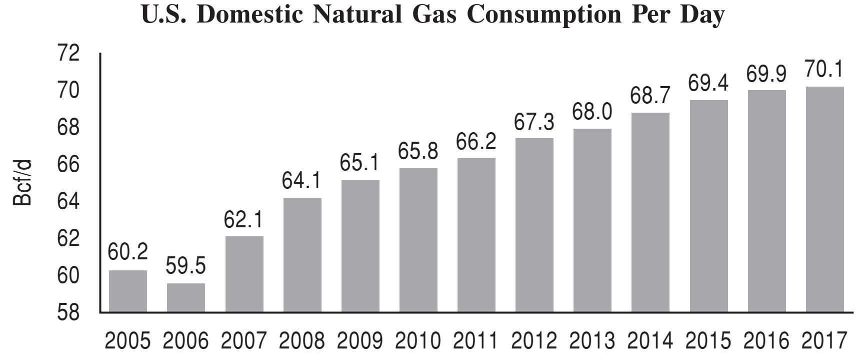
Once the raw natural gas has been conditioned or processed and the raw NGL mix fractionated into individual NGL components, the natural gas and NGL components are stored, transported and marketed to end-use markets. Both the natural gas industry and the NGL industry have hundreds of thousands of miles of intrastate and interstate transmission pipelines in addition to a network of barges, rails, trucks, terminals and storage to deliver natural gas and NGLs to market. The bulk of the NGL storage capacity is located near the refining and petrochemical complexes of the Texas and Louisiana Gulf Coasts, with a second major concentration in central Kansas. Each commodity system typically has storage capacity located both throughout the pipeline network and at major market centers to help temper seasonal demand and daily supply-demand shifts.

The U.S. natural gas pipeline grid transports natural gas from producing regions to customers, such as Local Distribution Companies, or LDCs, industrial users and electric generation facilities. Interstate pipelines carry natural gas across state boundaries and are subject to FERC regulation on (1) the rates charged for their services, (2) the terms and conditions of their services, and (3) the location, construction and abandonment of their facilities. Intrastate pipelines transport natural gas within a particular state and are typically not subject to FERC regulation. At the close of 2004, based on data from the EIA, the U.S. natural gas pipeline grid included 107 interstate systems and more than 90 intrastate systems which collectively accounted for over 297,000 miles of pipeline with a combined 178 Bcf/d of natural gas transportation capacity.

Natural gas storage plays a vital role in maintaining the reliability of gas available for deliveries. Natural gas is typically stored in underground storage facilities, including salt dome caverns and depleted reservoirs. Storage facilities are utilized by (1) pipelines, to manage temporary imbalances in operations, (2) natural gas end-users, such as LDCs, to manage the seasonality of demand and to satisfy future natural gas needs and (3) independent natural gas marketing and trading companies in connection with the execution of their trading strategies. Natural gas storage is expected to become an increasingly important component in managing the supply and demand imbalance created by significant liquefied natural gas, or LNG, shipments.

Natural gas is a critical component of energy consumption in the United States. Substantially all natural gas consumed in the United States is transported to the ultimate end-user on the natural gas pipeline grid. Therefore, utilization of the pipeline grid is highly correlated with growth in domestic consumption of natural gas. According to the EIA, natural gas consumption in the United States is expected to grow from approximately 60.2 Bcf/d in 2005 to approximately 70.1 Bcf/d in 2017, or by approximately 1.3% per year.

U.S. Domestic Natural Gas Consumption Per Day



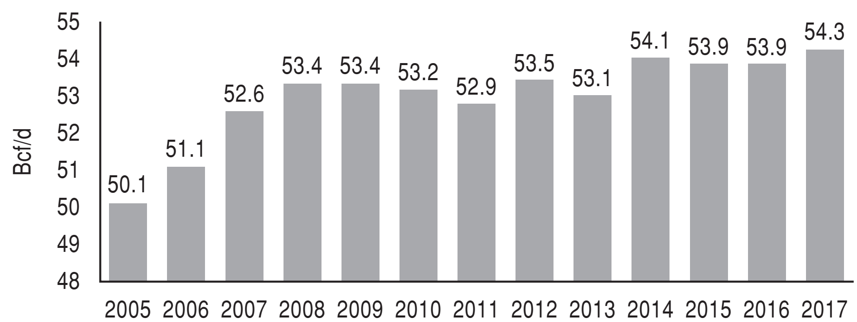
Source: Energy Insurance Administration

The industrial and electricity generation sectors are the largest users of natural gas in the United States. During the three years ended December 31, 2006, these two sectors accounted for approximately 57% of the total natural gas consumed in the United States. Additionally, significant natural gas demand comes from the residential and commercial sectors.

Demand for natural gas is usually greater during the winter, primarily due to residential and commercial heating applications. Natural gas produced in excess of that which is used during the summer months is typically stored to meet the increased demand for natural gas during the winter months. However, with the recent trend towards natural gas-fired electric generation, demand for natural gas during the summer months is now increasing to satisfy additional electricity requirements for residential and commercial cooling.

According to the EIA, domestic gas production in the United States is not expected to keep pace with domestic consumption. Production in the lower 48 states is estimated to grow 0.7% per year, from approximately 50.1 Bcf/d in 2005 to approximately 54.3 Bcf/d in 2017. This compares to estimated U.S. natural gas demand in 2012 of approximately 67.3 Bcf/d.

U.S. Domestic Natural Gas Production Per Day



Source: Energy Insurance Administration

While supply in certain areas in which we operate is experiencing an increase in production and reserves, traditional supply in other regions of the country is beginning to decline. As supply from these areas declines, or becomes less attractive because of vulnerability to hurricanes and other disruptions, the national supply profile is shifting to new, and, in some cases, to non-conventional sources of gas. The bulk of this supply shortfall is expected to be met through natural gas imports from Canada as well as through LNG imports, the majority of which are expected to be delivered through terminals along the U.S. Gulf Coast.

Marketing

Natural gas marketing involves the sale of pipeline-quality gas that is purchased from gathering systems or other pipelines. Marketers contract for transportation and storage services from companies such as Enogex, then capture the price differences between pipeline receipt/delivery point or storage injection/withdrawal months. Marketers also provide short-term market balancing, risk management and intermediation services. Marketers form commodity transaction relationships with producers, gatherers, processors, pipelines, local distribution companies, large end-users, power generators, and national and international banks through both direct transactions (over-the-counter) and exchange transactions (for example, transactions effected on the New York Mercantile Exchange, the Chicago Mercantile Exchange, Globex, the International Petroleum Exchange and the Intercontinental Exchange). Commodities transacted are generally pipeline quality natural gas and NGLs (post-processing).

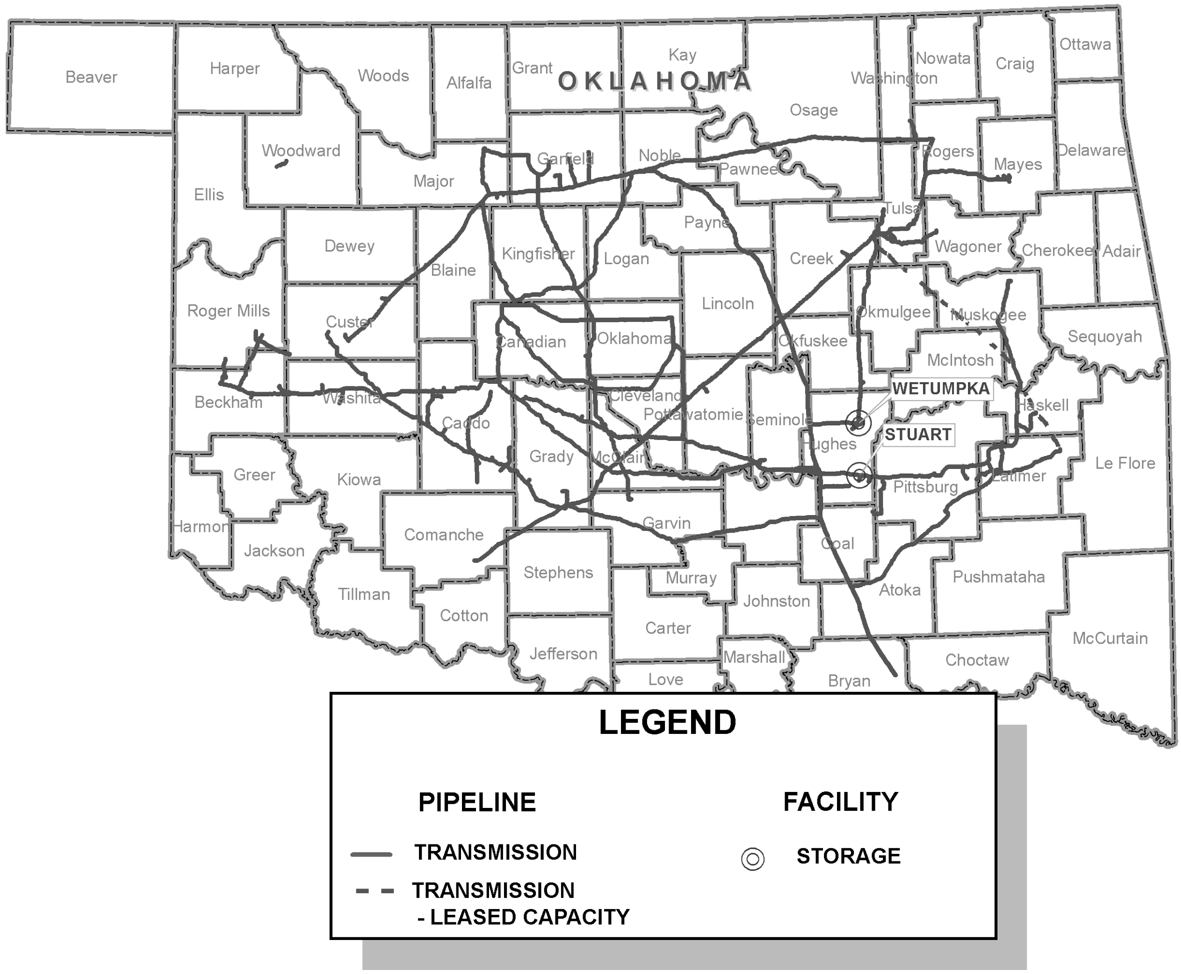
Marketing facilitates stable margins from physical assets through the following functions:

- *Hedging*. Hedging reduces commodity price risk and permits more predictable and stable cash distributions. For example, processing entities that have significant keep-whole arrangements can have unstable cash flow due to volatility in the spread between NGL and natural gas prices. Marketers stabilize cash flow by selling future NGLs, buying future natural gas, buying options or combinations thereof.
- *Asset Valuation*. Asset valuation and bidding makes use of arbitrage models (for example, capturing the price difference between pipeline locations), sales of asset-backed service offerings and experience with clearing lease prices for nearby assets.
- *Price Discovery*. Price discovery is a precursor to effective hedging and asset valuation. Active participation in markets for commodities and services helps obtain reliable pricing information. Through active long-term hedging, short-term balancing, service offering and participation in asset leasing, marketers often develop and maintain relationships with a variety of counterparties and institutions to obtain reliable commodity pricing and asset valuations. Reliable pricing information tends to facilitate value capture on hedges, which leads to more stable distributable cash flow.

In addition, marketing in areas adjacent to owned assets and/or areas of production growth provides gathering, processing, transportation and storage growth opportunities through market intelligence, reputation development and enhanced understanding of regional regulatory and counterparty issues.

Our Business

Transportation and Storage



General. Enogex's transportation and storage business owns and operates approximately 2,283 miles of intrastate natural gas transportation pipelines with approximately 1.44 TBtu/d of current throughput capacity and two storage facilities currently being operated at a working gas level of approximately 23 Bcf. Enogex provides fee-based intrastate transportation services on a firm and interruptible basis and, pursuant to Section 311 of the NGPA, provides interstate transportation services on an interruptible basis. Enogex's obligation to provide firm transportation service means that it is obligated to transport natural gas nominated by the shipper up to the maximum daily quantity specified in the contract. In exchange for that obligation on Enogex's part, the shipper pays a specified demand or reservation charge, whether or not it utilizes the capacity. In most cases, the shipper also pays a transportation or commodity charge with respect to quantities actually transported by Enogex. Enogex's obligation to provide interruptible transportation service means that it is only obligated to transport natural gas nominated by the shipper to the extent that it has available capacity. For this service, the shipper pays no demand or reservation charge but pays a transportation or commodity charge for quantities actually shipped. Enogex derives a substantial portion of its transportation revenues from firm transportation services. To the extent pipeline capacity is not needed for such firm intrastate transportation service, Enogex offers interruptible interstate transportation services pursuant to Section 311 of the NGPA as well as interruptible intrastate transportation services.

Enogex delivers natural gas to most interstate and intrastate pipelines and end-users connected to its systems from the Arkoma and Anadarko basins (including recent growth activity in western Oklahoma, the Texas Panhandle and the Woodford Shale play in southeastern Oklahoma). At December 31, 2006, Enogex was connected to 11 other major pipelines at approximately 64 pipeline interconnect points. These interconnections include Panhandle Eastern Pipe Line, Southern Star Central Gas Pipeline (formerly Williams Central), Natural Gas Pipeline Company of America, Oneok Gas Transmission, Northern Natural Gas Company, ANR Pipeline, Western Farmers Electric Cooperative, CenterPoint Energy Gas Transmission Co., El Paso Natural Gas Pipeline, Enbridge Pipelines and Ozark Gas Transmission, L.L.C. Further, Enogex is connected to 27 end-user customers, including 15 natural gas-fired electric generation facilities in Oklahoma.

Enogex owns and operates two natural gas storage facilities in Oklahoma, the Wetumka Storage Facility and the Stuart Storage Facility. These storage facilities are currently being operated at a working gas level of approximately 23 Bcf and have approximately 650 MMcf/d of maximum withdrawal capability and approximately 650 MMcf/d of injection capability. Enogex offers both firm and interruptible storage services to third parties. Services offered under Section 311 of the NGPA are pursuant to terms and conditions specified in Enogex's Statement of Operating Conditions for gas storage and at market-based rates negotiated with each customer. Enogex's storage facilities are also used to support its no-notice load following transportation contract with OG&E.

Enogex uses its storage assets to meet its contractual obligations under certain load following transportation contracts. Enogex also periodically conducts an open season to solicit commitments for contracted capacity and deliverability to third parties for contracts that generally do not exceed three years.

Customers and Contracts. Enogex's major transportation customers are OG&E and PSO, the second largest electric utility in Oklahoma. Enogex provides gas transmission delivery services to all of PSO's natural gas-fired electric generation facilities in Oklahoma under a firm intrastate transportation contract. The PSO contract, which expires January 1, 2013, and the OG&E contract, which expires April 30, 2009, provide for a monthly demand charge plus variable transportation charges (including fuel). As part of the no-notice load following contract with OG&E, Enogex provides natural gas storage services for OG&E. Enogex has been providing natural gas storage services to OG&E since August 2002 when it acquired the Stuart Storage Facility. Demand for natural gas on Enogex's system is usually greater during the summer, primarily due to demand by gas-fired electric generation facilities to serve residential and commercial electricity requirements. Natural gas produced in excess of that which is used during the winter months is typically stored to meet the increased demand for natural gas during the summer months. During 2006, 2005 and 2004, revenues from Enogex's firm intrastate transportation and storage contracts were approximately $98.1 million, $95.0 million and $95.6 million, respectively, of which $47.6 million, $47.6 million and $49.6 million was attributed to OG&E and $13.3 million in each of these years was attributed to PSO. Revenues from Enogex's firm intrastate transportation and storage contracts represented approximately 38% of Enogex's aggregate revenue from its transportation and storage business in each of the three years ended December 31, 2006.

Competition. Enogex's transportation and storage assets compete with interstate and other intrastate pipelines and storage facilities in providing transportation and storage services for natural gas. The principal elements of competition are rates, terms of services, flexibility and reliability of service. Natural gas-fired electric generation facilities contribute their highest value when they have the capability to provide load following service to the customer (*i.e.*, the ability of the generation facility to regulate generation to respond to and meet the instantaneous changes in customer demand for electricity). While the physical characteristics of natural gas units are known to provide quick start-up, on-line functionality and the ability to efficiently provide varying levels of electric generation relative to other forms of generation, a key part of their effectiveness is contingent upon having access to an integrated pipeline and storage system that can respond quickly to meet the corresponding fluctuating fuel needs of these units. We believe that Enogex is well positioned to compete for the needs of these generators due to the ability of its transportation and storage assets to provide no-notice load following service.

Natural gas competes with other forms of energy available to Enogex's customers and end-users, including electricity, coal and fuel oils. The primary competitive factor is price. Changes in the availability or price of natural gas or other forms of energy as well as weather and other factors affect the demand for natural gas on Enogex's system.

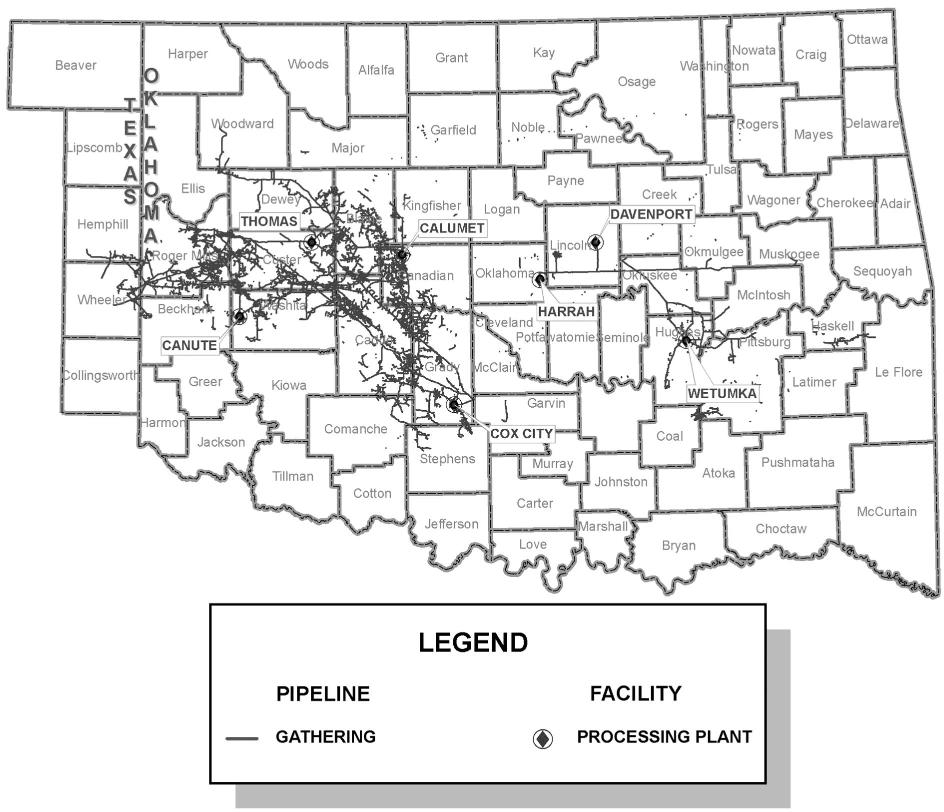
Regulation. The transportation rates charged by Enogex for transporting natural gas in interstate commerce are subject to the jurisdiction of the FERC under Section 311 of the NGPA. Rates to provide such service must be "fair and equitable" under the NGPA and are subject to review and approval by the FERC at least once every three years. The rate review may, but will not necessarily, involve an administrative-type hearing before the FERC staff panel and an administrative appellate review. For a number of years, Enogex has successfully settled, rather than litigated, its triennial rate cases. Offering interruptible Section 311 transportation gives Enogex the opportunity to utilize any unused capacity on an interruptible basis in interstate commerce and thus increase its transportation revenues without increasing its regulatory burden appreciably. Enogex currently has two zones under its Section 311 rate structure—an East Zone and a West Zone with a maximum transportation rate and a fuel retention rate for each zone. Enogex may charge up to its maximum established zonal East and West transportation rates and the fixed zonal fuel percentage for the fuel used in shipping natural gas on its system. The fixed zonal fuel percentages are adjusted annually and remain in effect for a calendar fuel year. The mechanism used to establish the percentages is a fuel tracker filed annually at the FERC that establishes prospectively the zonal fixed fuel factors (expressed as a percentage of natural gas shipped in the zone) for the next calendar year. Fuel usage is later trued-up to actual usage over a two-year period and based on the value of the gas at the time of usage.

On May 29, 2007, the FERC notified Enogex that it was commencing an audit to determine whether and how Enogex is complying with periodic regulatory reporting requirements for intrastate pipelines. Enogex will cooperate fully with the FERC, but at this preliminary stage cannot predict either the final outcome or the timing of the completion of this audit. On the same day, the FERC notified a number of other intrastate pipelines and storage entities of comparable audits.

Enogex received FERC approval to unbundle its remaining gathering assets and services from its transportation services and completed such unbundling, effective October 1, 2005. As a result, the FERC regulates Enogex's Section 311 transportation services but does not regulate its gathering services. In addition, the FERC does not regulate Enogex intrastate transportation services because these services are not Section 311 services. These services include those intrastate transportation services provided to the gas-fired power plants and other end users within Oklahoma. As such the rates charged by Enogex for transporting natural gas for the Oklahoma utility companies, independent power plants and other shippers within Oklahoma are not subject to FERC regulation. Nor are the rates charged by Enogex for any intrastate transportation service subject to direct state regulation by the Oklahoma Corporation Commission, or the OCC. However, the OCC, the Arkansas Public Service Commission, or APSC, and the FERC (all of which approve various electric rates of OG&E) have the authority to examine the appropriateness of any transportation charges or other fees paid by OG&E to Enogex which OG&E seeks to recover from its ratepayers in its cost-of-service for electric service. See Note 14 of Notes to Consolidated Financial Statements for a discussion of the OCC order OG&E received in July 2005 related to the amounts charged OG&E by Enogex for gas transportation and storage services.

Enogex's pipeline operations are subject to various state and federal safety and environmental and pipeline transportation laws. For example, the U.S. Department of Transportation has adopted regulations requiring pipeline operators to develop integrity management programs for its transportation pipelines. We currently estimate that Enogex will incur capital expenditures and operating costs of approximately $38.1 million between 2007 and 2011 to implement its pipeline integrity management program along certain segments of its natural gas pipelines. This includes Enogex's estimates for the repair, remediation and prevention or other mitigation that may be determined to be necessary as a result of the testing program. At this time, we cannot predict the ultimate costs of compliance with this regulation because those costs will depend on the number and extent of any repairs found to be necessary as a result of the pipeline integrity testing that is required by the rule. Enogex will continue its pipeline integrity testing programs to assess and maintain the integrity of its pipelines. The results of these tests could cause Enogex to incur significant and unanticipated capital and operating expenditures for repairs or upgrades deemed necessary to ensure the continued safe and reliable operations of its pipelines.

Gathering and Processing



General. Enogex provides well connect, gathering, measurement, treating, dehydration, compression and processing services for various types of producing wells owned by various sized producers who are active in the region. The streams of processable natural gas gathered from wells and other sources are gathered into Enogex's gas gathering systems and are delivered to processing plants for the extraction of NGLs. Enogex's gathering system includes approximately 5,474 miles of natural gas gathering pipelines with approximately 0.98 TBtu/d of gathered volumes extending from southwestern Oklahoma to the eastern Texas Panhandle. During 2006, Enogex connected 362 new producing wells (including 156 wells behind central receipt points), located in the Arkoma and Anadarko basins (including recent growth activity in western Oklahoma, the Texas Panhandle and the Woodford Shale play in southeastern Oklahoma) to its gathering systems. At March 31, 2007, Enogex's gathering system was connected to approximately 3,200 wells and approximately 200 central receipt points, all of which are equipped with state-of-the-art electronic flow measurement technology. Approximately 70% of Enogex's gathered volumes are received at wellheads while 30% is gathered from central receipt or other interconnection points.

Enogex is one of the largest gas processors in Oklahoma, operating six natural gas processing plants with a total inlet capacity of approximately 720 MMcf/d, all in Oklahoma. Where the quality of natural gas received dictates the removal of NGLs, such gas is aggregated through the gathering system to the inlet of one or more of six processing plants owned and operated by Enogex. The resulting processed stream of natural gas is then delivered from the tailgate of each plant into Enogex's intrastate natural gas transportation system. For the year ended December 31, 2006, Enogex extracted and sold approximately 371 million gallons of NGLs. The following table sets forth information with respect to Enogex's natural gas processing plants:

Processing Plant	Year Installed	Type of Plant	Fuel Capability	2006 Average Daily Inlet Volumes (MMcf/d)	Inlet Capacity (MMcf/d)
Calumet	1969	Lean Oil	Gas	111	250
Canute	1996	Cryogenic	Electric	42	60
Cox City	1994	Cryogenic	Gas/Electric	174	180
Harrah	1994	Cryogenic	Gas/Electric	26	38
Thomas	1981	Cryogenic	Gas	93	135
Wetumka	1983	Cryogenic	Gas	37	60
				483	723

In 2007 and 2008, Enogex expects to pursue several projects to enhance the profitability of its existing system. For example, Enogex plans to address tightening processing capacity as a result of increasing supply by:

- *Continuing to take steps to better reorganize the flow of gas in its system to take advantage of existing capacity*. We expect that a restaging of a compression turbine at the Thomas plant should allow realization of an additional 20 MMBtu/d of capacity at that plant. We expect the construction of a new pipeline between Enogex's large-diameter "super-header" gathering system and the Canute processing plant will permit Enogex to move excess gas available for processing on the "super-header" gathering system to the Canute processing plant (which is operating at under capacity). In addition, Enogex is reviewing options for moving excess gas available for processing at the Wetumka processing plant to the Harrah processing plant (which is operating at under capacity). As a result, we expect that Enogex will be able to increase the utilization of its existing plants.
- *Acquiring additional assets*. Enogex also intends to build or acquire additional processing capacity as the need arises. In particular, Enogex plans to build a new processing plant as part of its Atoka Midstream LLC joint venture in the Woodford Shale play in southeastern Oklahoma, which we believe could add up to 20 MMBtu/d of capacity.
- *Redeploying existing assets*. Enogex may relocate its currently idle Red Fork and Davenport processing plants, which we believe could add up to 48 MMBtu/d of additional gas processing capacity to Enogex's system.

Enogex's gathering and processing business has approximately 225,000 horsepower of owned compression. Management believes that Enogex's compression capability ranks among the top ten of gathering and processing businesses in the United States. Enogex also has its own compression overhaul center and specialized compression workforce.

Enogex is active in the extraction and marketing of NGLs from natural gas. The liquids extracted include condensate liquids, marketable ethane, propane, butanes and natural gasoline mix. The residue gas remaining after the liquid products have been extracted consists primarily of ethane and methane.

Approximately 19% of the commercial grade propane produced at Enogex's plants is sold on the local market. The balance of propane and the other NGLs produced by Enogex is delivered into pipeline facilities of a third party and transported to Conway, Kansas and Mont Belvieu, Texas, where they are sold under contract or on the spot market. Ethane, which may be optionally produced at all of Enogex's plants except the Calumet plant, is also sold under contract or on the spot market.

Enogex's large diameter, rich gas gathering pipelines in western Oklahoma are configured such that natural gas from the Wheeler County area in the Texas Panhandle can flow to the Cox City, Thomas or Calumet gas processing plants. These large-diameter "super-header" gathering systems of Enogex provide gas routing flexibility for Enogex to optimize the economics of its gas processing and to improve system utilization and reliability.

Several of Enogex's processing plants are currently operating at or near full capacity, such as the Cox City processing plant. As Enogex experiences increased growth in regions such as the Woodford Shale play, we will evaluate the need to expand Enogex's processing plants in order to meet the growing needs of Enogex's producer customers.

Natural Gas Supply. As of March 31, 2007, approximately 3,200 wells and 200 central receipt points were connected to Enogex's system in Oklahoma and the Texas Panhandle area, areas that have experienced an increase in drilling activity and production. Enogex has secured significant areas of dedication from numerous customers active throughout Enogex's areas of operations.

Customers and Contracts. Residue gas remaining after processing is primarily taken in kind by the producer customers into Enogex's transportation pipelines for redelivery either (i) to on-system customers such as the power plants of OG&E and PSO, or (b) into downstream interstate pipelines. Enogex's NGLs are typically sold to NGL marketers, its condensate liquid production is typically sold to marketers and refineries and its propane is typically sold in the local market to wholesale distributors. During 2006, Enogex's top ten natural gas producer customers accounted for approximately 64% of Enogex's gathering and processing volumes, with no one customer accounting for more than 19% of such volumes.

Competition. Competition for natural gas supply is primarily based on efficiency and reliability of operations, customer service, proximity to existing assets, access to markets and pricing. Competition to gather and process non-dedicated gas is based on providing the producer with the highest total value, which is primarily a function of gathering rate, processing value, system reliability, fuel rate, system run time, construction cycle time and prices at the wellhead. We believe Enogex will be able to continue to compete effectively. Enogex competes with gatherers and processors of all types and sizes, including those affiliated with various producers, other major pipeline companies and various independent midstream entities. Enogex's primary competitors are master limited partnerships who are active in its region, including Atlas Pipeline Partners, L.P., Crosstex Energy LP, DCP Midstream Partners, LP, Enbridge Energy Partners, L.P., Hiland Partners, LP, MarkWest Energy Partners, L.P. and Oneok Partners, L.P. In processing and marketing NGLs, Enogex competes against virtually all other gas processors extracting and selling NGLs in its market area.

Regulation. State regulation of natural gas gathering facilities generally includes various safety, environmental and nondiscriminatory rate and open access requirements and complaint-based rate regulation. Enogex may be subject to state common carrier, ratable take and common purchaser statutes. The common carrier and ratable take statutes generally require gatherers to carry, transport and deliver, without undue discrimination, natural gas production that may be tendered to the gatherer for handling. Similarly, common purchaser statutes generally require gatherers that purchase gas to purchase without undue discrimination as to source of supply or producer. These statutes may have the effect of restricting Enogex's right to decide with whom it contracts to purchase natural gas or, as an owner of gathering facilities, to decide with whom it contracts to purchase or gather natural gas.

Oklahoma and Texas have each adopted a form of complaint-based regulation of gathering operations that generally allows natural gas producers and shippers to file complaints with state regulators in an effort to resolve grievances relating to natural gas gathering open access and rate discrimination. Enogex's gathering operations could be adversely affected should they be subject in the future to the application of state or federal regulation of rates and services. Enogex's gathering operations also may be subject to safety and operational regulations relating to the integrity, design, installation, testing, construction, operation, replacement and management of gathering facilities. Additional rules and legislation pertaining to these matters are considered or adopted from time to time. We cannot predict what effect, if any, such changes might have on Enogex's operations, but the industry could be required to incur additional capital expenditures and increased costs depending on future legislative and regulatory changes.

Marketing

General. Enogex's commodity sales and services related to natural gas are conducted primarily through OERI. OERI is engaged in the business of natural gas marketing. OERI provides marketing services to Enogex for natural gas bought at the wellhead by Enogex from customers. As a service to the producers on Enogex's system, Enogex may agree to purchase the gas at the wellhead in conjunction with gathering their gas for transportation to other markets. OERI also purchases and sells natural gas to support the daily operational activities of Enogex's combined position of its businesses pursuant to contracts with Enogex and its subsidiaries relating to its gathering, processing, transportation and storage assets.

OERI focuses on serving customers along the natural gas value chain, from producers to end-users, by purchasing natural gas from suppliers and reselling to pipelines, local distribution companies and end-users, including the electric generation sector. The geographic scope of marketing efforts has been focused largely in the mid-continent area of the United States. These markets are natural extensions of OERI's business on Enogex's system. OERI contracts for pipeline capacity with Enogex and other pipelines to access multiple interconnections with the interstate pipeline system network that moves natural gas from the production basins primarily in the south central United States to the major consumption areas in Chicago, New York and other north central and mid-Atlantic regions of the United States.

OERI primarily participates in both intermediate-term markets (less than three years) and short-term "spot" markets for natural gas. Although OERI continues to increase its focus on intermediate-term sales, short-term sales of natural gas are expected to continue to play a critical role in the overall strategy because they provide an important source of market intelligence as well as an important portfolio balancing function in addition to risk management services. OERI's average daily sales volumes dropped from approximately 1.4 Bcf in 2005 to approximately 0.8 Bcf in 2006. This reflects selective deal execution to assure adequate margin in light of credit and other risks in the current high commodity price environment. OERI's risk management skills afford its customers the opportunity to tailor the risk profile and composition of their natural gas portfolio. Enogex follows a policy of hedging price risk on gas purchases or sales contracts entered into by OERI by buying and selling natural gas futures contracts on the New York Mercantile Exchange futures exchange and other derivatives in the over-the-counter market, subject to daily and monthly trading stop loss limits of $2.5 million and daily value-at-risk limits of $1.5 million in accordance with management's policies.

Competition. OERI competes in marketing natural gas with major integrated oil companies, marketing affiliates of major interstate and intrastate pipelines and commercial banks, national and local natural gas brokers, marketers and distributors for natural gas supplies. Competition for natural gas supplies is based primarily on reputation, credit support, the availability of gathering and transportation to high-demand markets and the ability to obtain a satisfactory price for the producer's natural gas. Competition for sales to customers is based primarily upon reliability, services offered and the price of delivered natural gas.

For the year ended December 31, 2006, approximately 54.4% of OERI's service volumes were with electric utilities, local gas distribution companies, pipelines and producers, of which approximately 8.7% was with Enogex. The remaining 45.6% of service volumes were to marketers, municipals, cooperatives and industrials. At December 31, 2006, approximately 82.4% of the payment exposure was to companies having investment grade ratings with Standard & Poor's Ratings Services, or Standard & Poor's, and approximately 1.2% having less than investment grade ratings. The remaining 16.4% of OERI's exposure is with privately held companies, municipals or cooperatives that were not rated by Standard & Poor's. OERI applies internal credit analyses and policies to these non-rated companies.

Technology Improvements

Enogex continues to upgrade its data and information systems in order to improve operational efficiencies and increase profitability of its business and that of its customers.

- Enogex recently completed implementation of an information system which Enogex believes has improved its ability to capture economic opportunities in operating its assets, provide improved customer service and better determine the earnings potential of its various assets and service.
- Enogex has installed a state-of-the-art Supervisory Control and Data Acquisition, or SCADA, system which provides a single system for pipeline equipment control, data collection, management and measurement of gas volumes and pressures.
- Information system implemented, together with Enogex's primary enterprise-wide general ledger software, has been used to accumulate and analyze financial data used in financial reporting. This change in information systems was made to eliminate previous stand-alone systems and integrate them into one system.
- Enogex implemented an enhanced digital asset mapping (GIS) system in May 2006. This system has improved access to pipeline equipment and system information. This information can be used for existing asset management activities including daily operations and maintenance, budgeting, planning and new project development.
- Enogex has recently implemented a new system called ProductionWatch. This system can provide data (such as volume, pressure, temperature, etc.) from Enogex's meters to its customers. This data service is available to customers by the Internet and is offered for a fee. Such data is attractive because it can enable customers to increase gas production and operating efficiency.

Safety and Health Regulation

Enogex is subject to the Natural Gas Pipeline Safety Act of 1968, or the NGPSA, and the Pipeline Safety Improvement Act of 2002. The NGPSA regulates safety requirements in the design, construction, operation and maintenance of natural gas pipeline facilities while the Pipeline Safety Improvement Act establishes mandatory inspections for all U.S. oil and natural gas transportation pipelines and some gathering lines in high-consequence areas within 10 years. The DOT has developed regulations implementing the Pipeline Safety Improvement Act that will require pipeline operators to implement integrity management programs, including more frequent inspections and other safety protections in areas where the consequences of potential pipeline accidents pose the greatest risk to people and their property.

A four mile portion of Enogex's pipeline is also subject to regulation by the DOT under the Accountable Pipeline and Safety Partnership Act of 1996, or the Hazardous Liquid Pipeline Safety Act, and comparable state statutes with respect to design, installation, testing, construction, operation, replacement and management of liquid pipeline facilities. The Hazardous Liquid Pipeline Safety Act covers petroleum and petroleum products and requires any entity that owns or operates pipeline facilities to comply with such regulations, to permit access to and copying of records and to file certain reports and provide information as required by the U.S. Secretary of Transportation. These regulations include potential fines and penalties for violations. We believe that Enogex is in material compliance with these Hazardous Liquid Pipeline Safety Act regulations.

States may be preempted by federal law from solely regulating pipeline safety but may assume responsibility for enforcing federal intrastate pipeline regulations and inspection of intrastate pipelines. In the State of Oklahoma, the OCC's Transportation Division, acting through the Pipeline Safety Department, administers the OCC's intrastate regulatory program to assure the safe transportation of natural gas, petroleum and other hazardous materials by pipeline. The OCC develops regulations and other approaches to assure safety in design, construction, testing, operation, maintenance and emergency response to pipeline facilities. The OCC derives its authority over intrastate pipeline operations through state statutes and certification agreements with the DOT. A similar regime for safety regulation is in place in Texas and administered by the Texas Railroad Commission. We anticipate that Enogex should be able to comply with currently existing state laws and regulations applicable to pipeline safety without incurring material costs. Enogex's natural gas pipelines have inspection and compliance programs designed to maintain compliance with pipeline safety and pollution control requirements.

In addition, Enogex is subject to a number of federal and state laws and regulations, including the federal Occupational Safety and Health Act of 1970, or OSHA, and comparable state statutes, whose purpose is to protect the safety and health of workers, both generally and within the pipeline industry. In addition, the OSHA hazard communication standard, the EPA community right-to-know regulations under Title III of the federal Superfund Amendment and Reauthorization Act and comparable state statutes require that information be maintained concerning hazardous materials used or produced in Enogex's operations and that this information be provided to employees, state and local government authorities and citizens. Enogex is also subject to OSHA Process Safety Management regulations, which are designed to prevent or minimize the consequences of catastrophic releases of toxic, reactive, flammable or explosive chemicals. These regulations apply to any process which involves a chemical at or above the specified thresholds or any process which involves flammable liquid or gas, pressurized tanks, caverns and wells in excess of 10,000 pounds at various locations. Enogex has an internal program of inspection designed to monitor and enforce compliance with worker safety and health requirements. We believe that Enogex is in material compliance with all applicable laws and regulations relating to worker safety and health.

Environmental Matters

General. Enogex's natural gas and NGL gathering, transportation and processing activities are subject to stringent and complex federal, state and local laws and regulations governing environmental protection as well as the discharge of materials into the environment. These laws and regulations can restrict or impact Enogex's business activities in many ways, such as restricting the way it can handle or dispose of its wastes, requiring remedial action to mitigate pollution conditions that may be caused by its operations or that are attributable to former operators, regulating future construction activities to avoid endangered species or enjoining some or all of the operations of facilities deemed in noncompliance with permits issued pursuant to such environmental laws and regulations. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, the imposition of remedial requirements, and the issuance of orders enjoining future operations. Certain environmental statutes impose strict, joint and several liability for costs required to clean up and restore sites where substances or wastes have been disposed or otherwise released into the environment. Moreover, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the release of substances or wastes into the environment.

We believe that Enogex's operations are in substantial compliance with applicable environmental laws and regulations and that compliance with existing federal, state and local environmental laws and regulations will not have a material adverse effect on Enogex's business, financial condition or results of operations. Nevertheless, the trend in environmental regulation is to place more restrictions and limitations on activities that may affect the environment. As a result, there can be no assurance as to amount or timing of future expenditures for environmental compliance or remediation, and actual future expenditures may be different from the amounts currently anticipated. Moreover, we cannot assure that future events, such as changes in existing laws, the promulgation of new laws, or the development or discovery of new facts or conditions will not cause Enogex to incur significant costs.

Approximately $0.9 million and $1.5 million, respectively, of Enogex's capital expenditures budgeted for 2007 and 2008 are to comply with environmental laws and regulations. Management believes that all of Enogex's operations are in substantial compliance with present federal, state and local environmental regulations. It is estimated that Enogex's total expenditures for capital, operating, maintenance and other costs to preserve and enhance environmental quality will be approximately $2.5 million during 2007 as compared to approximately $2.1 million in 2006. Management continues to evaluate Enogex's environmental management systems to ensure compliance with existing and proposed environmental legislation and regulations and to better position it in a competitive market. See Note 13 of Notes to Consolidated Financial Statements for a discussion of environmental matters, including the impact of existing and proposed environmental legislation and regulations.

Hazardous Waste. Enogex's operations generate wastes, including some characterized as hazardous waste, that are subject to RCRA and comparable state laws, which impose detailed requirements for the handling, storage, treatment and disposal of hazardous and solid waste. RCRA currently exempts many natural gas gathering and field processing wastes from classification as hazardous waste. Specifically, RCRA excludes from the definition of hazardous waste produced waters and other waste associated with the exploration, development or production of crude oil and natural gas. However, these oil and gas exploration and production wastes may still be regulated under state law or the less stringent solid waste requirements of RCRA. Moreover, ordinary industrial waste such as paint waste, waste solvents and waste compressor oils may be regulated as hazardous waste. The transportation of natural gas in pipelines may also generate some hazardous wastes that are subject to RCRA or comparable state law requirements.

Site Remediation. CERCLA (also known as "Superfund") and comparable state laws impose liability, without regard to fault or the legality of the original conduct, on certain classes of persons responsible for the release of hazardous substances into the environment. Such classes of persons include the current and past owners or operators of sites where a hazardous substance was released, and companies that disposed or arranged for disposal of hazardous substances at offsite locations such as landfills. Although petroleum as well as natural gas is excluded from CERCLA's definition of "hazardous substance," in the course of its ordinary operations Enogex will generate wastes that may fall within the definition of a "hazardous substance." CERCLA authorizes the U.S. Environmental Protection Agency, or EPA, and, in some cases, third parties to take actions in response to threats to the public health or the environment and to seek to recover from the responsible classes of persons the costs they incur. Under CERCLA, Enogex could be subject to joint and several, strict liability for the costs of cleaning up and restoring sites where hazardous substances have been released, for damages to natural resources and for the costs of certain health studies.

Enogex currently owns or leases, and has in the past owned or leased, numerous properties that for many years have been used for the measurement, gathering, compression and processing of natural gas. Although Enogex used operating and disposal practices that were standard in the industry at the time, petroleum hydrocarbons or wastes may have been disposed of or released on or under the properties owned or leased by us or on or under other locations where such substances have been taken for disposal. In fact, there is evidence that petroleum spills or releases have occurred at some of the properties owned or leased by Enogex. In addition, some of these properties have been operated by third parties or by previous owners whose treatment and disposal or release of petroleum hydrocarbon or wastes was not under our control. These properties and the substances disposed or released on them may be subject to CERCLA, RCRA and analogous state laws. Under such laws, Enogex could be required to remove previously disposed wastes (including waste disposed of by prior owners or operators) or remediate contaminated property (including groundwater contamination, whether from prior owners or operators or other historic activities or spills).

Air Emissions. Enogex's operations are subject to the federal Clean Air Act, as amended, and comparable state laws and regulations. These laws and regulations regulate emissions of air pollutants from various industrial sources, including Enogex's processing plants and compressor stations, and also impose various monitoring and reporting requirements. Such laws and regulations may require that Enogex obtain pre-approval for the construction or modification of certain projects or facilities expected to produce air emissions or result in the increase of existing air emissions, obtain and strictly comply with air permits containing various emissions and operational limitations, or subject Enogex to monetary penalties, injunctions, conditions or restrictions on operations, and potentially criminal enforcement actions. Enogex likely will be required to incur certain capital expenditures in the future for air pollution control equipment and technology in connection with obtaining and maintaining operating permits and approvals for air emissions. We believe, however, that Enogex's operations will not be materially adversely affected by such requirements, and the requirements are not expected to be any more burdensome to Enogex than to any other similarly situated companies.

Water Discharges. Enogex's operations are subject to the Federal Water Pollution Control Act of 1972, as amended, also known as the Clean Water Act, and analogous state laws and regulations. These laws and regulations impose detailed requirements and strict controls regarding the discharge of pollutants into state and federal waters. The discharge of pollutants, including discharges resulting from a spill or leak incident, is prohibited unless authorized by a permit or other agency approval. The Clean Water Act and regulations implemented thereunder also prohibit discharges of dredged and fill material in wetlands and other waters of the United States unless authorized by an appropriately issued permit. Any unpermitted release of pollutants from Enogex's pipelines or facilities could result in administrative, civil and criminal penalties as well as significant remedial obligations.

Other Laws and Regulations. Recent scientific studies have suggested that emissions of certain gases, commonly referred to as "greenhouse gases" and including carbon dioxide and methane, may be contributing to warming of the Earth's atmosphere. In response to such studies, the U.S. Congress is actively considering legislation to reduce emissions of greenhouse gases. In addition, several states have declined to wait on Congress to develop and implement climate control legislation and have already taken legal measures to reduce emissions of greenhouse gases. For instance, at least nine states in the Northeast (Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York and Vermont) and five states in the West (Arizona, California, New Mexico, Oregon and Washington) have passed laws, adopted regulations or undertaken regulatory initiatives to reduce the emission of greenhouse gases, primarily through the planned development of greenhouse gas emission inventories and/or regional greenhouse gas cap and trade programs. Also, as a result of the

U.S. Supreme Court's decision on April 2, 2007 in *Massachusetts, et al. v. EPA*, the EPA may be required to regulate greenhouse gas emissions from mobile sources (e.g. cars and trucks) even if Congress does not adopt new legislation specifically addressing emissions of greenhouse gases. Other nations have already agreed to regulate emissions of greenhouse gases pursuant to the United Nations Framework Convention on Climate Change, also known as the "Kyoto Protocol," an international treaty pursuant to which participating countries (not including the United States) have agreed to reduce their emissions of greenhouse gases to below 1990 levels by 2012. Passage of climate control legislation or other regulatory initiatives by Congress or various states of the U.S. as well as by foreign governmental authorities outside of the U.S., or the adoption of regulations by the EPA and analogous state or foreign governmental agencies that restrict emissions of greenhouse gases in areas in which Enogex conducts business could have an adverse effect on its operations and demand for its services or products.

Employees

Enogex and its subsidiaries had 532 employees at December 31, 2006.

Properties

Enogex's real property falls into two categories: (1) parcels that it owns in fee and (2) parcels in which Enogex's interest derives from leases, easements, rights-of-way, permits or licenses from landowners or governmental authorities permitting the use of such land for its operations. Certain of Enogex's processing plants and related facilities are located on land Enogex owns in fee title, and we believe that it has satisfactory title to these lands. The remainder of the land on which Enogex's plants and related facilities are located is held by Enogex pursuant to ground leases between Enogex, as lessee, and the fee owner of the lands, as lessors. Enogex, or its predecessors, have leased these lands for many years without any material challenge known to us or Enogex relating to the title to the land upon which the assets are located, and we believe that Enogex has satisfactory leasehold estates to such lands. We have no knowledge of any challenge to the underlying fee title of any material lease, easement, right-of-way, permit or license held by Enogex or to its title to any material lease, easement, right-of-way, permit or lease, and we believe that Enogex has satisfactory title to all of its material leases, easements, rights-of-way, permits and licenses.

Record title to some of Enogex's assets may continue to be held by prior owners until Enogex has made the appropriate filings in the jurisdictions in which such assets are located. Title to some of Enogex's assets may be subject to encumbrances. We believe that none of such encumbrances should materially detract from the value of Enogex's properties or our interest in those properties or should materially interfere with Enogex's use of them in the operation of its business. Substantially all of Enogex's pipelines are constructed on rights-of-way granted by the apparent owners of record of the properties. Lands over which pipeline rights-of-way have been obtained may be subject to prior liens that have not been subordinated to the rights-of-way grants.

At December 31, 2006, Enogex and its subsidiaries owned: (1) approximately 5,474 miles of intrastate natural gas gathering pipelines in Oklahoma and Texas; (2) approximately 2,283 miles of intrastate natural gas transportation pipelines in Oklahoma and Texas; (3) two natural gas storage facilities in Oklahoma operating at a working gas level of approximately 23 Bcf with approximately 650 MMcf/d of maximum withdrawal capacity and approximately 650 MMcf/d of injection capacity; and (4) six operating natural gas processing plants, with a total inlet capacity of approximately 720 MMcf/d, and two idle natural gas processing plants, all located in Oklahoma.

Enogex's Canute and Cox City processing plants are located on leased real property. Enogex's Calumet, Harrah, Thomas and Wetumka processing plants are located on property that it owns in fee.

We occupy approximately 109,493 square feet of office space at our executive offices at 600 Central Park Two, 515 Central Park Drive, Oklahoma City, Oklahoma 73124 under a lease that expires March 31, 2012. Although we may require additional office space as our business expands, we believe that our existing facilities are adequate to meet our needs for the immediate future.

Legal Proceedings

In the normal course of business, we and Enogex are confronted with issues or events that may result in a contingent liability. These generally relate to lawsuits, claims made by third parties, environmental actions or the action of various regulatory agencies and income tax related items. Management consults with legal counsel and other appropriate experts to assess the claim. If, in management's opinion, we and Enogex have incurred a probable loss as set forth by GAAP, an estimate is made of the loss and the appropriate accounting entries are reflected in the consolidated financial statements. Except as set forth below and in Notes 13 and 14 of Notes to Consolidated Financial Statements, management, after consultation with legal counsel, does not currently anticipate that liabilities arising out of these pending or threatened lawsuits, claims and contingencies will have a material adverse effect on our consolidated financial condition, results of operations or cash flows.

1. *United States of America ex rel., Jack J. Grynberg v. Enogex Inc., Enogex Services Corporation and OG&E*. (U.S. District Court for the Western District of Oklahoma, Case No. CIV-97-1010-L.) *United States of America ex rel., Jack J. Grynberg v. Transok Inc. et al*. (U.S. District Court for the Eastern District of Louisiana, Case No. 97-2089; U.S. District Court for the Western District of Oklahoma, Case No. 97-1009M.). On June 15, 1999, OGE Energy was served with the plaintiff's complaint, which is a qui tam action under the False Claims Act. Plaintiff Jack J. Grynberg, as individual relator on behalf of the U.S. Government, alleges: (a) each of the named defendants have improperly or intentionally mismeasured gas (both volume and Btu content) purchased from federal and Indian lands which have resulted in the underreporting and underpayment of gas royalties owed to the Federal government; (b) certain provisions generally found in gas purchase contracts are improper; (c) transactions by affiliated companies are not arms-length; (d) excess processing cost deduction; and (e) failure to account for production separated out as a result of gas processing. Grynberg seeks the following damages: (a) additional royalties which he claims should have been paid to the Federal government, some percentage of which Grynberg, as relator, may be entitled to recover; (b) treble damages; (c) civil penalties; (d) an order requiring defendants to measure the way Grynberg contends is the better way to do so; and (e) interest, costs and attorneys' fees.

In qui tam actions, the Federal government can intervene and take over such actions from the relator. The Department of Justice, on behalf of the Federal government, decided not to intervene in this action.

The plaintiff filed over 70 other cases naming over 300 other defendants in various Federal courts across the country containing nearly identical allegations. The Multidistrict Litigation Panel entered its order in late 1999 transferring and consolidating for pretrial purposes approximately 76 other similar actions filed in nine other Federal courts. The consolidated cases are now before the U.S. District Court for the District of Wyoming.

In October 2002, the court granted the Department of Justice's motion to dismiss certain of the plaintiff's claims and issued an order dismissing the plaintiff's valuation claims against all defendants. Various procedural motions have been filed. A hearing on the defendants' motions to dismiss for lack of subject matter jurisdiction, including public disclosure, original source and voluntary disclosure requirements was held in 2005 and the special master ruled that OG&E and all Enogex parties named in these proceedings should be dismissed. This ruling was appealed to the District Court of Wyoming.

On October 20, 2006, the District Court of Wyoming ruled on Grynberg's appeal, following and confirming the recommendation of the special master dismissing all claims against Enogex Inc., Enogex

Services Corp., Transok, Inc. and OG&E, for lack of subject matter jurisdiction. Judgment was entered on November 17, 2006 and Grynberg filed his notice of appeal with the District Court of Wyoming. The defendants filed motions for attorneys' fees regarding issues of liability and Rule 11 motions on January 8, 2007. The defendants also filed for other legal costs on December 18, 2006. A hearing on these motions was held on April 24, 2007, at which time the judge took the motions under advisement. Grynberg has also filed appeals with the Tenth Circuit Court of Appeals. We intend to vigorously defend this action. At this time, we are unable to provide an evaluation of the likelihood of an unfavorable outcome and an estimate of the amount or range of potential loss to Enogex.

2. *Will Price* (Price I). On September 24, 1999, various subsidiaries of OGE Energy were served with a class action petition filed in U.S. District Court, State of Kansas by Quinque Operating Company and other named plaintiffs, alleging mismeasurement of natural gas on non-federal lands. On April 10, 2003, the court entered an order denying class certification. On May 12, 2003, the plaintiffs (now Will Price, Stixon Petroleum, Inc., Thomas F. Boles and the Cooper Clark Foundation, on behalf of themselves and other royalty interest owners) filed a motion seeking to file an amended petition and the court granted the motion on July 28, 2003. In this amended petition, OG&E and Enogex Inc. were omitted from the case. Two of Enogex's subsidiaries remain as defendants. The plaintiffs' amended petition alleges that approximately 60 defendants, including two of Enogex's subsidiaries, have improperly measured natural gas. The amended petition reduces the claims to: (a) mismeasurement of volume only; (b) conspiracy, unjust enrichment and accounting; (c) a putative plaintiffs' class of only royalty owners; and (d) gas measured in three specific states. A hearing on class certification issues was held April 1, 2005. We intend to vigorously defend this action. At this time, we are unable to provide an evaluation of the likelihood of an unfavorable outcome and an estimate of the amount or range of potential loss to Enogex.

3. *Will Price* (Price II). On May 12, 2003, the plaintiffs (same as those in Price I above) filed a new class action petition (Price II) in the District Court of Stevens County, Kansas, relating to wrongful Btu analysis against natural gas pipeline owners and operators, naming the same defendants as in the amended petition of the Price I case. Two of Enogex's subsidiaries were served on August 4, 2003. The plaintiffs seek to represent a class of only royalty owners either from whom the defendants had purchased natural gas or measured natural gas since January 1, 1974 to the present. The class action petition alleges improper analysis of gas heating content. In all other respects, the Price II petition appears to be the same as the amended petition in Price I. A hearing on class certification issues was held April 1, 2005. We intend to vigorously defend this action. At this time, we are unable to provide an evaluation of the likelihood of an unfavorable outcome and an estimate of the amount or range of potential loss to Enogex.

4. *TCEQ Notice of Enforcement Action*. A Notice of Enforcement Action, or NOE, by the Texas Natural Resource Conservation Commission (now known as the Texas Commission on Environmental Quality, or TCEQ) was issued to Enogex Products Corporation, Enogex's subsidiary, by letter dated July 26, 2002. The NOE relates to the operation of a sulfur recovery unit owned and operated by Belvan Corp., Belvan Limited Partnership and Todd Ranch Limited Partnership, or Belvan, at its Crockett County, Texas natural gas processing facility. Enogex Products Corporation sold its interest in Belvan in March 2002. By agreed order dated October 19, 2006, the TCEQ agreed to a fine of less than $0.1 million. Pursuant to the Agreement of Sale and Purchase with the purchaser, Enogex Products Corporation retained some liability for amounts that Belvan pays to the TCEQ relating to this NOE not to exceed approximately $0.1 million. This amount is fully reserved on Enogex's books.

5. *Oklahoma Royalty Lawsuit*. On July 22, 2005, Enogex along with certain other unaffiliated co-defendants were served with a purported class action which had been filed on February 7, 2005 by Farris Buser and other named plaintiffs in the District Court of Canadian County, Oklahoma. The plaintiffs own royalty interests in certain oil and gas producing properties and allege they have been under-compensated by the named defendants, including Enogex and its subsidiaries, relating to the sale

of liquid hydrocarbons recovered during the transportation of natural gas from the plaintiffs' wells. The plaintiffs assert breach of contract, implied covenants, obligation, fiduciary duty, unjust enrichment, conspiracy and fraud causes of action and claim actual damages in excess of $10,000, plus attorneys' fees and costs, and punitive damages in excess of $10,000. Enogex and its subsidiaries filed a motion to dismiss which was granted on November 18, 2005, subject to the plaintiffs' right to conduct discovery and the possible re-filing of their allegations in the petition against the Enogex companies. On September 19, 2005, the co-defendants, BP America, Inc. and BP America Production Co., referred to herein collectively as BP, filed a cross claim against Enogex Products Corporation seeking indemnification and/or contribution from Enogex Products Corporation based upon the 1997 sale of a third-party interest in one of Enogex Products Corporation's natural gas processing plants. On May 17, 2006, the plaintiffs filed an amended petition against Enogex and its subsidiaries. Enogex and its subsidiaries filed a motion to dismiss the amended petition on August 2, 2006. The hearing on the dismissal motion was held on November 20, 2006 and the court denied Enogex's motion. Enogex filed an answer to the amended petition and BP's cross claim on January 16, 2007. Based on Enogex's investigation to date, we believe these claims and cross claims in this lawsuit are without merit and intend to continue vigorously defending this case.

MANAGEMENT

Management of OGE Enogex Partners L.P.

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

The board of directors and executive officers of our general partner will oversee our operations and make decisions on our behalf. Upon the closing of this offering, our general partner expects to have seven directors. OGE Energy will elect all seven members to the board of directors of our general partner, and we will have three directors that are independent as defined under the independence standards established by the New York Stock Exchange. The New York Stock Exchange does not require a listed limited partnership like us to have a majority of independent directors on the board of directors of our general partner or to establish a compensation committee or a nominating committee.

Governance Matters

Our general partner will have an audit committee of at least three directors who meet the independence and experience standards established by the New York Stock Exchange and the Securities Exchange Act of 1934, as amended, or the Exchange Act. The audit committee will assist the board of directors in its oversight of the integrity of our financial statements and our compliance with legal and regulatory requirements and partnership policies and controls. The audit committee will have the sole authority to retain and terminate our independent registered public accounting firm, approve all auditing services and related fees and the terms of those services and pre-approve any non-audit services to be rendered by our independent registered public accounting firm. The audit committee will also be responsible for confirming the independence and objectivity of our independent registered public accounting firm. Our independent registered public accounting firm will be given unrestricted access to the audit committee.

Three independent members of the board of directors of our general partner will serve on a conflicts committee to review specific matters that the board believes may involve conflicts of interest. The conflicts committee will determine if the resolution of the conflict of interest is fair and reasonable to us. The members of the conflicts committee may not be officers or employees of our general partner or directors, officers or employees of its affiliates, and must meet the independence and experience standards established by the New York Stock Exchange and the Exchange Act to serve on an audit committee of a board of directors, and certain other requirements. Any matters approved by the conflicts committee in good faith will be conclusively deemed to be fair and reasonable to us, approved by all of our partners and not a breach by our general partner of any duties it may owe us or our unitholders. For additional information, please see "Conflicts of Interest and Fiduciary Duties—Conflicts of Interest."

Even though most companies listed on the New York Stock Exchange are required to have a majority of independent directors serving on the board of directors of the listed company and to establish and maintain an audit committee, a compensation committee and a nominating/corporate governance committee each consisting solely of independent directors, the New York Stock Exchange does not require a listed limited partnership like us to have a majority of independent directors on the board of directors of our general partner or to establish a compensation committee or a nominating/corporate governance committee.

All of our executive management personnel are employees of OGE Energy or Enogex and will devote their time as they deem appropriate to conduct our business and affairs. The officers of our general partner will manage the day-to-day affairs of our business. We will also utilize a significant number of employees of OGE Energy to operate our business and the business of Enogex and provide us and Enogex with general and administrative services pursuant to certain service agreements. Please see "Certain Relationships and Related Party Transactions. We and Enogex will reimburse OGE Energy for allocated expenses of operational personnel who perform services for us and Enogex for our benefit, allocated general and administrative expenses and certain direct expenses. Please see "—Reimbursement of Expenses of Our General Partner."

Directors and Executive Officers of OGE Enogex GP LLC

The following table shows information regarding the current directors and executive officers of OGE Enogex GP LLC. Directors are elected for one-year terms. The business address of each of the directors and officers listed below is 600 Central Park Two, 515 Central Park Drive, Oklahoma City, Oklahoma 73124.

Name	Age	Position with OGE Enogex GP LLC
Steven E. Moore(1)	61	Director
Peter B. Delaney(2)	53	Chief Executive Officer and Director
James R. Hatfield(3)	49	Senior Vice President and Chief Financial Officer and Director
Danny P. Harris(4)	51	President and Chief Operating Officer and Director
E. Keith Mitchell	44	Senior Vice President
Patricia D. Horn	49	Vice President, General Counsel
Craig R. Jimenez	46	Vice President, Energy Marketing & Trading
Jean C. Leger, Jr.	48	Vice President, Operations
Ramiro F. Rangel	50	Vice President, Producer Services

(1) Mr. Moore is also the Chairman of the Board and Chief Executive Officer of OGE Energy.

(2) Mr. Delaney is also a director and the President and Chief Operating Officer of OGE Energy.

(3) Mr. Hatfield is also the Senior Vice President and Chief Financial Officer of OGE Energy.

(4) Mr. Harris is also a Senior Vice President of OGE Energy.

Steven E. Moore has been a director of our general partner since it was formed in May 2007. Mr. Moore is also Chairman and Chief Executive Officer of OGE Energy and OG&E, having been appointed to such positions with OGE Energy effective December 31, 1996. Mr. Moore has been a director of Enogex Inc. since August 1995. From December 31, 1996 until January 17, 2007, Mr. Moore also served as President of OGE Energy. Mr. Moore was appointed Chief Executive Officer and Chairman of OG&E in May 1996 and served as President of OG&E from August 1995 until January 17, 2007. Mr. Moore has been employed by OG&E for more than 31 years, having previously served as Senior Vice President of Law and Public Affairs. He also serves as a Chairman of the Board of INTEGRIS Health, Inc. and has served on many industry-wide committees in the electric utility industry. Mr. Moore has been a director of OGE Energy since 1996 and of OG&E since October 1995.

Peter B. Delaney has been Chief Executive Officer and a director of our general partner since May 2007. Mr. Delaney has served as Chief Executive Officer of Enogex Inc. since August 2002. Mr. Delaney has been a director of Enogex Inc. since July 2002. Mr. Delaney served as President of Enogex Inc. from December 2002 until June 2005. Mr. Delaney has also served as President and Chief Operating Officer and a director of OGE Energy Corp. and a director of OG&E since January 2007. From 2004 to January 2007, Mr. Delaney served as Executive Vice President and Chief Operating Officer of OGE Energy and OG&E. From 2002 to 2004, Mr. Delaney was also Executive Vice President, Finance and Strategic Planning of OGE Energy. Mr. Delaney joined OGE Energy in April 2002 as Executive Vice President in charge of corporate planning as well as Chief Executive Officer of Enogex. Prior to joining OGE Energy, Mr. Delaney completed a 15 year career on Wall Street, with his most recent position as a Managing Director at UBS Warburg, a leading global investment banking and securities firm, where he specialized in providing corporate finance and other advisory services to electric and natural gas utilities and other energy companies in the United States, Europe and South America.

James R. Hatfield has been Senior Vice President and Chief Financial Officer and a director of our general partner since May 2007. Mr. Hatfield has served as Treasurer of Enogex Inc. and Senior Vice President and Chief Financial Officer of OGE Energy and OG&E since 1999. Mr. Hatfield has been a director of Enogex Inc. since November 1996. He joined OG&E in 1994 as Treasurer and was elected Vice President and Treasurer of OG&E in 1997. Prior to joining OG&E, Mr. Hatfield worked for Aquila Gas Pipeline Corporation, a subsidiary of UtiliCorp of San Antonio, Texas. While at UtiliCorp, Mr. Hatfield held several positions, including Vice President—Investor Relations and Corporate Secretary, the position he held prior to joining OG&E. Mr. Hatfield has over 25 years of diversified experience in the electric utility and natural gas industries.

Danny P. Harris has been President and Chief Operating Officer and a director of our general partner since May 2007. Mr. Harris has served as President and a director of Enogex Inc. since June 2005 and as Senior Vice President of OGE Energy since 2005. Mr. Harris served as Vice President and Chief Operating Officer of Enogex Inc. from August 2001 until June 2005. From 2000 to 2001, Mr. Harris served as Director of Strategic Development of Enogex. Prior to joining Enogex in 1996, Mr. Harris was a District Manager at Natural Gas Pipeline Company of America. Mr. Harris has 20 years of diversified experience in the natural gas industry.

E. Keith Mitchell has been Senior Vice President of our general partner since May 2007. Since April 2007, Mr. Mitchell has served as Senior Vice President of Enogex Inc. and from January 2005 to April 2007, Mr. Mitchell served as Vice President, Transportation Services of Enogex Inc. From 2002 to 2004, Mr. Mitchell was Vice President, Sales Support of Enogex Inc., leading the contract management and technical sales support groups. Mr. Mitchell also served in other transportation and system planning positions. Prior to joining Enogex in 1994, Mr. Mitchell was a Vice President at Kansas Pipeline Operating Company, responsible for all marketing, supply, and transportation activities. Mr. Mitchell has over 22 years of diversified experience in the natural gas industry.

Patricia D. Horn has been Vice President and General Counsel of our general partner since May 2007. Ms. Horn has also served as Vice President, Legal, Regulatory and Environmental Health & Safety and General Counsel of Enogex Inc. since June 2002. Since May 2004, Ms. Horn has also been Assistant General Counsel of OGE Energy. From 1998 to 2002, Ms. Horn was Vice President, Legal, Regulatory, Human Resources and Environmental Health & Safety and General Counsel of Enogex Inc. Ms. Horn joined Enogex as Senior Counsel in 1997. Prior to joining Enogex, Ms. Horn was a partner in the energy practice group of an Oklahoma-based law firm. Ms. Horn has over 18 years of diversified experience in the natural gas industry.

Craig R. Jimenez has been Vice President, Energy Marketing & Trading of our general partner since May 2007. Mr. Jimenez has also served as Vice President, Energy Marketing & Trading at OGE Energy Resources Inc. since November 2005. From May 2005 to October 2005, Mr. Jimenez was Director of Quantitative Analysis and Business Support of Enogex. Prior to joining Enogex in May 2005, Mr. Jimenez was the Strategist for Energy Assets at Financial Engineering Associates, working with arbitrage and risk management programs from May 2003 to May 2005. Prior to joining Financial Engineering Associates, Mr. Jimenez held various trading positions at Mirant, including lead trader for weather-linked energy options. From 1991 through 1997, Mr. Jimenez was a developer of Saudi Aramco's scalable-parallel reservoir simulator. Mr. Jimenez has over 15 years of diversified experience in the energy industry.

Jean C. Leger, Jr. has been Vice President, Operations of our general partner since May 2007. Mr. Leger has also served as Vice President, Operations of Enogex Inc. since December 2004. From 2002 to 2005, Mr. Leger served as Director of Field Operations of Enogex Inc. From 1998 to 2002, Mr. Leger served as Enogex's Manager, West Oklahoma Business Unit. Prior to joining Enogex in 1993, Mr. Leger served in various positions with Sun Refining and Marketing and DuPont/Conoco. Mr. Leger has over 25 years of diversified experience in the energy industry.

Ramiro F. Rangel has been Vice President, Producer Services of our general partner since May 2007. Mr. Rangel has also served as Vice President, Producer Services of Enogex Inc. since October 2005. From April 2004 to September 2005, Mr. Rangel served as Director, Producer Services of Enogex Inc. Prior to joining Enogex, Mr. Rangel was the Director of Origination for Eagle Energy Partners, coordinating all marketing, supply, storage, and transportation in the mid-continent from November 2003. Prior to that, Mr. Rangel was the Vice President of Marketing for Louis Dreyfus Natural Gas Corporation from 1992 to 2001. Mr. Rangel has also held several management positions at The Williams Companies in marketing, operations and financial analysis. Mr. Rangel started his career with Conoco Exploration and Production. Mr. Rangel has over 25 years of experience in the natural gas industry.

Directors of our general partner hold office until the earlier of their death, resignation, removal or disqualification or until their successors have been elected and qualified. Officers of our general partner serve at the discretion of the board of directors. There are no family relationships among any of our directors or executive officers of our general partner.

Reimbursement of Expenses of Our General Partner

Our general partner will not receive any management fee or other compensation for its management of our partnership under the omnibus agreement with OGE Energy or otherwise. Under the terms of the omnibus agreement, we and Enogex will reimburse OGE Energy up to $ million annually for the provision of various general and administrative services for our benefit, including services for Enogex, subject to increases in the Consumer Price Index or as a result of an expansion of our operations. The limit on the amount of reimbursement will expire on the third anniversary of the closing of this offering. Our obligation to reimburse OGE Energy for operational expenses and certain direct expenses, including insurance coverage expense, is not subject to this cap. Our partnership agreement provides that our general partner will determine the expenses that are allocable to us. Please see "Certain Relationships and Related Party Transactions—Omnibus Agreement."

Executive Compensation

Our general partner, OGE Enogex GP LLC, was formed on May 30, 2007. Accordingly, our general partner has not accrued any obligations with respect to management incentive or retirement benefits for its directors and executive officers for the 2005 and 2006 fiscal years or year-to-date in 2007. The compensation of the executive officers of OGE Enogex GP LLC will be set by the compensation committee of the board of directors of OGE Energy and ratified by the board of directors of our general partner. The officers of our general partner, the employees of Enogex and the employees of OGE Energy providing services to us are participating in employee benefit plans and arrangements sponsored by OGE Energy. OGE Enogex GP LLC has entered into employment agreements with some of its officers as described below. The board of directors of our general partner may grant awards tied to the value of our common units to its outside directors. Prior to the closing of the offering our general partner may adopt a long-term incentive plan that will provide for the issuance of restricted units and performance units, among other types of awards.

Director Compensation

Officers or employees of OGE Enogex GP LLC or its affiliates who also serve as directors will not receive additional compensation for their service as a director of OGE Enogex GP LLC. Our general partner anticipates that directors who are not officers or employees of OGE Enogex GP LLC or its affiliates will receive compensation for attending meetings of the board of directors and committee meetings and will be eligible to participate in a long-term incentive plan. The amount of compensation has not yet been determined. In addition, each non-employee director will be reimbursed for his out-of-pocket expenses in connection with attending meetings of the board of directors or committees. Each director will be fully indemnified by us for his actions associated with being a director to the fullest extent permitted under Delaware law.

Compensation Discussion and Analysis

We do not directly employ any of the persons responsible for managing our business and we do not have a compensation committee. Any compensation decisions that are required to be made by our general partner, OGE Enogex GP LLC, will be made by the compensation committee of the board of directors of OGE Energy and ratified by the board of directors of our general partner. All of our executive officers are employees of OGE Energy or Enogex. Our reimbursement for the compensation of executive officers will be based on OGE Energy's methodology used for allocating general and administration expenses during a period pursuant to the terms of, and subject to the limitations contained in, the omnibus agreement.

During 2006, our executive officers were not specifically compensated for time expended with respect to our business or assets. Accordingly, we are not presenting any compensation for historical periods. Following the consummation of this offering, we currently expect that our Chief Executive Officer (our principal executive officer), our Chief Financial Officer (our principal financial officer) and three other persons (Messrs. Harris and Mitchell and Ms. Horn) who we expect will constitute our most highly compensated executive officers for 2007, referred to herein collectively as the named executive officers, will have substantially less than a majority of their compensation allocated to us. Compensation paid or awarded by us in 2007 with respect to our named executive officers will reflect only the portion of compensation paid by OGE Energy or Enogex, as the case may be, that is allocated to us pursuant to the allocation methodology used by OGE Energy or Enogex, as the case may be, and subject to the terms of the omnibus agreement. The compensation committee of OGE Energy has ultimate decision making authority with respect to the compensation, including the compensation based on our common units (*i.e.*, unit-based equity compensation), of our named executive officers; however, the allocation of the compensation expense to us is subject to ratification by the board of directors of our general partner and the omnibus agreement. Awards under any long-term incentive plan adopted by our general partner will be recommended by the compensation committee of OGE Energy and approved by the board of directors of our general partner.

We believe that, with respect to the compensation decisions relating to the named executive officers of our general partner, the compensation committee of OGE Energy will apply the same general principles and philosophies that it applies to the compensation of its executive officers.

With respect to compensation decisions relating to its executive officers, OGE Energy's compensation program is premised on two basic principles. First, its overall compensation levels must be sufficiently competitive to attract and retain talented leaders. At the same time, the compensation committee of OGE Energy believes that compensation should be set at reasonable and responsible levels, consistent with OGE Energy's continuing focus on controlling costs. Second, this executive compensation program should be substantially performance-based and should align the interests of the executives with those of OGE Energy's shareowners.

As mentioned above, our general partner may adopt a long-term incentive plan that would provide for long-term equity based awards intended to compensate the officers based on the performance of our common units. The cost of any such awards will be allocated to us pursuant to OGE Energy's allocation methodology and subject to the terms of the omnibus agreement. Any such unit-based equity compensation awards that we make would be intended to align the recipient's long-term interests with those of our unitholders.

The terms and amount of any such unit-based equity compensation awards will be recommended by OGE Energy's compensation committee or its delegate and approved by our general partner.

Long-Term Incentive Plan

General

OGE Enogex GP LLC may adopt a long-term incentive plan, or LTIP, for employees, consultants and directors of OGE Enogex GP LLC and its affiliates who perform services for us, including officers and employees of Enogex. Any such LTIP ultimately adopted would be expected to provide for the grant of restricted units, phantom units, unit options and substitute awards and, with respect to unit options and phantom units, the grant of distribution equivalent rights, or DERs. The LTIP would be administered by the compensation committee of the board of directors of OGE Energy.

Restricted Units and Performance Units

A restricted unit is a common unit that is subject to forfeiture. Upon vesting, the grantee receives a common unit that is not subject to forfeiture. A performance unit is a notional unit that entitles the grantee to receive upon the vesting of the performance unit cash equal to the fair market value of a common unit or, in the discretion of the board of directors, a common unit. We would expect that the board of directors of our general partner could make grants of restricted units and performance units under the LTIP to eligible individuals containing such terms, consistent with the LTIP, as the board of directors may determine, including the period over which restricted units and performance units granted will vest. We would expect that the board of directors of our general partner could, in its discretion, base vesting on the grantee's completion of a period of service or upon the achievement of specified financial objectives or other criteria. In addition, we would expect that the restricted and performance units would vest automatically upon a change of control of us or our general partner, subject to any contrary provisions in the award agreement.

We would expect that if a grantee's employment, consulting or board membership terminates for any reason, the grantee's restricted units and performance units would be automatically forfeited unless, and to the extent, the award agreement or the board of directors of our general partner provides otherwise. If we issue new common units with respect to any such awards, the total number of common units outstanding will increase.

Distributions made by us with respect to awards of restricted units may, in the discretion of the board of directors of our general partner, be subject to the same vesting requirements as the restricted units. We would expect that the board of directors of our general partner, in its discretion, could also grant tandem DERs with respect to performance units on such terms as it deems appropriate. DERs are rights that entitle the grantee to receive, with respect to a performance unit, cash equal to the cash distributions made by us on a common unit. However, DERs may be credited and paid in such other manner, including units, as the board of directors of our general partner may provide.

We intend for any restricted units and performance units granted under the LTIP to serve as a means of incentive compensation for performance and not primarily as an opportunity to participate in the equity appreciation of the common units. Therefore, we would expect that participants will not pay any consideration for the common units they receive with respect to these types of awards, and neither we nor our general partner will receive remuneration for the units delivered with respect to these awards.

Replacement Awards

We would expect that the board of directors of our general partner, in its discretion, could grant replacement awards to eligible individuals who, in connection with an acquisition made by us, OGE Enogex GP LLC or an affiliate, have forfeited an equity-based award in their former employer. A replacement award that is an option could have an exercise price less than the value of a common unit on the date of grant of the award.

Termination of Long-Term Incentive Plan

We would expect that the LTIP would terminate on the earlier of the 10th anniversary of the date it was initially approved by our unitholders or when common units are no longer available for delivery pursuant to awards under the LTIP, subject to earlier termination by the board of directors of our general partner. We would expect that the board of directors of our general partner would also have the right to alter or amend the LTIP or any part of it from time to time and the board of directors could amend any award; provided, however, that no change in any outstanding award would be made that would materially impair the rights of the participant without the consent of the affected participant. Subject to unitholder approval, if required by the rules of the principal national securities exchange upon which the common units are then traded, the board of directors of our general partner may increase the number of common units that may be delivered with respect to awards under the LTIP.

Retention Agreements

On June 22, 2007, Enogex Inc. entered into separate retention agreements with Ms. Patricia D. Horn, its Vice President, Legal, Regulatory and Environmental Health & Safety and General Counsel, Mr. Craig R. Jimenez, Vice President, Energy Marketing & Trading of OGE Energy Resources Inc., Mr. Jean C. Leger, Jr., its Vice President, Operations, Mr. Thomas L. Levescy, its Controller, Mr. E. Keith Mitchell, its Senior Vice President, and Mr. Ramiro F. Rangel, Vice President, Producer Services. Ms. Horn and Messrs. Jimenez, Leger, Mitchell and Rangel are also executive officers of our general partner.

Under the terms of the retention agreements, each of these executives will be eligible to receive a retention bonus equal to 75% of his or her annual base salary as in effect on June 30, 2007. The retention bonus will be payable in two equal installments. The first payment was made on or about June 22, 2007. The second payment is scheduled to be made on June 30, 2009; provided that, in order to receive the second payment, the executive must remain employed with Enogex or its affiliates, including our general partner, through June 30, 2009. The retention agreements further provide that if the executive resigns, voluntarily retires or is terminated for cause (as defined below) prior to June 30, 2009, the executive is not entitled to receive the second payment and will be required to repay the first payment.

If the executive's employment is terminated prior to June 30, 2009 by reason of death, permanent disability or without cause, then the executive, or his or her estate, will be entitled to retain the first payment, but will not receive the second payment.

For these purposes, "cause" is defined as (i) failure to meet performance expectations as determined by the chief operating officer of Enogex (other than a failure resulting from incapacity due to physical or mental illness or injury), after a written demand for substantial performance is delivered to the executive which specifically identifies the manner in which the executive has not substantially performed his or her duties or (ii) willful engaging by the executive in illegal conduct or gross misconduct which is materially and demonstrably injurious to Enogex or its affiliates.

SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

The following table sets forth the beneficial ownership of our units that will be issued upon the consummation of this offering and the related transactions and held by:

- each person who then will beneficially more than 5% of the then outstanding units;
- all of the directors of our general partner, OGE Enogex GP LLC;
- each named executive officer of OGE Enogex GP LLC; and
- all directors and executive officers of OGE Enogex GP LLC as a group.

The table does not reflect any common units that may be purchased in the offering through the directed unit program.

Name of Beneficial Owner	Common Units to be Beneficially Owned	Percentage of Common Units to be Beneficially Owned	Subordinated Units to be Beneficially Owned	Percentage of Subordinated Units to be Beneficially Owned	Percentage of Total Common and Subordinated Units to be Beneficially Owned
OGE Energy Corp. 321 North Harvey Oklahoma City, Oklahoma 73101(1)	3,280,605	30.4%	10,780,605	100%	65.2%
OGE Enogex Holdings LLC 321 North Harvey Oklahoma City, Oklahoma 73101(1)	3,280,605	30.4%	10,780,605	100%	65.2%
Steven E. Moore					
Peter B. Delaney					
James R. Hatfield					
Danny P. Harris					
E. Keith Mitchell					
Patricia D. Horn					
Craig R. Jimenez					
Jean C. Leger, Jr.					
Ramiro F. Rangel					
All directors and executive officers as a group (9 persons)					

(1) OGE Energy Corp. owns all of the outstanding membership interests in OGE Enogex Holdings LLC and is the beneficial owner of all common and subordinated units held by OGE Enogex Holdings LLC.

CERTAIN RELATIONSHIPS AND RELATED PARTY TRANSACTIONS

After this offering, an affiliate of our general partner will own 3,280,605 common units and 10,780,605 subordinated units representing an aggregate 63.9% limited partner interest in us. In addition, our general partner will own a 2% general partner interest in us and the incentive distribution rights.

Distributions and Payments to Our General Partner and Its Affiliates

The following table summarizes the distributions and payments to be made by us to our general partner and its affiliates in connection with the formation, ongoing operation and any liquidation of OGE Enogex Partners L.P. These distributions and payments were determined by and among affiliated entities and, consequently, may not be the result of arm's-length negotiations.

Formation Stage

The consideration received by OGE Energy and its subsidiaries, including our general partner, for the contribution to our wholly owned subsidiary of a 25% membership interest in Enogex	• 3,280,605 common units; • 10,780,605 subordinated units; • a 2% general partner interest; and • the incentive distribution rights.

Operational Stage

Distributions of available cash to our general partner and its affiliates	We will generally make cash distributions 98% to our unitholders, pro rata, including an affiliate of our general partner, as the holder of an aggregate 3,280,605 common units and 10,780,605 subordinated units, and 2% to our general partner. In addition, if distributions exceed the minimum quarterly distribution and other higher target distribution levels, our general partner will be entitled to increasing percentages of the distributions, up to 50% of the distributions above the highest target distribution level. Assuming we have sufficient available cash to pay the full minimum quarterly distribution on all of our outstanding units for four quarters, our general partner and its affiliates would receive an annual distribution of approximately \$0.6 million on their general partner interest and \$19.0 million on their common and subordinated units.

Payments to our general partner and its affiliates	Pursuant to the omnibus agreement, we and Enogex will reimburse OGE Energy and its affiliates for the payment of certain operating expenses and for the provision of various general and administrative services for our benefit. Please see "—Omnibus Agreement—Reimbursement of Operating and General and Administrative Expense." Our general partner and its affiliates will be entitled to reimbursement for any other expenses they incur on our behalf and any other necessary or appropriate expenses allocable to us or reasonably incurred by our general partner and its affiliates in connection with operating our business or the business of Enogex to the extent not otherwise covered by the omnibus agreement. Our partnership agreement provides that our general partner will determine any such expenses that are allocable to us in good faith.
Withdrawal or removal of our general partner	If our general partner withdraws or is removed, its general partner interest and its incentive distribution rights will either be sold to the new general partner for cash or converted into common units, in each case for an amount equal to the fair market value of those interests. Please see "The Partnership Agreement—Withdrawal or Removal of Our General Partner."

Liquidation Stage

Liquidation	Upon our liquidation, the partners, including our general partner, will be entitled to receive liquidating distributions according to their respective capital account balances.

Agreements Governing the Transactions

We and other parties will enter into various documents and agreements that will effect the offering transactions and the application of the proceeds of this offering. These agreements may not be the result of arm's-length negotiations, and they, or any of the transactions that they provide for, may not be effected on terms at least as favorable to the parties to these agreements as they could have been obtained from unaffiliated third parties. All of the transaction expenses incurred in connection with these transactions will be paid from the proceeds of this offering.

Omnibus Agreement

Upon the closing of this offering, we will enter into an omnibus agreement with OGE Energy, our general partner and others that will address the reimbursement of our general partner for costs incurred on our behalf, competition and indemnification matters. Any or all of the provisions of the omnibus agreement, other than the indemnification provisions described below, will be terminable by OGE Energy at its option if our general partner is removed without cause and units held by our general partner and its affiliates are not voted in favor of that removal. The omnibus agreement will also terminate in the event of a change of control of us or our general partner.

Reimbursement of Operating and General and Administrative Expense

Under the omnibus agreement, we and Enogex will reimburse OGE Energy for the payment of certain operating expenses of us and Enogex, including compensation and benefits of operating personnel, and for the provision of various general and administrative services for our benefit. Specifically, we and Enogex will reimburse OGE Energy for the following expenses:

- general and administrative services, which are capped at $ million annually for three years, subject to increases based on increases in the Consumer Price Index and subject to further increases in connection with expansions of our operations through the acquisition or construction of new assets or businesses, including the acquisition of additional interests in Enogex from OGE Energy, with the concurrence of our conflicts committee; thereafter, our general partner will determine the general and administrative expenses to be allocated to us in accordance with our partnership agreement; and
- operations and certain direct expense, which are not subject to the $ million cap for general and administrative expenses.

Pursuant to these arrangements, OGE Energy will perform centralized corporate functions for us and Enogex, such as legal, accounting, treasury, finance, investor relations, insurance administration and claims processing, risk management, health, safety and environmental, information technology, human resources, credit, payroll, internal audit, taxes, facilities, fleet management and media services. We and Enogex will reimburse OGE Energy for the direct expenses to provide these services as well as other direct expenses it incurs on our behalf, such as compensation of operational personnel performing services for our or Enogex's benefit and the cost of their employee benefits, including 401(k), pension and health insurance benefits.

Competition

OGE Energy will not be restricted, under either our partnership agreement or the omnibus agreement, from competing with us. OGE Energy may acquire, construct or dispose of additional midstream energy or other assets in the future without any obligation to offer us the opportunity to purchase or construct those assets.

Indemnification

Under the omnibus agreement, OGE Energy will indemnify us and Enogex for three years after the closing of this offering against certain potential environmental claims, losses and expenses associated with the operation of Enogex's assets and occurring before the closing date of this offering that are not reserved on the books of Enogex Predecessor as of the closing date of this offering. OGE Energy's maximum liability for this indemnification obligation will not exceed $ million and OGE Energy will not have any obligation under this indemnification until our aggregate losses exceed $. Enogex has agreed to indemnify OGE Energy against environmental liabilities related to Enogex's assets arising or occurring after the closing date of this offering.

Additionally, OGE Energy will indemnify us for losses attributable to pre-closing encumbrances on the 25% interest in Enogex that OGE Energy will contribute to us at closing and will indemnify us and Enogex for losses attributable to pre-closing litigation relating to Enogex's assets, income taxes attributable to Enogex's pre-closing operations, in each case, that are not reserved on the books of Enogex Predecessor as of the closing of this offering and certain defects in title to Enogex's assets as of the closing of this offering and any failure to obtain prior to the closing of this offering certain consents and permits necessary to operate those assets. Enogex will indemnify OGE Energy for all losses attributable to the post-closing operations of the assets contributed to it, to the extent not subject to OGE Energy's indemnification obligations. OGE Energy's obligations under this additional indemnification will survive for three years after the closing of this offering, except that the indemnification for income tax liabilities will terminate upon the expiration of the applicable statute of limitations.

Contribution, Conveyance and Assumption Agreement

Pursuant to a Contribution, Conveyance and Assumption Agreement, OGE Energy, OGE Enogex Holdings LLC and their affiliates have agreed to contribute to our wholly owned subsidiary a 25% membership interest in Enogex.

As consideration for these assets and agreements, we have agreed to issue 3,280,605 common units, 10,780,605 subordinated units, collectively representing approximately 65.2% of the common and subordinated units to be outstanding immediately after this offering (assuming no exercise of the underwriters' option to purchase additional common units), to OGE Enogex Holdings and issue a 2% general partner interest and the incentive distribution rights to OGE Enogex GP LLC.

Enogex LLC Limited Liability Company Agreement

OGE Enogex Holdings LLC, which is a wholly owned subsidiary of OGE Energy, and Enogex Operating LLC, which is our wholly owned subsidiary, will enter into a limited liability company operating agreement. This agreement will govern the ownership and management of Enogex and designate Enogex Operating LLC as the managing member of Enogex. In addition, the agreement will provide that the amount of cash reserves for future maintenance capital expenditures, working capital and other matters and the amount of monthly cash distributions to Enogex's members will be determined by the managing member. In addition, approval of the following actions relating to Enogex is required by the board of directors of our general partner:

- effecting any merger or consolidation involving Enogex;
- effecting any sale or exchange of all or substantially all of Enogex's assets;
- dissolving or liquidating Enogex;
- creating or causing to exist any consensual restriction on the ability of Enogex or its subsidiaries to make distributions, pay any indebtedness, make loans or advances or transfer assets to us or our subsidiaries;
- settling or compromising any claim, dispute or litigation directly against, or otherwise relating to indemnification by Enogex of, any of the directors or officers of OGE Enogex GP LLC or Enogex Operating LLC; or
- issuing additional membership interests in Enogex.

Approval of the conflicts committee of our general partner's board of directors will be required to amend Enogex's limited liability company operating agreement.

Contracts with Affiliates

Transportation and Storage Agreement with OG&E

As part of a 2002 settlement agreement with the OCC, OG&E agreed to consider competitive bidding as a basis to select its provider for gas transportation service to its natural gas-fired electric generation facilities pursuant to the terms set forth in the 2002 settlement agreement. Because the required integrated service was not available in the marketplace from parties other than us, OG&E advised the OCC that, after careful consideration, competitive bidding for gas transportation was rejected in favor of a new intrastate integrated, firm no-notice load following gas transportation and storage services agreement with us. This seven-year agreement provides for gas transportation and storage services for each of OG&E's natural gas-fired electric generation facilities. OG&E has indicated to us that it currently intends to consider competitive bids for gas transportation and storage services prior to the termination of Enogex's current agreement with OG&E on April 30, 2009, but it is not obligated to do so.

OG&E will pay us annual demand fees of approximately $46.8 million for the right to transport specified maximum daily quantities, or MDQs, and maximum hourly quantities, or MHQs, of gas at various minimum gas delivery pressures depending on the operational needs of the individual generation facility. In addition, OG&E supplies system fuel in-kind for its pro-rata share of actual fuel and lost and unaccounted for gas on the transportation system. To the extent OG&E transports gas in quantities exceeding the prescribed MDQs or MHQs, it pays an overrun service charge. During the years ended December 31, 2006, 2005 and 2004, OG&E paid us approximately $47.6 million, $47.6 million and $49.6 million, respectively, for gas transportation and storage services.

CONFLICTS OF INTEREST AND FIDUCIARY DUTIES

Conflicts of Interest

Conflicts of interest exist and may arise in the future as a result of the relationships between our general partner and its affiliates (including OGE Energy) on the one hand, and us and our unaffiliated limited partners, on the other hand. The directors and executive officers of our general partner have certain fiduciary duties to manage our general partner in a manner beneficial to its owner, an affiliate of OGE Energy. At the same time, our general partner has a fiduciary duty to manage us in a manner beneficial to us and our unitholders. OGE Energy has the authority to appoint our general partner's directors, who in turn appoints our general partner's executive officers.

Conflicts of interest may arise as a result of the relationships between us and our unitholders, on the one hand, and Enogex, its managing member and its non-managing member, OGE Enogex Holdings LLC, on the other hand. OGE Enogex Holdings LLC owns a 75% membership interest in Enogex and controls our general partner. The directors and officers of Enogex's managing member have fiduciary duties to manage Enogex in a manner beneficial to us, as such managing member's owner. At the same time, Enogex's managing member has a fiduciary duty to manage Enogex in a manner beneficial to Enogex's non-managing member, OGE Enogex Holdings LLC. The board of directors of our general partner may resolve any such conflict and has broad latitude to consider the interests of all parties to the conflict. The resolution of these conflicts may not always be in the best interest of us or our unitholders.

Whenever a conflict arises between our general partner or its affiliates, on the one hand, and us or any other partner, on the other hand, our general partner will resolve that conflict. Our partnership agreement contains provisions that modify and limit our general partner's fiduciary duties to our unitholders. Our partnership agreement also restricts the remedies available to unitholders for actions taken by our general partner that, without those limitations, might constitute breaches of fiduciary duty.

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 the conflict is:

- approved by the conflicts committee, although our general partner is not obligated to seek such approval;
- approved by the vote of a majority of the outstanding common units, excluding any common units owned by our general partner or any of its affiliates;
- on terms no less favorable to us than those generally being provided to or available from unrelated third parties; or
- fair and reasonable to us, taking into account the totality of the relationships among the parties involved, including other transactions that may be particularly favorable or advantageous to us.

Our general partner may, but is not required to, seek the approval of such resolution from the conflicts committee of its board of directors. If our general partner does not seek approval from the conflicts committee and its board of directors determines that the resolution or course of action taken with respect to the conflict of interest satisfies either of the standards set forth in the third or fourth bullet points above, then it will be presumed that, in making its decision, the board of directors acted in good faith, and in any proceeding brought by or on behalf of any limited partner or the partnership, the person bringing or prosecuting such proceeding will have the burden of overcoming such presumption. Unless the resolution of a conflict is specifically provided for in our partnership agreement, our general partner or the conflicts committee may consider any factors it determines in good faith to consider when resolving a conflict.

Conflicts of interest could arise in the situations described below, among others.

After this offering, our wholly owned subsidiary will own a 25% membership interest in Enogex, and a wholly owned subsidiary of OGE Energy will own the remaining 75% membership interest. OGE Energy is not obligated to offer to us the remaining 75% interest in Enogex.

After this offering, our wholly owned subsidiary will own a 25% membership interest in Enogex, and OGE Energy will retain, through a wholly owned subsidiary, the remaining 75% membership interest. OGE Energy is under no obligation to offer to us the opportunity to purchase over time the remaining 75% interest in Enogex. The board of directors of OGE Energy owes fiduciary duties to its shareholders, and not our unitholders, in making any decision to offer us this opportunity. Furthermore, the execution of any purchase agreement with respect to any interest in Enogex will be subject to the approval of the conflicts committee of our general partner. The consummation of any such purchase will also be conditioned upon, among other things, our ability to finance the purchase and our obtaining all necessary consents. Please see "Conflicts of Interest and Fiduciary Duties."

OGE Energy is not limited in its ability to compete with us, which could cause conflicts of interest and limit our ability to acquire additional assets or businesses, which in turn could adversely affect our results of operations and cash available for distribution to our unitholders.

Neither our partnership agreement nor the omnibus agreement between us, our general partner and OGE Energy and certain of its affiliates will prohibit OGE Energy and its affiliates (other than our general partner) from owning assets or engaging in businesses that compete directly or indirectly with us. In addition, OGE Energy 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. OGE Energy is a large, established participant in the energy business, and has significantly greater resources than we have, which factors may make it more difficult for us to compete with OGE Energy with respect to commercial activities as well as for acquisition candidates. As a result, competition from OGE Energy and its affiliates could adversely impact our results of operations and cash available for distribution to our unitholders.

Neither our partnership agreement nor any other agreement requires OGE Energy to pursue a business strategy that favors us or utilizes Enogex's assets or dictates what markets to pursue or grow. OGE Energy's directors have a fiduciary duty to make these decisions in the best interests of the owners of OGE Energy, which may be contrary to our interests.

Because certain of the directors and executive officers of our general partner are also directors and/or officers of OGE Energy, such directors and officers have fiduciary duties to OGE Energy that may cause them to pursue business strategies that disproportionately benefit OGE Energy or that otherwise are not in our best interests.

Our general partner is allowed to take into account the interests of parties other than us, such as OGE Energy, in resolving conflicts of interest.

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 our unitholders. Decisions made by our general partner in its individual capacity will be made by OGE Energy and not by the board of directors of our general partner. Examples include the exercise of its limited call right, its voting rights with respect to any units it owns, its registration rights and its determination whether to consent to any merger or consolidation involving us.

We will not have any employees and will rely on the employees of OGE Energy and its affiliates.

All of the executive officers of our general partner will be employees of OGE Energy and will devote a portion of their time to our business and affairs. We will also utilize a significant number of employees of OGE Energy and Enogex to operate our business and provide us with general and administrative services for which we and Enogex will reimburse OGE Energy for allocated expenses of operational personnel who perform services for our benefit and we and Enogex will reimburse OGE Energy for allocated general and administrative expenses. OGE Energy and its affiliates will conduct businesses and activities of their own in which we will have no economic interest. If these separate activities are significantly greater than our activities, there could be material competition for the time and effort of the employees who provide services to us.

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 duties owed to our unitholders.

Although our general partner has a fiduciary duty to manage us in a manner beneficial to us and our unitholders, the directors and executive officers of our general partner have a fiduciary duty to manage our general partner in a manner beneficial to OGE Energy, its ultimate parent. Our partnership agreement contains provisions that reduce the standards to which our general partner would otherwise be held by state fiduciary duty laws and also contains provisions that restrict the remedies available to unitholders for actions taken by our general partner that might otherwise constitute breaches of fiduciary duties. 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 in such cases it has no duty or obligation to give any consideration to any interest of, or factors affecting, us, our affiliates or our unitholders. Decisions made by our general partner in its individual capacity will be made by OGE Energy and not by the board of directors of our general partner. Examples include the exercise of its limited call right, its rights to vote or transfer common units that it owns, its registration rights and the determination of whether to consent to any merger or consolidation of the partnership;
- provides that our general partner will not have any liability to us or our unitholders for decisions made in its capacity as a general partner so long as it acted in good faith;
- generally provides that affiliated transactions and resolutions of conflicts of interest not approved by the conflicts committee of the board of directors of our general partner 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 must 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;
- provides that our general partner and its executive officers and directors will not be liable for monetary damages to us or our limited partners for any acts or omissions unless there has been a final and non-appealable judgment entered by a court of competent jurisdiction determining that our general partner or those other persons acted in bad faith or engaged in fraud or willful

misconduct or, in the case of a criminal matter, acted with knowledge that the conduct was criminal; and

- provides that in resolving conflicts of interest, it will be presumed that in making its decision that our general partner acted in good faith, and in any proceeding brought by or on behalf of any limited partner or us, the person bringing or prosecuting such proceeding will have the burden of overcoming such presumption.

By purchasing a common unit, a common unitholder will agree to become bound by the provisions in our partnership agreement, including the provisions discussed above.

Except in limited circumstances, our general partner has the power and authority to conduct our business without unitholder approval.

Under our partnership agreement, our general partner has full power and authority to do all things, other than those items that require unitholder approval or with respect to which our general partner has sought conflicts committee approval, on such terms as it determines to be necessary or appropriate to conduct our business including, but not limited to, the following:

- the making of any expenditures, the lending or borrowing of money, the assumption or guarantee of or other contracting for, indebtedness and other liabilities, the issuance of evidences of indebtedness, including indebtedness that is convertible into our securities, and the incurring of any other obligations;
- the purchase, sale or other acquisition or disposition of our securities, or the issuance of additional options, rights, warrants and appreciation rights relating to our securities;
- the mortgage, pledge, encumbrance, hypothecation or exchange of any or all of our assets;
- the negotiation, execution and performance of any contracts, conveyances or other instruments;
- the distribution of our cash;
- the selection and dismissal of employees and agents, outside attorneys, accountants, consultants and contractors and the determination of their compensation and other terms of employment or hiring;
- the maintenance of insurance for our benefit and the benefit of our partners;
- the formation of, or acquisition of an interest in, the contribution of property to, and the making of loans to, any limited or general partnerships, joint ventures, corporations, limited liability companies or other relationships;
- the control of any matters affecting our rights and obligations, including the bringing and defending of actions at law or in equity and otherwise engaging in the conduct of litigation, arbitration or mediation and the incurring of legal expense and the settlement of claims and litigation;
- the indemnification of any person against liabilities and contingencies to the extent permitted by law;
- the making of tax, regulatory and other filings, or rendering of periodic or other reports to governmental or other agencies having jurisdiction over our business or assets; and
- the entering into of agreements with any of its affiliates to render services to us or to itself in the discharge of its duties as our general partner.

Our partnership agreement provides that our general partner must act in good faith when making decisions on our behalf. Please see "The Partnership Agreement—Voting Rights" for information regarding matters that require unitholder approval.

Our general partner determines the amount and timing of asset purchases and sales, capital expenditures, borrowings, issuance of additional partnership securities and the creation, reduction or increase of reserves, each of which can affect the amount of cash that is distributed to our unitholders.

The amount of cash that is available for distribution to our unitholders is affected by decisions of our general partner regarding such matters as:

- amount and timing of asset purchases and sales;
- cash expenditures;
- borrowings;
- the issuance of additional units; and
- the creation, reduction or increase of reserves in any quarter.

In addition, our general partner may use an amount equal to two times the amount needed to pay the minimum quarterly distribution on our units, which would not otherwise constitute available cash from operating surplus, in order to permit the payment of cash distributions on its units and incentive distribution rights. All of these actions may affect the amount of cash distributed to our unitholders and our general partner and may facilitate the conversion of subordinated units into common units. Please see "Provisions of Our Partnership Agreement Relating to Cash Distributions."

In addition, borrowings by us and our affiliates do not constitute a breach of any duty owed by our general partner to our unitholders, including borrowings that have the purpose or effect of:

- enabling our general partner or its affiliates to receive distributions on any subordinated units held by them or the incentive distribution rights; or
- hastening the expiration of the subordination period.

For example, in the event we have not generated sufficient cash from our operations to pay the minimum quarterly distribution on our common units and our subordinated units, our partnership agreement permits us to borrow funds, which would enable us to make this distribution on all outstanding units. Please see "Provisions of Our Partnership Agreement Relating to Cash Distributions—Subordination Period."

Our partnership agreement provides that we and our subsidiaries may borrow funds from our general partner and its affiliates. Our general partner and its affiliates may not borrow funds from us or our subsidiaries.

We will reimburse costs incurred by our general partner and its affiliates.

To the extent not otherwise provided for in the omnibus agreement, we and Enogex will reimburse our general partner and its affiliates for costs incurred in managing and operating us and Enogex, including costs incurred in rendering corporate staff and support services to us and Enogex. Our partnership agreement provides that our general partner will determine the expenses that are allocable to us in good faith. Please see "Certain Relationships and Related Party Transactions—Omnibus Agreement."

Our partnership agreement does not restrict our general partner from causing us to pay it or its affiliates for any services rendered to us or Enogex or entering into additional contractual arrangements with any of these entities on our behalf.

Our partnership agreement allows our general partner to determine, in good faith, any amounts to pay itself or its affiliates for any services rendered to us or Enogex. Our general partner may also enter into additional contractual arrangements with any of its affiliates on our behalf. Neither our partnership agreement nor any of the other agreements, contracts or arrangements between us, on the one hand, and our general partner and its affiliates, on the other hand, that will be in effect as of the closing of this offering be the result of arm's-length negotiations. Similarly, agreements, contracts or arrangements between us and our general partner and its affiliates that are entered into following the closing of this offering will not be required to be negotiated on an arm's-length basis, although, in some circumstances, our general partner may determine that the conflicts committee of our general partner may make a determination on our behalf with respect to one or more of these types of situations.

Our general partner will determine, in good faith, the terms of any of these transactions entered into after the sale of the common units offered in this offering.

Our general partner and its affiliates will have no obligation to permit us or Enogex to use any facilities or assets of our general partner or its affiliates, except as may be provided in contracts entered into specifically dealing with that use. There is no obligation of our general partner or its affiliates to enter into any contracts of this kind.

Our general partner intends to limit its liability regarding our obligations.

Our general partner intends to limit its liability under contractual arrangements so that the other party has recourse only to our assets, and not against our general partner or its assets. Our partnership agreement provides that any action taken by our general partner to limit its liability is not a breach of our general partner's fiduciary duties, even if we could have obtained more favorable terms without the limitation on liability.

Our general partner may exercise its right to call and purchase common units if it and its affiliates own more than 80% of the common units.

Our general partner may exercise its right to call and purchase common units as provided in our partnership agreement or assign this right to one of its affiliates or to us. Our general partner is not bound by fiduciary duty restrictions in determining whether to exercise this right. As a result, a common unitholder may have his common units purchased from him at an undesirable time or price. Please see "The Partnership Agreement—Limited Call Right."

Common unitholders will have no right to enforce obligations of our general partner and its affiliates under agreements with us.

Any agreements between us on the one hand, and our general partner and its affiliates, on the other, will not grant to the unitholders, separate and apart from us, the right to enforce the obligations of our general partner and its affiliates in our favor.

We may choose not to retain separate counsel for ourselves or the holders of common units in the event of a conflict of interest with our general partner and its affiliates.

The attorneys, independent accountants and others who have performed services for us regarding this offering have been retained by our general partner. Attorneys, independent accountants and others who perform services for us are selected by our general partner or the conflicts committee and may perform services for our general partner and its affiliates. We may retain separate counsel for ourselves or the holders of common units in the event of a conflict of interest between our general partner and its affiliates, on the one hand, and us or the holders of common units, on the other, depending on the nature of the conflict. We do not intend to do so in most cases.

Our general partner may elect to cause us to issue Class B units to it in connection with a resetting of the target distribution levels related to our general partner's incentive distribution rights without the approval of the conflicts committee of our general partner or our unitholders. This may result in lower distributions to our unitholders in certain situations.

Our general partner has the right, at a time when there are no subordinated units outstanding and it has received incentive distributions at the highest level to which it is entitled (48%) for each of the prior four consecutive quarters, to reset the initial cash target distribution levels at higher levels based on the distribution at the time of the exercise of the reset election. Following a reset election by our general partner, the minimum quarterly distribution amount will be reset to an amount equal to the average cash distribution amount per common unit for the two quarters immediately preceding the reset election (such amount is referred to herein as the "reset minimum quarterly distribution") and the target distribution levels will be reset to correspondingly higher levels based on percentage increases above the reset minimum quarterly distribution amount.

In connection with resetting these target distribution levels, our general partner will be entitled to receive a number of Class B units. The Class B units will be entitled to the same cash distributions per unit as our common units and will be convertible into an equal number of common units. The number of Class B units to be issued will be equal to that number of common units whose aggregate quarterly cash distributions equaled the average of the distributions to our general partner on the incentive distribution rights in the prior two quarters. We anticipate that our general partner would exercise this reset right in order to facilitate acquisitions or internal growth projects that would not be sufficiently accretive to cash distributions per common unit without such conversion; however, it is possible that our general partner could exercise this reset election at a time when it is experiencing, or may be expected to experience, declines in the cash distributions it receives related to its incentive distribution rights and may therefore desire to be issued our Class B units, which are entitled to receive cash distributions from us on the same priority as our common units, rather than retain the right to receive incentive distributions based on the initial target distribution levels. As a result, a reset election may cause our common unitholders to experience dilution in the amount of cash distributions that they would have otherwise received had we not issued new Class B units to our general partner in connection with resetting the target distribution levels related to our general partner incentive distribution rights. Please see "Provisions of Our Partnership Agreement Relating to Cash Distributions—General Partner Interest and Incentive Distribution Rights."

Fiduciary Duties

Our general partner is accountable to us and our unitholders as a fiduciary. Fiduciary duties owed to unitholders by our general partner are prescribed by law and our partnership agreement. The Delaware Act provides that Delaware limited partnerships may, in their partnership agreements, modify, restrict or expand the fiduciary duties otherwise owed by a general partner to limited partners and the partnership.

Our partnership agreement contains various provisions modifying and restricting the fiduciary duties that might otherwise be owed by our general partner. We have adopted these restrictions to allow our general partner or its affiliates to engage in transactions with us that would otherwise be prohibited by state law fiduciary duty standards and to take into account the interests of other parties in addition to our interests when resolving conflicts of interest. We believe this is appropriate and necessary because our general partner's board of directors will have fiduciary duties to manage our general partner in a manner beneficial to its owners and fiduciary duties to manage us in a manner beneficial to our unitholders. Without these modifications, our general partner's ability to make decisions involving conflicts of interest would be restricted. The modifications to the fiduciary standards enable our general partner to take into consideration all parties involved in the proposed action, so long as the resolution is fair and reasonable to us. However, these modifications also enable our general partner to attract and retain experienced and capable directors. These modifications are detrimental to our common unitholders because they restrict the remedies available to unitholders for actions that, without those limitations, might constitute breaches of fiduciary duty, as described below, and permit our general partner to take into account the interests of parties, other than us, when resolving conflicts of interest. The following is a summary of the material restrictions of the fiduciary duties owed by our general partner to the limited partners:

State law fiduciary duty standards	Fiduciary duties are generally considered to include an obligation to act in good faith and with due care and loyalty. The duty of care, in the absence of a provision in a partnership agreement providing otherwise, would generally require a general partner to act for the partnership in the same manner as a prudent person would act on his own behalf. The duty of loyalty, in the absence of a provision in a partnership agreement providing otherwise, would generally prohibit a general partner of a Delaware limited partnership from taking any action or engaging in any transaction where a conflict of interest is present. The Delaware Act generally provides that a limited partner may institute legal action on behalf of the partnership to recover damages from a third party where a general partner has refused to institute the action or where an effort to cause a general partner to do so is not likely to succeed. In addition, the statutory or case law of some jurisdictions may permit a limited partner to institute legal action on behalf of himself and all other similarly situated limited partners to recover damages from a general partner for violations of its fiduciary duties to the limited partners.

Partnership agreement modified standards	Our partnership agreement contains provisions that waive or consent to conduct by our general partner and its affiliates that might otherwise raise issues about compliance with fiduciary duties or applicable law. For example, our partnership agreement provides that when our general partner is acting in its capacity as our general partner, as opposed to in its individual capacity, it must act in "good faith" and will not be subject to any other standard under applicable law. In addition, when our general partner is acting in its individual capacity, as opposed to in its capacity as our general partner, it may act without any fiduciary obligation to us or the unitholders whatsoever. These provisions reduce the standards to which our general partner would otherwise be held. In addition to the other more specific provisions limiting the obligations of our general partner, our partnership agreement further provides that our general partner and the officers and directors of our general partner will not be liable for monetary damages to us or our limited partners for errors of judgment or for any acts or omissions unless there has been a final and non-appealable judgment by a court of competent jurisdiction determining that our general partner or the officers and directors of our general partner acted in bad faith or engaged in fraud or willful misconduct or, in the case of a criminal matter, acted with knowledge that the conduct was unlawful. Our partnership agreement generally provides that affiliated transactions and resolutions of conflicts of interest not involving a vote of unitholders and that are not approved by the conflicts committee of the board of directors of our general partner must be: • on terms no less favorable to us than those generally being provided to or available from unrelated third parties; or • "fair and reasonable" to us, taking into account the totality of the relationships between the parties involved (including other transactions that may be particularly favorable or advantageous to us).

If our general partner does not seek approval from the conflicts committee and its board of directors determines that the resolution or course of action taken with respect to the conflict of interest satisfies either of the standards set forth in the bullet points above, then it will be presumed that, in making its decision, the board of directors, which may include board members affected by the conflict of interest, acted in good faith and in any proceeding brought by or on behalf of any limited partner or the partnership, the person bringing or prosecuting such proceeding will have the burden of overcoming such presumption. These standards reduce the obligations to which our general partner would otherwise be held.

By purchasing our common units, each common unitholder automatically agrees to be bound by the provisions in our partnership agreement, including the provisions discussed above. This is in accordance with the policy of the Delaware Act favoring the principle of freedom of contract and the enforceability of partnership agreements. The failure of a limited partner to sign a partnership agreement does not render the partnership agreement unenforceable against that person.

Under our partnership agreement, we must indemnify our general partner and the officers and directors of our general partner and certain other specified persons, to the fullest extent permitted by law, against liabilities, costs and expenses incurred by our general partner or these other persons. We must provide this indemnification unless there has been a final and non-appealable judgment by a court of competent jurisdiction determining that these persons acted in bad faith or engaged in fraud or willful misconduct. We must also provide this indemnification for criminal proceedings unless our general partner or these other persons acted with knowledge that their conduct was unlawful. Thus, our general partner could be indemnified for its negligent acts if it meets the requirements set forth above. To the extent these provisions purport to include indemnification for liabilities arising under the Securities Act, in the opinion of the SEC such indemnification is contrary to public policy and, therefore, unenforceable. Please see "The Partnership Agreement—Indemnification."

DESCRIPTION OF THE COMMON UNITS

The Units

The common units and the subordinated units are separate classes of limited partner interests in us. The holders of units are entitled to participate in partnership distributions and exercise the rights or privileges available to limited partners under our partnership agreement. For a description of the relative rights and preferences of holders of common units and subordinated units in and to partnership distributions, please see this section and "Provisions of Our Partnership Agreement Relating to Cash Distributions." For a description of the rights and privileges of limited partners under our partnership agreement, including voting rights, please see "The Partnership Agreement."

Transfer Agent and Registrar

Duties

will serve as registrar and transfer agent for the common units. We will pay all fees charged by the transfer agent for transfers of common units except the following that must be paid by unitholders:

- surety bond premiums to replace lost or stolen certificates, taxes and other governmental charges;
- special charges for services requested by a common unitholder; and
- other similar fees or charges.

There will be no charge to unitholders for disbursements of our cash distributions. We will indemnify the transfer agent, its agents and each of their stockholders, directors, officers and employees against all claims and losses that may arise out of acts performed or omitted for its activities in that capacity, except for any liability due to any gross negligence or intentional misconduct of the indemnified person or entity.

Resignation or Removal

The transfer agent may resign, by notice to us, or be removed by us. The resignation or removal of the transfer agent will become effective upon our appointment of a successor transfer agent and registrar and its acceptance of the appointment. If no successor has been appointed and has accepted the appointment within 30 days after notice of the resignation or removal, our general partner may act as the transfer agent and registrar until a successor is appointed.

Transfer of Common Units

By transfer of common units in accordance with our partnership agreement, each transferee of common units shall be admitted as a limited partner with respect to the common units transferred when such transfer and admission is reflected in our books and records. Each transferee:

- represents that the transferee has the capacity, power and authority to become bound by our partnership agreement;
- automatically agrees to be bound by the terms and conditions of, and is deemed to have executed, our partnership agreement; and
- gives the consents and approvals contained in our partnership agreement, such as the approval of all transactions and agreements that we are entering into in connection with our formation and this offering.

A transferee will become a substituted limited partner of our partnership for the transferred common units automatically upon the recording of the transfer on our books and records.

We may, at our discretion, treat the nominee holder of a common unit as the absolute owner. In that case, the beneficial holder's rights are limited solely to those that it has against the nominee holder as a result of any agreement between the beneficial owner and the nominee holder.

Common units are securities and are transferable according to the laws governing transfers of securities. In addition to other rights acquired upon transfer, the transferor gives the transferee the right to become a substituted limited partner in our partnership for the transferred common units.

Until a common unit has been transferred on our books, we and the transfer agent may treat the record holder of the unit as the absolute owner for all purposes, except as otherwise required by law or stock exchange regulations.

THE PARTNERSHIP AGREEMENT

The following is a summary of the material provisions of our partnership agreement. The form of our partnership agreement is included in this prospectus as Appendix A. We will provide prospective investors with a copy of our partnership agreement upon request at no charge.

We summarize the following provisions of our partnership agreement elsewhere in this prospectus:

- with regard to distributions of available cash, please see "Provisions of Our Partnership Agreement Relating to Cash Distributions";
- with regard to the fiduciary duties of our general partner, please see "Conflicts of Interest and Fiduciary Duties";
- with regard to the transfer of common units, please see "Description of the Common Units—Transfer of Common Units"; and
- with regard to allocations of taxable income and taxable loss, please see "Material Tax Consequences."

Organization and Duration

Our partnership was organized on May 30, 2007 and will have a perpetual existence unless terminated pursuant to the terms of our partnership agreement.

Purpose

Our purpose under the partnership agreement is limited to any business activity that is approved by our general partner and that lawfully may be conducted by a limited partnership organized under Delaware law; provided, that our general partner shall not cause us to engage, directly or indirectly, in any business activity that our general partner determines would cause us to be treated as an association taxable as a corporation or otherwise taxable as an entity for federal income tax purposes.

Although our general partner has the ability to cause us and our subsidiaries to engage in activities other than the business of gathering, processing, transporting and marketing natural gas, our general partner has no current plans to do so and may decline to do so free of any fiduciary duty or obligation whatsoever to us or the limited partners, including any duty to act in good faith or in the best interests of us or the limited partners. Our general partner is authorized in general to perform all acts it determines to be necessary or appropriate to carry out our purposes and to conduct our business.

Power of Attorney

Each limited partner, and each person who acquires a unit from a unitholder, by accepting the common unit, automatically grants to our general partner and, if appointed, a liquidator, a power of attorney to, among other things, execute and file documents required for our qualification, continuance or dissolution. The power of attorney also grants our general partner the authority to amend, and to make consents and waivers under, our partnership agreement.

Cash Distributions

Our partnership agreement specifies the manner in which we will make cash distributions to holders of our common units and other partnership securities as well as to our general partner in respect of its general partner interest and its incentive distribution rights. For a description of these cash distribution provisions, please see "Provisions of Our Partnership Agreement Relating to Cash Distributions."

Capital Contributions

Unitholders are not obligated to make additional capital contributions, except as described below under "—Limited Liability."

Our general partner has the right, but not the obligation, to contribute a proportionate amount of capital to us to maintain its 2% general partner interest if we issue additional units. Our general partner's 2% interest, and the percentage of our cash distributions to which it is entitled, will be proportionately reduced if we issue additional units in the future and our general partner does not contribute a proportionate amount of capital to us to maintain its 2% general partner interest. Our general partner will be entitled to make a capital contribution in order to maintain its 2% general partner interest in the form of the contribution to us of common units based on the current market value of the contributed common units.

Voting Rights

The following is a summary of the unitholder vote required for the matters specified below. Matters requiring the approval of a "unit majority" require:

- during the subordination period, the approval of a majority of the common units, excluding those common units held by our general partner and its affiliates, and a majority of the subordinated units, voting as separate classes; and
- after the subordination period, the approval of a majority of the common units and Class B units, if any, voting as a class.

In voting their common, Class B and subordinated units, our general partner and its affiliates will have no fiduciary duty or obligation whatsoever to us or our limited partners, including any duty to act in good faith or in the best interests of us or our limited partners.

Issuance of additional units	No approval right.
Amendment of the partnership agreement	Certain amendments may be made by our general partner without the approval of the unitholders. Other amendments generally require the approval of a unit majority. Please see "—Amendment of the Partnership Agreement."
Merger of our partnership or the sale of all or substantially all of our assets	Unit majority in certain circumstances. Please see "—Merger, Consolidation, Conversion, Sale or Other Disposition of Assets."
Dissolution of our partnership	Unit majority. Please see "—Termination and Dissolution."
Continuation of our business upon dissolution	Unit majority. Please see "—Termination and Dissolution."
Withdrawal of our general partner	Under most circumstances, the approval of a majority of the common units, excluding common units held by our general partner and its affiliates, is required for the withdrawal of our general partner prior to January 1, 2018 in a manner that would cause a dissolution of our partnership.

	Please see "—Withdrawal or Removal of the General Partner."
Removal of our general partner	Not less than 66⅔% of the outstanding units, voting as a single class, including units held by our general partner and its affiliates. Please see "—Withdrawal or Removal of the General Partner."
Transfer of our general partner interest	Our general partner may transfer all, but not less than all, of its general partner interest in us without a vote of our unitholders to an affiliate or another person in connection with its merger or consolidation with or into, or sale of all or substantially all of its assets, to such person. The approval of a majority of the common units, excluding common units held by our general partner and its affiliates, is required in other circumstances for a transfer of the general partner interest to a third party prior to January 1, 2018. Please see " —Transfer of General Partner Interest."
Transfer of incentive distribution rights	Except for transfers to an affiliate or to another person as part of our general partner's merger or consolidation with or into, or sale of all or substantially all of its assets, to such person, the approval of a majority of the common units, excluding common units held by our general partner and its affiliates, is required in most circumstances for a transfer of the incentive distribution rights to a third party prior to January 1, 2018. Please see "—Transfer of Incentive Distribution Rights."
Transfer of membership interests in our general partner	No approval required at any time. Please see "—Transfer of Membership Interests in Our General Partner."

Limited Liability

Assuming that a limited partner does not participate in the control of our business within the meaning of the Delaware Act and that it otherwise acts in conformity with the provisions of our partnership agreement, its liability under the Delaware Act will be limited, subject to possible exceptions, to the amount of capital it is obligated to contribute to us for its common units plus its share of any undistributed profits and assets. If it were determined, however, that the right, or exercise of the right, by the limited partners as a group:

- to remove or replace our general partner;
- to approve some amendments to our partnership agreement; or
- to take other action under our partnership agreement;

constituted "participation in the control" of our business for the purposes of the Delaware Act, then the limited partners could be held personally liable for our obligations under the laws of Delaware, to the same extent as our general partner. This liability would extend to persons who transact business with us who reasonably believe that the limited partner is a general partner. Neither our partnership agreement nor the Delaware Act specifically provides for legal recourse against our general partner if a limited partner were to lose limited liability through any fault of our general partner. While this does not mean that a limited partner could not seek legal recourse, we know of no precedent for this type of a claim in Delaware case law.

Under the Delaware Act, a limited partnership may not make a distribution to a partner if, after the distribution, all liabilities of the limited partnership, other than liabilities to partners on account of their partner interests and liabilities for which the recourse of creditors is limited to specific property of the partnership, would exceed the fair value of the assets of the limited partnership. For the purpose of determining the fair value of the assets of a limited partnership, the Delaware Act provides that the fair value of property subject to liability for which recourse of creditors is limited shall be included in the assets of the limited partnership only to the extent that the fair value of that property exceeds the nonrecourse liability. The Delaware Act provides that a limited partner who receives a distribution and knew at the time of the distribution that the distribution was in violation of the Delaware Act shall be liable to the limited partnership for the amount of the distribution for three years. Under the Delaware Act, a substituted limited partner of a limited partnership is liable for the obligations of its assignor to make contributions to the partnership, except that such person is not obligated for liabilities unknown to him at the time it became a limited partner and that could not be ascertained from the partnership agreement.

Our subsidiaries conduct business primarily in Oklahoma and Texas, although we or our subsidiaries may conduct business in other states in the future. Maintenance of our limited liability as a controlling member of the operating company may require compliance with legal requirements in the jurisdictions in which the operating company conducts business, including qualifying our subsidiaries to do business there.

Limitations on the liability of limited partners for the obligations of a limited partnership have not been clearly established in many jurisdictions. If, by virtue of our membership interest in our operating company or otherwise, it were determined that we were conducting business in any state without compliance with the applicable limited partnership or limited liability company statute, or that the right or exercise of the right by the limited partners as a group to remove or replace our general partner, to approve some amendments to our partnership agreement, or to take other action under our partnership agreement constituted "participation in the control" of our business for purposes of the statutes of any relevant jurisdiction, then the limited partners could be held personally liable for our obligations under the law of that jurisdiction to the same extent as our general partner under the circumstances. We will operate in a manner that our general partner considers reasonable and necessary or appropriate to preserve the limited liability of the limited partners.

Issuance of Additional Securities

Our partnership agreement authorizes us to issue an unlimited number of additional partnership securities for the consideration and on the terms and conditions determined by our general partner without the approval of the unitholders.

It is possible that we will fund acquisitions through the issuance of additional common units, subordinated units or other partnership securities. Holders of any additional common units we issue will be entitled to share equally with the then-existing holders of common units in our distributions of available cash. In addition, the issuance of additional common units or other partnership securities may dilute the value of the interests of the then-existing holders of common units in our net assets.

In accordance with Delaware law and the provisions of our partnership agreement, we may also issue additional partnership securities that, as determined by our general partner, may have special voting rights to which the common units are not entitled. In addition, our partnership agreement does not prohibit the issuance by our subsidiaries of equity securities, which may effectively rank senior to the common units.

Our general partner's 2% interest in us is represented by unit equivalents for allocation and distribution purposes. Upon issuance of additional partnership securities, our general partner will be entitled, but not required, to make additional capital contributions to us in exchange for a proportionate number of general partner unit equivalents to the extent necessary to maintain its 2% interest in the total number of units and unit equivalents outstanding prior to the issuance of additional partnership securities. Our general partner's 2% general partner interest in us will thus be reduced if we issue additional units in the future (other than the issuance of common units upon exercise by the underwriters of the option to purchase additional common units, the issuance of units in connection with a reset of the incentive distribution target levels relating to our general partner's incentive distribution rights or the issuance of units upon conversion of outstanding partnership securities) and our general partner does not contribute a proportionate amount of capital to us to maintain its 2% general partner interest. Moreover, our general partner will have the right, which it may from time to time assign in whole or in part to any of its affiliates, to purchase common units, subordinated units or other partnership securities whenever, and on the same terms that, we issue those securities to persons other than our general partner and its affiliates, to the extent necessary to maintain the percentage interest of it and its affiliates that existed immediately prior to each such issuance. The holders of common units will not have preemptive rights to acquire additional common units or other partnership securities.

Amendment to the Partnership Agreement

General

Amendments to our partnership agreement may be proposed only by or with the consent of our general partner. However, our general partner will have no duty or obligation to propose any amendment and may decline to do so free of any fiduciary duty or obligation whatsoever to us or the limited partners, including any duty to act in good faith or in the best interests of us or the limited partners. In order to adopt a proposed amendment, other than the amendments discussed below, our general partner is required to seek written approval of the holders of the number of units required to approve the amendment or call a meeting of the limited partners to consider and vote upon the proposed amendment. Except as described below, an amendment must be approved by a unit majority.

Prohibited Amendments

No amendment may:

- enlarge the obligations of any limited partner without its consent, unless approved by at least a majority of the type or class of limited partner interests so affected; or
- enlarge the obligations of, restrict in any way any action by or rights of, or reduce in any way the amounts distributable, reimbursable or otherwise payable by us to our general partner or any of its affiliates without the consent of our general partner, which consent may be given or withheld at its option.

The provision of our partnership agreement preventing the amendments having the effects described in any of the clauses above can be amended upon the approval of the holders of at least 90% of the outstanding units voting together as a single class (including units owned by our general partner and its affiliates). Upon completion of the offering, an affiliate of our general partner will own approximately 65.2% of the outstanding common and subordinated units (approximately 62.0% if the underwriters exercise in full their option to purchase additional common units).

No Limited Partner Approval

Our general partner may generally make amendments to our partnership agreement without the approval of any limited partner to reflect:

- a change in our name, the location of our principal place of our business, our registered agent or our registered office;
- the admission, substitution, withdrawal or removal of partners in accordance with our partnership agreement;
- a change that our general partner determines to be necessary or appropriate to qualify or continue our qualification as a limited partnership or a partnership in which the limited partners have limited liability under the laws of any state or to ensure that neither we nor the operating company nor any of its subsidiaries will be treated as an association taxable as a corporation or otherwise taxed as an entity for federal income tax purposes;
- a change in our fiscal year or taxable year and related changes;
- an amendment that is necessary, in the opinion of our counsel, to prevent us or our general partner or the directors, officers, agents or trustees of our general partner from in any manner being subjected to the provisions of the Investment Company Act of 1940, the Investment Advisors Act of 1940, or "plan asset" regulations adopted under ERISA, whether or not substantially similar to plan asset regulations currently applied or proposed;
- an amendment that our general partner determines to be necessary or appropriate for the authorization of additional partnership securities or rights to acquire partnership securities, including any amendment that our general partner determines is necessary or appropriate in connection with:
  - the adjustments of the minimum quarterly distribution, first target distribution, second target distribution and third target distribution in connection with the reset of our general partner's incentive distribution rights as described under "Provisions of Our Partnership Agreement Relating to Cash Distributions—General Partner's Right to Reset Incentive Distribution Levels";
  - the implementation of the provisions relating to our general partner's right to reset its incentive distribution rights in exchange for Class B units; or
  - any modification of the incentive distribution rights made in connection with the issuance of additional partnership securities or rights to acquire partnership securities, provided that, any such modifications and related issuance of partnership securities have received approval by a majority of the members of the conflicts committee of our general partner;
- any amendment expressly permitted in our partnership agreement to be made by our general partner acting alone;
- an amendment effected, necessitated or contemplated by a merger agreement that has been approved under the terms of our partnership agreement;
- any amendment that our general partner determines to be necessary or appropriate for the formation by us of, or our investment in, any corporation, partnership or other entity, as otherwise permitted by our partnership agreement;

- conversions into, mergers with or conveyances to another limited liability entity that is newly formed and has no assets, liabilities or operations at the time of the conversion, merger or conveyance other than those it receives by way of the conversion, merger or conveyance; or
- any other amendments substantially similar to any of the matters described in the clauses above.

In addition, our general partner may make amendments to our partnership agreement without the approval of any limited partner if our general partner determines that those amendments:

- do not adversely affect the limited partners (or any particular class of limited partners) in any material respect;
- are necessary or appropriate to satisfy any requirements, conditions or guidelines contained in any opinion, directive, order, ruling or regulation of any federal or state agency or judicial authority or contained in any federal or state statute;
- are necessary or appropriate to facilitate the trading of limited partner interests or to comply with any rule, regulation, guideline or requirement of any securities exchange on which the limited partner interests are or will be listed for trading;
- are necessary or appropriate for any action taken by our general partner relating to splits or combinations of units under the provisions of our partnership agreement; or
- are required to effect the intent expressed in this prospectus or the intent of the provisions of our partnership agreement or are otherwise contemplated by our partnership agreement.

Opinion of Counsel and Limited Partner Approval

Our general partner will not be required to obtain an opinion of counsel that an amendment will not result in a loss of limited liability to the limited partners or result in our being treated as an association taxable as a corporation or otherwise taxable as an entity for federal income tax purposes in connection with any of the amendments described under "—No Limited Partner Approval." No other amendments to our partnership agreement will become effective without the approval of holders of at least 90% of the outstanding units voting as a single class unless we first obtain an opinion of counsel to the effect that the amendment will not affect the limited liability under applicable law of any of our limited partners.

In addition to the above restrictions, any amendment that would have a material adverse effect on the rights or preferences of any type or class of outstanding units in relation to other classes of units will require the approval of at least a majority of the type or class of units so affected. Any amendment that reduces the voting percentage required to take any action is required to be approved by the affirmative vote of limited partners whose aggregate outstanding units constitute not less than the voting requirement sought to be reduced.

Merger, Consolidation, Conversion, Sale or Other Disposition of Assets

A merger, consolidation or conversion of us requires the prior consent of our general partner. However, our general partner will have no duty or obligation to consent to any merger, consolidation or conversion and may decline to do so free of any fiduciary duty or obligation whatsoever to us or the limited partners, including any duty to act in good faith or in the best interest of us or the limited partners.

In addition, our partnership agreement generally prohibits our general partner without the prior approval of the holders of a unit majority, from causing us to, among other things, sell, exchange or otherwise dispose of all or substantially all of our assets in a single transaction or a series of related transactions, including by way of merger, consolidation or other combination, or approving on our behalf the sale, exchange or other disposition of all or substantially all of the assets of our subsidiaries. Our general partner may, however, mortgage, pledge, hypothecate or grant a security interest in all or substantially all of our assets without that approval. Our general partner may also sell all or substantially all of our assets under a foreclosure or other realization upon those encumbrances without that approval. Finally, our general partner may consummate any merger without the prior approval of our unitholders if we are the surviving entity in the transaction, our general partner has received an opinion of counsel regarding limited liability and tax matters, the transaction would not result in a material amendment to our partnership agreement, each of our units will be an identical unit of our partnership following the transaction, and the units to be issued do not exceed 20% of our outstanding units immediately prior to the transaction.

If the conditions specified in our partnership agreement are satisfied, our general partner may convert us or any of our subsidiaries into a new limited liability entity or merge us or any of our subsidiaries into, or convey all of our assets to, a newly formed entity if the sole purpose of that conversion, merger or conveyance is to effect a mere change in our legal form into another limited liability entity, our general partner has received an opinion of counsel regarding limited liability and tax matters, and the governing instruments of the new entity provide the limited partners and the general partner with the same rights and obligations as contained in our partnership agreement. The limited partners are not entitled to dissenters' rights of appraisal under our partnership agreement or applicable Delaware law in the event of a conversion, merger or consolidation, a sale of substantially all of our assets or any other similar transaction or event.

Termination and Dissolution

We will continue as a limited partnership until terminated under our partnership agreement. We will dissolve upon:

- the election of our general partner to dissolve us, if approved by the holders of units representing a unit majority;
- there being no limited partners, unless we are continued without dissolution in accordance with applicable Delaware law;
- the entry of a decree of judicial dissolution of our partnership; or
- the withdrawal or removal of our general partner or any other event that results in its ceasing to be our general partner other than by reason of a transfer of its general partner interest in accordance with our partnership agreement or withdrawal or removal following approval and admission of a successor.

Upon a dissolution under the last clause above, the holders of a unit majority may also elect, within specific time limitations, to continue our business on the same terms and conditions described in our partnership agreement by appointing as a successor general partner an entity approved by the holders of units representing a unit majority, subject to our receipt of an opinion of counsel to the effect that:

- the action would not result in the loss of limited liability of any limited partner; and
- neither our partnership, our operating company nor any of our other subsidiaries would be treated as an association taxable as a corporation or otherwise be taxable as an entity for federal income tax purposes upon the exercise of that right to continue.

Liquidation and Distribution of Proceeds

Upon our dissolution, unless we are continued as a new limited partnership, the liquidator authorized to wind up our affairs will, acting with all of the powers of our general partner that are necessary or appropriate to liquidate our assets and apply the proceeds of the liquidation as described in "Provisions of Our Partnership Agreement Relating to Cash Distributions—Distributions of Cash Upon Liquidation." The liquidator may defer liquidation or distribution of our assets for a reasonable period of time or distribute assets to partners in kind if it determines that a sale would be impractical or would cause undue loss to our partners.

Withdrawal or Removal of Our General Partner

Except as described below, our general partner has agreed not to withdraw voluntarily as our general partner prior to January 1, 2018 without obtaining the approval of the holders of at least a majority of the outstanding common units, excluding common units held by our general partner and its affiliates, and furnishing an opinion of counsel regarding limited liability and tax matters. On or after January 1, 2018, our general partner may withdraw as general partner without first obtaining approval of any unitholder by giving 90 days' written notice, and that withdrawal will not constitute a violation of our partnership agreement. Notwithstanding the information above, our general partner may withdraw without unitholder approval upon 90 days' notice to the limited partners if at least 50% of the outstanding common units are held or controlled by one person and its affiliates other than our general partner and its affiliates. In addition, our partnership agreement permits our general partner in some instances to sell or otherwise transfer all of its general partner interest in us without the approval of the limited partners. Please see "—Transfer of General Partner Interest" and "—Transfer of Incentive Distribution Rights."

Upon withdrawal of our general partner under any circumstances, other than as a result of a transfer by our general partner of all or a part of its general partner interest in us, the holders of a unit majority may select a successor to that withdrawing general partner. If a successor is not elected, or is elected but an opinion of counsel regarding limited liability and tax matters cannot be obtained, we will be dissolved, wound up and liquidated, unless within a specified period after that withdrawal, the holders of a unit majority agree in writing to continue our business and to appoint a successor general partner. Please see "—Termination and Dissolution."

Our general partner may not be removed unless that removal is approved by the vote of the holders of not less than 66⅔% of the outstanding units, voting together as a single class, including units held by our general partner and its affiliates, and we receive an opinion of counsel regarding limited liability and tax matters. Any removal of our general partner is also subject to the approval of a successor general partner by the vote of the holders of a majority of the outstanding common units and Class B units, if any, voting as a separate class, and subordinated units, voting as a separate class. The ownership of more than 33⅓% of the outstanding units by our general partner and its affiliates would give them the practical ability to prevent our general partner's removal. At the closing of this offering, an affiliate of our general partner will own approximately 65.2% of the outstanding common and subordinated units (approximately 62.0% if the underwriters exercise in full their option to purchase additional common units).

Our partnership agreement also provides that if our general partner is removed as our general partner under circumstances where cause does not exist and units held by our general partner and its affiliates are not voted in favor of that removal:

- the subordination period will end, and all outstanding subordinated units will immediately convert into common units on a one-for-one basis;
- any existing arrearages in payment of the minimum quarterly distribution on the common units will be extinguished; and

- our general partner will have the right to convert its general partner interest and its incentive distribution rights into common units or to receive cash in exchange for those interests based on the fair market value of those interests at that time.

In the event of removal of our general partner under circumstances where cause exists or withdrawal of our general partner where that withdrawal violates our partnership agreement, a successor general partner will have the option to purchase the general partner interest and incentive distribution rights of the departing general partner for a cash payment equal to the fair market value of those interests. Under all other circumstances where our general partner withdraws or is removed by the limited partners, the departing general partner will have the option to require the successor general partner to purchase the general partner interest of the departing general partner and its incentive distribution rights for fair market value. In each case, this fair market value will be determined by agreement between the departing general partner and the successor general partner. If no agreement is reached, an independent investment banking firm or other independent expert selected by the departing general partner and the successor general partner will determine the fair market value. Or, if the departing general partner and the successor general partner cannot agree upon an expert, then an expert chosen by agreement of the experts selected by each of them will determine the fair market value.

If the option described above is not exercised by either the departing general partner or the successor general partner, the departing general partner's general partner interest and its incentive distribution rights will automatically convert into common units equal to the fair market value of those interests as determined by an investment banking firm or other independent expert selected in the manner described in the preceding paragraph.

In addition, we will be required to reimburse the departing general partner for all amounts due the departing general partner, including, without limitation, all employee-related liabilities, including severance liabilities, incurred for the termination of any employees employed by the departing general partner or its affiliates for our benefit.

Transfer of General Partner Interest

Except for transfer by our general partner of all, but not less than all, of its general partner interest to:

- an affiliate of our general partner (other than an individual); or
- another entity as part of the merger or consolidation of our general partner with or into another entity or the transfer by our general partner of all or substantially all of its assets to another entity,

our general partner may not transfer all or any of its general partner interest to another person prior to January 1, 2018 without the approval of the holders of at least a majority of the outstanding common units, excluding common units held by our general partner and its affiliates. As a condition of this transfer, the transferee must assume, among other things, the rights and duties of our general partner, agree to be bound by the provisions of our partnership agreement and furnish an opinion of counsel regarding limited liability and tax matters.

Our general partner and its affiliates may at any time transfer units to one or more persons without unitholder approval, except that they may not transfer subordinated units to us.

Transfer of Membership Interests in Our General Partner

At any time, OGE Energy and its affiliates may sell or transfer all or part of their membership interests in OGE Enogex GP LLC, our general partner, to an affiliate or third party without the approval of our unitholders.

Transfer of Incentive Distribution Rights

Our general partner or its affiliates or a subsequent holder may transfer its incentive distribution rights to an affiliate of the holder (other than an individual) or another entity as part of the merger or consolidation of such holder with or into another entity, the sale of all of the ownership interest in such holder or the sale of all or substantially all of such holder's assets to, such entity without the prior approval of the unitholders. Prior to January 1, 2018, other transfers of incentive distribution rights will require the affirmative vote of holders of a majority of the outstanding common units, excluding common units held by our general partner and its affiliates. On or after January 1, 2018, the incentive distribution rights will be freely transferable.

Change of Management Provisions

Our partnership agreement contains specific provisions that are intended to discourage a person or group from attempting to remove OGE Enogex GP LLC as our general partner or otherwise change the management of our general partner. If any person or group other than our general partner and its affiliates acquires beneficial ownership of 20% or more of any class of units, that person or group loses voting rights on all of its units. This loss of voting rights does not apply to any person or group that acquires the units from our general partner or its affiliates and any transferees of that person or group approved by our general partner or to any person or group who acquires the units with the prior approval of the board of directors of our general partner.

Our partnership agreement also provides that if our general partner is removed as our general partner under circumstances where cause does not exist and units held by our general partner and its affiliates are not voted in favor of that removal:

- the subordination period will end and all outstanding subordinated units will immediately convert into common units on a one-for-one basis;
- any existing arrearages in payment of the minimum quarterly distribution on the common units will be extinguished; and
- our general partner will have the right to convert its general partner interest and its incentive distribution rights into common units or to receive cash in exchange for those interests based on the fair market value of those interests at that time.

Limited Call Right

If at any time our general partner and its affiliates own more than 80% of the then-issued and outstanding limited partner interests of any class, our general partner will have the right, which it may assign in whole or in part to any of its affiliates or to us, to acquire all, but not less than all, of the limited partner interests of the class held by unaffiliated persons as of a record date to be selected by our general partner, on at least 10 but not more than 60 days notice. The purchase price in the event of this purchase is the greater of:

- the highest price paid by our general partner or any of its affiliates for any limited partner interests of the class purchased within the 90 days preceding the date on which our general partner first mails notice of its election to purchase those limited partner interests; and

- the average of the daily closing prices of the partnership securities of such class over the 20 trading days preceding the date three days before the date the notice is mailed.

The limited call right is exercisable by our general partner, acting in its individual capacity, and may be assigned to its affiliates.

As a result of our general partner's right to purchase outstanding limited partner interests, a holder of limited partner interests may have his limited partner interests purchased at an undesirable time or price. The tax consequences to a unitholder of the exercise of this call right are the same as a sale by that unitholder of his common units in the market. Please see "Material Tax Consequences—Disposition of Common Units."

Meetings; Voting

Except as described below regarding a person or group owning 20% or more of any class of units then outstanding, record holders of units on the record date will be entitled to notice of, and to vote at, meetings of our limited partners and to act upon matters for which approvals may be solicited.

Our general partner does not anticipate that any meeting of unitholders will be called in the foreseeable future. Any action that is required or permitted to be taken by the unitholders may be taken either at a meeting of the unitholders or without a meeting if consents in writing describing the action so taken are signed by holders of the number of units necessary to authorize or take that action at a meeting. Meetings of the unitholders may be called by our general partner or by unitholders owning at least 20% of the outstanding units of the class for which a meeting is proposed. Unitholders may vote either in person or by proxy at meetings. The holders of a majority of the outstanding units of the class or classes for which a meeting has been called represented in person or by proxy will constitute a quorum unless any action by the unitholders requires approval by holders of a greater percentage of the units, in which case the quorum will be the greater percentage. The unit equivalents representing the general partner interest are unit equivalents for distribution and allocation purposes, do not entitle our general partner to any vote other than its rights as general partner under our partnership agreement, will not be entitled to vote on any action required or permitted to be taken by the unitholders and will not count toward or be considered outstanding when calculating required votes, determining the presence of a quorum or for similar purposes.

Each record holder of a unit has a vote according to its percentage interest in us, although additional limited partner interests having special voting rights could be issued. Please see "—Issuance of Additional Securities." However, if at any time any person or group, other than our general partner and its affiliates, or a direct or subsequently approved transferee of our general partner or its affiliates, acquires, in the aggregate, beneficial ownership of 20% or more of any class of units then outstanding, that person or group will lose voting rights on all of its units and the units may not be voted on any matter and will not be considered to be outstanding when sending notices of a meeting of unitholders, calculating required votes, determining the presence of a quorum or for other similar purposes. Common units held in nominee or street name account will be voted by the broker or other nominee in accordance with the instruction of the beneficial owner unless the arrangement between the beneficial owner and his nominee provides otherwise. Except as our partnership agreement otherwise provides, subordinated units will vote together with common units and Class B units as a single class.

Any notice, demand, request, report or proxy material required or permitted to be given or made to record holders of common units under our partnership agreement will be delivered to the record holder by us or by the transfer agent.

Status as Limited Partner

By transfer of common units in accordance with our partnership agreement, each transferee of common units shall be admitted as a limited partner with respect to the common units transferred when such transfer and admission is reflected in our books and records. Except as described under "—Limited Liability," the common units will be fully paid, and unitholders will not be required to make additional contributions.

Non-Citizen Assignees; Redemption

If we are or become subject to federal, state or local laws or regulations that, in the reasonable determination of our general partner, create a substantial risk of cancellation or forfeiture of any property that we have an interest in because of the nationality, citizenship or other related status of any limited partner, we may redeem the units held by the limited partner at their current market price. In order to avoid any cancellation or forfeiture, our general partner may require each limited partner to furnish information about his nationality, citizenship or related status. If a limited partner fails to furnish information about his nationality, citizenship or other related status within 30 days after a request for the information or our general partner determines after receipt of the information that the limited partner is not an eligible citizen, the limited partner may be treated as a non-citizen assignee. A non-citizen assignee, is entitled to an interest equivalent to that of a limited partner for the right to share in allocations and distributions from us, including liquidating distributions. A non-citizen assignee does not have the right to direct the voting of his units and may not receive distributions in-kind upon our liquidation.

Indemnification

Under our partnership agreement, in most circumstances, we will indemnify the following persons, to the fullest extent permitted by law, from and against all losses, claims, damages or similar events:

- our general partner;
- any departing general partner;
- any person who is or was an affiliate of a general partner or any departing general partner;
- any person who is or was a director, officer, member, partner, fiduciary or trustee of any entity set forth in the preceding three bullet points;
- any person who is or was serving as director, officer, member, partner, fiduciary or trustee of another person at the request of our general partner,any departing general partner, an affiliate of our general partner or an affiliate of any departing general partner; and
- any person designated by our general partner.

Any indemnification under these provisions will only be out of our assets. Unless it otherwise agrees, our general partner will not be personally liable for, or have any obligation to contribute or lend funds or assets to us to enable us to effectuate, indemnification. We may purchase insurance against liabilities asserted against and expenses incurred by persons for our activities, regardless of whether we would have the power to indemnify the person against liabilities under our partnership agreement.

Reimbursement of Expenses

Our partnership agreement requires us to reimburse our general partner for all direct and indirect expenses it incurs or payments it makes on our behalf and all other expenses allocable to us or otherwise incurred by our general partner in connection with operating our business or the business of

Enogex. These expenses include salary, bonus, incentive compensation and other amounts paid to persons who perform services for us or Enogex or on our or Enogex's behalf and expenses allocated to our general partner by its affiliates. Our general partner is entitled to determine in good faith the expenses that are allocable to us.

Books and Reports

Our general partner is required to keep appropriate books of our business at our principal offices. The books will be maintained for both tax and financial reporting purposes on an accrual basis. For tax and fiscal reporting purposes, our fiscal year is the calendar year.

We will furnish or make available (by posting on our website or other reasonable means) to record holders of common units, within 120 days after the close of each fiscal year, an annual report containing audited financial statements and a report on those financial statements by our independent public accountants. Except for our fourth quarter, we will also furnish or make available summary financial information within 90 days after the close of each quarter.

We will furnish each record holder of a unit with information reasonably required for tax reporting purposes within 90 days after the close of each calendar year. This information is expected to be furnished in summary form so that some complex calculations normally required of partners can be avoided. Our ability to furnish this summary information to unitholders will depend on the cooperation of unitholders in supplying us with specific information. Every unitholder will receive information to assist him in determining his federal and state tax liability and filing his federal and state income tax returns, regardless of whether he supplies us with information.

Right to Inspect Our Books and Records

Our partnership agreement provides that a limited partner can, for a purpose reasonably related to his interest as a limited partner, upon reasonable written demand stating the purpose of such demand and at his own expense, have furnished to him:

- a current list of the name and last known address of each partner;
- a copy of our tax returns;
- information as to the amount of cash, and a description and statement of the agreed value of any other property or services, contributed or to be contributed by each partner and the date on which each partner became a partner;
- copies of our partnership agreement, our certificate of limited partnership, related amendments and powers of attorney under which they have been executed;
- information regarding the status of our business and financial condition; and
- any other information regarding our affairs as is just and reasonable.

Our general partner may, and intends to, keep confidential from the limited partners trade secrets or other information the disclosure of which our general partner believes in good faith is not in our best interests or that we are required by law or by agreements with third parties to keep confidential.

Registration Rights

Under our partnership agreement, we have agreed to register for resale under the Securities Act and applicable state securities laws any common units, Class B units, subordinated units or other partnership securities proposed to be sold by our general partner or any of its affiliates or their assignees if an exemption from the registration requirements is not otherwise available. These registration rights continue for two years following any withdrawal or removal of our general partner. We are obligated to pay all expenses incidental to the registration, excluding underwriting discounts and commissions. Please see "Units Eligible for Future Sale."

UNITS ELIGIBLE FOR FUTURE SALE

After the sale of the common units offered hereby, a wholly owned subsidiary of OGE Energy will hold an aggregate of 3,280,605 common units and 10,780,605 subordinated units. All of the subordinated units will convert into common units at the end of the subordination period. The sale of these units could have an adverse impact on the price of the common units or on any trading market that may develop.

The common units sold in the offering will generally be freely transferable without restriction or further registration under the Securities Act, except that any common units owned by an "affiliate" of ours may not be resold publicly except in compliance with the registration requirements of the Securities Act or under an exemption under Rule 144 or otherwise. Rule 144 permits securities acquired by an affiliate of the issuer to be sold into the market in an amount that does not exceed, during any three-month period, the greater of:

- 1% of the total number of the securities outstanding; or
- the average weekly reported trading volume of the common units for the four calendar weeks prior to the sale.

Sales under Rule 144 are also subject to other requirements regarding the manner of sale, notice and the availability of current public information about us. A person who is not deemed to have been an affiliate of ours at any time during the three months preceding a sale, and who has beneficially owned his common units for at least two years, would be entitled to sell common units under Rule 144 without regard to the public information requirements, volume limitations, manner of sale provisions and notice requirements of Rule 144.

Our partnership agreement does not restrict our ability to issue additional partnership securities at any time. Any issuance of additional common units or other equity securities would result in a corresponding decrease in the proportionate ownership interest in us represented by, and could adversely affect the cash distributions to and market price of, common units then outstanding. Please see "The Partnership Agreement—Issuance of Additional Securities."

Under our partnership agreement, our general partner and its affiliates have the right to cause us to register under the Securities Act and state securities laws the offer and sale of any common units, Class B units, subordinated units or other partnership securities that they hold. Subject to the terms and conditions of our partnership agreement, these registration rights allow our general partner and its affiliates or their assignees holding any units or other partnership securities to require registration of any of these units or other partnership securities and to include them in a registration by us of other units or other partnership securities, including units or other partnership securities offered by us or by any unitholder. Our general partner will continue to have these registration rights for two years following its withdrawal or removal as our general partner. In connection with any registration of this kind, we will indemnify each unitholder participating in the registration and its officers, directors and controlling persons from and against any liabilities under the Securities Act or any state securities laws arising from the registration statement or prospectus. We will bear all costs and expenses incidental to any registration, excluding any underwriting discounts and commissions. Except as described below, our general partner and its affiliates may sell their units or other partnership securities in private transactions at any time, subject to compliance with applicable laws.

We, the executive officers and directors of our general partner, our general partner and its affiliates (including OGE Energy) have agreed not to sell any common units they beneficially own for a period of 180 days from the date of this prospectus. For a description of these lock-up provisions, please see "Underwriting."

MATERIAL TAX CONSEQUENCES

This section is a summary of the material tax considerations that may be relevant to prospective unitholders who are individual citizens or residents of the U.S. and, unless otherwise noted in the following discussion, is the opinion of Baker Botts L.L.P., counsel to our general partner and us, insofar as it relates to matters of U.S. federal income tax law and legal conclusions with respect to those matters. This section is based upon current provisions of the Internal Revenue Code, existing and proposed regulations and current administrative rulings and court decisions, all of which are subject to change. Later changes in these authorities may cause the tax consequences to vary substantially from the consequences described below. Unless the context otherwise requires, references in this section to "us" or "we" are references to OGE Enogex Partners L.P. and our operating company.

The following discussion does not comment on all federal income tax matters affecting us or the unitholders. Moreover, the discussion focuses on unitholders who are individual citizens or residents of the U.S. and has only limited application to corporations, estates, trusts, nonresident aliens or other unitholders subject to specialized tax treatment, such as tax-exempt institutions, foreign persons, individual retirement accounts (IRAs), real estate investment trusts (REITs), employee benefit plans or mutual funds. Accordingly, we urge each prospective unitholder to consult, and depend on, his own tax advisor in analyzing the federal, state, local and foreign tax consequences particular to him of the ownership or disposition of common units.

All statements as to matters of law and legal conclusions, but not as to factual matters, contained in this section, unless otherwise noted, are the opinion of Baker Botts L.L.P. and are based on the accuracy of the representations made by us.

No ruling has been or will be requested from the IRS regarding any matter affecting us or prospective unitholders. Instead, we will rely on opinions of Baker Botts L.L.P. Unlike a ruling, an opinion of counsel represents only that counsel's best legal judgment and does not bind the IRS or the courts. Accordingly, the opinions and statements made here may not be sustained by a court if contested by the IRS. Any contest of this sort with the IRS may materially and adversely impact the market for the common units and the prices at which common units trade. In addition, the costs of any contest with the IRS, principally legal, accounting and related fees, will result in a reduction in cash available for distribution to our unitholders and our general partner and thus will be borne indirectly by our unitholders and our general partner. Furthermore, the tax treatment of us, or of an investment in us, may be significantly modified by future legislative or administrative changes or court decisions. Any modifications may or may not be retroactively applied.

For the reasons described below, Baker Botts L.L.P. has not rendered an opinion with respect to the following specific federal income tax issues: (1) the treatment of a unitholder whose common units are loaned to a short seller to cover a short sale of common units (please see "—Tax Consequences of Unit Ownership—Treatment of Short Sales"); (2) whether our monthly convention for allocating taxable income and losses is permitted by existing Treasury Regulations (please see "—Disposition of Common Units—Allocations Between Transferors and Transferees"); and (3) whether our method for depreciating Section 743 adjustments is sustainable in certain cases (please see "—Tax Consequences of Unit Ownership—Section 754 Election" and "—Uniformity of Units").

Partnership Status

A partnership is not a taxable entity and incurs no federal income tax liability. Instead, each partner of a partnership is required to take into account his share of items of income, gain, loss and deduction of the partnership in computing his federal income tax liability, regardless of whether cash distributions are made to him by the partnership. Distributions by a partnership to a partner are generally not taxable unless the amount of cash distributed is in excess of the partner's adjusted basis in his partnership interest.

Section 7704 of the Internal Revenue Code provides that publicly traded partnerships will, as a general rule, be taxed as corporations. However, an exception, referred to herein as the "Qualifying Income Exception," exists with respect to publicly traded partnerships of which 90% or more of the gross income for every taxable year consists of "qualifying income." Qualifying income includes income and gains derived from the transportation, storage, processing and marketing of crude oil, natural gas and products thereof. Other types of qualifying income include interest (other than from a financial business), dividends, gains from the sale of real property and gains from the sale or other disposition of capital assets held for the production of income that otherwise constitutes qualifying income. We estimate that approximately % of our current gross income is not qualifying income; however, this estimate could change from time to time. Based upon and subject to this estimate, the factual representations made by us and our general partner and a review of the applicable legal authorities, Baker Botts L.L.P. is of the opinion that at least 90% of our current gross income constitutes qualifying income. The portion of our income that is qualifying income can change from time to time.

No ruling has been or will be sought from the IRS and the IRS has made no determination as to our classification as a partnership for federal income tax purposes or whether our operations generate "qualifying income" under Section 7704 of the Internal Revenue Code. Instead, we will rely on the opinion of Baker Botts L.L.P. that, based upon the Internal Revenue Code, its regulations, published revenue rulings and court decisions and the representations described below, we will be classified as a partnership and the operating company will be disregarded as an entity separate from us for federal income tax purposes.

In rendering its opinion, Baker Botts L.L.P. has relied on factual representations made by us and our general partner. The representations made by us and our general partner upon which Baker Botts L.L.P. has relied are:

(1) Neither we nor the operating company has elected or will elect to be treated as a corporation; and

(2) For each taxable year, more than 90% of our gross income will be income that Baker Botts L.L.P. has opined or will opine is "qualifying income" within the meaning of Section 7704(d) of the Internal Revenue Code.

If we fail to meet the Qualifying Income Exception, other than a failure that is determined by the IRS to be inadvertent and that is cured within a reasonable time after discovery, we will be treated as if we had transferred all of our assets, subject to liabilities, to a newly formed corporation, on the first day of the year in which we fail to meet the Qualifying Income Exception, in return for stock in that corporation, and then distributed that stock to the unitholders in liquidation of their interests in us. This deemed contribution and liquidation should be tax-free to unitholders and us so long as we, at that time, do not have liabilities in excess of the tax basis of our assets. Thereafter, we would be treated as a corporation for federal income tax purposes.

If we were taxable as a corporation in any taxable year, either as a result of a failure to meet the Qualifying Income Exception or otherwise, our items of income, gain, loss and deduction would be reflected only on our tax return rather than being passed through to the unitholders, and our net earnings would be taxed to us at corporate rates. In addition, any distribution made to a unitholder would be treated as either taxable dividend income, to the extent of our current or accumulated earnings and profits, or, in the absence of earnings and profits, a nontaxable return of capital, to the extent of the unitholder's tax basis in his common units, or taxable gain, after the unitholder's tax basis in his common units is reduced to zero. Accordingly, taxation as a corporation would result in a material reduction in a unitholder's cash flows and after-tax return and thus would likely result in a substantial reduction of the value of the units.

The discussion below is based on Baker Botts L.L.P.'s opinion that we will be classified as a partnership for federal income tax purposes.

Limited Partner Status

Unitholders who have become limited partners of OGE Enogex Partners L.P. will be treated as partners of OGE Enogex Partners L.P. for federal income tax purposes. Also:

a) assignees who are awaiting admission as limited partners, and

b) unitholders whose common units are held in street name or by a nominee and who have the right to direct the nominee in the exercise of all substantive rights attendant to the ownership of their common units

will be treated as partners of OGE Enogex Partners L.P. for federal income tax purposes.

A beneficial owner of common units whose units have been transferred to a short seller to complete a short sale would appear to lose his status as a partner with respect to those units for federal income tax purposes. Please see "—Tax Consequences of Unit Ownership—Treatment of Short Sales."

Income, gain, deductions or losses would not appear to be reportable by a unitholder who is not a partner for federal income tax purposes, and any cash distributions received by a unitholder who is not a partner for federal income tax purposes would therefore be fully taxable as ordinary income. These holders are urged to consult their own tax advisors with respect to their tax status as partners in OGE Enogex Partners L.P. for federal income tax purposes.

Tax Consequences of Unit Ownership

Flow-Through of Taxable Income

We will not pay any federal income tax. Instead, each unitholder will be required to report on his income tax return his share of our income, gains, losses and deductions without regard to whether corresponding cash distributions are received by him. Consequently, we may allocate income to a unitholder even if he has not received a cash distribution. Each unitholder will be required to include in income his allocable share of our income, gains, losses and deductions for our taxable year or years ending with or within his taxable year. Please see "—Tax Treatment of Operations—Accounting Method and Taxable Year."

Treatment of Distributions

Distributions by us to a unitholder generally will not be taxable to the unitholder for federal income tax purposes to the extent of his tax basis in his common units immediately before the distribution. Our cash distributions in excess of a unitholder's tax basis in his common units generally will be considered to be gain from the sale or exchange of the common units, taxable in accordance with the rules described under "—Disposition of Common Units." Any reduction in a unitholder's share of our liabilities for which no partner, including our general partner, bears the economic risk of loss, known as "nonrecourse liabilities," will be treated as a distribution of cash to that unitholder. To the extent our distributions cause a unitholder's "at risk" amount to be less than zero at the end of any taxable year, he must recapture any losses deducted in previous years. Please see "—Limitations on Deductibility of Losses."

A decrease in a unitholder's percentage interest in us because of our issuance of additional common units will decrease his share of our nonrecourse liabilities, and thus will result in a corresponding deemed distribution of cash. A non-pro rata distribution of money or property may result in ordinary income to a unitholder, regardless of his tax basis in his common units, if the distribution reduces the unitholder's share of our "unrealized receivables," including depreciation recapture, and/or substantially appreciated "inventory items," both as defined in Section 751 of the Internal Revenue Code, and collectively, "Section 751 Assets." To that extent, he will be treated as having been distributed his proportionate share of the Section 751 Assets and having exchanged those assets with us in return for the non-pro rata portion of the actual distribution made to him. This latter deemed exchange will generally result in the unitholder's realization of ordinary income, which will equal the excess of (1) the non-pro rata portion of that distribution over (2) the unitholder's tax basis for the share of Section 751 Assets deemed relinquished in the exchange.

Ratio of Taxable Income to Distributions

We estimate that a purchaser of common units in this offering who owns those common units from the date of closing of this offering through the record date for distributions for the period ending December 31, 2010, will be allocated on a cumulative basis an amount of federal taxable income for that period that will be % or less of the cash distributed with respect to that period. Thereafter, we anticipate that the ratio of allocable taxable income to cash distributions to the unitholders will increase. These estimates are based upon the assumption that gross income from operations will approximate the amount required to make the minimum quarterly distribution on all units and other assumptions with respect to capital expenditures, cash flows, net working capital and anticipated cash distributions. These estimates and assumptions are subject to, among other things, numerous business, economic, regulatory, competitive and political uncertainties beyond our control. Further, the estimates are based on current tax law and tax reporting positions that we will adopt and with which the IRS could disagree. Accordingly, we cannot assure you that these estimates will prove to be correct. The actual percentage of distributions that will constitute taxable income could be higher or lower than our estimate, and any differences could be material and could materially affect the value of the common units. For example, the ratio of allocable taxable income to cash distributions to a purchaser of common units in this offering will be greater, and perhaps substantially greater, than our estimate with respect to the period described above if:

- gross income from operations exceeds the amount required to make the minimum quarterly distribution on all units, yet we only distribute the minimum quarterly distribution on all units; or

- we make a future offering of common units and use the proceeds of the offering in a manner that does not produce substantial additional deductions during the period described above, such as to repay indebtedness outstanding at the time of this offering 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 applicable to our assets at the time of this offering.

Basis of Common Units

A unitholder's initial tax basis for his common units will be the amount he paid for the common units plus his share of our nonrecourse liabilities. That basis will be increased by his share of our income and by any increases in his share of our nonrecourse liabilities. That basis will be decreased, but not below zero, by distributions from us, by the unitholder's share of our losses, by any decreases in his share of our nonrecourse liabilities and by his share of our expenditures that are not deductible in computing taxable income and are not required to be capitalized. A unitholder will have no share of our debt that is recourse to our general partner, but will have a share, generally based on his share of profits, of our nonrecourse liabilities. Please see "—Disposition of Common Units—Recognition of Gain or Loss."

Limitations on Deductibility of Losses

The deduction by a unitholder of his share of our losses will be limited to the tax basis in his units and, in the case of an individual unitholder or a corporate unitholder, if more than 50% of the value of the corporate unitholder's stock is owned directly or indirectly by or for five or fewer individuals or some tax-exempt organizations, to the amount for which the unitholder is considered to be "at risk" with respect to our activities, if that is less than his tax basis. A unitholder must recapture losses deducted in previous years to the extent that distributions cause his at risk amount to be less than zero at the end of any taxable year. Losses disallowed to a unitholder or recaptured as a result of these limitations will carry forward and will be allowable as a deduction in a later year to the extent that his tax basis or at risk amount, whichever is the limiting factor, is subsequently increased. Upon the taxable disposition of a unit, any gain recognized by a unitholder can be offset by losses that were previously suspended by the at risk limitation but may not be offset by losses suspended by the basis limitation. Any excess loss above that gain previously suspended by the at risk or basis limitations is no longer utilizable.

In general, a unitholder will be at risk to the extent of the tax basis of his units, excluding any portion of that basis attributable to his share of our nonrecourse liabilities, reduced by any amount of money he borrows to acquire or hold his units, if the lender of those borrowed funds owns an interest in us, is related to the unitholder or can look only to the units for repayment. A unitholder's at risk amount will increase or decrease as the tax basis of the unitholder's units increases or decreases, other than tax basis increases or decreases attributable to increases or decreases in his share of our nonrecourse liabilities.

The passive loss limitations generally provide that individuals, estates, trusts and some closely-held corporations and personal service corporations can deduct losses from passive activities, which are generally corporate or partnership activities in which the taxpayer does not materially participate, only to the extent of the taxpayer's income from those passive activities. The passive loss limitations are applied separately with respect to each publicly traded partnership. Consequently, any passive losses we generate will only be available to offset our passive income generated in the future and will not be available to offset income from other passive activities or investments, including our investments or a unitholder's investments in other publicly traded partnerships, or a unitholder's salary or active business income. Passive losses that are not deductible because they exceed a unitholder's share of income we generate may be deducted in full when he disposes of his entire investment in us in a fully taxable transaction with an unrelated party. The passive activity loss rules are applied after other applicable limitations on deductions, including the at risk rules and the basis limitation.

A unitholder's share of our net income may be offset by any of our suspended passive losses, but it may not be offset by any other current or carryover losses from other passive activities, including those attributable to other publicly traded partnerships.

Limitations on Interest Deductions

The deductibility of a non-corporate taxpayer's "investment interest expense" is generally limited to the amount of that taxpayer's "net investment income." Investment interest expense includes:

- interest on indebtedness properly allocable to property held for investment;
- our interest expense attributed to portfolio income; and
- the portion of interest expense incurred to purchase or carry an interest in a passive activity to the extent attributable to portfolio income.

The computation of a unitholder's investment interest expense will take into account interest on any margin account borrowing or other loan incurred to purchase or carry a unit. Net investment income includes gross income from property held for investment and amounts treated as portfolio income under the passive loss rules, less deductible expenses, other than interest, directly connected with the production of investment income, but generally does not include gains attributable to the disposition of property held for investment. The IRS has indicated that net passive income earned by a publicly traded partnership will be treated as investment income to its unitholders. In addition, the unitholder's share of our portfolio income will be treated as investment income.

Entity-Level Collections

If we are required or elect under applicable law to pay any federal, state, local or foreign income tax on behalf of any unitholder or our general partner or any former unitholder, we are authorized to pay those taxes from our funds. That payment, if made, will be treated as a distribution of cash to the partner on whose behalf the payment was made. If the payment is made on behalf of a person whose identity cannot be determined, we are authorized to treat the payment as a distribution to all current unitholders. We are authorized to amend our partnership agreement in the manner necessary to maintain uniformity of intrinsic tax characteristics of units and to adjust later distributions, so that after giving effect to these distributions, the priority and characterization of distributions otherwise applicable under the partnership agreement is maintained as nearly as is practicable. Payments by us as described above could give rise to an overpayment of tax on behalf of an individual unitholder in which event the unitholder would be required to file a claim in order to obtain a credit or refund.

Allocation of Income, Gain, Loss and Deduction

In general, if we have a net profit, our items of income, gain, loss and deduction will be allocated among our general partner and the unitholders in accordance with their percentage interests in us. At any time that distributions are made to the common units in excess of distributions to the subordinated units, or incentive distributions are made to our general partner, gross income will be allocated to the recipients to the extent of these distributions. Gross income may also be allocated to holders of subordinated units after the close of the subordination period to the extent necessary to give them economic rights at liquidation identical to the rights of common units. If we have a net loss for the entire year, that loss will be allocated first to our general partner and the unitholders in accordance with their percentage interests in us to the extent of their positive capital accounts and, second, to our general partner.

For tax purposes, we are required to adjust the "book" basis of all assets contributed to us by our general partner and its affiliates, referred to below as "Contributed Property," to their fair market values at the time this offering closes. We are further required to adjust this book basis for each asset in proportion to tax depreciation or amortization we or our unitholders later claim with respect to the asset. Section 704(c) principles set forth in Treasury regulations require that subsequent allocations of depreciation, gain, loss and similar items with respect to the asset take into account, among other things, the difference between the "book" and tax basis of the asset. In this context, we use the term "book" as that term is used in Treasury regulations relating to partnership allocations for tax purposes. The "book" value of our property for this purpose may not be the same as the book value of our property for financial reporting purposes.

For example, a substantial portion of our Contributed Property will be depreciable property with a "book" basis in excess of its tax basis. Section 704(c) principles generally will require that depreciation with respect to each such property be allocated disproportionately to purchasers of common units in this offering and away from our general partner and its affiliates. To the extent these disproportionate allocations do not produce a result to holders of common units similar to that which would be the case if all of our initial assets had a tax basis equal to their "book" basis on the date this offering closes, purchasers of common units in this offering will be allocated the additional tax deductions needed to produce that result as to any asset with respect to which we elect the "remedial method" of taking into account the difference between the "book" and tax basis of the asset.

In the event we issue additional common units or engage in certain other transactions in the future, "reverse Section 704(c) allocations," similar to the Section 704(c) allocations described above, will be made to all holders of partner interests, including purchasers of common units in this offering, to account for the difference between the "book" basis and the fair market value of all property held by us at the time of the future transaction.

In addition, items of recapture income will be allocated to the extent possible to the unitholder who was allocated the deduction giving rise to the treatment of that gain as recapture income in order to minimize the recognition of ordinary income by unitholders that did not receive the benefit of such deduction. Finally, although we do not expect that our operations will result in the creation of negative capital accounts, if negative capital accounts nevertheless result, items of our income and gain will be allocated in an amount and manner to eliminate the negative balance as quickly as possible.

An allocation of items of our income, gain, loss or deduction, other than an allocation required under Section 704(c) principles, will generally be given effect for federal income tax purposes in determining a partner's share of an item of income, gain, loss or deduction only if the allocation has substantial economic effect. In any other case, a partner's share of an item will be determined on the basis of his interest in us, which will be determined by taking into account all the facts and circumstances, including:

- his relative contributions to us;
- the interests of all the partners in profits and losses;
- the interests of all the partners in cash flows; and
- the rights of all the partners to distributions of capital upon liquidation.

Baker Botts L.L.P. is of the opinion that, with the exception of the issues described in "—Tax Consequences of Unit Ownership—Section 754 Election," "—Uniformity of Units" and "—Disposition of Common Units—Allocations Between Transferors and Transferees," allocations under our partnership agreement will be given effect for federal income tax purposes in determining a partner's share of an item of income, gain, loss or deduction.

Treatment of Short Sales

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, he would no longer be treated for tax purposes as a partner for those units during the period of the loan and may recognize gain or loss from the disposition. As a result, during this period:

- any of our income, gain, loss or deduction with respect to those units would not be reportable by the unitholder;
- any cash distributions received by the unitholder as to those units would be fully taxable; and
- all of these distributions would appear to be ordinary income.

Baker Botts L.L.P. has not rendered an opinion regarding the treatment of a unitholder where common units are loaned to a short seller to cover a short sale of common units; therefore, 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. The IRS has announced that it is actively studying issues relating to the tax treatment of short sales of partner interests. Please also see "—Disposition of Common Units—Recognition of Gain or Loss."

Alternative Minimum Tax

Each unitholder will be required to take into account his distributive share of any items of our income, gain, loss or deduction for purposes of the alternative minimum tax. The current minimum tax rate for noncorporate taxpayers is 26% on the first $175,000 of alternative minimum taxable income in excess of the exemption amount and 28% on any additional alternative minimum taxable income. Prospective unitholders are urged to consult with their tax advisors as to the impact of an investment in units on their liability for the alternative minimum tax.

Tax Rates

In general, the highest U.S. federal income tax rate for individuals is currently 35.0% and the maximum U.S. federal income tax rate for net capital gains of an individual is currently 15.0% if the asset disposed of was held for more than 12 months at the time of disposition.

Section 754 Election

We will make the election permitted by Section 754 of the Internal Revenue Code. That election is irrevocable without the consent of the IRS. The election will generally permit us to adjust a common unit purchaser's tax basis in our assets (or "inside basis") under Section 743(b) of the Internal Revenue Code to reflect his purchase price. This election does not apply to a person who purchases common units directly from us. The Section 743(b) adjustment belongs to the purchaser and not to other unitholders. For purposes of this discussion, a unitholder's inside basis in our assets will be considered to have two components: (1) his share of our tax basis in our assets (or "common basis") and (2) his Section 743(b) adjustment to that basis.

The timing of deductions attributable to Section 743(b) adjustments to our common basis will depend upon a number of factors, including the nature of the assets to which the adjustment is allocable, the extent to which the adjustment offsets any Section 704(c) type gain or loss with respect to an asset and certain elections we make as to the manner in which we apply Section 704(c) principles with respect to an asset to which the adjustment is applicable. Please see "—Allocation of Income, Gain, Loss and Deduction." The timing of these deductions may affect the uniformity of our units. Please see "—Uniformity of Units."

A Section 754 election is advantageous if the transferee's tax basis in his units is higher than the units' share of the aggregate tax basis of our assets immediately prior to the transfer. In that case, as a result of the election, the transferee would have, among other items, a greater amount of depreciation and depletion deductions and his share of any gain or loss on a sale of our assets would be less. Conversely, a Section 754 election is disadvantageous if the transferee's tax basis in his units is lower than those units' share of the aggregate tax basis of our assets immediately prior to the transfer. Thus, the fair market value of the units may be affected either favorably or unfavorably by the election. A basis adjustment is required regardless of whether a Section 754 election is made in the case of a transfer of an interest in us if we have a substantial built-in loss immediately after the transfer or if we distribute property and have a substantial basis reduction. Generally, a built-in loss or basis reduction is substantial if it exceeds $250,000.

The calculations involved in the Section 754 election are complex and will be made on the basis of assumptions as to the value of our assets and other matters. For example, the allocation of the Section 743(b) adjustment among our assets must be made in accordance with the Internal Revenue Code. The IRS could seek to reallocate some or all of any Section 743(b) adjustment allocated by us to our tangible assets to goodwill instead. Goodwill, as an intangible asset, is generally either nonamortizable or amortizable over a longer period of time or under a less accelerated method than our tangible assets. We cannot assure you that the determinations we make will not be successfully challenged by the IRS and that the deductions resulting from them will not be reduced or disallowed altogether. Should the IRS require a different basis adjustment to be made, and should, in our opinion, the expense of compliance exceed the benefit of the election, we may seek permission from the IRS to revoke our Section 754 election. If permission is granted, a subsequent purchaser of units may be allocated more income than he would have been allocated had the election not been revoked.

Tax Treatment of Operations

Accounting Method and Taxable Year

We use the year ending December 31 as our taxable year and the accrual method of accounting for federal income tax purposes. Each unitholder will be required to include in income his share of our income, gain, loss and deduction for our taxable year ending within or with his taxable year. In addition, a unitholder who has a taxable year ending on a date other than December 31 and who disposes of all of his units following the close of our taxable year but before the close of his taxable year must include his share of our income, gain, loss and deduction in income for his taxable year, with the result that he will be required to include in income for his taxable year his share of more than one year of our income, gain, loss and deduction. Please see "—Disposition of Common Units—Allocations Between Transferors and Transferees."

Initial Tax Basis, Depreciation and Amortization Expense

The tax basis of our assets will be used for purposes of computing depreciation and cost recovery deductions and, ultimately, gain or loss on the disposition of those assets. The federal income tax burden associated with the difference between the fair market value of our assets and their tax basis immediately prior to this offering will be borne by our general partner and its affiliates. Please see "—Tax Consequences of Unit Ownership—Allocation of Income, Gain, Loss and Deduction."

To the extent allowable, we may elect to use the depreciation and cost recovery methods that will result in the largest deductions being taken in the early years after assets are placed in service. Part or all of the goodwill, going concern value and other intangible assets we acquire in connection with this offering may not produce any amortization deductions because of the application of the "anti-churning" restrictions of Section 197. Property we subsequently acquire or construct may be depreciated using accelerated methods permitted by the Internal Revenue Code.

If we dispose of depreciable property by sale, foreclosure or otherwise, all or a portion of any gain, determined by reference to the amount of depreciation previously deducted and the nature of the property, may be subject to the recapture rules and taxed as ordinary income rather than capital gain. Similarly, a unitholder who has taken cost recovery or depreciation deductions with respect to property we own will likely be required to recapture some or all of those deductions as ordinary income upon a sale of his interest in us. Please see "—Tax Consequences of Unit Ownership—Allocation of Income, Gain, Loss and Deduction" and "—Disposition of Common Units—Recognition of Gain or Loss."

The costs incurred in selling our units (called "syndication expenses") must be capitalized and cannot be deducted currently, ratably or upon our termination. There are uncertainties regarding the classification of costs as organization expenses, which may be amortized by us, and as syndication expenses, which may not be amortized by us. The underwriting discounts and commissions we incur will be treated as syndication expenses.

Valuation and Tax Basis of Our Properties

The federal income tax consequences of the ownership and disposition of units will depend in part on our estimates of the relative fair market values, and the initial tax bases, of our assets. Although we may from time to time consult with professional appraisers regarding valuation matters, we will make many of the relative fair market value estimates ourselves. These estimates and determinations of basis are subject to challenge and will not be binding on the IRS or the courts. If the estimates of fair market value or basis are later found to be incorrect, the character and amount of items of income, gain, loss or deduction previously reported by unitholders might change, and unitholders might be required to adjust their tax liability for prior years and incur interest and penalties with respect to those adjustments.

Disposition of Common Units

Recognition of Gain or Loss

Gain or loss will be recognized on a sale of units equal to the difference between the unitholder's amount realized and the unitholder's tax basis for the units sold. A unitholder's amount realized will be measured by the sum of the cash or the fair market value of other property received by him plus his share of our nonrecourse liabilities. Because the amount realized includes a unitholder's share of our nonrecourse liabilities, the gain recognized on the sale of units could result in a tax liability in excess of any cash received from the sale.

Prior distributions from us in excess of cumulative net taxable income for a common unit that decreased a unitholder's tax basis in that common unit will, in effect, become taxable income if the common unit is sold at a price greater than the unitholder's tax basis in that common unit, even if the price received is less than his original cost.

Except as noted below, gain or loss recognized by a unitholder, other than a "dealer" in units, on the sale or exchange of a unit held for more than one year will generally be taxable as capital gain or loss. Capital gain recognized by an individual on the sale of units held more than 12 months will generally be taxed at a maximum rate of 15%. However, a portion of this gain or loss will be separately computed and taxed as ordinary income or loss under Section 751 of the Internal Revenue Code to the extent attributable to assets giving rise to depreciation recapture or other "unrealized receivables" or to "inventory items" we own. The term "unrealized receivables" includes potential recapture items, including depreciation recapture. Ordinary income attributable to unrealized receivables, inventory items and depreciation recapture may exceed net taxable gain realized upon the sale of a unit and may be recognized even if there is a net taxable loss realized on the sale of a unit. Thus, a unitholder may recognize both ordinary income and a capital loss upon a sale of units. Net capital losses may offset capital gains and no more than $3,000 of ordinary income, in the case of individuals, and may only be used to offset capital gains in the case of corporations.

The IRS has ruled that a partner who acquires interests in a partnership in separate transactions must combine those interests and maintain a single adjusted tax basis for all those interests. Upon a sale or other disposition of less than all of those interests, a portion of that tax basis must be allocated to the interests sold using an "equitable apportionment" method, which generally means that the tax basis allocated to the interest sold equals an amount that bears the same relation to the partner's tax basis in his entire interest in the partnership as the value of the interest sold bears to the value of the partner's entire interest in the partnership. Treasury Regulations under Section 1223 of the Internal Revenue Code allow a selling unitholder who can identify common units transferred with an ascertainable holding period to elect to use the actual holding period of the common units transferred. Thus, according to the ruling, a common unitholder will be unable to select high or low basis common units to sell as would be the case with corporate stock, but, according to the regulations, may designate specific common units sold for purposes of determining the holding period of units transferred. A unitholder electing to use the actual holding period of common units transferred must consistently use that identification method for all subsequent sales or exchanges of common units. A unitholder considering the purchase of additional units or a sale of common units purchased in separate transactions is urged to consult his tax advisor as to the possible consequences of this ruling and application of the regulations.

Specific provisions of the Internal Revenue Code affect the taxation of some financial products and securities, including partner interests, by treating a taxpayer as having sold an "appreciated" partnership interest, one in which gain would be recognized if it were sold, assigned or terminated at its fair market value, if the taxpayer or related persons enter(s) into:

- a short sale;
- an offsetting notional principal contract; or
- a futures or forward contract with respect to the partnership interest or substantially identical property.

Moreover, if a taxpayer has previously entered into a short sale, an offsetting notional principal contract or a futures or forward contract with respect to the partnership interest, the taxpayer will be treated as having sold that position if the taxpayer or a related person then acquires the partnership interest or substantially identical property. The Secretary of the Treasury is also authorized to issue regulations that treat a taxpayer that enters into transactions or positions that have substantially the same effect as the preceding transactions as having constructively sold the financial position.

Allocations Between Transferors and Transferees

In general, our taxable income and losses will be determined annually, will be prorated on a monthly basis and will be subsequently apportioned among the unitholders in proportion to the number of units owned by each of them as of the opening of the applicable exchange on the first business day of the month, which we refer to in this prospectus as the "Allocation Date." However, gain or loss realized on a sale or other disposition of our assets other than in the ordinary course of business will be allocated among the unitholders on the Allocation Date in the month in which that gain or loss is recognized. As a result, a unitholder transferring units may be allocated income, gain, loss and deduction realized after the date of transfer.

The use of this method may not be permitted under existing Treasury Regulations as there is no controlling authority on this issue. Accordingly, Baker Botts L.L.P. is unable to opine on the validity of this method of allocating income and deductions between unitholders. If this method is not allowed under the Treasury Regulations, or only applies to transfers of less than all of the unitholder's interest, our taxable income or losses might be reallocated among the unitholders. We are authorized to revise our method of allocation between unitholders, as well as unitholders whose interests vary during a taxable year, to conform to a method permitted under future Treasury Regulations.

A unitholder who owns units at any time during a quarter and who disposes of them prior to the record date set for a cash distribution for that quarter will be allocated items of our income, gain, loss and deductions attributable to that quarter but will not be entitled to receive that cash distribution.

Transfer Notification Requirements

A unitholder who sells any of his units, other than through a broker, generally is required to notify us in writing of that sale within 30 days after the sale (or, if earlier, January 15 of the year following the sale). A unitholder who acquires units generally is required to notify us in writing of that acquisition within 30 days after the purchase, unless a broker or nominee will satisfy such requirement. We are required to notify the IRS of any such transfers of units and to furnish specified information to the transferor and transferee. Failure to notify us of a transfer of units may, in some cases, lead to the imposition of penalties.

Constructive Termination

We will be considered to have been terminated for tax purposes if there is a sale or exchange of 50% or more of the total interests in our capital and profits within a twelve-month period. A constructive termination results in the closing of our taxable year for all unitholders. In the case of a unitholder reporting on a taxable year different from our taxable year, the closing of our taxable year may result in more than 12 months of our taxable income or loss being includable in his taxable income for the year of termination. Please see "—Tax Treatment of Operations—Accounting Method and Taxable Year." We would be required to make new tax elections after a termination, including a new election under Section 754 of the Internal Revenue Code, and a termination would result in a deferral of our deductions for depreciation. A termination could also result in penalties if we were unable to determine that the termination had occurred. Moreover, a termination might either accelerate the application of, or subject us to, any tax legislation enacted before the termination.

Uniformity of Units

Because we cannot match transferors and transferees of units, we must maintain uniformity of the economic and tax characteristics of the units to a purchaser of these units. In the absence of uniformity, we may be unable to completely comply with a number of federal income tax requirements, both statutory and regulatory. Any non-uniformity could have a negative impact on the value of the units. The timing of deductions attributable to Section 743(b) adjustments to the common basis of our assets with respect to persons purchasing units after this offering may affect the uniformity of our units. Please see "—Tax Consequences of Unit Ownership—Section 754 Election." For example, it is possible that we own, or will acquire, certain depreciable assets that are not subject to the typical rules governing depreciation (under Section 168 of the Internal Revenue Code) or amortization (under Section 197 of the Internal Revenue Code) of assets. This could cause the timing of a purchaser's deductions to differ, depending on when the unit he purchased was issued, or whether the unit was originally issued to our general partner and its affiliates.

Our partnership agreement permits our general partner to take positions in filing our tax returns that preserve the uniformity of our units even under circumstances like those described above. These positions may include reducing for some unitholders the depreciation, amortization or loss deductions to which they would otherwise be entitled or reporting a slower amortization of Section 743(b) adjustments for some unitholders than that to which they would otherwise be entitled. Our counsel, Baker Botts L.L.P., is unable to opine on the validity of such filing positions. A unitholder's basis in units is reduced by his or her share of our deductions (whether or not such deductions were claimed on an individual income tax return) so that any position that we take that understates deductions will overstate the unitholder's basis in his or her common units, which may cause the unitholder to understate gain or overstate loss on any sale of such units. The IRS may challenge any method of depreciating the Section 743(b) adjustment described in this paragraph. If this challenge were sustained, the uniformity of units might be affected, and the gain from the sale of units might be increased without the benefit of additional deductions. Please see "—Disposition of Common Units—Recognition of Gain or Loss."

Tax-Exempt Organizations and Non-U.S. Investors

Ownership of units by employee benefit plans, other tax-exempt organizations, non-resident aliens, foreign corporations and other foreign persons raises issues unique to those investors and, as described below, may have substantially adverse tax consequences to them.

Employee benefit plans and most other organizations exempt from federal income tax, including individual retirement accounts and other retirement plans, are subject to federal income tax on unrelated business taxable income. Virtually all of our income allocated to a unitholder that is a tax-exempt organization will be unrelated business taxable income and will be taxable to it.

Non-resident aliens and foreign corporations, trusts or estates that own units will be considered to be engaged in business in the U.S. because of the ownership of units. As a consequence, they will be required to file federal tax returns to report their share of our income, gain, loss or deduction and pay federal income tax at regular rates on their share of our net earnings or gain. Moreover, under rules applicable to publicly traded partnerships, we will withhold at the highest applicable effective tax rate from cash distributions made quarterly to foreign unitholders. Each foreign unitholder must obtain a taxpayer identification number from the IRS and submit that number to our transfer agent on a Form W-8BEN or applicable substitute form in order to obtain credit for these withholding taxes. A change in applicable law may require us to change these procedures.

In addition, because a foreign corporation that owns units will be treated as engaged in a U.S. trade or business, that corporation may be subject to the U.S. branch profits tax at a rate of 30%, in addition to regular federal income tax, on its share of our income and gain, as adjusted for changes in the foreign corporation's "U.S. net equity," which is effectively connected with the conduct of a U.S. trade or business. That tax may be reduced or eliminated by an income tax treaty between the U.S. and the country in which the foreign corporate unitholder is a "qualified resident." In addition, this type of unitholder is subject to special information reporting requirements under Section 6038C of the Internal Revenue Code.

Under a ruling of the IRS, a foreign unitholder who sells or otherwise disposes of a unit will be subject to federal income tax on gain realized on the sale or disposition of that unit to the extent that this gain is effectively connected with a U.S. trade or business of the foreign unitholder. Apart from the ruling, a foreign unitholder will not be taxed or subject to withholding upon the sale or disposition of a unit if he has owned less than 5% in value of the units during the five-year period ending on the date of the disposition and if the units are regularly traded on an established securities market at the time of the sale or disposition.

Administrative Matters

Information Returns and Audit Procedures

We intend to furnish to each unitholder, within 90 days after the close of each taxable year, specific tax information, including a Schedule K-1, which describes his share of our income, gain, loss and deduction for our preceding taxable year. In preparing this information, which will not be reviewed by counsel, we will take various accounting and reporting positions, some of which have been mentioned earlier, to determine his share of income, gain, loss and deduction. We cannot assure you that those positions will yield a result that conforms to the requirements of the Internal Revenue Code, Treasury Regulations or administrative interpretations of the IRS. Neither we nor Baker Botts L.L.P. can assure prospective unitholders that the IRS will not successfully contend in court that those positions are impermissible. Any challenge by the IRS could negatively affect the value of the units.

The IRS may audit our federal income tax information returns. Adjustments resulting from an IRS audit may require each unitholder to adjust a prior year's tax liability, and possibly may result in an audit of his return. Any audit of a unitholder's return could result in adjustments not related to our returns as well as those related to our returns.

Partnerships generally are treated as separate entities for purposes of federal tax audits, judicial review of administrative adjustments by the IRS and tax settlement proceedings. The tax treatment of partnership items of income, gain, loss and deduction are determined in a partnership proceeding rather than in separate proceedings with the partners. The Internal Revenue Code requires that one partner be designated as the "Tax Matters Partner" for these purposes. Our partnership agreement names our general partner, OGE Enogex GP LLC, as our Tax Matters Partner.

The Tax Matters Partner will make some elections on our behalf and on behalf of unitholders. In addition, the Tax Matters Partner can extend the statute of limitations for assessment of tax deficiencies against unitholders for items in our returns. The Tax Matters Partner may bind a unitholder with less than a 1% profits interest in us to a settlement with the IRS unless that unitholder elects, by filing a statement with the IRS, not to give that authority to the Tax Matters Partner. The Tax Matters Partner may seek judicial review, by which all the unitholders are bound, of a final partnership administrative adjustment and, if the Tax Matters Partner fails to seek judicial review, judicial review may be sought by any unitholder having at least a 1% interest in profits or by any group of unitholders having in the aggregate at least a 5% interest in profits. However, only one action for judicial review will go forward, and each unitholder with an interest in the outcome may participate.

A unitholder must file Form 8082 with the IRS identifying the treatment of any item on his federal income tax return that is not consistent with the treatment of the item on our return. Intentional or negligent disregard of this consistency requirement may subject a unitholder to substantial penalties.

Nominee Reporting

Persons who hold an interest in us as a nominee for another person are required to furnish to us:

(1) the name, address and taxpayer identification number of the beneficial owner and the nominee;

(2) whether the beneficial owner is:

   a. a person that is not a U.S. person;

   b. a foreign government, an international organization or any wholly owned agency or instrumentality of either of the foregoing; or

   c. a tax-exempt entity;

(3) the amount and description of units held, acquired or transferred for the beneficial owner; and

(4) specific information including the dates of acquisitions and transfers, means of acquisitions and transfers, and acquisition cost for purchases, as well as the amount of net proceeds from sales.

Brokers and financial institutions are required to furnish additional information, including whether they are U.S. persons and specific information on units they acquire, hold or transfer for their own account. A penalty of $50 per failure, up to a maximum of $100,000 per calendar year, is imposed by the Internal Revenue Code for failure to report that information to us. The nominee is required to supply the beneficial owner of the units with the information furnished to us.

Accuracy-Related and Assessable Penalties

An additional tax equal to 20% of the amount of any portion of an underpayment of tax that is attributable to one or more specified causes, including negligence or disregard of rules or regulations, substantial understatements of income tax and substantial valuation misstatements, is imposed by the Internal Revenue Code. No penalty will be imposed, however, for any portion of an underpayment if it is shown that there was a reasonable cause for that portion and that the taxpayer acted in good faith regarding that portion.

For individuals, a substantial understatement of income tax in any taxable year exists if the amount of the understatement exceeds the greater of 10% of the tax required to be shown on the return for the taxable year or $5,000. The amount of any understatement subject to penalty generally is reduced if any portion is attributable to a position adopted on the return:

(1) for which there is, or was, "substantial authority"; or

(2) as to which there is a reasonable basis and the pertinent facts of that position are disclosed on the return.

More stringent rules apply to "tax shelters," but we believe we are not a tax shelter. If any item of income, gain, loss or deduction included in the distributive shares of unitholders might result in that kind of an "understatement" of income for which no "substantial authority" exists, we must disclose the pertinent facts on our return. In addition, we will make a reasonable effort to furnish sufficient information for unitholders to make adequate disclosure on their returns to avoid liability for this penalty.

A substantial valuation misstatement exists if the value of any property, or the adjusted basis of any property, claimed on a tax return is 200% or more of the amount determined to be the correct amount of the valuation or adjusted basis. No penalty is imposed unless the portion of the underpayment attributable to a substantial valuation misstatement exceeds $5,000 ($10,000 for most corporations). If the valuation claimed on a return is 400% or more than the correct valuation, the penalty imposed increases to 40%.

Reportable Transactions

If we were to engage in a "reportable transaction," we (and possibly you and others) would be required to make a detailed disclosure of the transaction to the IRS. A transaction may be a reportable transaction based upon any of several factors, including the fact that it is a type of tax avoidance transaction publicly identified by the IRS as a "listed transaction" or that it produces certain kinds of losses in excess of $2 million in any taxable year, or $4 million in any combination of taxable years. Our participation in a reportable transaction could increase the likelihood that our federal income tax information return (and possibly your tax return) would be audited by the IRS. Please see "—Information Returns and Audit Procedures" above.

Moreover, if we were to participate in a reportable transaction with a significant purpose to avoid or evade tax, or in any listed transaction, you may be subject to the following provisions of the American Jobs Creation Act of 2004:

- accuracy-related penalties with a broader scope, significantly narrower exceptions, and potentially greater amounts than described above at "—Accuracy-Related and Assessable Penalties,"
- for those persons otherwise entitled to deduct interest on federal tax deficiencies, nondeductibility of interest on any resulting tax liability, and
- in the case of a listed transaction, an extended statute of limitations.

State, Local, Foreign and Other Tax Considerations

In addition to federal income taxes, you likely will be subject to other taxes, such as state, local and foreign income taxes, unincorporated business taxes, and estate, inheritance or intangible taxes that may be imposed by the various jurisdictions in which we do business or own property or in which you are a resident. Although an analysis of those various taxes is not presented here, each prospective unitholder should consider their potential impact on his investment in us. We will initially own property or do business in Oklahoma and Texas. We may also own property or do business in other jurisdictions in the future. Although you may not be required to file a return and pay taxes in some jurisdictions because your income from those jurisdictions falls below the filing and payment requirements, you will be required to file income tax returns and to pay income taxes in many of the jurisdictions in which we do business or own property and may be subject to penalties for failure to comply with those requirements. In some jurisdictions, tax losses may not produce a tax benefit in the year incurred and may not be available to offset income in subsequent taxable years. Some of the jurisdictions may require us, or we may elect, to withhold a percentage of income from amounts to be distributed to a unitholder who is not a resident of the jurisdiction. Withholding, the amount of which may be greater or less than a particular unitholder's income tax liability to the jurisdiction, generally does not relieve a nonresident unitholder from the obligation to file an income tax return. We may, but are not required to, treat amounts withheld as if distributed to unitholders for purposes of determining the amounts distributed by us. Please see "—Tax Consequences of Unit Ownership—Entity-Level Collections." Based on current law and our estimate of our future operations, our general partner anticipates that any amounts required to be withheld will not be material.

It is the responsibility of each unitholder to investigate the legal and tax consequences, under the laws of pertinent jurisdictions, of his investment in us. Accordingly, each prospective unitholder is urged to consult, and depend upon, his tax counsel or other advisor with regard to those matters. Further, it is the responsibility of each unitholder to file all state, local and foreign, as well as U.S. federal tax returns, that may be required of him. Baker Botts L.L.P. has not rendered an opinion on the state, local or foreign tax consequences of an investment in us.

INVESTMENT IN OGE ENOGEX PARTNERS L.P. BY EMPLOYEE BENEFIT PLANS

An investment in us by an employee benefit plan is subject to additional considerations because the investments of these plans are subject to the fiduciary responsibility and prohibited transaction provisions of ERISA and restrictions imposed by Section 4975 of the Internal Revenue Code. For these purposes the term "employee benefit plan" includes, but is not limited to, qualified pension, profit-sharing and stock bonus plans, Keogh plans, simplified employee pension plans and tax deferred annuities or IRAs established or maintained by an employer or employee organization. Among other things, consideration should be given to:

- whether the investment is prudent under Section 404(a)(1)(B) of ERISA;
- whether in making the investment, that plan will satisfy the diversification requirements of Section 404(a)(1)(C) of ERISA; and
- whether the investment will result in recognition of unrelated business taxable income by the plan and, if so, the potential after-tax investment return. Please see "Material Tax Consequences—Tax-Exempt Organizations and Other Investors."

The person with investment discretion with respect to the assets of an employee benefit plan, often called a fiduciary, should determine whether an investment in us is authorized by the appropriate governing instrument and is a proper investment for the plan.

Section 406 of ERISA and Section 4975 of the Internal Revenue Code prohibit employee benefit plans, and also IRAs that are not considered part of an employee benefit plan, from engaging in specified transactions involving "plan assets" with parties that are "parties in interest" under ERISA or "disqualified persons" under the Internal Revenue Code with respect to the plan.

In addition to considering whether the purchase of common units is a prohibited transaction, a fiduciary of an employee benefit plan should consider whether the plan will, by investing in us, be deemed to own an undivided interest in our assets, with the result that our operations would be subject to the regulatory restrictions of ERISA, including its prohibited transaction rules, as well as the prohibited transaction rules of the Internal Revenue Code.

The Department of Labor regulations provide guidance with respect to whether the assets of an entity in which employee benefit plans acquire equity interests would be deemed "plan assets" under some circumstances. Under these regulations, an entity's assets would not be considered to be "plan assets" if, among other things:

(1) the equity interests acquired by employee benefit plans are publicly offered securities—*i.e.*, the equity interests are widely held by 100 or more investors independent of the issuer and each other, freely transferable and registered under some provisions of the federal securities laws;

(2) the entity is an "operating company,"—*i.e.*, it is primarily engaged in the production or sale of a product or service other than the investment of capital either directly or through a majority-owned subsidiary or subsidiaries; or

(3) there is no significant investment by benefit plan investors, which is defined to mean that less than 25% of the value of each class of equity interest is held by the employee benefit plans referred to above, IRAs and other employee benefit plans not subject to ERISA, including governmental plans.

Our assets should not be considered "plan assets" under these regulations because it is expected that the investment will satisfy the requirements in (a) above.

Plan fiduciaries contemplating a purchase of common units should consult with their own counsel regarding the consequences under ERISA and the Internal Revenue Code in light of the serious penalties imposed on persons who engage in prohibited transactions or other violations.

UNDERWRITING

We are offering our common units described in this prospectus through the underwriters named below. UBS Securities LLC and Lehman Brothers Inc. are the representatives of the underwriters and the joint book-running managers of this offering. Subject to the terms and conditions of an underwriting agreement, which will be filed as an exhibit to the registration statement, each of the underwriters has severally agreed to purchase the number of common units listed next to its name in the following table:

Underwriters	Number of Common Units
UBS Securities LLC	
Lehman Brothers Inc.	
Total	7,500,000

The underwriting agreement provides that the underwriters must buy all of the common units if they buy any of them. However, the underwriters are not required to take or pay for the common units covered by the underwriters' option to purchase additional common units described below.

Our common units and the common units to be sold upon the exercise of the underwriters' option to purchase additional common units, if any, are offered subject to a number of conditions, including:

- receipt and acceptance of our common units by the underwriters;
- our delivery of customary closing documents to the underwriters; and
- the underwriters' right to reject orders in whole or in part.

We have been advised by the representatives that the underwriters intend to make a market in our common units, but that they are not obligated to do so and may discontinue making a market at any time without notice.

Option to Purchase Additional Common Units

We have granted the underwriters an option to buy up to an aggregate 1,125,000 additional common units. This option may be exercised if the underwriters sell more than 7,500,000 common units in connection with this offering. The underwriters have 30 days from the date of this prospectus to exercise this option. If the underwriters exercise this option, they will each purchase additional common units approximately in proportion to the amounts specified in the table above.

Discounts and Commissions

Common units sold by the underwriters to the public will initially be offered at the initial offering price set forth on the cover of this prospectus. Any common units sold by the underwriters to securities dealers may be sold at a discount of up to $ per common unit from the initial public offering price. Any of these securities dealers may resell any common units purchased from the underwriters to other brokers or dealers at a discount of up to $ per common unit from the initial public offering price. If all the common units are not sold at the initial public offering price, the representatives may change the offering price and the other selling terms. Sales of common units made outside of the United States may be made by affiliates of the underwriters. Upon execution of the underwriting agreement, the underwriters will be obligated to purchase the common units at the prices and upon the terms stated therein, and, as a result, will thereafter bear any risk associated with changing the offering price to the public or other selling terms.

The following table shows the per unit and total underwriting discounts and commissions we will pay to the underwriters assuming both no exercise and full exercise of the underwriters' option to purchase up to an additional 1,125,000 common units.

	No Exercise	Full Exercise
Per Unit	$	$
Total	$	$

We will pay a structuring fee equal to $ to UBS Securities LLC for evaluation, analysis and structuring of our partnership.

We estimate that the total expenses of this offering payable by us, not including the underwriting discounts and commissions and fees, will be approximately $2.5 million.

No Sales of Similar Securities

We, the executive officers and directors of our general partner, our general partner and its affiliates (including OGE Energy) and the participants in our directed unit program will enter into lock-up agreements with the underwriters. Under these agreements, we and each of these persons may not, without the prior written approval of UBS Securities LLC and Lehman Brothers Inc., offer, sell, contract to sell or otherwise dispose of or hedge our common units or securities convertible into or exchangeable for our common units, enter into any swap or other agreement that transfers, in whole or in part, any of the economic consequences of ownership of the common units, make any demand for or exercise any right or file or cause to be filed a registration statement with respect to the registration of any common units or securities convertible, exercisable or exchangeable into common units or any of our other securities or publicly disclose the intention to do any of the foregoing. These restrictions will be in effect for a period of 180 days after the date of this prospectus. The lock-up period will be extended under certain circumstances where we release, or pre-announce a release of our earnings or announce material news or a material event during the 17 days before or 16 days after the termination of the 180-day period in which case the restrictions described above will continue to apply until the expiration of the 18-day period beginning on the issuance of the earnings release or the announcement of the material news or material event.

At any time and without public notice, UBS Securities LLC and Lehman Brothers Inc. may in their discretion, release all or some of the securities from these lock-up agreements. When determining whether or not to release common units from these restrictions, the primary factors that the representatives will consider include the requesting unitholder's reasons for requesting the release, the number of common units for which the release is being requested and the prevailing economic and equity market conditions at the time of the request. The representatives have no present intent to release any of the securities from these lock-up agreements.

Indemnification

We, our general partner and certain of its affiliates, have agreed to indemnify the underwriters against certain liabilities, including liabilities under the Securities Act, and to contribute to payments that the underwriters may be required to make for these liabilities. If we are unable to provide this indemnification, we will contribute to payments the underwriters may be required to make in respect of those liabilities.

Directed Unit Program

At our request, some of the underwriters have established a directed unit program under which they have reserved up to common units for sale at the initial offering price to persons who are directors, officers or employees of our general partner, or who are otherwise associated with us. The number of common units available for sale to the general public will be reduced to the extent such persons purchase common units reserved under the directed unit program. Any reserved common units not so purchased will be offered by the underwriters to the general public on the same basis as the other common units offered hereby. The purchasers in the directed unit program will be subject to substantially the same form of lock-up agreement described above. We have agreed to indemnify the underwriters against certain liabilities and expenses, including liabilities under the Securities Act, in connection with the directed unit program.

New York Stock Exchange

We intend to apply to list our common units on the New York Stock Exchange under the trading symbol "OGP."

Price Stabilization, Short Positions

In connection with this offering, the underwriters may engage in activities that stabilize, maintain or otherwise affect the price of our common units, including:

- stabilizing transactions;
- short sales;
- purchases to cover positions created by short sales;
- imposition of penalty bids; and
- syndicate covering transactions.

Stabilizing transactions consist of bids or purchases made for the purpose of preventing or retarding a decline in the market price of our common units while this offering is in progress. These transactions may also include making short sales of our common units, which involves the sale by the underwriters of a greater number of common units than they are required to purchase in this offering and purchasing common units on the open market to cover positions created by short sales. Short sales may be "covered" shorts, which are short positions in an amount not greater than the underwriters' option to purchase additional common units referred to above, or may be "naked" shorts, which are short positions in excess of that amount.

The underwriters may close out any covered short position by either exercising their option to purchase additional common units, in whole or in part, or by purchasing common units in the open market. In making this determination, the underwriters will consider, among other things, the price of common units available for purchase in the open market as compared to the price at which they may purchase common units through their option to purchase additional common units.

Naked short sales are in excess of the underwriters' option to purchase additional common units. The underwriters must close out any naked short position by purchasing common units in the open market. A naked short position is more likely to be created if the underwriters are concerned that there may be downward pressure on the price of the common units in the open market that could adversely affect investors who purchased common units in this offering.

The underwriters also may impose a penalty bid. This occurs when a particular underwriter repays to the underwriters a portion of the underwriting discount received by it because the representatives have repurchased common units sold by or for the account of that underwriter in stabilizing or short covering transactions.

As a result of these activities, the price of our common units may be higher than the price that otherwise might exist in the open market. If these activities are commenced, they may be discontinued by the underwriters at any time. The underwriters may carry out these transactions on the New York Stock Exchange, in the over-the-counter market or otherwise.

Determination of Offering Price

Prior to this offering, there has been no public market for our common units. The initial public offering price was determined by negotiation by us and the representatives of the underwriters. The principal factors considered in determining the initial public offering price include:

- the information set forth in this prospectus and otherwise available to the representatives;
- our history and prospects, and the history and prospects of the industry in which we compete;
- our past and present financial performance and an assessment of the directors and executive officers of our general partner;
- our prospects for future earnings and cash flows and the present state of our development;
- the general condition of the securities markets at the time of this offering; and
- the recent market prices of, and demand for, publicly traded common units of generally comparable master limited partnerships.

Electronic Distribution

A prospectus in electronic format may be made available on the Internet sites or through other online services maintained by one or more of the underwriters and/or selling group members participating in this offering, or by their affiliates. In those cases, prospective investors may view offering terms online and, depending upon the particular underwriter or selling group member, prospective investors may be allowed to place orders online. The underwriters may agree with us to allocate a specific number of units for sale to online brokerage account holders. Any such allocation for online distributions will be made by the representatives on the same basis as other allocations.

Other than the prospectus in electronic format, the information on any underwriter's or selling group member's web site and any information contained in any other web site maintained by an underwriter or selling group member is not part of the prospectus or the registration statement of which this prospectus forms a part, has not been approved and/or endorsed by us or any underwriter or selling group member in its capacity as underwriter or selling group member and should not be relied upon by investors.

Discretionary Sales

The underwriters have informed us that they do not intend to confirm sales to discretionary accounts that exceed 5% of the total number of units offered by them.

Stamp Taxes

If you purchase common units offered in this prospectus, you may be required to pay stamp taxes and other charges under the laws and practices of the country of purchase, in addition to the offering price listed on the cover page of this prospectus.

Affiliations

The underwriters and their affiliates may from time to time in the future engage in transactions with us and perform services for us in the ordinary course of their business. In addition, some of the underwriters have engaged in, and may in the future engage in, transactions with us and our predecessor and perform services for us in the ordinary course of their business.

NASD Conduct Rules

Because the National Association of Securities Dealers, Inc. views the common units offered hereby as interests in a direct participation program, this offering is being made in compliance with Rule 2810 of the NASD's Conduct Rules. In no event will the maximum amount of compensation to be paid to NASD members in connection with this offering exceed 10%. Investor suitability with respect to the common units should be judged similarly to the suitability with respect to other securities that are listed for trading on a national securities exchange.

LEGAL MATTERS

The validity of the common units will be passed upon for us by Jones Day, Chicago, Illinois. Certain tax matters in connection with the common units offered hereby will be passed upon for us by Baker Botts L.L.P., Houston, Texas. Certain legal matters in connection with the common units offered hereby will be passed upon for the underwriters by Vinson & Elkins L.L.P., Houston, Texas.

EXPERTS

The consolidated financial statements of Enogex Inc. at December 31, 2006 and 2005 and for each of the three years in the period ended December 31, 2006 appearing in this Prospectus and Registration Statement have been audited by Ernst & Young LLP, independent registered public accounting firm, as set forth in their report thereon appearing elsewhere herein, and are included in reliance upon such report given on the authority of such firm as experts in accounting and auditing.

The balance sheet of OGE Enogex Partners L.P. as of June 14, 2007 appearing in this Prospectus and Registration Statement has been audited by Ernst & Young LLP, independent registered public accounting firm, as set forth in their report thereon appearing elsewhere herein, and is included in reliance upon such report given on the authority of such firm as experts in accounting and auditing.

The balance sheet of OGE Enogex GP LLC as of June 14, 2007 appearing in this Prospectus and Registration Statement has been audited by Ernst & Young LLP, independent registered public accounting firm, as set forth in their report thereon appearing elsewhere herein, and is included in reliance upon such report given on the authority of such firm as experts in accounting and auditing.

WHERE YOU CAN FIND MORE INFORMATION

We have filed with the SEC a registration statement on Form S-l regarding the common units offered by this prospectus. This prospectus does not contain all of the information found in the registration statement. For further information regarding us and the common units offered by this prospectus, you should review the full registration statement, including its exhibits and schedules, filed under the Securities Act. The registration statement of which this prospectus constitutes a part, including its exhibits and schedules, may be inspected and copied at the public reference room maintained by the SEC at 100 F Street, N.E., Room 1580, Washington, D.C. 20549. Copies of the materials may also be obtained from the SEC at prescribed rates by writing to the public reference room maintained by the SEC at 100 F Street, N.E., Room 1580, Washington, D.C. 20549. You may obtain information on the operation of the public reference room by calling the SEC at 1-800-SEC-0330. The SEC maintains a website on the Internet at http://www.sec.gov. Our registration statement, of which this prospectus constitutes a part, can be downloaded from the SEC's website.

We intend to furnish our unitholders annual reports containing our audited historical consolidated financial statements and furnish or make available quarterly reports containing our unaudited interim financial information for the first three quarters of each of our fiscal years.

FORWARD-LOOKING STATEMENTS

This prospectus contains forward-looking statements and information that are based on our beliefs and those of our general partner, as well as assumptions made by and information currently available to us and our general partner. These forward-looking statements are identified as any statement that does not relate to historical or current facts. In particular, a significant amount of information included under "Cash Distribution Policy and Restrictions on Distributions" is comprised of forward-looking statements. When used in this prospectus, such words as "may," "believe," "expect," "anticipate," "project," "plan," "goal," "forecast," "intend," "could," "should," "estimate," "continue" and similar expressions and statements regarding our plans and objectives for future operations are intended to identify forward-looking statements. Although we and our general partner believe that such expectations reflected in such forward-looking statements are reasonable, neither we nor our general partner can give assurances that such expectations will prove to be correct. Such statements are subject to a variety of risks, uncertainties and assumptions. If one or more of these risks or uncertainties occur, or if any underlying assumption proves incorrect, our actual results may vary materially from those anticipated, estimated, projected or expected. You should not put undue reliance on any forward-looking statements. When considering forward-looking statements, please review the risk facts described under the caption "Risk Factors" in this prospectus.

INDEX TO FINANCIAL STATEMENTS

OGE ENOGEX PARTNERS L.P.

UNAUDITED PRO FORMA CONSOLIDATED FINANCIAL STATEMENTS AND FOOTNOTES

FOR THE THREE MONTHS ENDED MARCH 31, 2007 AND THE YEAR ENDED DECEMBER 31, 2006

Introduction

OGE Enogex Partners L.P., a Delaware limited partnership (the "Partnership"), was formed on May 30, 2007, by OGE Energy Corp. ("OGE Energy"), to further develop its natural gas midstream assets and operations. OGE Energy intends to offer common units in the Partnership to the public (the "Offering"). In connection with the Offering, OGE Energy's subsidiary, Enogex Inc., will be merged with and into a Delaware corporation that will then convert to a Delaware limited liability company, to be named Enogex LLC. OGE Energy will then contribute a 25% interest in Enogex LLC to the Partnership. OGE Energy will retain the remaining 75% interest in Enogex LLC. At the completion of the Offering, subsidiaries of OGE Energy will own a 63.9% limited partner interest in the Partnership and a 2% general partner interest in the Partnership, through OGE Enogex GP LLC, the Partnership's general partner ("General Partner"), and the Partnership will own a 25% interest in Enogex LLC. A wholly owned subsidiary of the Partnership will serve as Enogex LLC's managing member and will control its assets and operations. The accompanying unaudited pro forma consolidated financial statements give effect to the Offering and related transactions.

Unless the context requires otherwise, for purposes of this pro forma presentation, all references to "we", "our", "us" and the "Partnership" refer to OGE Enogex Partners L.P. and its subsidiaries, including Enogex LLC. Enogex LLC's financial information is consolidated with the Partnership due to the fact that the Partnership, through ownership of Enogex LLC's managing member, will control Enogex LLC upon completion of the Offering. References to Enogex Inc. refer to Enogex LLC and its subsidiaries.

The unaudited pro forma consolidated balance sheet at March 31, 2007 assumes the Offering and related transactions occurred on March 31, 2007. The unaudited pro forma consolidated statements of income for the year ended December 31, 2006 and for the three months ended March 31, 2007 assume the Offering and related transactions occurred on January 1, 2006. See Note 1 in the accompanying notes to the unaudited pro forma consolidated financial statements for further discussion.

The unaudited pro forma consolidated financial statements and accompanying notes have been prepared in conformity with U.S. generally accepted accounting principles consistent with those used in, and should be read together with, Enogex Inc.'s historical consolidated financial statements and related notes, which are included elsewhere in this prospectus.

The adjustments reflected in the unaudited pro forma consolidated financial statements are based on currently available information and certain estimates and assumptions; therefore, actual results may differ from the pro forma adjustments. However, management believes that the assumptions used provide a reasonable basis for presenting the significant effects of the Offering and the related transactions, and that the pro forma adjustments in the unaudited pro forma consolidated financial statements give appropriate effect to the assumptions and are applied in conformity with accounting principles generally accepted in the United States.

The unaudited pro forma consolidated financial statements do not purport to present the Partnership's results of operations had the Offering and related transactions to be effected in connection with the Offering actually been completed at the dates indicated. In addition, they do not project the Partnership's results of operations for any future period.

Under the provisions of the senior notes currently expected to be repaid in connection with the Offering, a make-whole premium of approximately $30 million will be paid and funded with a portion of the proceeds from the Offering contributed by the Partnership to Enogex LLC. As this item does not have a continuing impact, no adjustment for this item is provided in the pro forma consolidated statements of income.

OGE ENOGEX PARTNERS L.P.

UNAUDITED PRO FORMA CONSOLIDATED STATEMENT OF INCOME

	Year Ended December 31, 2006		
	Enogex LLC Predecessor	Pro Forma Adjustments	OGE Enogex Partners L.P. Pro Forma
	(in millions, except per unit data)		
OPERATING REVENUES	$2,367.8		$2,367.8
COST OF GOODS SOLD	2,060.4		2,060.4
Gross margin on revenues	307.4		307.4
Other operation and maintenance	110.0	$ 2.0 (a) 2.0 (b)	114.0
Depreciation	42.3		42.3
Impairment of assets	0.3		0.3
Taxes other than income	16.0		16.0
OPERATING INCOME	138.8	(4.0)	134.8
OTHER INCOME (EXPENSE)			
Interest income	11.1	(8.3)(d)	2.8
Other income	7.7		7.7
Other expense	(0.3)		(0.3)
Net other income	18.5	(8.3)	10.2
INTEREST EXPENSE	31.8	(32.2)(d) 1.1 (e) 21.0 (f) 1.8 (g)	23.5
INCOME FROM CONTINUING OPERATIONS BEFORE TAXES	125.5	(4.0)	121.5
INCOME TAX EXPENSE	48.0	(48.0)(h)	—
INCOME FROM CONTINUING OPERATIONS BEFORE NON-CONTROLLING INTEREST	77.5	44.0	121.5
NON-CONTROLLING INTEREST	—	(92.6)(c)	(92.6)
NET INCOME FROM CONTINUING OPERATIONS	$ 77.5	$(48.6)	$ 28.9
General partner's interest in net income			$ 0.6
Limited partners' interest in net income			$ 28.3
Number of limited partner units			21.6
Basic and diluted earnings per limited partner units			$ 1.31

The accompanying notes are an integral part of the unaudited pro forma consolidated financial statements.

OGE ENOGEX PARTNERS L.P.

UNAUDITED PRO FORMA CONSOLIDATED STATEMENT OF INCOME

	Three Months Ended March 31, 2007		
	Enogex LLC Predecessor	Pro Forma Adjustments	OGE Enogex Partners L.P. Pro Forma
	(in millions, except per unit data)		
OPERATING REVENUES	$ 557.8		$ 557.8
COST OF GOODS SOLD	484.0		484.0
Gross margin on revenues	73.8		73.8
Other operation and maintenance	27.8	$ 0.5 (a) 0.1 (b)	28.4
Depreciation	11.3		11.3
Taxes other than income	4.5		4.5
OPERATING INCOME	30.2	(0.6)	29.6
OTHER INCOME (EXPENSE)			
Interest income	2.6	(2.5)(d)	0.1
Other income	0.3		0.3
Other expense	(0.1)		(0.1)
Net other income	2.8	(2.5)	0.3
INTEREST EXPENSE	8.1	(8.0)(d) 0.4 (e) 5.2 (f)	5.7
INCOME BEFORE TAXES	24.9	(0.7)	24.2
INCOME TAX EXPENSE	9.4	(9.4)(h)	—
INCOME BEFORE NON-CONTROLLING INTEREST	15.5	8.7	24.2
NON-CONTROLLING INTEREST	—	(18.3)(c)	(18.3)
NET INCOME	$ 15.5	$ (9.6)	$ 5.9
General partner's interest in net income			$ 0.1
Limited partners' interest in net income			$ 5.8
Number of limited partner units			21.6
Basic and diluted earnings per limited partner units			$ 0.27

The accompanying notes are an integral part of the unaudited pro forma consolidated financial statements.

OGE ENOGEX PARTNERS L.P.

UNAUDITED PRO FORMA CONSOLIDATED BALANCE SHEET

	March 31, 2007		
	Enogex LLC Predecessor	Pro Forma Adjustments	OGE Enogex Partners L.P. Pro Forma
		(in millions)	
ASSETS			
CURRENT ASSETS			
Cash and cash equivalents	$ 3.1	(400.0)(l) 300.0 (n) (5.5)(n) 150.0 (o) (13.0)(p) (30.0)(q)	$ 4.6
Accounts receivable, less reserve of $0.9	182.3		182.3
Accounts receivable—affiliates	3.9		3.9
Advances to parent	176.3	4.9 (j) (174.4)(k) (6.8)(m)	—
Fuel inventories	26.4		26.4
Materials and supplies, at average cost	1.9		1.9
Price risk management	5.9		5.9
Gas imbalances	3.6		3.6
Accumulated deferred tax assets	1.2	(1.2) (j)	—
Prepayments	2.8		2.8
Other	6.1		6.1
Total current assets	413.5	(176.0)	237.5
OTHER PROPERTY AND INVESTMENTS, at cost	1.6		1.6
PROPERTY, PLANT AND EQUIPMENT			
In service	1,260.4		1,260.4
Construction work in progress	23.1		23.1
Total property, plant and equipment	1,283.5		1,283.5
Less accumulated depreciation	403.6		403.6
Net property, plant and equipment	879.9		879.9
DEFERRED CHARGES AND OTHER ASSETS			
Prepaid benefit obligation	0.5		0.5
Price risk management	1.5		1.5
Unamortized debt issuance costs	1.6	(0.3)(l) (1.3)(l) 5.5(n)	5.5
Other	6.1		6.1
Total deferred charges and other assets	9.7	3.9	13.6
TOTAL ASSETS	$1,304.7	$(172.1)	$1,132.6

The accompanying notes are an integral part of the unaudited pro forma consolidated financial statements.

OGE ENOGEX PARTNERS L.P.

UNAUDITED PRO FORMA CONSOLIDATED BALANCE SHEET (Continued)

	March 31, 2007		
	Enogex LLC Predecessor	Pro Forma Adjustments	OGE Enogex Partners L.P. Pro Forma
		(in millions)	
LIABILITIES AND STOCKHOLDERS' EQUITY			
CURRENT LIABILITIES			
Accounts payable	$ 194.6		$ 194.6
Customer deposits	2.8		2.8
Accrued taxes	3.5		3.5
Accrued interest	6.8	(6.8)(m)	—
Accrued compensation	4.5		4.5
Long-term debt due within one year	3.0		3.0
Price risk management	4.4		4.4
Gas imbalances	12.9		12.9
Other	14.6		14.6
Total current liabilities	247.1	(6.8)	240.3
LONG-TERM DEBT	403.5	(400.0)(l) (2.5)(l) 300.0 (n)	301.0
COMMITMENTS AND CONTINGENCIES (NOTE 10)			
DEFERRED CREDITS AND OTHER LIABILITIES			
Accrued pension and benefit obligations	16.5		16.5
Accumulated deferred income taxes	233.2	(233.2)(j)	—
Price risk management	0.9		0.9
Other	2.8		2.8
Total deferred credits and other liabilities	253.4	(233.2)	20.2
NON-CONTROLLING INTEREST IN THE PARTNERSHIP		354.6 (s)	354.6
OWNERS' EQUITY			
Common stockholder's equity	305.2	(305.2)(i)	—
Retained earnings	104.2	(104.2)(i)	—
Owners' net investment		409.4 (i) (225.2)(r) 236.9 (j) (174.4)(k) 0.9 (l) 150.0 (o) (13.0)(p) (30.0)(q) (354.6)(s)	—
Partners' equity		225.2 (r)	225.2
Accumulated other comprehensive loss, net of tax	(8.7)		(8.7)
Total owners' equity	400.7	(184.2)	216.5
TOTAL LIABILITIES AND OWNERS' EQUITY	$1,304.7	$(172.1)	$1,132.6

The accompanying notes are an integral part of the unaudited pro forma consolidated financial statements.

OGE ENOGEX PARTNERS L.P.

NOTES TO UNAUDITED PRO FORMA CONSOLIDATED FINANCIAL STATEMENTS

1. Basis of Presentation

The historical financial information for the year ended December 31, 2006 is derived from and should be read in conjunction with the audited historical consolidated financial statements of Enogex Inc. The historical financial information for the three months ended March 31, 2007 and balance sheet information at March 31, 2007 is derived from and should be read in conjunction with the unaudited historical condensed financial statements of Enogex Inc. In each case, the historical financial information reflects 100% of Enogex Inc.'s operations, but following the contribution of 25% of the membership interests in Enogex LLC by OGE Energy to the Partnership (and as reflected in the pro forma financial data), the Partnership will own only a 25% interest in Enogex LLC. The pro forma adjustments have been prepared as if certain transactions to be effected at the closing of the Offering had taken place on March 31, 2007, in the case of the pro forma balance sheet, or as of January 1, 2006, in the case of the pro forma statements of income for the year ended December 31, 2006 and the three months ended March 31, 2007. These transactions include:

- the conversion of Enogex Inc. to a Delaware limited liability company;
- the conversion of outstanding intercompany loans from Enogex to OGE Energy to a dividend to OGE Energy;
- the contribution by OGE Energy of a 25% membership interest in Enogex LLC to a subsidiary of the Partnership;
- the issuance by the Partnership of common units to the public;
- the payment of underwriting discounts and commissions, the structuring fee and other offering expenses;
- the contribution by the Partnership of proceeds of the Offering to Enogex LLC to allow for the anticipated repayment by Enogex LLC of a portion of its existing $400 million 8.125% senior notes due 2010 and the refinancing by Enogex LLC of those senior notes; and
- expected interest expense under Enogex LLC's new credit facility.

2. Summary of Significant Accounting Policies

The accounting policies followed in preparing the unaudited pro forma consolidated financial statements are those used by Enogex Inc. as set forth in its historical consolidated financial statements contained elsewhere in this prospectus.

3. Pro Forma Adjustments and Assumptions

The unaudited pro forma consolidated financial statements give pro forma effect to the following:

(a) Reflects additional operating and maintenance expenses resulting from additional finance and governance personnel and governance expenses incurred at Enogex LLC subsequent to the Offering of approximately $0.5 million and approximately $2.0 million for the quarter ended March 31, 2007 and year ended December 31, 2006, respectively.

(b) Reflects additional operating and maintenance expenses associated with annual and quarterly reports to unitholders, tax returns and Schedule K-1 preparation and distribution, investor relations, registrar and transfer agent fees, incremental insurance costs, accounting, auditing and legal services, independent director compensation and estimated amounts payable to OGE Energy and its affiliates in connection with the omnibus agreement incurred at OGE Enogex Partners L.P.

subsequent to the Offering of approximately $0.1 million and approximately $2.0 million for the quarter ended March 31, 2007 and year ended December 31, 2006, respectively.

(c) Reflects OGE Energy's non-controlling interest in the net income of approximately $18.3 million for the quarter ended March 31, 2007 and approximately $92.6 million in net income for the year ended December 31, 2006.

(d) Reflects reversal of interest expense, including the amortization of debt issuance cost (before capitalized interest), on the refinanced long-term debt of approximately $8.0 million and approximately $32.2 million for the quarter ended March 31, 2007 and year ended December 31, 2006, respectively. Also reflects reversal of interest income from OGE Energy due to the elimination of outstanding intercompany loans to OGE Energy of approximately $2.5 million and approximately $8.3 million for the quarter ended March 31, 2007 and year ended December 31, 2006, respectively.

(e) Reflects amortization of debt issuance costs of approximately $0.4 million and approximately $1.1 million for the quarter ended March 31, 2007 and year ended December 31, 2006, respectively, related to the $300 million of new long-term debt using an assumed annual interest rate of 7.0%.

(f) Reflects interest expense of approximately $5.2 million and approximately $21.0 million for the quarter ended March 31, 2007 and year ended December 31, 2006, respectively, related to the $300 million of new long-term debt.

(g) Reflects the interest expense on the new credit facility of approximately $1.8 million for the year ended December 31, 2006. There is no comparable item for the quarter ended March 31, 2007. In calculating the interest expense, an average monthly outstanding balance of the change in historical advances to OGE Energy using an annual interest rate of 6.25% was used. This interest rate represents the weighted-average rate Enogex expects to achieve under the new credit facility.

(h) Reflects reversal of corporate income taxes of approximately $9.4 million and approximately $48.0 million for the quarter ended March 31, 2007 and year ended December 31, 2006, respectively, as Enogex LLC will no longer be a taxable entity subsequent to its conversion to a limited liability company.

(i) Reflects the conversion of Stockholder's Equity to Members' Equity of approximately $409.4 million due to the conversion of Enogex Inc. to a limited liability company.

(j) Reflects the elimination of income taxes and the corresponding deferred taxes at the Partnership level of approximately $236.9 million as a result of conversion of Enogex Inc. to a limited liability company.

(k) Reflects conversion of outstanding intercompany loans to OGE Energy to a dividend to OGE Energy of approximately $174.4 million.

(l) Reflects the repayment of approximately $400.0 million of senior notes due 2010 and the write-off of associated debt issuance costs, net of amortization and interest rate swap liability, totaling $0.9 million.

(m) Reflects reversal of the accrued interest payable of approximately $6.8 million related to the repaid debt.

(n) Reflects fees and expenses of approximately $5.5 million related to Enogex's new credit facility and an issuance of up to $300 million of new long-term debt.

(o) Reflects the sale of 7,500,000 common units at an assumed price of $20.00 per unit resulting in gross proceeds of $150.0 million. If the underwriters were to exercise their over-allotment option to purchase an additional 1,125,000 common units, gross proceeds would equal $172.5 million.

(p) Reflects estimated underwriting discount and fees of approximately $13.0 million associated with the offering.

(q) Reflects contribution to Enogex LLC for the payment of the $30.0 million make-whole premium in connection with the $400.0 million refinanced debt.

(r) Reflects the conversion of approximately $225.2 million of member interests into general and limited partner interests, which include a 2% general partner interest, subordinated units representing a 49% limited partner interest held by a subsidiary of OGE Energy, common units representing a 14.9% limited partner interest held by a subsidiary of OGE Energy and public common units representing a 34.1% limited partner interest.

(s) Reflects OGE Enogex Holdings LLC's non-controlling majority interest in Enogex LLC of approximately $354.6 million.

4. Commitments and Contingencies

Commitments and contingencies of Enogex Inc. are set out in the unaudited consolidated interim financial statements for the three months ended March 31, 2007 contained elsewhere in this prospectus.

5. Net Income Per Unit

Pro forma net income per unit is determined by dividing the pro forma net income that would have been allocated, in accordance with the net income allocation provisions of the limited partnership agreement, to the holders of common and subordinated units under the two-class method, after deducting the general partner's interest of 2% in the pro forma net income, by the number of common and subordinated units expected to be outstanding at the closing of the offering. For purposes of this calculation, we assumed that (1) the Minimum Quarterly Distribution was made to all unitholders for each quarter during the periods presented and (2) the number of units outstanding was 10,780,605 common units and 10,780,605 subordinated units. The common and subordinated unitholders each represent 49% limited partner interests. All units were assumed to have been outstanding since January 1, 2006. Basic and diluted pro forma net income per unit is equivalent since there are no dilutive units outstanding at the date of closing of the initial public offering of the common units of OGE Enogex Partners L.P. Pursuant to the partnership agreement, to the extent that the quarterly distributions exceed certain targets, the general partner is entitled to receive certain incentive distributions that will result in more net income proportionately being allocated to the general partner than to the holders of common and subordinated units. The pro forma net income per unit calculations assume that no incentive distributions were made to the general partner because no such distribution would have been paid based upon the pro forma cash available for distribution for the period.

ENOGEX INC.

CONSOLIDATED FINANCIAL STATEMENTS AND FOOTNOTES

FOR THE YEAR ENDED DECEMBER 31, 2006

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ENOGEX INC.
CONSOLIDATED STATEMENTS OF INCOME

	Year Ended December 31		
	2006	2005	2004
		(in millions)	
OPERATING REVENUES	**$2,367.8**	$4,340.1	$3,372.2
COST OF GOODS SOLD (exclusive of depreciation shown below)	**2,060.4**	4,090.4	3,118.2
Gross margin on revenues	**307.4**	249.7	254.0
Other operation and maintenance	**110.0**	96.6	93.5
Depreciation	**42.3**	40.4	41.1
Impairment of assets	**0.3**	—	7.8
Taxes other than income	**16.0**	15.4	16.0
OPERATING INCOME	**138.8**	97.3	95.6
OTHER INCOME (EXPENSE)			
Interest income	**11.1**	2.9	3.2
Other income	**7.7**	0.8	4.5
Other expense	**(0.3)**	(0.3)	(0.3)
Net other income	**18.5**	3.4	7.4
INTEREST EXPENSE			
Interest on long-term debt	**31.4**	32.2	31.8
Interest on short-term debt and other interest charges	**0.4**	0.4	0.4
Interest expense	**31.8**	32.6	32.2
INCOME FROM CONTINUING OPERATIONS BEFORE TAXES	**125.5**	68.1	70.8
INCOME TAX EXPENSE	**48.0**	23.4	26.4
INCOME FROM CONTINUING OPERATIONS	**77.5**	44.7	44.4
DISCONTINUED OPERATIONS (NOTE 6)			
Income from discontinued operations	**59.1**	84.2	18.6
Income tax expense	**23.1**	34.4	7.0
Income from discontinued operations	**36.0**	49.8	11.6
NET INCOME	**$ 113.5**	$ 94.5	$ 56.0

The accompanying Notes to Consolidated Financial Statements are an integral part hereof.

ENOGEX INC.

CONSOLIDATED BALANCE SHEETS

	December 31 2006	December 31 2005
	(in millions)	
ASSETS		
CURRENT ASSETS		
Accounts receivable, net	**$ 205.6**	$ 437.0
Accounts receivable—affiliates	**5.2**	10.7
Advances to parent	**144.4**	125.5
Natural gas inventories	**35.9**	35.7
Materials and supplies, at average cost	**1.8**	2.7
Price risk management	**37.4**	89.0
Gas imbalances	**2.8**	32.0
Accumulated deferred tax assets	**0.2**	1.8
Prepayments	**2.8**	4.0
Other	**6.4**	9.1
Total current assets	**442.5**	747.5
OTHER PROPERTY AND INVESTMENTS, at cost	**1.6**	1.6
PROPERTY, PLANT AND EQUIPMENT		
In service	**1,252.6**	1,183.1
Construction work in progress	**11.1**	13.9
Total property, plant and equipment	**1,263.7**	1,197.0
Less accumulated depreciation	**398.0**	356.0
Net property, plant and equipment	**865.7**	841.0
In service of discontinued operations	**—**	60.6
Less accumulated depreciation	**—**	25.7
Net property, plant and equipment of discontinued operations	**—**	34.9
Net property, plant and equipment	**865.7**	875.9
DEFERRED CHARGES AND OTHER ASSETS		
Prepaid benefit obligation	**1.0**	7.8
Price risk management	**1.7**	9.0
Unamortized debt issuance costs	**1.7**	2.2
Other	**5.6**	6.2
Deferred charges and other assets of discontinued operations	**—**	2.4
Total deferred charges and other assets	**10.0**	27.6
TOTAL ASSETS	**$1,319.8**	$1,652.6

The accompanying Notes to Consolidated Financial Statements are an integral part hereof.

ENOGEX INC.

CONSOLIDATED BALANCE SHEETS (Continued)

	December 31	
	2006	**2005**
	(in millions)	
LIABILITIES AND STOCKHOLDER'S EQUITY		
CURRENT LIABILITIES		
Accounts payable	**$ 195.0**	$ 391.3
Customers' deposits	**2.5**	1.5
Accrued taxes	**6.6**	6.7
Accrued interest	**15.0**	15.0
Accrued compensation	**8.9**	7.4
Long-term debt due within one year	**3.0**	—
Price risk management	**5.6**	81.9
Gas imbalances	**11.1**	35.8
Other	**19.0**	14.6
Total current liabilities	**266.7**	554.2
LONG-TERM DEBT	**403.7**	407.6
COMMITMENTS AND CONTINGENCIES (NOTE 13)		
DEFERRED CREDITS AND OTHER LIABILITIES		
Accrued pension and benefit obligations	**16.3**	8.5
Accumulated deferred income taxes	**230.7**	229.6
Price risk management	**1.1**	10.7
Other	**1.3**	1.6
Total deferred credits and other liabilities	**249.4**	250.4
STOCKHOLDER'S EQUITY		
Common stockholder's equity	**315.2**	430.2
Retained earnings	**88.7**	7.2
Accumulated other comprehensive income (loss), net of tax	**(3.9)**	3.0
Total stockholder's equity	**400.0**	440.4
TOTAL LIABILITIES AND STOCKHOLDER'S EQUITY	**$1,319.8**	$1,652.6

The accompanying Notes to Consolidated Financial Statements are an integral part hereof.

ENOGEX INC.

CONSOLIDATED STATEMENTS OF CAPITALIZATION

		December 31	
		2006	**2005**
		(in millions)	
STOCKHOLDER'S EQUITY			
Common stock, par value $0.10 per share; authorized 10.0 shares; and outstanding 1.4 and 1.9 shares, respectively		**$ 0.1**	$ 0.2
Premium on capital stock		**315.1**	430.0
Retained earnings		**88.7**	7.2
Accumulated other comprehensive income (loss), net of tax		**(3.9)**	3.0
Total stockholder's equity		**400.0**	440.4
LONG-TERM DEBT SERIES	DATE DUE		
8.28%	Medium-Term Notes, Series Due 2007	**3.0**	3.0
7.07%	Medium-Term Notes, Series Due 2008	**1.0**	1.0
8.125%	Senior Notes, Series Due 2010	**400.0**	400.0
Unamortized swap monetization		**2.7**	3.6
Total long-term debt		**406.7**	407.6
Less long-term debt due within one year		**3.0**	—
Total long-term debt (excluding long-term debt due within one year)		**403.7**	407.6
Total Capitalization		**$803.7**	$848.0

The accompanying Notes to Consolidated Financial Statements are an integral part hereof.

ENOGEX INC.

CONSOLIDATED STATEMENTS OF RETAINED EARNINGS

	Year Ended December 31		
	2006	2005	2004
		(in millions)	
BALANCE AT BEGINNING OF PERIOD	**$ 7.2**	$ 60.7	$18.8
ADD: Net income	**113.5**	94.5	56.0
Total	**120.7**	155.2	74.8
DEDUCT: Dividends declared on common stock	**32.0**	148.0	14.1
BALANCE AT END OF PERIOD	**$88.7**	$ 7.2	$60.7

The accompanying Notes to Consolidated Financial Statements are an integral part hereof.

ENOGEX INC.
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	Year Ended December 31		
	2006	**2005**	**2004**
		(in millions)	
Net income	**$113.5**	$94.5	$56.0
Other comprehensive income (loss), net of tax:			
Deferred hedging gains (losses) [$3.1, $4.7, and ($1.1) pre-tax, respectively]	**1.9**	2.9	(0.7)
Total other comprehensive income (loss), net of tax	**1.9**	2.9	(0.7)
Total comprehensive income	**$115.4**	$97.4	$55.3

The accompanying Notes to Consolidated Financial Statements are an integral part hereof.

ENOGEX INC.

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31		
	2006	2005	2004
		(in millions)	
CASH FLOWS FROM OPERATING ACTIVITIES			
Income from continuing operations	**$ 77.5**	$ 44.7	$ 44.4
Adjustments to reconcile income from continuing operations to net cash provided from operating activities			
Depreciation	**42.3**	40.4	41.1
Impairment of assets	**0.3**	—	7.8
Deferred income taxes, net	**21.0**	12.9	15.1
(Gain) loss on sale of assets	**(1.6)**	0.1	(3.3)
Price risk management assets	**58.9**	(58.0)	(3.8)
Price risk management liabilities	**(78.1)**	68.0	4.2
Other assets	**(2.0)**	0.7	(1.3)
Other liabilities	**(16.5)**	2.9	4.2
Change in certain current assets and liabilities			
Accounts receivable, net	**231.4**	(58.1)	(164.0)
Accounts receivable—affiliates	**5.5**	(2.2)	(5.4)
Natural gas, materials and supplies inventories	**0.4**	9.5	56.4
Gas imbalance asset	**29.2**	67.8	(29.9)
Other current assets	**3.9**	4.3	6.3
Accounts payable	**(196.3)**	17.4	158.4
Income taxes payable—affiliates	**(26.4)**	67.2	(7.2)
Customers' deposits	**1.0**	(1.2)	(3.1)
Accrued taxes	**(0.1)**	(0.1)	0.1
Accrued interest	**—**	(0.8)	(1.4)
Accrued compensation	**1.5**	—	0.5
Gas imbalance liability	**(24.7)**	19.6	(6.5)
Other current liabilities	**4.4**	0.1	5.6
Net Cash Provided from Operating Activities	**131.6**	235.2	118.2
CASH FLOWS FROM INVESTING ACTIVITIES			
Capital expenditures	**(67.1)**	(34.7)	(29.0)
Proceeds from sale of assets	**2.1**	0.3	5.9
Other investing activities	**(0.1)**	(0.1)	0.6
Net Cash Used in Investing Activities	**(65.1)**	(34.5)	(22.5)
CASH FLOWS FROM FINANCING ACTIVITIES			
Retirement of long-term debt	**—**	(34.3)	(51.0)
Increase (decrease) in advances to parent, net	**7.6**	(121.7)	(53.5)
Repurchase of common stock	**(115.0)**	—	—
Dividends paid on common stock	**(32.0)**	(148.0)	(14.1)
Net Cash Used in Financing Activities	**(139.4)**	(304.0)	(118.6)
DISCONTINUED OPERATIONS			
Net cash (used in) provided from operating activities	**(19.9)**	(43.0)	47.4
Net cash provided from (used in) investing activities	**92.8**	146.4	(3.1)
Net cash used in financing activities	**—**	(0.1)	(21.4)
Net Cash Provided from Discontinued Operations	**72.9**	103.3	22.9
NET CHANGE IN CASH	**—**	—	—
CASH AT BEGINNING OF PERIOD	**—**	—	—
CASH AT END OF PERIOD	**$ —**	$ —	$ —

The accompanying Notes to Consolidated Financial Statements are an integral part hereof.

1. Summary of Significant Accounting Policies

Organization

The operations of Enogex Inc. and its subsidiaries (collectively, the "Company") consist of three related business segments: (i) the transportation and storage of natural gas, (ii) the gathering and processing of natural gas and (iii) the marketing of natural gas. The vast majority of the Company's natural gas gathering, processing, transportation and storage assets are located in the major gas producing basins of Oklahoma. The Company is a wholly owned subsidiary of OGE Energy which is an energy and energy services provider offering physical delivery and related services for both electricity and natural gas primarily in the south central United States. The Company has a transportation contract with its affiliate, Oklahoma Gas and Electric Company ("OG&E"), to transport natural gas to OG&E's natural gas-fired electric generation facilities. The Company also provides natural gas storage services for OG&E. The Company has been providing natural gas storage services to OG&E since August 2002 when it acquired the Stuart Storage Facility.

In May 2007, OGE Energy Corp. ("OGE Energy"), an Oklahoma corporation, formed OGE Enogex Partners L.P., a Delaware limited partnership (the "Partnership"), as part of its strategy to further develop its natural gas midstream assets and operations. OGE Energy intends to offer units, representing limited partner interests in the Partnership, to the public (the "Offering"). In connection with the Offering, Enogex Inc., an Oklahoma corporation, will be merged with and into a Delaware corporation, with the Delaware corporation continuing as the surviving entity, and the Delaware corporation will then convert to a Delaware limited liability company, to be named Enogex LLC. OGE Energy will then contribute a 25% membership interest in Enogex LLC to a wholly owned subsidiary of the Partnership. A wholly owned subsidiary of OGE Energy will retain the remaining 75% membership interest in Enogex LLC. At the completion of the Offering, a wholly owned subsidiary of OGE Energy will own a 63.9% limited partner interest and a 2% general partner interest in the Partnership, through its ownership of OGE Enogex GP LLC, the Partnership's general partner ("General Partner"), and the Partnership's wholly owned subsidiary will continue to own its 25% interest in Enogex LLC. The Partnership's wholly owned subsidiary will serve as Enogex LLC's managing member and will control its assets and operations.

At the closing of the Offering the following transactions are expected to occur:

- OGE Energy or its subsidiaries will contribute to the Partnership's wholly owned subsidiary a 25% membership interest in Enogex LLC;
- The Partnership will issue to OGE Enogex Holdings LLC, a wholly owned subsidiary of OGE Energy, 3,280,605 common units and 10,780,605 subordinated units, collectively representing a 63.9% limited partner interest in the Partnership;
- The Partnership will issue to the General Partner a 2% general partner interest in the Partnership and all of the Partnership's incentive distribution rights, which will entitle the General Partner to increasing percentages of the cash the Partnership distributes in excess of $0.3881 per unit per quarter;
- Enogex LLC expects to enter into a $250 million credit facility for working capital, capital expenditures and other corporate purposes, including acquisitions;
- The Partnership will enter into an omnibus agreement with its General Partner and OGE Energy and certain of its affiliates which will address, among other things, the Partnership's and Enogex LLC's reimbursement of expenses to OGE Energy for the payment of certain operating

expenses and the provision of various general and administrative services in connection with the Offering and the indemnification of the Partnership and Enogex LLC by OGE Energy Corp. for certain matters; and

- The Partnership will issue 7,500,000 common units to the public in the Offering, representing a 34.1% limited partner interest in the Partnership, and expects to contribute the proceeds to Enogex LLC in order to pay expenses associated with the offering and related formation transactions, allow for the anticipated repayment by Enogex LLC of a portion of its existing senior notes due 2010, including a make-whole premium, pay fees and expenses related to Enogex LLC's new credit facility and an issuance of new long-term debt and apply the remaining proceeds to fund future capital expenditures, working capital and other corporate purposes.

Enogex LLC also currently expects to refinance its $400 million 8.125% senior notes due in 2010 with a combination of $300 million of new long-term debt and proceeds from the Offering that the Partnership expects to contribute to Enogex LLC for the anticipated repayment of that debt.

At December 31, 2006, the Company had three wholly owned active subsidiaries: Enogex Products Corporation ("Products"), OGE Energy Resources, Inc. ("OERI") and Enogex Gas Gathering, L.L.C. ("Gathering"). In May 2006, Gathering sold certain gas gathering assets in the Kinta, Oklahoma area, which have been reported as discontinued operations in the Company's Consolidated Financial Statements (see Note 6 for a further discussion). In December 2006, the Company entered into a joint venture arrangement with a third party. The joint venture, Atoka Midstream, LLC, is constructing and will own and operate a gathering system and processing plant and related facilities relating to production in certain areas in southeastern Oklahoma. The Company holds its 50% membership in Atoka Midstream LLC through Enogex Atoka LLC ("Enogex Atoka"), a wholly owned subsidiary of the Company. Enogex Atoka is acting as the managing member and operator of the facilities owned by the joint venture.

Principles of Consolidation

The consolidated financial statements include the accounts and operations of the Company and its subsidiaries. All significant intercompany transactions have been eliminated in consolidation.

Use of Estimates

In preparing the Consolidated Financial Statements, management is required to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and contingent liabilities at the date of the Consolidated Financial Statements and the reported amounts of revenues and expenses during the reporting period. Changes to these assumptions and estimates could have a material affect on the Company's Consolidated Financial Statements particularly as they relate to pension expense and impairment estimates. However, the Company believes it has taken reasonable, but conservative, positions where assumptions and estimates are used in order to minimize the negative financial impact to the Company that could result if actual results vary from the assumptions and estimates. In management's opinion, the areas of the Company where the most significant judgment is exercised is in the valuation of pension plan assumptions, impairment estimates, contingency reserves, fair value and cash flow hedges, operating revenues, natural gas purchases, the allowance for uncollectible accounts receivable and the valuation of energy purchase and sale contracts.

Cash

Under the Company's cash management arrangement with OGE Energy, the Company remits all excess cash to OGE Energy who then funds the Company's controlled disbursement accounts as amounts are presented for payment. Outstanding checks in excess of cash balances were approximately $18.5 million and $21.0 million at December 31, 2006 and 2005, respectively, and are classified as Accounts Payable in the Consolidated Balance Sheets. Sufficient funds were available to fund these outstanding checks when they were presented for payment.

Allowance for Uncollectible Accounts Receivable

The allowance for uncollectible accounts receivable is calculated based on outstanding accounts receivable balances over 180 days old. In addition, other outstanding accounts receivable balances less than 180 days old are reserved on a case-by-case basis when the Company believes the required payment of specific amounts owed is unlikely to occur. The allowance for uncollectible accounts receivable was approximately $1.1 million and $1.2 million at December 31, 2006 and 2005, respectively.

Credit risk is the risk of financial loss to the Company if counterparties fail to perform their contractual obligations. The Company maintains credit policies with regard to its counterparties that management believes minimize overall credit risk. These policies include the evaluation of a potential counterparty's financial condition (including credit rating), collateral requirements under certain circumstances and the use of standardized agreements which provide for the netting of cash flows associated with a single counterparty. The Company also monitors the financial condition of existing counterparties on an ongoing basis.

Natural Gas Inventories

Natural gas inventory is held by the Company and OERI. The Company maintains natural gas inventory to provide operational support for its pipeline deliveries. In addition, as part of its recurring buy and sell activity, OERI injects and withdraws natural gas in to and out of inventory under the terms of its storage capacity contracts. In order to mitigate market price exposures, the Company and OERI enters into contracts or hedging instruments to protect the cash flows associated with its inventory. OERI has elected not to designate inventory hedging contracts as fair value or cash flow hedges under Statement of Financial Accounting Standard ("SFAS") No. 133, "Accounting for Derivative Instruments and Hedging Activities," as amended. The fair value of the hedging instruments is recorded on the books of OERI as Price Risk Management assets, liabilities or against the brokerage deposits in Other Current Assets with an offsetting gain or loss recorded in current earnings. All natural gas inventory held by the Company is recorded at the lower of cost or market. During 2006, the Company recorded write-downs to market value related to natural gas storage inventory of approximately $18.7 million. The amount of the Company's natural gas inventory was approximately $35.9 million and $35.7 million at December 31, 2006 and 2005, respectively. Natural gas storage inventory is presented in Natural Gas Inventories on the Consolidated Balance Sheets and in Cost of Goods Sold on the Consolidated Statements of Income.

Gas Imbalances

Gas imbalances occur when the actual amounts of natural gas delivered from or received by the Company's pipeline system differ from the amounts scheduled to be delivered or received. Imbalances are due to or due from shippers and operators and can be settled in cash or made up in-kind. The Company values all imbalances at an average of current market indices applicable to the Company's operations, not to exceed net realizable value. Also included in Gas Imbalances on the Consolidated Balance Sheets are planned or managed imbalances related to OERI's business, referred to as park and loan transactions. Park and loan assets were approximately $15.7 million at December 31, 2005 and park and loan liabilities were approximately $10.2 million at December 31, 2005. There were no park and loan assets or liabilities at December 31, 2006. Operational imbalance assets were approximately $2.8 million and $16.3 million, respectively, at December 31, 2006 and 2005 and operational imbalance liabilities were approximately $11.1 million and $25.6 million, respectively, at December 31, 2006 and 2005. The decrease in operational imbalances was primarily due to the Company beginning to manage imbalances related to its storage operations on a combined basis in 2006 for its two storage facilities which resulted in a decrease in net imbalance volumes.

Property, Plant and Equipment

All property, plant and equipment are recorded at cost. Newly constructed plant is added to plant balances at cost, which includes contracted services, direct labor, materials, overhead, transportation costs and capitalized interest. Replacements of units of property are capitalized as plant. For assets that belong to a common plant account, the replaced plant is removed from plant balances and charged to Accumulated Depreciation. For assets that do not belong to a common plant account, the replaced plant is removed from plant balances with the related accumulated depreciation and the remaining balance is recorded as a loss in the Consolidated Statements of Income as Other Expense. Repair and removal costs are included in the Consolidated Statements of Income as Other Operation and Maintenance Expense.

The Company's property, plant and equipment are divided into the following major classes at December 31, 2006 and 2005, respectively.

December 31	2006	2005
	(in millions)	
Transportation and storage assets	**$ 691.5**	$ 683.6
Gathering and processing assets	**564.6**	505.9
Marketing assets	**7.6**	7.5
Total property, plant and equipment	**$1,263.7**	$1,197.0

The unamortized amount of computer software costs was approximately $6.6 million and $8.6 million at December 31, 2006 and 2005, respectively. During 2006, 2005 and 2004, amortization expense for computer software costs was approximately $2.5 million, $1.8 million and $2.3 million, respectively.

Depreciation

Depreciation is computed principally on the straight-line method using estimated useful lives of three to 83 years for transportation and storage assets, three to 30 years for gathering and processing assets and three to 10 years for marketing assets. Amortization of intangibles other than debt costs is computed using the straight-line method over the respective lives of the intangibles ranging up to 20 years.

Impairment of Assets

The Company assesses potential impairments of assets or asset groups when there is evidence that events or changes in circumstances require an analysis of the recoverability of an asset or asset group.

For purposes of recognition and measurement of an impairment loss, a long-lived asset or assets shall be grouped with other assets and liabilities at the lowest level for which identifiable cash flows are largely independent of the cash flows of other assets and liabilities. Estimates of future cash flows used to test the recoverability of a long-lived asset or asset group shall include only the future cash flows (cash inflows less associated cash outflows) that are directly associated with and that are expected to arise as a direct result of the use and eventual disposition of the asset or asset group. The fair value of these assets is based on third-party evaluations, prices for similar assets, historical data and projected cash flow. An impairment loss is recognized when the sum of the expected future net cash flows is less than the carrying amount of the asset. The amount of any recognized impairment is based on the estimated fair value of the asset subject to impairment compared to the carrying amount of such asset. The Company expects to continue to evaluate the strategic fit and financial performance of each of its assets in an effort to ensure a proper economic allocation of resources. The magnitude and timing of any potential impairment or gain on the disposition of any assets is not known at this time.

Revenue Recognition

Operating revenues for transportation, storage, gathering and processing services for the Company are recorded each month based on the current month's estimated volumes, contracted prices (considering current commodity prices), historical seasonal fluctuations and any known adjustments. The estimates are reversed in the following month and customers are billed on actual volumes and contracted prices. Gas sales are calculated on current month nominations and contracted prices. Operating revenues associated with the production of natural gas liquids are estimated based on current month estimated production and contracted prices. These amounts are reversed in the following month and the customers are billed on actual production and contracted prices. Estimated operating revenues are reflected in Accounts Receivable, Net on the Consolidated Balance Sheets and in Operating Revenues on the Consolidated Statements of Income.

Estimates for gas purchases are based on sales volumes and contracted purchase prices. Estimated gas purchases are included in Accounts Payable on the Consolidated Balance Sheets and in Cost of Goods Sold on the Consolidated Statements of Income.

The Company recognizes revenue from natural gas gathering, processing, transportation and storage services to third parties as services are provided. Revenue associated with natural gas liquids is recognized when the production is sold. Substantially all of OERI's natural gas contracts qualify as derivatives and, therefore, are accounted for at fair value as prescribed in SFAS No. 133. Under fair value accounting, fixed-price forwards, swaps, options, futures and other financial instruments with third parties are recorded at estimated fair market values, net of reserves, with the corresponding market changes in fair value recognized in earnings and offsetting amounts recorded as Price Risk Management assets, liabilities or against the brokerage deposits in Other Current Assets in the Consolidated Balance Sheets.

Stock-Based Compensation

The Company adopted SFAS No. 123 (Revised), "Share-Based Payment," using the modified prospective transition method, effective January 1, 2006, which required the Company to measure and recognize the cost of employee services received in exchange for an award of equity instruments based on the grant date fair value of the award. See Note 3 for a further discussion related to the Company's stock-based compensation. Pursuant to the provisions of SFAS No. 123, "Accounting for Stock-Based Compensation," the Company had elected to continue using the intrinsic value method of accounting for stock options granted under OGE Energy's employee compensation plans in accordance with

Accounting Principles Board ("APB") Opinion No. 25, "Accounting for Stock Issued to Employees." Accordingly, prior to January 1, 2006, the Company did not recognize compensation expense for stock options. The Company would have recognized $0.1 million each in 2005 and 2004 had it elected to adopt the fair value recognition provisions of SFAS No. 123. For purposes of this pro forma calculation, the value of the options was determined using a Black-Scholes option pricing formula and amortized to expense over the options' vesting periods. Pro forma information is not included for 2006 as all share-based payments have been accounted for under SFAS No. 123(R).

Accrued Vacation

The Company accrues vacation pay by establishing a liability for vacation earned during the current year, but not payable until the following year.

Accumulated Other Comprehensive Income (Loss)

The components of accumulated other comprehensive income (loss) at December 31, 2006 and 2005 are as follows:

December 31	2006	2005
	(in millions)	
Defined benefit pension plan:		
Net loss, net of tax	**$(5.7)**	$ —
Prior service cost, net of tax	**(0.3)**	—
Defined benefit postretirement plans:		
Net loss, net of tax	**(2.1)**	—
Net transition obligation, net of tax	**(0.5)**	—
Prior service cost, net of tax	**(0.3)**	—
Deferred hedging gains, net of tax	**5.0**	3.1
Minimum pension liability adjustment, net of tax	**—**	(0.1)
Total accumulated other comprehensive income (loss), net of tax	**$(3.9)**	$ 3.0

Defined Benefit Pension and Postretirement Plans

The Company adopted certain provisions of SFAS No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans, an amendment of FASB Statements No. 87, 88, 106 and 132R," effective December 31, 2006, which requires the Company to separately disclose the items that have not yet been recognized as components of net periodic pension cost including, net loss, prior service cost and net transition obligation at December 31, 2006. Accumulated other comprehensive income included an after tax loss of approximately $5.7 million ($9.3 million pre-tax) and $0.3 million ($0.5 million pre-tax) at December 31, 2006 related to the net loss and prior service cost of OGE Energy's defined benefit pension plan, respectively. Accumulated other comprehensive income included an after tax loss of approximately $2.1 million ($4.8 million pre-tax), $0.5 million ($0.8 million pre-tax) and $0.3 million ($0.5 million pre-tax) at December 31, 2006 related to the net loss, net transition obligation and prior service cost of OGE Energy's defined benefit postretirement plans, respectively.

The following amounts in accumulated other comprehensive income at December 31, 2006 are expected to be recognized as components of net periodic benefit cost in 2007:

	(in millions)
Defined benefit pension plan:	
Net loss, net of tax	**$0.3**
Prior service cost, net of tax	**0.1**
Defined benefit postretirement plans:	
Net transition obligation, net of tax	**0.2**
Prior service cost, net of tax	**0.2**
Net loss, net of tax	**0.1**
Total	**$0.9**

Minimum Pension Liability Adjustment

Accumulated other comprehensive income included an after tax loss of approximately $0.1 million ($0.2 million pre-tax) at December 31, 2005 related to a minimum pension liability adjustment based on a review of the funded status of OGE Energy's pension plan by OGE Energy's actuarial consultants as of December 31, 2005.

Environmental Costs

Accruals for environmental costs are recognized when it is probable that a liability has been incurred and the amount of the liability can be reasonably estimated. Costs are charged to expense if they relate to the remediation of conditions caused by past operations or if they are not expected to mitigate or prevent contamination from future operations. Where environmental expenditures relate to facilities currently in use, such as pollution control equipment, the costs may be capitalized and depreciated over the future service periods. Estimated remediation costs are recorded at undiscounted amounts, independent of any insurance, based on prior experience, assessments and current technology. Accrued obligations are regularly adjusted as environmental assessments and estimates are revised, and remediation efforts proceed. For sites where the Company has been designated as one of several potentially responsible parties, the amount accrued represents the Company's estimated share of the cost.

Related Party Transactions

OGE Energy allocated operating costs to the Company of approximately $19.1 million, $17.9 million and $19.4 million during 2006, 2005 and 2004, respectively. OGE Energy allocates operating costs to its affiliates based on several factors. Operating costs directly related to specific affiliates are assigned to those affiliates. Where more than one affiliate benefits from certain expenditures, the costs are shared between those affiliates receiving the benefits. Operating costs incurred for the benefit of all affiliates are allocated among the affiliates, based primarily upon head-count, occupancy, usage or the "Distrigas" method. The Distrigas method is a three-factor formula that uses an equal weighting of payroll, net operating revenues and gross property, plant and equipment. OGE Energy adopted the Distrigas method in January 1996 as a result of a recommendation by the Oklahoma Corporation Commission ("OCC") Staff. OGE Energy believes this method provides a reasonable basis for allocating common expenses.

In 2006, 2005 and 2004, the Company received approximately $34.9 million, $34.9 million and $34.3 million, respectively, from OG&E for transporting gas to OG&E's natural gas-fired electric generation facilities. In 2006, 2005 and 2004, the Company received approximately $12.7 million, $12.7 million and $15.3 million, respectively, from OG&E for natural gas storage services. In 2006, 2005 and 2004, the Company also recorded natural gas sales to OG&E of approximately $60.4 million, $94.6 million and $45.2 million, respectively. Approximately $5.4 million and $11.2 million were recorded at December 31, 2006 and 2005, respectively, and are included in Accounts Receivable—Affiliates in the Consolidated Balance Sheets for these activities.

In 2006, 2005 and 2004, the Company recorded interest income of approximately $8.4 million, $2.3 million and $1.2 million, respectively, from OGE Energy for advances made by the Company to OGE Energy.

In 2005 and 2004, the Company recorded interest expense of approximately $0.1 million and less than $0.1 million, respectively, to OGE Energy for advances made by OGE Energy to the Company. OGE Energy made no advances to the Company during 2006. The interest rate charged on advances to the Company from OGE Energy approximates OGE Energy's commercial paper rate.

In 2006, 2005 and 2004, the Company paid approximately $32.0 million, $148.0 million and $14.1 million, respectively, in dividends to OGE Energy. In 2006, the Company repurchased 456,963 shares of its common stock for approximately $115.0 million. During the three months ended March 31, 2007, the Company repurchased 35,967 shares of its common stock for approximately $10.0 million. In May 2007, the Company repurchased 88,574 shares of its common stock for approximately $25.0 million.

2. Accounting Pronouncements

In July 2006, the FASB issued FASB Interpretation No. 48, "Accounting for Uncertainty in Income Taxes, an interpretation of FASB Statement No. 109," which clarifies the accounting for uncertainty in income taxes recognized in an enterprise's financial statements in accordance with SFAS No. 109, "Accounting for Income Taxes." This interpretation prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. This interpretation also provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosure and transition. This interpretation is effective for fiscal years beginning after December 15, 2006. The Company adopted this new interpretation effective January 1, 2007. The Company did not record a cumulative effect of change in accounting principle as a result of the implementation of FIN No. 48 because the Company does not believe any unrecognized tax benefits existed at January 1, 2007. The Company will recognize accrued interest related to future unrecognized tax benefits in interest expense and recognize penalties in operating and maintenance expense.

In September 2006, the FASB issued SFAS No. 157, "Fair Value Measurements," which defines fair value, establishes a framework for measuring fair value in generally accepted accounting principles and expands disclosures about fair value measurements. SFAS No. 157 expands disclosures about the use of fair value to measure assets and liabilities in interim and annual periods subsequent to initial recognition. The guidance in SFAS No. 157 applies to derivatives and other financial instruments measured at fair value under SFAS No. 133 at initial recognition and in all subsequent periods. Therefore, SFAS No. 157 nullifies the guidance in footnote 3 of Emerging Issues Task Force Issue No. 02-3, "Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities." SFAS No. 157 also amends SFAS No. 133 to remove the guidance similar to that nullified in EITF 02-3. SFAS No. 157 is effective for financial statements issued for fiscal years beginning after November 15, 2007, and interim periods within those fiscal years. The provisions of SFAS No. 157 should be applied prospectively as of the beginning of the fiscal year in which it is initially applied, except in certain conditions. The Company will adopt this new standard effective January 1, 2008. Management has not yet determined what the impact of this new standard will be on its consolidated financial position or results of operations.

In September 2006, the FASB issued SFAS No. 158 which requires an employer to: (i) recognize the overfunded or underfunded status of a defined benefit postretirement plan (other than a multiemployer plan) as an asset or liability in its statement of financial position and to recognize changes in that funded status in the year in which the changes occur through comprehensive income of a business entity; and (ii) to measure the fair value of the funded status of a plan as of the date of its year-end statement of financial position, with limited exceptions. The requirement to initially recognize the funded status of the defined benefit postretirement plan and the disclosure requirements are effective for the year ended December 31, 2006 for the Company. The requirement to measure plan assets and benefit obligations at fair value in accordance with SFAS No. 157 as of the date of the employer's fiscal year-end statement of financial position is effective for fiscal years ending after December 15, 2008. The Company adopted provision (i) above of this new standard effective December 31, 2006. At December 31, 2006, the projected benefit obligation and fair value of assets of the Company's portion of OGE Energy's pension plan and restoration of retirement income plan was approximately $41.7 million and $42.7 million, respectively, for an overfunded status of approximately $1.0 million. The above amounts have been recorded in Prepaid Benefit Obligation with the offset in Accumulated Other Comprehensive Income in the Company's Consolidated Balance Sheet. Also, at December 31, 2006, the accumulated postretirement benefit obligation of the Company's portion of OGE Energy's postretirement benefit plans was approximately $15.9 million for an underfunded status of approximately $15.9 million. There was no fair value of assets allocated to the Company at December 31, 2006. The above amounts have been recorded in Accrued Pension and Benefit Obligations with the offset in Accumulated Other Comprehensive Income in the Company's Consolidated Balance Sheet. The Company will adopt provision (ii) above of this new standard effective December 31, 2008. Management has not yet determined what the impact of provision (ii) of this new standard will be on its consolidated financial position or results of operations.

3. Stock-based Compensation

On January 21, 1998, OGE Energy adopted a Stock Incentive Plan (the "1998 Plan"). In 2003, OGE Energy adopted, and its shareowners approved, a new Stock Incentive Plan (the "2003 Plan" and together with the 1998 Plan, the "Plans"). The 2003 Plan replaced the 1998 Plan and no further awards will be granted under the 1998 Plan. As under the 1998 Plan, under the 2003 Plan, restricted stock, stock options, stock appreciation rights and performance units may be granted to officers, directors and other key employees of OGE Energy and its subsidiaries. OGE Energy has authorized the issuance of up to 2,700,000 shares under the 2003 Plan.

Prior to January 1, 2006, OGE Energy accounted for the Plans under the recognition and measurement provisions of APB Opinion No. 25, as permitted by SFAS No. 123. OGE Energy also previously adopted the disclosure provisions under SFAS No. 123 and SFAS No. 148, "Accounting for Stock-Based Compensation—Transition and Disclosure." The Company recorded compensation expense of approximately $0.1 million pre-tax (less than $0.1 million after tax) and $0.5 million pre-tax ($0.3 million after tax) in 2005 and 2004, respectively, related to its portion of OGE Energy's performance units in Other Operation and Maintenance Expense in the Consolidated Statements of Income. No compensation expense related to stock options was recognized in 2005 or 2004 as all options granted under those plans had an exercise price equal to the market value of OGE Energy's common stock on the grant date. Effective January 1, 2006, OGE Energy adopted SFAS No. 123(R) using the modified prospective transition method. Under that transition method, the Company's compensation cost recognized in the first quarter of 2006 included: (i) compensation cost for all share-based payments granted prior to, but not yet vested as of January 1, 2006, based on the fair value calculated in accordance with the provisions of SFAS No. 123(R); and (ii) compensation cost for all share-based payments granted in the first quarter of 2006, based on the fair value calculated in accordance with the provisions of SFAS No. 123(R). Results for prior periods were not restated.

As a result of adopting SFAS No. 123(R) on January 1, 2006, the Company recorded a cumulative effect adjustment of approximately $0.1 million pre-tax (less than $0.1 million after tax) on January 1, 2006 for non-vested outstanding share-based compensation grants at December 31, 2005, which is not included in the amounts discussed below. The Company determined that the cumulative effect adjustment was immaterial for presentation purposes and is, therefore, included in Other Operation and Maintenance Expense in the Consolidated Statement of Income. The Company recorded compensation expense of approximately $1.7 million pre-tax ($1.0 million after tax) in 2006 related to its portion of OGE Energy's share-based payments.

Prior to the adoption of SFAS No. 123(R), OGE Energy presented all tax benefits of deductions resulting from the exercise of stock options or other share-based payments as operating cash flows in the Consolidated Statements of Cash Flows. SFAS No. 123(R) requires cash flows resulting in tax benefits from tax deductions in excess of the compensation cost recognized for share-based payments ("excess tax benefits") to be classified as financing cash flows. OGE Energy recorded an excess tax benefit of approximately $2.8 million in 2006 related to OGE Energy's 2006 share-based payments, which amount will be presented as a financing cash inflow and realized when OGE Energy's 2006 income tax return is completed in 2007. OGE Energy realized an excess tax benefit of approximately $1.4 million in 2006 related to OGE Energy's 2005 share-based payments, which amount was presented as a financing cash inflow and realized when OGE Energy's 2005 income tax return was filed in August 2006. OGE Energy realized an excess tax benefit of approximately $0.8 million during 2005 related to OGE Energy's 2004 share-based payments. OGE Energy did not realize an excess tax benefit during 2004 related to OGE Energy's 2003 share-based payments.

Performance Units

Under the Plans, OGE Energy has issued performance units that represent the value of one share of OGE Energy's common stock. The performance units provide for accelerated vesting if there is a change in control (as defined in the Plans). Each performance unit is subject to forfeiture if the recipient terminates employment with OGE Energy or a subsidiary prior to the end of the three-year award cycle for any reason other than death, disability or retirement. In the event of death, disability or retirement, a participant will receive a prorated payment based on such participant's number of full months of service during the three-year award cycle, further adjusted based on the achievement of the performance goals during the award cycle. The following table is a summary of the terms of OGE Energy's outstanding performance units awarded during 2004, 2005 and 2006.

Condition	Settlement	Vesting Period	SFAS No. 123(R) Classification
Total Shareholder Return	⅔—Stock(A)	3-year cliff	Equity
	⅓—Cash	3-year cliff	Liability
Earnings Per Share	⅔—Stock(A)	3-year cliff	Equity
	⅓—Cash	3-year cliff	Liability

(A) All of OGE Energy's 2006 performance units will be settled in stock.

The performance units granted based on total shareholder return ("TSR") are contingently awarded and will be payable in cash or shares of OGE Energy's common stock (other than performance units awarded in 2006, which will be payable only in shares of common stock) subject to the condition that the number of performance units, if any, earned by the employees upon the expiration of a three-year award cycle is dependent on OGE Energy's TSR ranking relative to a peer group of companies. The performance units granted based on earnings per share ("EPS") are contingently awarded and will be payable in cash or shares of OGE Energy's common stock (other than performance units awarded in 2006, which will be payable only in shares of common stock) based on OGE Energy's EPS growth over a three-year award cycle compared to a target set at the time of the grant by the Compensation Committee of OGE Energy's Board of Directors. If there is no or only a partial payout for the performance units at the end of the three-year award cycle, the unearned performance units are cancelled. During 2006, 2005 and 2004, respectively, OGE Energy awarded 239,856, 201,794 and 162,591 performance units to certain employees of OGE Energy and its subsidiaries, of which 49,910, 38,652 and 23,827 performance units were awarded to certain employees of the Company.

Performance Units—Total Shareholder Return

The Company recorded compensation expense of approximately $1.2 million pre-tax ($0.7 million after tax) in 2006 related to the performance units based on TSR. The Company recorded compensation expense of less than $0.1 million pre-tax and after tax and approximately $0.5 million pre-tax ($0.3 million after tax) in 2005 and 2004, respectively, related to the performance units based on TSR. The fair value of the performance units based on TSR was estimated on the grant date using a lattice-based valuation model that factors in information, including the expected dividend yield, expected price volatility, risk-free interest rate and the probable outcome of the market condition, over the expected life of the performance units. Compensation expense for the performance units settled in stock is a fixed amount determined at the grant date fair value and is recognized over the three-year award cycle regardless of whether performance units are awarded at the end of the award cycle. Compensation expense for the performance units settled in cash is based on the change in the fair value of the performance units for each reporting period. This liability for the performance units will be remeasured at each reporting date until the date of settlement. Dividends are not accrued or paid during the performance period and, therefore, are not included in the fair value calculation. Expected price volatility is based on the historical volatility of OGE Energy's common stock for the past three years and was simulated using the Geometric Brownian Motion process. The risk-free interest rate for the performance unit grants is based on the three-year U.S. Treasury yield curve in effect at the time of the grant. The expected life of the units is based on the non-vested period since inception of the three-year award cycle. There are no post-vesting restrictions related to OGE Energy's performance units based on TSR. The fair value of the performance units based on TSR was calculated based on the following assumptions at the grant date.

	2006	2005	2004
Expected dividend yield	4.9%	5.3%	6.5%
Expected price volatility	16.8%	22.3%	23.0%
Risk-free interest rate	4.66%	3.28%	2.47%
Expected life of units (in years)	2.85	2.85	2.94
Fair value of units granted	$22.93	$21.56	$20.10

The fair value of the performance units based on TSR which are settled in cash was remeasured at December 31, 2006 based on the following assumptions:

	2005
Expected dividend yield	4.0%
Expected price volatility	15.8%
Risk-free interest rate	4.96%
Expected life of units (in years)	1.00
Fair value of units at 12/31/06	$62.62

A summary of the activity for OGE Energy's performance units applicable to the Company's employees based on TSR at December 31, 2006 and changes during 2006 are summarized in the following table. Following the end of a three-year performance period, payout of the performance units based on TSR is determined by OGE Energy's TSR for such period compared to a peer group and payout requires the approval of the Compensation Committee of OGE Energy's Board of Directors. Payouts, if any, are made in two-thirds stock and one-third cash (other than payouts of performance units awarded in 2006, which will be made only in common stock) and are considered made when the payout is approved by the Compensation Committee.

	Number of Units	Stock Conversion Ratio(A)	Aggregate Intrinsic Value
	(dollars in millions)		
Units Outstanding at 12/31/05	58,743	1 : 1	
Granted(B)	36,887	1 : 1	
Converted	(12,560)	1 : 1	$0.5
Forfeited	(4,294)	1 : 1	
Employee migration(C)	(1,153)	1 : 1	
Units Outstanding at 12/31/06	77,623	1 : 1	$5.8
Units Fully Vested at 12/31/06(D)	18,179	1 : 1	$1.3

(A) One performance unit = one share of OGE Energy's common stock.

(B) Represents target number of units granted. Actual number of units earned, if any, is dependent upon performance and may range from 0% to 200% of the target.

(C) Due to certain employees transferring between OGE Energy and its subsidiaries.

(D) These performance units awarded in 2004 became fully vested at December 31, 2006 and if certified by the Compensation Committee of OGE Energy's Board of Director's will be converted in February 2007.

A summary of the activity for OGE Energy's non-vested performance units applicable to the Company's employees based on TSR at December 31, 2006 and changes during 2006 are summarized in the following table:

	Number of Units	Weighted-Average Grant Date Fair Value
Units Non-Vested at 12/31/05	46,183	$20.92
Granted(E)	36,887	$22.93
Vested(F)	(18,179)	$20.10
Forfeited	(4,294)	$21.69
Employee migration(G)	(1,153)	$19.61
Units Non-Vested at 12/31/06(H)	59,444	$22.39

(E) Represents target number of units granted. Actual number of units earned, if any, is dependent upon performance and may range from 0% to 200% of the target.

(F) These performance units awarded in 2004 became fully vested at December 31, 2006 and if certified by the Compensation Committee of OGE Energy's Board of Director's will be converted in February 2007.

(G) Due to certain employees transferring between OGE Energy and its subsidiaries.

(H) Of the 59,444 performance units not vested at December 31, 2006, 53,671 performance units are assumed to vest at the end of the applicable vesting period.

At December 31, 2006, there was approximately $0.7 million in unrecognized compensation cost related to non-vested performance units based on TSR which is expected to be recognized over a weighted-average period of 1.62 years.

Performance Units—Earnings Per Share

The Company recorded compensation expense of approximately $0.4 million pre-tax ($0.3 million after tax) in 2006 related to the performance units based on EPS. The Company recorded compensation expense of approximately $0.1 million pre-tax ($0.1 million after tax) in 2005 related to the performance units based on EPS. No compensation expense related to performance units based on EPS was recognized in 2004 as the 2004 performance units did not have an EPS component. The fair value of the performance units based on EPS is based on grant date fair value which is equivalent to the price of one share of OGE Energy's common stock on the date of grant. The fair value of performance units based on EPS varies as the number of performance units that will vest is based on the grant date fair value of the units and the probable outcome of the performance condition. OGE Energy reassesses at each reporting date whether achievement of the performance condition is probable and accrues compensation expense if and when achievement of the performance condition is probable. As a result, the compensation expense recognized for these performance units can vary from period to period. There are no post-vesting restrictions related to OGE Energy's performance units based on EPS. The grant date fair value of the 2005 and 2006 performance units was $23.78 and $28.00, respectively.

A summary of the activity for OGE Energy's performance units applicable to the Company's employees based on EPS at December 31, 2006 and changes during 2006 are summarized in the following table. Following the end of a three-year performance period, payout of the performance units based on EPS growth is determined by OGE Energy's growth in EPS for such period compared to a target set at the beginning of the three-year period by the Compensation Committee of OGE Energy's Board of Directors and payout requires the approval of the Compensation Committee. Payouts, if any, are made in two-thirds stock and one-third cash (other than payouts of performance units awarded in 2006, which will be made only in common stock) and are considered made when approved by the Compensation Committee.

	Number of Units	Stock Conversion Ratio(A)	Aggregate Intrinsic Value
	(dollars in millions)		
Units Outstanding at 12/31/05	8,625	1 : 1	
Granted(B)	12,299	1 : 1	
Forfeited	(1,064)	1 : 1	
Employee migration(C)	(47)	1 : 1	
Units Outstanding at 12/31/06	19,813	1 : 1	$1.6

(A) One performance unit = one share of OGE Energy's common stock.

(B) Represents target number of units granted. Actual number of units earned, if any, is dependent upon performance and may range from 0% to 200% of the target.

(C) Due to certain employees transferring between OGE Energy and its subsidiaries.

A summary of the activity for OGE Energy's non-vested performance units applicable to the Company's employees based on EPS at December 31, 2006 and changes during 2006 are summarized in the following table:

	Number of Units	Weighted-Average Grant Date Fair Value
Units Non-Vested at 12/31/05	8,625	$23.78
Granted(D)	12,299	$28.00
Forfeited	(1,064)	$25.86
Employee migration(E)	(47)	$ 7.83
Units Non-Vested at 12/31/06(F)	19,813	$26.33

(D) Represents target number of units granted. Actual number of units earned, if any, is dependent upon performance and may range from 0% to 200% of the target.

(E) Due to certain employees transferring between OGE Energy and its subsidiaries.

(F) Of the 19,813 performance units not vested at December 31, 2006, 17,888 performance units are assumed to vest at the end of the applicable vesting period.

At December 31, 2006, there was approximately $0.5 million in unrecognized compensation cost related to non-vested performance units based on EPS which is expected to be recognized over a weighted-average period of 1.70 years.

Stock Options

The Company recorded compensation expense of less than $0.1 million pre-tax and after tax in 2006 related to stock options. During 2006 and 2005, no stock options were granted under the 2003 Plan. During 2004, 54,700 stock options were granted under the 2003 Plan. Compensation expense for the non-vested stock options at December 31, 2005 was a fixed amount determined at the grant date fair value and was recognized over the remaining vesting period during 2006. No compensation expense related to stock options was recognized in 2005 or 2004 as all options granted under those plans had an exercise price equal to the market value of OGE Energy's common stock on the grant date. OGE Energy accounts for stock option grants as separate grants. The options granted under the Plans vest in one-third annual installments beginning one year from the date of grant and have a contractual life of 10 years. Each option is subject to forfeiture if the recipient terminates employment with OGE Energy or a subsidiary for any reason other than death, disability or retirement. Dividends are not paid or accrued on unexercised options. The options provide for accelerated vesting if there is a change in control (as defined in the Plans). The fair value of each option grant under the Plans is estimated on the grant date using the Black-Scholes option pricing model that factors in information, including the expected dividend yield, expected price volatility and risk-free interest rate. The fair value was $2.05 at the grant date for the stock options that are not fully vested at December 31, 2006 and was calculated based on the following assumptions at the grant date.

	2004
Expected dividend yield	6.27%
Expected price volatility	18.58%
Risk-free interest rate	3.77%
Expected life of options (in years)	7
Weighted-average fair value of options granted	$ 2.05

A summary of the activity for OGE Energy's options applicable to the Company's employees at December 31, 2006 and changes during 2006 are summarized in the following table:

	Number of Options	Weighted-Average Exercise Price	Aggregate Intrinsic Value	Weighted-Average Remaining Contractual Term
		(dollars in millions)		
Options Outstanding at 12/31/05	208,637	$21.31		
Exercised	(99,731)	$22.26	$1.3	
Forfeited	(1,467)	$23.58		
Options Outstanding at 12/31/06	107,439	$20.40	$2.1	4.64 years
Options Fully Vested and Exercisable at 12/31/06	93,065	$19.91	$1.9	4.39 years

A summary of the activity for OGE Energy's non-vested options applicable to the Company's employees at December 31, 2006 and changes during 2006 are summarized in the following table:

	Number of Options	Weighted-Average Grant Date Fair Value
Options Non-Vested at 12/31/05	57,777	$1.96
Vested	(43,403)	$1.92
Options Non-Vested at 12/31/06(A)	14,374	$2.05

(A) All of the 14,374 stock options not vested at December 31, 2006 vested in January 2007.

At December 31, 2006, there was no unrecognized compensation cost related to non-vested options, which became fully vested in January 2007.

OGE Energy issues new shares to satisfy stock option exercises. OGE Energy received approximately $14.5 million in 2006 related to exercised stock options. OGE Energy recorded an excess tax benefit of approximately $2.8 million in 2006 related to OGE Energy's 2006 share-based payments, which amount will be presented as a financing cash inflow and realized when OGE Energy's 2006 income tax return is completed in 2007. OGE Energy realized an excess tax benefit of approximately $1.4 million in 2006 related to OGE Energy's 2005 share-based payments, which amount was presented as a financing cash inflow and realized when OGE Energy's 2005 income tax return was filed in August 2006. Energy Corp realized an excess tax benefit of approximately $0.8 million during 2005 related to OGE Energy's 2004 share-based payments. OGE Energy did not realize an excess tax benefit during 2004 related to OGE Energy's 2003 share-based payments.

4. Asset Sales

During September 2004, the Company received notification from a customer that a transportation agreement involving four of its non-contiguous pipeline asset segments located in West Texas and used to serve the customer's power plants would be terminated effective December 31, 2004. In response to this notification, the Company recognized, during the third quarter of 2004, a pre-tax impairment loss of approximately $8.6 million related to its natural gas pipeline assets that were used to provide service to this customer. In December 2004, the Company received notification that all of this customers' plants in West Texas were shut down and service was no longer required. In November 2006, the Company sold the four non-contiguous pipeline asset segments for approximately $1.0 million. The Company recognized a pre-tax gain of approximately $1.0 million in the fourth quarter of 2006 related to the sale of these assets.

5. Price Risk Management Assets and Liabilities

Non-Trading Activities

The Company periodically utilizes derivative contracts to manage the exposure of its assets to unfavorable changes in commodity prices, as well as to reduce exposure to adverse interest rate fluctuations. During 2006 and 2005, the Company's use of non-trading price risk management instruments involved the use of commodity price futures, commodity price swap contracts and interest rate swap agreements. The commodity price futures, commodity price swap contracts and interest rate swap agreements involved the exchange of fixed price or rate payments in exchange for floating price or rate payments over the life of the instrument without an exchange of the underlying principal amount.

In accordance with SFAS No. 133, the Company recognizes its non-exchange traded derivative instruments as Price Risk Management assets or liabilities in the Consolidated Balance Sheets at fair value with such amounts classified as current or long-term based on their anticipated settlement. Exchange traded transactions are settled on a net basis daily through margin accounts with a clearing broker and, therefore, are recorded at fair value on a net basis in Other Current Assets in the Consolidated Balance Sheets. The accounting for changes in the fair value of a derivative depends on the intended use of the derivative and resulting designation. For derivative instruments that are designated and qualify as a fair value hedge, the gain or loss on the derivative instrument is recognized in current earnings on the same line item as the gain or loss recorded for the change in the fair value of the hedged item. For derivatives that are designated and qualify as a cash flow hedge, the effective portion of the change in fair value of the derivative instrument is reported as a component of Accumulated Other Comprehensive Income and recognized into earnings in the same period during which the hedged transaction affects earnings. The ineffective portion of a derivative's change in fair value is recognized currently in earnings. Forecasted transactions designated as the hedged item in a cash flow hedge are regularly evaluated to assess whether they continue to be probable of occurring. If the forecasted transactions are no longer probable of occurring, hedge accounting will cease on a prospective basis and all future changes in the fair value of the derivative will be recognized directly in earnings. If the forecasted transactions are no longer reasonably possible of occurring, any associated amounts recorded in Accumulated Other Comprehensive Income will also be recognized directly in earnings.

The Company may designate certain derivative instruments for the purchase or sale of physical commodities as normal purchases and normal sales contracts under the provisions of SFAS No. 133. Normal purchases and normal sales contracts are not recorded in Price Risk Management assets or liabilities in the Consolidated Balance Sheets and earnings recognition is recorded in the period in which physical delivery of the commodity occurs. The Company applies normal purchases and normal sales to: (i) commodity contracts for the purchase and sale of natural gas by its subsidiaries; and (ii) commodity contracts for the sale of natural gas liquids produced by Products. At December 31, 2006 and 2005, the Company had no outstanding interest rate swap agreements.

Trading Activities

The Company, through its subsidiary, OERI, engages in energy trading activities primarily related to the purchase and sale of natural gas. Contracts utilized in these activities generally include forward swap contracts as well as over-the-counter and exchange traded futures and options. Energy trading activities are accounted for in accordance with SFAS No. 133 and EITF Issue No. 02-3. In accordance with SFAS No. 133, financial instruments that qualify as derivatives are reflected at fair value with the resulting unrealized gains and losses recorded as Price Risk Management assets or liabilities in the Consolidated Balance Sheets, classified as current or long-term based on their anticipated settlement or against the brokerage deposits in Other Current Assets. Unrealized gains and losses from changes in the market value of open contracts are included in Natural Gas Pipeline Operating Revenues in the Consolidated Statements of Income. Energy trading contracts resulting in delivery of a commodity that meet the requirements of EITF Issue No. 99-19, "Reporting Revenues Gross as a Principal or Net as an Agent," are included as sales or purchases in the Consolidated Statements of Income depending on whether the contract relates to the sale or purchase of the commodity.

In accordance with FASB Interpretation No. 39 (As Amended), "Offsetting of Amounts Related to Certain Contracts an interpretation of APB Opinion No. 10 and FASB Statement No. 105," fair value amounts recognized for forward, interest rate swap, currency swap, option and other conditional or exchange contracts executed with the same counterparty under a master netting arrangement may be offset. The reporting entity's choice to offset or not must be applied consistently. A master netting arrangement exists if the reporting entity has multiple contracts, whether for the same type of conditional or exchange contract or for different types of contracts, with a single counterparty that are subject to a contractual agreement that provides for the net settlement of all contracts through a single payment in a single currency in the event of default on or termination of any one contract. Offsetting the fair values recognized for forward, interest rate swap, currency swap, option and other conditional or exchange contracts outstanding with a single counterparty results in the net fair value of the transactions being reported as an asset or a liability in the consolidated balance sheet. The Company has presented the fair values of its contracts under master netting agreements using a net fair value presentation. If these transactions with the same counterparty were presented on a gross basis in the Consolidated Balance Sheets, current Price Risk Management assets and liabilities would be approximately $41.0 million and $9.2 million, respectively, at December 31, 2006, and non-current Price Risk Management assets and liabilities would be approximately $1.7 million and $1.1 million, respectively, at December 31, 2006. If these transactions with the same counterparty were presented on a gross basis in the Consolidated Balance Sheets, current Price Risk Management assets and liabilities would be approximately $116.5 million and $109.4 million, respectively, at December 31, 2005, and non-current Price Risk Management assets and liabilities would be approximately $9.0 million and $10.7 million, respectively, at December 31, 2005.

6. Discontinued Operations

In April 2005, Enogex Compression Company, LLC ("Enogex Compression"), a subsidiary of the Company, received an unsolicited offer to buy its interest in Enerven Compression Services, LLC ("Enerven"), a joint venture focused on the rental of natural gas compression assets. After evaluating this offer, Enogex Compression sold its interest in Enerven for approximately $7.3 million in August 2005. Enogex Compression recognized an after tax gain of approximately $1.8 million related to the sale of this business.

The Company regularly evaluates the long-term stability, profitability and core competency of each of its businesses within the regulatory and market framework in which each business operates. Based on these evaluations, in September 2005, the Company announced that it had entered into an agreement to sell its interest in Enogex Arkansas Pipeline Corporation ("EAPC"), which held the 75% interest in the NOARK Pipeline System Limited Partnership. This sale was completed on October 31, 2005. The Company received approximately $177.4 million in cash proceeds and recognized an after tax gain of approximately $36.7 million from the sale of this interest in the fourth quarter of 2005. The Company used approximately $31.9 million of the proceeds to repay principal and accrued interest on long-term debt and approximately $46.7 million to pay taxes associated with EAPC. The balance of the proceeds of approximately $98.8 million was used, among other things, to reduce short-term debt levels at OGE Energy and fund capital expenditures.

In March 2006, the Company announced that its wholly owned subsidiary, Gathering, had entered into an agreement to sell certain gas gathering assets in the Kinta, Oklahoma, area. The Gathering assets included in the transaction were approximately 568 miles of gas gathering pipeline and 22 compressor units with current volumes of approximately 145 million cubic feet per day, all in eastern Oklahoma. The sale price was approximately $93 million. This transaction closed on May 1, 2006 and the Company recorded an after tax gain of approximately $34.1 million during the second quarter of 2006. The proceeds from the sale, were used, among other things, to reduce short-term debt levels at OGE Energy and fund capital expenditures.

The Consolidated Financial Statements of the Company have been reclassified to reflect Enogex Compression's sale of its Enerven interest, the Company's sale of its EAPC interest and Gathering's gas gathering assets in Kinta, Oklahoma as discontinued operations. Accordingly, revenues, costs and expenses and cash flows of Enerven, EAPC and the Gathering assets that were sold have been excluded from the respective captions in the Consolidated Financial Statements and have been separately reported as discontinued operations in the applicable financial statement captions. Enogex Compression's sale of its Enerven interest and the Company's sale of its EAPC interest were completed during 2005 and, therefore, there are no results of operations for these transactions during 2006. Summarized financial information for the discontinued operations as of December 31 is as follows:

CONSOLIDATED STATEMENTS OF INCOME DATA

Year Ended December 31	2006	2005	2004
		(in millions)	
Operating revenues from discontinued operations	**$ 9.4**	$106.0	$120.1
Income from discontinued operations before taxes	**59.1**	84.2	18.6

7. Supplemental Cash Flow Information

The following table discloses information about investing and financing activities that affect recognized assets and liabilities but which do not result in cash receipts or payments. Also disclosed in the table is cash paid for interest, net of interest capitalized, and cash paid for income taxes, net of income tax refunds.

Year Ended December 31	2006	2005	2004
		(in millions)	
NON-CASH INVESTING AND FINANCING ACTIVITIES			
Change in fair value of long-term debt due to interest rate swaps	**$ —**	$(3.9)	$ 0.3
SUPPLEMENTAL CASH FLOW INFORMATION			
Cash Paid During the Period for			
Interest (net of interest capitalized of $0.9, $0, $0)	**$31.9**	$35.9	$37.5
Income taxes (net of income tax refunds)	**89.0**	9.8	19.1

8. Income Taxes

The items comprising income tax expense are as follows:

Year Ended December 31	2006	2005	2004
		(in millions)	
Provision for Current Income Taxes from Continuing Operations			
Federal	**$24.8**	$11.1	$11.3
State	**2.2**	—	0.9
Total Provision for Current Income Taxes from Continuing Operations	**27.0**	11.1	12.2
Provision for Deferred Income Taxes, net from Continuing Operations			
Federal	**19.0**	10.0	12.1
State	**2.0**	2.3	2.1
Total Provision for Deferred Income Taxes, net, from Continuing Operations	**21.0**	12.3	14.2
Total Income Tax Expense from Continuing Operations	**$48.0**	$23.4	$26.4

The Company is a member of an affiliated group that files consolidated income tax returns. Income taxes are allocated to each company in the affiliated group based on its separate taxable income or loss. The following schedule reconciles the statutory federal tax rate to the effective income tax rate:

Year Ended December 31	2006	2005	2004
Statutory federal tax rate	**35.0%**	35.0%	35.0%
State income taxes, net of federal income tax benefit	**3.4**	3.5	2.8
Excess deferred taxes(A)	**—**	(4.7)	—
Medicare Part D subsidy	**—**	(0.2)	—
Other	**(0.2)**	0.8	(0.5)
Effective income tax rate as reported	**38.2%**	34.4%	37.3%

(A) During 2005, the Company performed a detailed analysis of all deferred tax assets and liabilities. In connection with this analysis, it was determined that an excess liability existed. The removal of this excess liability caused a permanent difference in the effective tax rate for 2005 of approximately 4.7%.

The Company adopted the provisions of FASB Interpretation No. 48, "Accounting for Uncertainty in Income Taxes, an amendment of FASB Statement No. 109," on January 1, 2007. The Company did not record a cumulative effect of change in accounting principle as a result of the implementation of FIN No. 48 because the Company does not believe any unrecognized tax benefits existed at January 1, 2007. The Company will recognize accrued interest related to future unrecognized tax benefits in interest expense and recognize penalties in operating and maintenance expense.

The Company follows the provisions of SFAS No. 109 which uses an asset and liability approach to accounting for income taxes. Under SFAS No. 109, deferred tax assets or liabilities are computed based on the difference between the financial statement and income tax bases of assets and liabilities using the enacted marginal tax rate. Deferred income tax expenses or benefits are based on the changes in the asset or liability from period to period.

The components of Accumulated Deferred Taxes at December 31, 2006 and 2005, respectively, are as follows:

December 31	2006	2005
	(in millions)	
Current Accumulated Deferred Tax Assets		
Accrued vacation	**$ 1.0**	$ 1.1
Uncollectible accounts	**0.6**	0.4
Other	**(1.4)**	0.3
Total Current Accumulated Deferred Tax Assets	**$ 0.2**	$ 1.8
Non-Current Accumulated Deferred Tax Liabilities		
Accelerated depreciation and other property related differences	**$237.8**	$228.7
Company pension plan	**0.8**	4.0
Other	**—**	1.1
Total Non-Current Accumulated Deferred Tax Liabilities	**238.6**	233.8
Non-Current Accumulated Deferred Tax Assets		
Postretirement medical and life insurance benefits	**(6.6)**	(3.4)
Other	**(1.3)**	(0.8)
Total Non-Current Accumulated Deferred Tax Assets	**(7.9)**	(4.2)
Non-Current Accumulated Deferred Income Tax Liabilities, net	**$230.7**	$229.6

9. Long-Term Debt

A summary of the Company's long-term debt is included in the Consolidated Statements of Capitalization. At December 31, 2006, the Company is in compliance with all of its debt agreements.

Long-Term Debt Maturities

Maturities of the Company's long-term debt during the next five years consist of $3.0 million in 2007; $1.0 million in 2008 and $400.0 million in 2010. There are no maturities of the Company's long-term debt in years 2009 or 2011.

The Company has previously incurred costs related to debt refinancings. Unamortized debt expense is classified as Deferred Charges and Other Assets and the unamortized premium and discount on long-term debt is classified as Long-Term Debt in the Consolidated Balance Sheets and are being amortized over the life of the respective debt.

10. Short-Term Debt

The Company has an intercompany borrowing agreement with OGE Energy whereby the Company has access to up to $200 million of OGE Energy's revolving credit amount. The following table shows OGE Energy's revolving credit agreement and available cash at December 31, 2006.

Revolving Credit Agreement and Available Cash

Entity	Amount Available	Amount Outstanding	Weighted-Average Interest Rate	Maturity
	(in millions)			
OGE Energy(A)	$600.0	$ —	—	December 6, 2011(B)
Cash	—	N/A	N/A	N/A
Total	$600.0	$ —	—	

(A) This bank facility is available to back up OGE Energy's commercial paper borrowings and to provide revolving credit borrowings. This bank facility can also be used as a letter of credit facility. At December 31, 2006, there were no outstanding commercial paper borrowings.

(B) In December 2006, OGE Energy amended and restated its revolving credit agreement. This credit facility has a five-year term with an option to extend the term for two additional one-year periods. Also, this credit facility has an additional option at the end of the two renewal options to convert the outstanding balance to a one-year term loan.

OGE Energy's ability to access the commercial paper market could be adversely impacted by a credit ratings downgrade or major market disruptions. Pricing grids associated with the back-up lines of credit could cause annual fees and borrowing rates to increase if an adverse ratings impact occurs. The impact of any future downgrades would result in an increase in the cost of short-term borrowings but would not result in any defaults or accelerations as a result of the rating changes.

11. Retirement Plans and Postretirement Benefit Plans

In September 2006, the FASB issued SFAS No. 158 which requires an employer to: (i) recognize the overfunded or underfunded status of a defined benefit postretirement plan (other than a multiemployer plan) as an asset or liability in its statement of financial position and to recognize changes in that funded status in the year in which the changes occur through comprehensive income of a business entity; and (ii) to measure the fair value of the funded status of a plan as of the date of its year-end statement of financial position, with limited exceptions. The requirement to initially recognize the funded status of the defined benefit postretirement plan and the disclosure requirements are effective for the year ended December 31, 2006 for the Company. The requirement to measure plan assets and benefit obligations at fair value in accordance with SFAS No. 157 as of the date of the employer's fiscal year-end statement of financial position is effective for fiscal years ending after December 15, 2008. SFAS No. 158 also requires additional disclosures for defined benefit pension plans and other defined benefit postretirement plans.

Defined Benefit Pension Plan

All eligible employees of the Company and participating affiliates are covered by a non-contributory defined benefit pension plan sponsored by OGE Energy. For employees hired on or after February 1, 2000, the pension plan is a cash balance plan, under which OGE Energy annually will credit to the employee's account an amount equal to five percent of the employee's annual compensation plus accrued interest. Employees hired prior to February 1, 2000, will receive the greater of the cash balance benefit or a benefit based primarily on years of service and the average of the five highest consecutive years of compensation during an employee's last 10 years prior to retirement, with reductions in benefits for each year prior to age 62 unless the employee's age and years of credited service equal or exceed 80.

It is OGE Energy's policy to fund the plan on a current basis based on the net periodic SFAS No. 87, "Employers' Accounting for Pensions," pension expense as determined by the Company's actuarial consultants. Additional amounts may be contributed from time to time to increase the funded status of the plan. During 2006 and 2005, OGE Energy made contributions to its pension plan of approximately $90.0 million and $32.0 million, respectively, of which approximately $7.0 million and $2.3 million, respectively, were allocated to the Company, to ensure that the pension plan maintains an adequate funded status. Such contributions are intended to provide not only for benefits attributed to service to date, but also for those expected to be earned in the future. In August 2006, legislation was passed that changed the funding requirement for single- and multi-employer defined benefit pension plans as discussed below. During 2007, OGE Energy may contribute up to $50.0 million to its pension plan, of which approximately $4.0 million is expected to be allocated to the Company. The expected contribution to the pension plan, anticipated to be in the form of cash, is a discretionary contribution and is not required to satisfy the minimum regulatory funding requirement specified by the Employee Retirement Income Security Act of 1974, as amended.

At December 31, 2006, the projected benefit obligation and fair value of assets of the Company's portion of OGE Energy's pension plan and restoration of retirement income plan was approximately $41.7 million and $42.7 million, respectively, for an overfunded status of approximately $1.0 million. The above amounts have been recorded in Prepaid Pension and Benefit Obligations with the offset in Accumulated Other Comprehensive Income in the Company's Consolidated Balance Sheet. The entry did not impact the results of operations in 2006 and did not require a usage of cash and is therefore excluded from the Consolidated Statement of Cash Flows. The amount in Accumulated Other Comprehensive Income represents a net periodic benefit cost to be recognized in the Consolidated Statements of Income in future periods.

During 2005, OGE Energy made contributions to the pension plan that exceeded amounts previously recognized as net periodic pension expense and recorded a net prepaid benefit obligation at December 31, 2005 of approximately $88.9 million, of which approximately $7.7 million was allocated to the Company. At December 31, 2005, OGE Energy's projected pension benefit obligation exceeded the fair value of the pension plan assets by approximately $154.6 million, of which approximately $4.1 million was allocated to the Company. As a result of recording a prepaid benefit obligation and having a funded status where the projected benefit obligations exceeded the fair value of plan assets, provisions of SFAS No. 87 required the recognition of an additional minimum liability in the amount of approximately $181.4 million for OGE Energy, of which approximately $0.1 million was allocated to the Company at December 31, 2005. The offset of this entry was an intangible asset and Accumulated Other Comprehensive Income, net of a deferred tax asset; therefore, this adjustment did not impact the results of operations in 2005 and did not require a usage of cash and is therefore excluded from the Consolidated Statement of Cash Flows. The amount recorded as an intangible asset equaled the unrecognized prior service cost with the remainder recorded in Accumulated Other Comprehensive Income. The amount in Accumulated Other Comprehensive Income represents a net periodic benefit cost to be recognized in the Consolidated Statements of Income in future periods.

In accordance with SFAS No. 88, "Employer's Accounting for Settlements and Curtailments of Defined Benefit Pension Plans and for Termination Benefits," a one-time settlement charge is required to be recorded by an organization when lump sum payments or other settlements that relieve the organization from the responsibility for the pension benefit obligation during a plan year exceed the service cost and interest cost components of the organization's net periodic pension cost. During 2006, the Company experienced an increase in both the number of employees electing to retire and the amount of lump sum payments to be paid to such employees upon retirement in 2006. As a result, OGE Energy recorded a pension settlement charge for 2006 of approximately $17.1 million in the fourth quarter of 2006, of which approximately $0.8 million was allocated to the Company. The pension settlement charge did not require a cash outlay by the Company and did not increase the Company's total pension expense over time, as the charge was an acceleration of costs that otherwise would have been recognized as pension expense in future periods.

Pension Plan Costs and Assumptions

On August 17, 2006, President Bush signed The Pension Protection Act of 2006 (the "Pension Protection Act") into law. The Pension Protection Act makes changes to important aspects of qualified retirement plans. Among other things, it introduces a new funding requirement for single- and multi-employer defined benefit pension plans, provides legal certainty on a prospective basis for cash balance and other hybrid plans and addresses contributions to defined contribution plans, deduction limits for contributions to retirement plans and investment advice provided to plan participants. The Company is currently analyzing the impact of the Pension Protection Act on its pension plans.

Plan Investments, Policies and Strategies

The pension plan's assets consist primarily of investments in mutual funds, U.S. Government securities, listed common stocks and corporate debt. The following table shows, by major category, the percentage of the fair value of the plan assets held at December 31, 2006 and 2005:

December 31	2006	2005
Equity securities	**64%**	59%
Debt securities	**34%**	36%
Other	**2%**	5%
Total	**100%**	100%

The pension plan assets are held in a trust which follows an investment policy and strategy designed to maximize the long-term investment returns of the trust at prudent risk levels. Common stocks are used as a hedge against moderate inflationary conditions, as well as for participation in normal economic times. Fixed income investments are utilized for high current income and as a hedge against deflation. OGE Energy has retained an investment consultant responsible for the general investment oversight, analysis, monitoring investment guideline compliance and providing quarterly reports to certain of OGE Energy's members and OGE Energy's Employee Benefit Funds Management Committee (the "Committee").

The various investment managers used by the trust operate within the general operating objectives as established in the investment policy and within the specific guidelines established for their respective portfolio. The table below shows the target asset allocation percentages for each major category of plan assets:

Asset Class	Target Allocation	Minimum	Maximum
Domestic Equity	30%	—%	60%
Domestic Mid-Cap Equity	10%	—%	10%
Domestic Small-Cap Equity	10%	—%	10%
International Equity	10%	—%	10%
Fixed Income Domestic	38%	30%	70%
Cash	2%	—%	5%

The portfolio is rebalanced on an annual basis to bring the asset allocations of various managers in line with the target asset allocation listed above. More frequent rebalancing may occur if there are dramatic price movements in the financial markets which may cause the trust's exposure to any asset class to exceed or fall below the established allowable guidelines.

To evaluate the progress of the portfolio, investment performance is reviewed quarterly. It is, however, expected that performance goals will be met over a full market cycle, normally defined as a three to five year period. Analysis of performance is within the context of the prevailing investment environment and the advisors' investment style. The goal of the trust is to provide a rate of return consistently from three to five percent over the rate of inflation (as measured by the national Consumer Price Index) on a fee adjusted basis over a typical market cycle of no less than three years and no more than five years. Each investment manager is expected to outperform its respective benchmark. Below is a list of each asset class utilized with appropriate comparative benchmark(s) each manager is evaluated against:

Asset Class	Comparative Benchmark(s)
Fixed Income	Lehman Aggregate Index
Equity Index	S&P 500 Index
Value Equity	Russell 1000 Value Index—Short-term S&P 500 Index—Long-term
Growth Equity	Russell 1000 Growth Index—Short-term S&P 500 Index—Long-term
Mid-Cap Equity	S&P 400 Midcap Index
Small-Cap Equity	Russell 2000 Index
International Equity	Morgan Stanley Capital International Europe, Australia and Far East Index

The fixed income manager is expected to use discretion over the asset mix of the trust assets in its efforts to maximize risk-adjusted performance. Exposure to any single issuer, other than the U.S. government, its agencies, or its instrumentalities (which have no limits) is limited to five percent of the fixed income portfolio as measured by market value. At least 75% of the invested assets must possess an investment grade rating at or above Baa3 or BBB- by Moody's Investors Service ("Moody's"), Standard & Poor's Ratings Services ("Standard & Poor's") or Fitch Ratings ("Fitch"). The portfolio may invest up to 10% of the portfolio's market value in convertible bonds as long as the securities purchased meet the quality guidelines. The purchase of any of OGE Energy's equity, debt or other securities is prohibited.

The domestic value equity managers focus on stocks that the manager believes are undervalued in price and earn an average or less than average return on assets, and often pays out higher than average dividend payments. The domestic growth equity manager will invest primarily in growth companies which consistently experience above average growth in earnings and sales, earn a high return on assets, and reinvest cash flow into existing business. The domestic mid-cap equity portfolio manager focuses on companies with market capitalizations lower than the average company traded on the public exchanges with the following characteristics: price/earnings ratio at or near the S&P 400 Midcap Index, small dividend yield, return on equity at or near the S&P 400 Midcap Index and earnings per share growth rate at or near the S&P 400 Midcap Index. The domestic small-capitalization equity manager will purchase shares of companies with market capitalizations lower that the average company traded on the public exchanges with the following characteristics: price/earnings ratio at or near the Russell 2000, small dividend yield, return on equity at or near the Russell 2000 and earnings per share growth rate at or near the Russell 2000. The international global equity manager invests primarily in non-dollar denominated equity securities. Investing internationally diversifies the overall trust across the global equity markets. The manager is required to operate under certain restrictions including: regional constraints, diversification requirements and percentage of U.S. securities. The Morgan Stanley Capital International Europe, Australia and the Far East Index (''EAFE'') is the benchmark for comparative performance purposes. The EAFE Index is a market value weighted index comprised of over 1,000 companies traded on the stock markets of Europe, Australia, New Zealand and the Far East. All of the equities which are purchased for the international portfolio are thoroughly researched. Only investments in companies with a market capitalization in excess of $100 million are allowable. No more than five percent of the portfolio can be invested in any one stock at the time of purchase. All securities are freely traded on a recognized stock exchange and there are no 144-A securities and no over-the-counter derivatives. The following investment categories are excluded: options (other than traded currency options), commodities, futures (other than currency futures or currency hedging), short sales/margin purchases, private placements, unlisted securities and real estate (but not real estate shares).

For all domestic equity investment managers, no more than eight percent (five percent for mid-cap and small-cap equity managers) can be invested in any one stock at the time of purchase and no more than 16% (10% for mid-cap and small-cap equity managers) after accounting for price appreciation. A minimum of 95% of the total assets of an equity manager's portfolio must be allocated to the equity markets. Options or financial futures may not be purchased unless prior approval of the Committee is received. The purchase of securities on margin is prohibited as is securities lending. Private placement or venture capital may not be purchased. All interest and dividend payments must be swept on a daily basis into a short-term money market fund for re-deployment. The purchase of any of OGE Energy's equity, debt or other securities is prohibited. The purchase of equity or debt issues of the portfolio manager's organization is also prohibited. The aggregate positions in any company may not exceed one percent of the fair market value of its outstanding stock.

Restoration of Retirement Income Plan

OGE Energy provides a restoration of retirement income plan to those participants in OGE Energy's pension plan whose benefits are subject to certain limitations under the Internal Revenue Code (the ''Code''). The benefits payable under this restoration of retirement income plan are equivalent to the amounts that would have been payable under the pension plan but for these limitations. The restoration of retirement income plan is intended to be an unfunded plan.

Postretirement Benefit Plans

In addition to providing pension benefits, OGE Energy provides certain medical and life insurance benefits for eligible retired members (“postretirement benefits”). Regular, full-time, active employees hired prior to February 1, 2000, whose age and years of credited service total or exceed 80 or have attained age 55 with 10 years of vesting service at the time of retirement are entitled to these postretirement benefits. Employees hired on or after February 1, 2000, are not entitled to postretirement medical benefits but are entitled to postretirement life insurance benefits. Eligible retirees must contribute such amount as OGE Energy specifies from time to time toward the cost of coverage for postretirement benefits. The benefits are subject to deductibles, co-payment provisions and other limitations. The Company charges to expense the SFAS No. 106, “Employers’ Accounting for Postretirement Benefits Other Than Pensions,” costs.

At December 31, 2006, the accumulated postretirement benefit obligation of the Company’s portion of OGE Energy’s postretirement benefit plans was approximately $15.9 million for an underfunded status of approximately $15.9 million. There was no fair value of assets allocated to the Company at December 31, 2006. The above amounts have been recorded in Accrued Pension and Benefit Obligations with the offset in Accumulated Other Comprehensive Income in the Company’s Consolidated Balance Sheet. The entry did not impact the results of operations in 2006 and did not require a usage of cash and is therefore excluded from the Consolidated Statement of Cash Flows. The amount in Accumulated Other Comprehensive Income represents a net periodic benefit cost to be recognized in the Consolidated Statements of Income in future periods.

The details of the funded status of the pension plan (including the restoration of retirement income plan) and the postretirement benefit plans and the amounts included in the Consolidated Balance Sheets are as follows:

Obligations and Funded Status

December 31	Pension Plan and Restoration of Retirement Income Plan 2006	2005	Postretirement Benefit Plans 2006	2005
	(in millions)			
Change in Benefit Obligation				
Beginning obligations	**$(38.6)**	$(33.2)	**$(13.4)**	$(11.2)
Service cost	**(3.3)**	(2.9)	**(0.5)**	(0.4)
Interest cost	**(2.1)**	(1.9)	**(0.8)**	(0.6)
Participants’ contributions	**—**	—	**(0.2)**	(0.2)
Actuarial losses	**(1.7)**	(2.1)	**(1.8)**	(1.7)
Benefits paid	**4.0**	1.5	**0.8**	0.7
Ending obligations	**(41.7)**	(38.6)	**(15.9)**	(13.4)
Change in Plans’ Assets				
Beginning fair value	**34.5**	31.8	**—**	—
Actual return on plans’ assets	**5.2**	1.8	**—**	—
Employer contributions	**7.0**	2.4	**0.6**	0.5
Participants’ contributions	**—**	—	**0.2**	0.2
Benefits paid	**(4.0)**	(1.5)	**(0.8)**	(0.7)
Ending fair value	**42.7**	34.5	**—**	—
Funded status at end of year	**$ 1.0**	$ (4.1)	**$(15.9)**	$(13.4)

Incremental Effect of Applying SFAS No. 158 on Individual Line Items in the Consolidated Balance Sheet at December 31, 2006

December 31	Before Application of SFAS No. 158	Adjustments	After Application of SFAS No. 158
		(in millions)	
Prepaid benefit obligation	$ 10.8	$(9.8)	$ 1.0
Total deferred charges and other assets	19.8	(9.8)	10.0
Accrued pension and benefit obligations:			
Defined postretirement benefit plans	9.9	6.0	15.9
Accumulated deferred income taxes	237.6	(6.9)	230.7
Total deferred credits and other liabilities	250.2	(0.9)	249.3
Accumulated other comprehensive loss	5.0	(8.9)	(3.9)
Total stockholder's equity	408.9	(8.9)	400.0

Amounts recognized in the Consolidated Balance Sheets consist of:

December 31	Pension Plan and Restoration of Retirement Income Plan 2005	Postretirement Benefit Plans 2005
	(in millions)	
Prepaid benefit obligation	$ 7.8	$ —
Accrued pension and benefit obligations	(0.2)	(8.4)
Intangible asset—unrecognized prior service cost	0.1	—
Net amount recognized	$ 7.7	$(8.4)

Net Periodic Benefit Cost

Year Ended December 31	Pension Plan and Restoration of Retirement Income Plan 2006	2005	2004	Postretirement Benefit Plans 2006	2005	2004
			(in millions)			
Service cost	**$ 3.3**	$ 2.9	$ 2.6	**$ 0.5**	$ 0.4	$ 0.4
Interest cost	**2.1**	1.9	1.7	**0.8**	0.6	0.6
Return on plan assets	**(3.1)**	(2.7)	(2.3)	**—**	—	—
Amortization of transition obligation	**—**	—	—	**0.1**	0.2	0.1
Amortization of net loss	**0.8**	0.6	0.4	**0.4**	0.1	0.1
Amortization of recognized prior service cost	**0.1**	0.1	—	**0.3**	0.3	0.3
Settlement	**0.8**	—	—	**—**	—	—
Net periodic benefit cost(A)	**$ 4.0**	$ 2.8	$ 2.4	**$ 2.1**	$ 1.6	$ 1.5

(A) The capitalized portion of the net periodic pension benefit cost was approximately $0.2 million, $0.7 million and $0.5 million at December 31, 2006, 2005 and 2004, respectively. The capitalized portion of the net periodic postretirement benefit cost was approximately $0.1 million, $0.2 million and $0.2 million at December 31, 2006, 2005 and 2004, respectively.

Rate Assumptions

Year Ended December 31	Pension Plan 2006	Pension Plan 2005	Pension Plan 2004	Postretirement Benefit Plans 2006	Postretirement Benefit Plans 2005	Postretirement Benefit Plans 2004
Discount rate	**5.75%**	5.50%	5.75%	**5.75%**	5.50%	5.75%
Rate of return on plans' assets	**8.50%**	8.50%	8.75%	**8.50%**	8.50%	8.75%
Compensation increases	**4.50%**	4.50%	4.50%	**4.50%**	4.50%	4.50%
Assumed health care cost trend:						
Initial trend	**N/A**	N/A	N/A	**9.00%**	9.00%	10.00%
Ultimate trend rate	**N/A**	N/A	N/A	**4.50%**	4.50%	4.50%
Ultimate trend year	**N/A**	N/A	N/A	**2012**	2011	2010

N/A—not applicable

The overall expected rate of return on plan assets assumption remained 8.50% in 2005 and 2006 in determining net periodic benefit cost. The rate of return on plan assets assumption is the average long-term rate of earnings expected on the funds currently invested and to be invested for the purpose of providing benefits specified by the pension plan or postretirement benefit plans. This assumption is reexamined at least annually and updated as necessary. The rate of return on plan assets assumption reflects a combination of historical return analysis, forward-looking return expectations and the plans' current and expected asset allocation.

The Company expects to pay benefits related to its pension plan and restoration of retirement income plan of approximately $2.8 million in 2007, $3.1 million in 2008, $3.6 million in 2009, $3.9 million in 2010, $4.2 million in 2011 and an aggregate of $27.1 million in years 2012 to 2016. These expected benefits were based on the same assumptions used to measure the Company's benefit obligation at the end of the year and include benefits attributable to estimated future employee service.

The assumed health care cost trend rates have a significant effect on the amounts reported for postretirement medical benefit plans. Future health care cost trend rates are assumed to be eight percent in 2007 with the rates decreasing in subsequent years by one percentage point per year through 2010. A one-percentage point change in the assumed health care cost trend rate would have the following effects:

One-Percentage Point Increase

Year Ended December 31	2006	2005	2004
	(in millions)		
Effect on aggregate of the service and interest cost components	**$0.2**	$0.2	$0.2
Effect on accumulated postretirement benefit obligations	**2.4**	2.0	1.7

One-Percentage Point Decrease

Year Ended December 31	2006	2005	2004
	(in millions)		
Effect on aggregate of the service and interest cost components	**$0.2**	$0.1	$0.1
Effect on accumulated postretirement benefit obligations	**1.9**	1.6	1.4

Medicare Prescription Drug, Improvement and Modernization Act of 2003

On December 8, 2003, President Bush signed into law the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (the "Medicare Act"). The Medicare Act expanded Medicare to include, for the first time, coverage for prescription drugs. In May 2004, the FASB issued FASB Staff Position No. FAS 106-2, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003." FAS 106-2 provided guidance on the accounting for the effects of the Medicare Act for employers that sponsor postretirement heath care plans that provide prescription drug benefits. FAS 106-2 also required those employers to provide certain disclosures regarding the effect of the federal subsidy provided by the Medicare Act. OGE Energy adopted this new standard effective July 1, 2004 with retroactive application to the date of the Medicare Act's enactment. Management expects that the accumulated plan benefit obligation ("APBO") for OGE Energy with respect to its postretirement medical plan will be reduced by approximately $39.7 million as a result of savings to OGE Energy with respect to its postretirement medical plan resulting from the Medicare Act provided subsidy, which will reduce OGE Energy's costs for its postretirement medical plan by approximately $6.5 million annually, of which approximately $0.4 million is expected to be allocated to the Company. The $0.4 million in annual savings is comprised of a reduction of approximately $0.2 million from amortization of the $2.7 million gain due to the reduction of the APBO, a reduction in the interest cost on the APBO of approximately $0.1 million and a reduction in the service cost due to the subsidy of approximately $0.1 million.

The Company expects to pay gross benefits payments related to its postretirement benefit plans, including prescription drug benefits, of approximately $0.7 million in 2007, $0.7 million in 2008, $0.8 million in 2009, $0.9 million in 2010, $0.9 million in 2011 and an aggregate of $6.0 million in years 2012 to 2016. The Company expects to receive federal subsidy receipts provided by the Medicare Act of approximately $0.1 million in 2007, $0.1 million in 2008, $0.1 million in 2009, $0.1 million in 2010, $0.1 million in 2011 and an aggregate of $0.6 million in years 2012 to 2016. The Company did not receive any federal subsidy receipts in 2006.

Defined Contribution Plan

OGE Energy provides a defined contribution savings plan. Each regular full-time employee of OGE Energy or a participating affiliate is eligible to participate in the plan immediately. All other employees of OGE Energy or a participating affiliate are eligible to become participants in the plan after completing one year of service as defined in the plan. Participants may contribute each pay period any whole percentage between two percent and 19% of their compensation, as defined in the plan, for that pay period. Contributions of the first six percent of compensation are called "Regular Contributions" and any contributions over six percent of compensation are called "Supplemental Contributions." Participants who have attained age 50 before the close of a year are allowed to make additional contributions, referred to as "Catch-Up Contributions," subject to the limitations of the Code. OGE Energy contributes to the Plan each pay period on behalf of each participant an amount equal to 50% of the participant's Regular Contributions for participants whose employment or re-employment date, as defined in the plan, occurred before February 1, 2000 and who have less than 20 years of service, as defined in the plan, and an amount equal to 75% of the participant's Regular Contributions for participants whose employment or re-employment date occurred before February 1, 2000 and who have 20 or more years of service. For participants whose employment or re-employment date occurred on or after February 1, 2000, OGE Energy shall contribute 100% of the Regular Contributions deposited during such pay period by such participant. No OGE Energy contributions are made with respect to a participant's Supplemental Contributions, Catch-Up Contributions, or with respect to a participant's Regular Contributions based on overtime payments, pay-in-lieu of overtime for exempt personnel, special lump-sum recognition awards and lump-sum merit awards included in compensation for determining the amount of participant contributions. OGE Energy's contribution which is initially allocated for investment to the OGE Energy Common Stock Fund may be made in shares of OGE Energy's common stock or in cash which is used to invest in OGE Energy's common stock. Once made, OGE Energy's contribution may be reallocated, at any time, by participants to other available investment options. The Company contributed approximately $1.2 million, $1.2 million and $1.1 million during 2006, 2005 and 2004, respectively, to the defined contribution plan.

Deferred Compensation Plan

OGE Energy provides a deferred compensation plan. The plan's primary purpose is to provide a tax-deferred capital accumulation vehicle for a select group of management, highly compensated employees and non-employee members of the Board of Directors of OGE Energy and to supplement such employees' defined contribution plan contributions as well as offering this plan to be competitive in the marketplace.

Eligible employees who enroll in the plan have the following deferral options: (i) eligible employees may elect to defer up to a maximum of 70% of base salary and 100% of bonus awards; or (ii) eligible employees may elect a deferral percentage of base salary and bonus awards based on the deferral percentage elected for a year under the defined contribution plan with such deferrals to start when maximum deferrals to the qualified defined contribution plan have been made because of limitations in that plan. Eligible directors who enroll in the plan may elect to defer up to a maximum of 100% of directors' meeting fees and annual retainers. OGE Energy matches employee (but not non-employee director) deferrals to provide for the match that would have been made under the defined contribution plan had such deferrals been made under that plan without regard to the statutory limitations on elective deferrals and matching contributions applicable to the defined contribution plan. In addition, the Benefits Committee may award discretionary employer contribution credits to a participant under the plan. OGE Energy accounts for the contributions related to the Company's executive officers in this plan as Accrued Pension and Benefit Obligations and OGE Energy accounts for the contributions related to the Company's directors in this plan as Other Deferred Credits and Other Liabilities in the Consolidated Balance Sheets. The investment associated with these contributions is accounted for as Other Property and Investments in OGE Energy's Consolidated Balance Sheets. The appreciation of these investments is accounted for as Other Income and the increase in the liability under the plan is accounted for as Other Expense in OGE Energy's Consolidated Statements of Income.

Supplemental Executive Retirement Plan

OGE Energy provides a supplemental executive retirement plan in order to attract and retain lateral hires or other executives designated by the Compensation Committee of OGE Energy's Board of Directors who may not otherwise qualify for a sufficient level of benefits under OGE Energy's pension plan. The supplemental executive retirement plan is intended to be an unfunded plan and not subject to the benefit limits imposed by the Code.

12. Report of Business Segments

The Company's business is divided into three reportable segments, defined as components of the enterprise about which financial information is available and evaluated regularly by our management. Our reportable segments are strategic business units that offer different services. Each segment is managed separately based on similarities in economic characteristics, products and services, types of customers, methods of distribution and regulatory environment. These segments are as follows: (i) transportation and storage of natural gas, (ii) gathering and processing of natural gas, and (iii) marketing of natural gas. Intersegment revenues are recorded at prices comparable to those of unaffiliated customers and are affected by regulatory considerations. The following tables summarize the results of the Company's business segments for the years ended December 31, 2006, 2005 and 2004.

Year Ended December 31, 2006	Transportation and Storage	Gathering and Processing	Marketing	Eliminations	Total
			(in millions)		
Operating revenues	**$ 225.9**	**$704.3**	**$1,941.3**	**$ (503.7)**	**$2,367.8**
Cost of goods sold	**100.3**	**536.7**	**1,927.1**	**(503.7)**	**2,060.4**
Gross margin on revenues	**125.6**	**167.6**	**14.2**	**—**	**307.4**
Other operation and maintenance	**41.2**	**59.5**	**9.3**	**—**	**110.0**
Depreciation	**17.9**	**24.2**	**0.2**	**—**	**42.3**
Impairment of assets	**—**	**0.3**	**—**	**—**	**0.3**
Taxes other than income	**11.8**	**3.8**	**0.4**	**—**	**16.0**
Operating income	**$ 54.7**	**$ 79.8**	**$ 4.3**	**$ —**	**$ 138.8**
Total assets	**$1,441.2**	**$843.7**	**$ 231.4**	**$(1,196.5)**	**$1,319.8**
Capital expenditures	**$ 9.8**	**$ 57.6**	**$ —**	**$ (0.3)**	**$ 67.1**

Year Ended December 31, 2005	Transportation and Storage	Gathering and Processing	Marketing	Eliminations	Total
			(in millions)		
Operating revenues	$ 246.4	$644.5	$4,003.0	$ (553.8)	$4,340.1
Cost of goods sold	147.3	504.3	3,992.6	(553.8)	4,090.4
Gross margin on revenues	99.1	140.2	10.4	—	249.7
Other operation and maintenance	32.9	55.3	8.4	—	96.6
Depreciation	17.3	23.0	0.1	—	40.4
Taxes other than income	11.6	3.4	0.4	—	15.4
Operating income	$ 37.3	$ 58.5	$ 1.5	$ —	$ 97.3
Total assets	$1,456.9	$729.0	$ 525.4	$(1,058.7)	$1,652.6
Capital expenditures	$ 9.2	$ 25.6	$ —	$ (0.1)	$ 34.7

Year Ended December 31, 2004	Transportation and Storage	Gathering and Processing	Marketing	Eliminations	Total
			(in millions)		
Operating revenues	$ 249.4	$524.7	$3,048.4	$(450.3)	$3,372.2
Cost of goods sold	134.9	401.3	3,032.3	(450.3)	3,118.2
Gross margin on revenues	114.5	123.4	16.1	—	254.0
Other operation and maintenance	29.9	51.3	12.3	—	93.5
Depreciation	17.1	22.6	1.4	—	41.1
Impairment of assets	8.8	(1.0)	—	—	7.8
Taxes other than income	11.6	3.8	0.6	—	16.0
Operating income	$ 47.1	$ 46.7	$ 1.8	$ —	$ 95.6
Total assets	$1,576.3	$616.1	$ 511.3	$(984.0)	$1,719.7
Capital expenditures	$ 12.0	$ 20.4	$ 0.2	$ (3.6)	$ 29.0

13. Commitments and Contingencies

Capital Expenditures

The Company's capital expenditures are estimated at approximately: 2007—$124.8 million, 2008—$139.0 million, 2009—$60.8 million, 2010—$60.0 million, 2011—$60.0 million and 2012—$60.0 million.

Operating Lease Obligations

The Company has operating lease obligations expiring at various dates. Future minimum payments for noncancellable operating leases are as follows:

Year Ended December 31	2007	2008	2009	2010	2011	2012 and Beyond
			(in millions)			
Noncancellable operating leases	$2.2	$1.8	$1.3	$1.4	$1.5	$0.4

Payments for operating lease obligations were approximately $3.4 million, $4.3 million and $4.3 million in 2006, 2005 and 2004, respectively.

Agreement with Cheyenne Plains Gas Pipeline Company, L.L.C.

Cheyenne Plains Gas Pipeline Company, L.L.C ("Cheyenne Plains") operates the Cheyenne Plains Pipeline that provides firm transportation services in Wyoming, Colorado and Kansas with a capacity of 730,000 decatherms/day ("Dth/day"). OGE Energy Resources LLC, ("OERI"), a wholly owned subsidiary of the Company, entered into a Firm Transportation Service Agreement ("FTSA") with Cheyenne Plains in 2004, for 60,000 Dth/day of firm capacity on the Cheyenne Plains Pipeline. The FTSA was for a 10-year term beginning with the in-service date of the Cheyenne Plains Pipeline in March 2005 with an annual demand fee of approximately $7.4 million. Effective March 1, 2007, OERI and Cheyenne Plains amended the FTSA to provide for OERI to turn back 20,000 Dth/day of its capacity beginning in January 2008 for the remainder of the term. OERI's new demand fee obligations, net of this turn back and other immaterial release agreements, are estimated at approximately $6.9 million in 2007; $5.9 million in 2008; $6.5 million for each of the years 2009 through 2014; and $1.6 million in 2015.

Agreement with Midcontinent Express Pipeline, LLC

On December 15, 2006, the Company announced that it had entered into a firm capacity lease agreement with Midcontinent Express Pipeline, LLC for a primary term of 10 years (subject to possible extensions) for certain capacity on the its system. The leased capacity provided for in this agreement is up to 500 million cubic feet ("MMcf") per day and is dependent on the shipper volumes that commit to the project. The Company's capacity will be a part of the proposed Midcontinent Express Pipeline ("MEP"), a joint venture between Kinder Morgan Energy Partners, L.P. and Energy Transfer Partners, L.P. In addition to the Company's leased capacity, the proposed MEP project includes a new pipeline originating near Bennington, Oklahoma and terminating in Butler, Alabama. Pending necessary regulatory approval, the MEP project is currently expected to be in service during the first quarter of 2009. Depending on the final capacity that MEP subscribes to pursuant to the agreement, the Company expects its revenues from this firm capacity lease agreement to be between $12 million and $30 million annually. The Company currently estimates that its capital expenditures related to this project during 2007 and 2008 will be between $65 million and $100 million. The Company's lease agreement with MEP is subject to certain contingencies including regulatory approval. Prior to such approval, the Company may incur expenditures of between approximately $20 million and $40 million primarily related to commitments for materials that can be sold or used in normal operations in the event the MEP project does not proceed. The amount not recovered or utilized for such expenditures is not expected to be material.

Agreement with Boardwalk's Gulf Crossing Project

In March 2007, the Company entered into a firm capacity lease agreement with Gulf Crossing Pipeline Company LLC for a primary term of seven years (subject to a possible extension) for certain capacity on the Company system. The leased capacity provided for in this agreement is up to 165 MMcf per day and is dependent on the shipper volumes that commit to the project. Boardwalk Pipeline Partners, LP, has announced plans to build the Gulf Crossing pipeline, which includes 355 miles of new interstate natural gas pipeline. It initially is expected to transport gas from the supply areas in Sherman, Texas, Bennington, Oklahoma, and Paris, Texas to the Perryville, Louisiana Hub. Depending on the final capacity that Gulf Crossing subscribes to pursuant to the agreement, the Company expects its revenues from this firm capacity lease agreement to be between $1.6 million and $5.7 million annually. The Company currently estimates that its capital expenditures related to this project during 2007 and 2008 will be between approximately $2 million and $5 million. The lease agreement with Gulf Crossing is subject to certain regulatory approval. Prior to such approval, the Company may incur expenditures of up to $5 million primarily related to commitments for material that can be sold or used in normal operations in the event the Gulf Crossing project does not proceed. The amount not recovered or utilized for such expenditures is not expected to be material. Subject to regulatory approvals, the Gulf Crossing project is expected to have a commercial operation date in late 2008. Gulf Crossing filed applications with the FERC on June, 19, 2007 requesting certificates of public convenience and necessity authorizing Gulf Crossing to construct, abandon and lease certain facilities relating to its Gulf Crossing pipeline. In a related application, the Company filed its FERC application on June 20, 2007 for issuance of a limited-jurisdiction certificate authorizing its lease of intrastate pipeline capacity to Gulf Crossing. Both the Company and Gulf Crossing have requested approval of the applications by November 2007.

Natural Gas Measurement Cases

United States of America ex rel., Jack J. Grynberg v. Enogex Inc., Enogex Services Corporation and OG&E. (United States District Court for the Western District of Oklahoma, Case No. CIV-97-1010-L.) United States of America ex rel., Jack J. Grynberg v. Transok Inc. et al. (United States District Court for the Eastern District of Louisiana, Case No. 97-2089; United States District Court for the Western District of Oklahoma, Case No. 97-1009M.). On June 15, 1999, OGE Energy was served with Plaintiff's complaint, which is a qui tam action under the False Claims Act. Plaintiff Jack J. Grynberg, as individual relator on behalf of the United States Government, alleges: (i) each of the named defendants have improperly or intentionally mismeasured gas (both volume and British thermal unit ("Btu") content) purchased from federal and Indian lands which have resulted in the under-reporting and underpayment of gas royalties owed to the Federal Government; (ii) certain provisions generally found in gas purchase contracts are improper; (iii) transactions by affiliated companies are not arms-length; (iv) excess processing cost deduction; and (v) failure to account for production separated out as a result of gas processing. Grynberg seeks the following damages: (a) additional royalties which he claims should have been paid to the Federal Government, some percentage of which Grynberg, as relator, may be entitled to recover; (b) treble damages; (c) civil penalties; (d) an order requiring defendants to measure the way Grynberg contends is the better way to do so; and (e) interest, costs and attorneys' fees.

In qui tam actions, the United States Government can intervene and take over such actions from the relator. The Department of Justice, on behalf of the United States Government, decided not to intervene in this action.

The plaintiff filed over 70 other cases naming over 300 other defendants in various Federal Courts across the country containing nearly identical allegations. The Multidistrict Litigation Panel entered its order in late 1999 transferring and consolidating for pretrial purposes approximately 76 other similar actions filed in nine other Federal Courts. The consolidated cases are now before the United States District Court for the District of Wyoming.

In October 2002, the court granted the Department of Justice's motion to dismiss certain of the plaintiff's claims and issued an order dismissing the plaintiff's valuation claims against all defendants. Various procedural motions have been filed. A hearing on the defendants' motions to dismiss for lack of subject matter jurisdiction, including public disclosure, original source and voluntary disclosure requirements was held in 2005 and the special master ruled that OG&E and all Enogex parties named in these proceedings should be dismissed. This ruling was appealed to the District Court of Wyoming.

On October 20, 2006, the District Court of Wyoming ruled on Grynberg's appeal, following and confirming the recommendation of the special master dismissing all claims against Enogex Inc., Enogex Services Corp., Transok, Inc. and OG&E, for lack of subject matter jurisdiction. Judgment was entered on November 17, 2006 and Grynberg filed his notice of appeal with the District Court of Wyoming. The defendants filed motions for attorneys' fees regarding issues of liability and Rule 11 motions on January 8, 2007. The defendants also filed for other legal costs on December 18, 2006. A hearing on these motions was held on April 24, 2007, at which time the judge in this matter took these motions under advisement. Grynberg has also filed appeals with the Tenth Circuit Court of Appeals. OGE Energy intends to vigorously defend this action. At this time, OGE Energy is unable to provide an evaluation of the likelihood of an unfavorable outcome and an estimate of the amount or range of potential loss to OGE Energy.

Will Price (Price I)—On September 24, 1999, various subsidiaries of OGE Energy were served with a class action petition filed in United States District Court, State of Kansas by Quinque Operating

Company and other named plaintiffs, alleging mismeasurement of natural gas on non-federal lands. On April 10, 2003 the Court entered an order denying class certification. On May 12, 2003, plaintiffs (now Will Price, Stixon Petroleum, Inc., Thomas F. Boles and the Cooper Clark Foundation, on behalf of themselves and other royalty interest owners) filed a motion seeking to file an amended petition and the court granted the motion on July 28, 2003. In this amended petition, OG&E and the Company were omitted from the case. Two subsidiaries of the Company remain as defendants. The plaintiffs' amended petition alleges that approximately 60 defendants, including two of the Company's subsidiaries, have improperly measured natural gas. The amended petition reduces the claims to: (1) mismeasurement of volume only; (2) conspiracy, unjust enrichment and accounting; (3) a putative plaintiffs' class of only royalty owners; and (4) gas measured in three specific states. A hearing on class certification issues was held April 1, 2005. OGE Energy intends to vigorously defend this action. At this time, OGE Energy is unable to provide an evaluation of the likelihood of an unfavorable outcome and an estimate of the amount or range of potential loss to OGE Energy.

Will Price (Price II)—On May 12, 2003, the plaintiffs (same as those in Price I above) filed a new class action petition (Price II) in the District Court of Stevens County, Kansas, relating to wrongful Btu analysis against natural gas pipeline owners and operators, naming the same defendants as in the amended petition of the Price I case. Two of the Company's subsidiaries were served on August 4, 2003. The plaintiffs seek to represent a class of only royalty owners either from whom the defendants had purchased natural gas or measured natural gas since January 1, 1974 to the present. The class action petition alleges improper analysis of gas heating content. In all other respects, the Price II petition appears to be the same as the amended petition in Price I. A hearing on class certification issues was held April 1, 2005. OGE Energy intends to vigorously defend this action. At this time, OGE Energy is unable to provide an evaluation of the likelihood of an unfavorable outcome and an estimate of the amount or range of potential loss to OGE Energy.

Pipeline Rupture

On May 10, 2005, a natural gas pipeline rupture occurred on a Company facility within the ANR Pipeline, Inc. plant site in Custer County, near Clinton, Oklahoma, resulting in an explosion and fire. No injuries were reported as a result of the incident. It is anticipated that any third party damages related to this incident will not be material to the Company as they will be covered by insurance following payment of the deductible, which deductible has been accrued in the Company's Consolidated Financial Statements.

Farris Buser Litigation

On July 22, 2005, the Company along with certain other unaffiliated co-defendants was served with a purported class action which had been filed on February 7, 2005 by Farris Buser and other named plaintiffs in the District Court of Canadian County, Oklahoma. The plaintiffs own royalty interests in certain oil and gas producing properties and allege they have been under-compensated by the named defendants, including the Company, relating to the sale of liquid hydrocarbons recovered during the transportation of natural gas from the plaintiffs' wells. The plaintiffs assert breach of contract, implied covenants, obligation, fiduciary duty, unjust enrichment, conspiracy and fraud causes of action and claim actual damages in excess of $10,000, plus attorneys' fees and costs, and punitive damages in excess of $10,000. The Company filed a motion to dismiss which was granted on November 18, 2005, subject to the plaintiffs' right to conduct discovery and the possible re-filing of their allegations in the petition against the Company. On September 19, 2005, the co-defendants, BP America, Inc. and BP America Production Co. (collectively, "BP"), filed a cross claim against Products seeking indemnification and/or contribution from Products based upon the 1997 sale of a third party interest in one of Products' natural gas processing plants. On May 17, 2006, the plaintiffs filed an amended petition against the Company. The Company filed a motion to dismiss the amended petition on August 2, 2006. The hearing on the dismissal motion was held on November 20, 2006 and the court denied the Company's motion. The Company filed an answer to the amended petition and BP's cross claim on January 16, 2007. Based on its investigation to date, the Company believes these claims and cross claims in this lawsuit are without merit and intends to continue vigorously defending this case.

Calpine Corporation Bankruptcy

Calpine Corporation, Calpine Energy Services, L.P., and several other affiliates (collectively "Calpine") voluntarily filed for Chapter 11 bankruptcy protection from creditors on December 20, 2005 (Case No. 05-60200 (BRL)) United States Bankruptcy Court, S.D. of New York. The Company provides natural gas transportation services pursuant to long-term contracts to two Calpine-owned power generation plants in Oklahoma. Calpine is continuing to operate the plants and request services pursuant to the contracts. The total unpaid amount due to the Company from Calpine is approximately $0.3 million which has been fully reserved on the Company's books.

Potential Collateral Requirements

At December 31, 2006 in the event Moody's or Standard & Poor's were to lower the Company's senior unsecured debt rating to a below investment grade rating, the Company would be required to post approximately $3.3 million of collateral to satisfy its obligation under its financial and physical contracts.

Environmental Laws and Regulations

Approximately $0.9 million and $1.5 million, respectively, of the Company's capital expenditures budgeted for 2007 and 2008 are to comply with environmental laws and regulations. The Company's management believes that all of its operations are in substantial compliance with present federal, state and local environmental regulations. It is estimated that the Company's total expenditures for capital, operating, maintenance and other costs to preserve and enhance environmental quality will be approximately $2.5 million during 2007 as compared to approximately $2.1 million in 2006. The Company continues to evaluate its environmental management systems to ensure compliance with existing and proposed environmental legislation and regulations and to better position itself in a competitive market.

The construction and operation of pipelines, plants and other facilities for transporting, processing, compressing or storing natural gas and other products may be subject to federal, state and local environmental laws and regulations, including those that can impose obligations to clean up hazardous substances at the locations at which the Company operates. In most instances, the applicable regulatory requirements relate to water and air pollution control or solid waste management measures. Appropriate governmental authorities may enforce these laws and regulations with a variety of civil and criminal enforcement measures, including monetary penalties, assessment and remediation requirements and injunctions as to future compliance. The Company generates some materials subject to the requirements of the Federal Resource Conservation and Recovery Act and the Clean Water Act and comparable state statutes, prepares and files reports and documents pursuant to the Toxic Substance Control Act and the Emergency Planning and Community Right to Know Act and obtains permits pursuant to the Federal Clean Air Act and comparable state air statutes.

Environmental regulation can increase the cost of planning, design, initial installation and operation of the Company's facilities. Historically, the Company's total expenditures for environmental control facilities and for remediation have not been significant in relation to its results of operations or financial condition. The Company believes, however, that it is reasonably likely that the trend in environmental legislation and regulations will continue to be towards stricter standards.

The Company has and will continue to evaluate the impact of its operations on the environment. As a result, contamination on Company property may be discovered from time to time.

Other

In the normal course of business, the Company is confronted with issues or events that may result in a contingent liability. These generally relate to lawsuits, claims made by third parties, environmental actions or the action of various regulatory agencies and income tax related items. When appropriate, management consults with legal counsel and other appropriate experts to assess the claim. If, in management's opinion, the Company has incurred a probable loss as set forth by accounting principles generally accepted in the United States, an estimate is made of the loss and the appropriate accounting entries are reflected in the Company's Consolidated Financial Statements. Except as otherwise stated above and in Note 14 below, management, after consultation with legal counsel, does not currently anticipate that liabilities arising out of these pending or threatened lawsuits, claims and contingencies will have a material adverse effect on the Company's consolidated financial position, results of operations or cash flows.

14. Regulation

Completed Regulatory Matters

FERC Section 311 2001 Rate Case

Pursuant to a settlement accepted by the Federal Energy Regulatory Commission ("FERC") in May 2003 to resolve the Company's 2001 Section 311 rate case, the Company assessed a fee under certain market conditions for processing customer gas gathered behind processing plants so that it met the heating value standards of natural gas transmission pipelines ("default processing fee"). Pursuant to the Company's Statement of Operating Conditions ("SOC") that was effective through September 30, 2004, if the Company's annual processing gross margin exceeded a specified threshold, the Company was required to record a default processing fee refund obligation in an amount equal to the lesser of the default processing fees or the amount of the processing margin in excess of the specified threshold. In June 2004, the Company billed default processing fees of approximately $0.2 million, which was recorded as deferred revenue. Based on the processing gross margin for 2004, these default processing fees billed to customers were recorded as deferred revenue and were refunded or credited to customers by April 30, 2005.

FERC Section 311 2004 Rate Case and Related FERC Dockets and 2006 Fuel Filing

On September 1, 2004, the Company made a filing at the FERC to revise its previously approved SOC to permit, among other things, the unbundling, effective October 1, 2004, of its previously bundled gathering and transportation services. As a result, effective October 1, 2004, the FERC regulates the Company's Section 311 transportation services but does not regulate the Company's gathering services. The OCC regulates gathering pursuant to Oklahoma statute.

On September 30, 2004, the Company made its required triennial filing at the FERC to update its Section 311 maximum interruptible transportation rate. On September 29, 2004, the Company filed an updated fuel factor with the FERC for the last quarter of 2004. Finally, on November 15, 2004, the Company filed its annual updated system-wide fuel factor for fuel year 2005 (calendar year 2005). The proceedings were resolved by a unanimous settlement that the FERC approved without modification or condition, by order of September 19, 2005. The Settlement established new maximum interruptible Section 311 zonal rates for an East Zone and a West Zone on the Company system, confirmed that the Company could unbundle its gathering and transportation services and permitted the fuel factor percentages for the last quarter of 2004 and for fuel year 2005 to become effective, as filed. The FERC order concluded all four proceedings which resulted in no refunds being due. The Company must file its next rate case no later than October 1, 2007 to comply with the FERC's requirement for triennial filings.

2007 Fuel Filing

As required by the fuel tracker provisions of its SOC, the Company files annually to update its fuel percentages. On November 15, 2006, the Company filed zonal fuel percentages for the 2007 calendar fuel year. As had been agreed in the settlement of the 2004 Section 311 rate case, the Company established an East Zone fixed fuel percentage and a West Zone fixed fuel percentage to be recalculated annually to replace the system-wide fixed fuel percentage previously established annually for the Company system. By order dated December 19, 2006, the FERC approved and accepted the Company's November 15, 2006 zonal fuel factors as fair and equitable effective January 1, 2007.

Gas Transportation and Storage Agreement

As part of a 2002 agreed-upon settlement of an OG&E rate case (the "2002 Settlement Agreement"), OG&E also agreed to consider competitive bidding as a basis to select its provider for gas transportation service to its natural gas-fired electric generation facilities pursuant to the terms set forth in the 2002 Settlement Agreement. Because the required integrated service was not available in the marketplace from parties other than the Company, OG&E advised the OCC that, after careful consideration, competitive bidding for gas transportation was rejected in favor of a new intrastate integrated, firm no-notice load following gas transportation and storage services agreement with the Company. This seven-year agreement provides for gas transportation and storage services for each of OG&E's natural gas-fired electric generation facilities. OG&E will pay the Company annual demand fees of approximately $46.8 million for the right to transport specified maximum daily quantities ("MDQ") and maximum hourly quantities ("MHQ") of gas at various minimum gas delivery pressures depending on the operational needs of the individual generation facility. In addition, OG&E supplies system fuel in-kind for its pro-rata share of actual fuel and lost and unaccounted for gas on the transportation system. To the extent OG&E transports gas in quantities exceeding the prescribed MDQ's or MHQ's, it pays an overrun service charge. During the years ended December 31, 2006, 2005 and 2004, OG&E paid the Company approximately $47.6 million, $47.6 million and $49.6 million, respectively, for gas transportation and storage services.

On July 14, 2005, the OCC issued an order in this case approving a $41.9 million annual recovery. The OCC order disallowed the recovery by OG&E of the amount that the Company charges OG&E for the cost of fuel used, or otherwise unaccounted for, in providing natural gas transportation and storage service to OG&E. Over the last three years, this amount has ranged from $1.0 million to $3.4 million annually. This amount was approximately $1.0 million in 2006 and is projected to be approximately $1.1 million in 2007. The OCC's order required OG&E to refund to its Oklahoma customers the difference between the amounts collected from such customers in the past based on an annual rate of $46.8 million for gas transportation and storage services and the $41.9 million annual rate authorized by the OCC's order. Based on the order, OG&E's refund obligation was approximately $8.8 million. OG&E began refunding this obligation in September 2005 through its automatic fuel adjustment clause. The obligation was fully refunded at September 30, 2006.

In connection with the Company gas transportation and storage agreement, OG&E also recorded a refund obligation in Arkansas of approximately $1.1 million at December 31, 2005. OG&E provided to the Arkansas Public Service Commission the OCC evidence and above findings showing that the Arkansas refund was calculated consistently with the Oklahoma refund. OG&E applied the refund obligation to its fuel clause under-recoveries balance in April and customers began receiving this refund in April 2006 and will continue through March 2007.

Pending Regulatory Matters

Market-Based Rate Authority

On December 22, 2003, OG&E and OERI filed a triennial market power update based on the supply margin assessment test. On May 13, 2004, the FERC directed all utilities with pending three year market-based reviews to revise the generation market power portion of their three year review to address the new interim tests. OG&E and OERI submitted a compliance filing to the FERC on February 7, 2005 that applied the interim tests to OG&E and OERI. In the compliance filing, OG&E and OERI passed the pivotal supplier screen but did not pass the market share screen in the OG&E control area. OG&E and OERI provided an explanation as to why their failure of the market share screen in the OG&E control area should not be viewed as an indication that they can exercise generation market power.

On June 7, 2005, the FERC issued an order on OG&E's and OERI's market-based rate filing. Because OG&E and OERI failed the market share screen for OG&E's control area, the FERC established hearing procedures to investigate whether OG&E and OERI may continue to sell power at market-based rates in OG&E's control area. The order established a rebuttable presumption that OG&E and OERI have the ability to exercise market power in the OG&E control area. OG&E and OERI were requested to provide additional information that demonstrates to the FERC that they cannot exercise market power in the first-tier markets as well. However, the order conditionally allows OG&E and OERI to sell power in first-tier markets subject to OG&E and OERI providing additional information that clearly shows that they pass the market share screen for the first-tier markets. OG&E and OERI provided that additional information on July 7, 2005. On August 8, 2005, OG&E and OERI informed the FERC that they will: (i) adopt the FERC default rate mechanism for sales of one week or less to loads that sink in OG&E's control area; and (ii) commit not to enter into any sales with a duration of between one week and one year to loads that sink in OG&E's control area. OG&E and OERI also informed the FERC that any new agreements for long-term sales (one year or longer in duration) to loads that sink in OG&E's control area will be filed with the FERC and that OG&E and OERI will not make such sales under their respective market based rate tariffs. On January 20, 2006, the FERC issued a Notice of Institution of Proceeding and Refund Effective Date for the purpose of establishing the date from which any subsequent market-based sales would be subject to refund in the event the FERC concludes after investigation that the rates for such sales are not just and reasonable. The refund effective date was March 27, 2006.

On March 21, 2006, the FERC issued an order conditionally accepting OG&E's and OERI's proposal to mitigate the presumption of market power in the OG&E control area. First, the FERC accepted the additional information related to first-tier markets submitted by OG&E and OERI, and concluded that OG&E and OERI satisfy the FERC's generation market power standard for directly interconnected first-tier control areas. Second, the FERC directed the Company to make certain revisions to its mitigation proposal and file a cost-based rate tariff for short-term sales (one week or less) made within the OG&E control area. The FERC also expanded the scope of the proposed mitigation to all sales made within the OG&E control area (instead of only to sales sinking to load within the OG&E control area). On April 20, 2006, the Company submitted: (i) a compliance filing containing the specified revisions to the Company's market-based rate tariffs and the new cost-based rate tariff; and (ii) a request for rehearing asking the FERC to reconsider its expanded mitigation directive contained in the March 21, 2006 order. On May 22, 2006, the FERC issued a tolling order that effectively provided the FERC additional time to consider the April 20, 2006 rehearing request. On July 25, 2006 and August 25, 2006, pursuant to a FERC March 20, 2006 order, OG&E and OERI filed revisions to their market-based rate tariffs to allow them to sell energy imbalance service into the wholesale markets administered by the Southwest Power Pool at market-based rates. The FERC has not yet acted on OG&E's April 20, 2006, July 25, 2006 or August 25, 2006 filings. On February 6, 2007, OG&E and OERI submitted to the FERC a change in status report notifying the FERC that OG&E has placed into service OG&E's Centennial wind farm, a wind farm with a nameplate capacity rating of 120 MW. OG&E and OERI explained that adding this capacity was not material to the FERC's grant of market-based rate status to OG&E and OERI. On March 9, 2007, the FERC accepted OG&E's and OERI's change of status filing.

15. Fair Value of Financial Instruments

The following information is provided regarding the estimated fair value of the Company's financial instruments, including derivative contracts related to the Company's price risk management activities, as of December 31:

	2006		2005	
December 31	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(in millions)			
Price Risk Management Assets				
Energy Trading Contracts	**$ 39.1**	**$ 39.1**	$ 98.0	$ 98.0
Price Risk Management Liabilities				
Energy Trading Contracts	**$ 6.7**	**$ 6.7**	$ 92.6	$ 92.6
Long-Term Debt				
Company Notes	**$406.7**	**$433.5**	$407.6	$441.2

The carrying value of the financial instruments on the Consolidated Balance Sheets not otherwise discussed above approximates fair value except for long-term debt which is valued at the carrying amount. The valuation of the Company's energy trading contracts was determined primarily based on quoted market prices. However, in certain instances where market quotes are not available, other valuation techniques or models are used to estimate market values. The valuation of instruments also considers the credit risk of the counterparties and the potential impact of liquidating the position in an orderly manner over a reasonable period of time. The fair value of the Company's long-term debt is based on management's estimate of current rates available for similar issues with similar maturities.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Stockholder
Enogex Inc.

We have audited the accompanying consolidated balance sheets and statements of capitalization of Enogex Inc. as of December 31, 2006 and 2005, and the related consolidated statements of income, retained earnings, comprehensive income and cash flows for each of the three years in the period ended December 31, 2006. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. We were not engaged to perform an audit of the Company's internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes 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. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Enogex Inc. at December 31, 2006 and 2005, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2006, in conformity with U.S. generally accepted accounting principles.

As discussed in Notes 2, 3 and 11 to the consolidated financial statements, in 2006 Enogex Inc. adopted Statement of Financial Accounting Standards No. 123 (Revised), "Share-Based Payment," and Statement of Financial Accounting Standards No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans."

/s/ Ernst & Young LLP
Oklahoma City, Oklahoma
June 22, 2007

ENOGEX INC.

CONDENSED CONSOLIDATED FINANCIAL STATEMENTS AND FOOTNOTES

FOR THE THREE MONTHS ENDED MARCH 31, 2007

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ENOGEX INC.

CONDENSED CONSOLIDATED STATEMENTS OF INCOME

(Unaudited)

	Three Months Ended March 31, 2007	Three Months Ended March 31, 2006
	(in millions)	
OPERATING REVENUES	**$557.8**	$763.2
COST OF GOODS SOLD (exclusive of depreciation shown below)	**484.0**	678.0
Gross margin on revenues	**73.8**	85.2
Other operation and maintenance	**27.8**	28.6
Depreciation	**11.3**	10.2
Taxes other than income	**4.5**	4.3
OPERATING INCOME	**30.2**	42.1
OTHER INCOME (EXPENSE)		
Interest income	**2.6**	2.5
Other income	**0.3**	6.0
Other expense	**(0.1)**	—
Net other income	**2.8**	8.5
INTEREST EXPENSE		
Interest on long-term debt	**8.0**	8.0
Interest on short-term debt and other interest charges	**0.1**	0.1
Interest expense	**8.1**	8.1
INCOME FROM CONTINUING OPERATIONS BEFORE TAXES	**24.9**	42.5
INCOME TAX EXPENSE	**9.4**	16.3
INCOME FROM CONTINUING OPERATIONS	**15.5**	26.2
DISCONTINUED OPERATIONS (NOTE 5)		
Income from discontinued operations	**—**	1.3
Income tax expense	**—**	0.5
Income from discontinued operations	**—**	0.8
NET INCOME	**$ 15.5**	$ 27.0

The accompanying Notes to Condensed Consolidated Financial Statements are an integral part hereof.

ENOGEX INC.

CONDENSED CONSOLIDATED BALANCE SHEETS

(Unaudited)

	March 31, 2007	December 31, 2006
	(in millions)	
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	**$ 3.1**	$ —
Accounts receivable, less reserve of $0.9 and $1.0, respectively	**182.3**	205.6
Accounts receivable—affiliates	**3.9**	5.2
Advances to parent	**176.3**	144.4
Fuel inventories	**26.4**	35.9
Materials and supplies, at average cost	**1.9**	1.8
Price risk management	**5.9**	37.4
Gas imbalances	**3.6**	2.8
Accumulated deferred tax assets	**1.2**	0.2
Prepayments	**2.8**	2.8
Other	**6.1**	6.4
Total current assets	**413.5**	442.5
OTHER PROPERTY AND INVESTMENTS, at cost	**1.6**	1.6
PROPERTY, PLANT AND EQUIPMENT		
In service	**1,260.4**	1,252.6
Construction work in progress	**23.1**	11.1
Total property, plant and equipment	**1,283.5**	1,263.7
Less accumulated depreciation	**403.6**	398.0
Net property, plant and equipment	**879.9**	865.7
DEFERRED CHARGES AND OTHER ASSETS		
Prepaid benefit obligation	**0.5**	1.0
Price risk management	**1.5**	1.7
Unamortized debt issuance costs	**1.6**	1.7
Other	**6.1**	5.6
Total deferred charges and other assets	**9.7**	10.0
TOTAL ASSETS	**$1,304.7**	$1,319.8

The accompanying Notes to Condensed Consolidated Financial Statements are an integral part hereof.

ENOGEX INC.

CONDENSED CONSOLIDATED BALANCE SHEETS (Continued)

(Unaudited)

	March 31, 2007	December 31, 2006
	(in millions)	
LIABILITIES AND STOCKHOLDERS' EQUITY		
CURRENT LIABILITIES		
Accounts payable	**$ 194.6**	$ 195.0
Customer deposits	**2.8**	2.5
Accrued taxes	**3.5**	6.6
Accrued interest	**6.8**	15.0
Accrued compensation	**4.5**	8.9
Long-term debt due within one year	**3.0**	3.0
Price risk management	**4.4**	5.6
Gas imbalances	**12.9**	11.1
Other	**14.6**	19.0
Total current liabilities	**247.1**	266.7
LONG-TERM DEBT	**403.5**	403.7
COMMITMENTS AND CONTINGENCIES (NOTE 10)		
DEFERRED CREDITS AND OTHER LIABILITIES		
Accrued pension and benefit obligations	**16.5**	16.3
Accumulated deferred income taxes	**233.2**	230.7
Price risk management	**0.9**	1.1
Other	**2.8**	1.3
Total deferred credits and other liabilities	**253.4**	249.4
STOCKHOLDER'S EQUITY		
Common stockholder's equity	**305.2**	315.2
Retained earnings	**104.2**	88.7
Accumulated other comprehensive loss, net of tax	**(8.7)**	(3.9)
Total stockholder's equity	**400.7**	400.0
TOTAL LIABILITIES AND STOCKHOLDER'S EQUITY	**$1,304.7**	$1,319.8

The accompanying Notes to Condensed Consolidated Financial Statements are an integral part hereof.

ENOGEX INC.

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

(Unaudited)

	Three Months Ended March 31, 2007	Three Months Ended March 31, 2006
	(in millions)	
CASH FLOWS FROM OPERATING ACTIVITIES		
Income from continuing operations	**$ 15.5**	$ 26.2
Adjustments to reconcile income from continuing operations to net cash provided from operating activities		
Depreciation	**11.3**	10.2
Deferred income taxes, net	**4.6**	3.0
Gain on sale of assets	**—**	(0.6)
Price risk management assets	**31.5**	61.5
Price risk management liabilities	**(6.7)**	(56.1)
Other assets	**0.2**	0.7
Other liabilities	**(2.7)**	0.3
Change in certain current assets and liabilities		
Accounts receivable, net	**23.3**	238.7
Accounts receivable—affiliates	**1.3**	2.9
Fuel, materials and supplies inventories	**9.4**	1.4
Gas imbalance asset	**(0.8)**	21.3
Other current assets	**0.3**	(2.0)
Accounts payable	**(0.4)**	(191.8)
Income taxes payable—affiliates	**(19.1)**	(37.1)
Customer deposits	**0.3**	—
Accrued taxes	**(3.1)**	(3.1)
Accrued interest	**(8.2)**	(8.2)
Accrued compensation	**(4.4)**	(3.6)
Gas imbalance liability	**1.8**	(11.9)
Other current liabilities	**(4.4)**	(2.0)
Net Cash Provided from Operating Activities	**49.7**	49.8
CASH FLOWS FROM INVESTING ACTIVITIES		
Capital expenditures	**(25.5)**	(20.1)
Proceeds from sale of assets	**0.1**	0.8
Net Cash Used in Investing Activities	**(25.4)**	(19.3)
CASH FLOWS FROM FINANCING ACTIVITIES		
Decrease in advances to parent, net	**(12.9)**	(31.4)
Repurchase of common stock	**(10.0)**	—
Contributions from partners	**1.7**	—
Net Cash Used in Financing Activities	**(21.2)**	(31.4)
DISCONTINUED OPERATIONS		
Net cash provided from operating activities	**—**	1.1
Net cash used in investing activities	**—**	(0.2)
Net Cash Provided from Discontinued Operations	**—**	0.9
NET INCREASE IN CASH AND CASH EQUIVALENTS	**3.1**	—
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	**—**	—
CASH AND CASH EQUIVALENTS AT END OF PERIOD	**$ 3.1**	$ —

The accompanying Notes to Condensed Consolidated Financial Statements are an integral part hereof.

ENOGEX INC.

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(unaudited)

1. Summary of Significant Accounting Policies

Organization

In May 2007, OGE Energy Corp. (“OGE Energy”), an Oklahoma corporation, formed OGE Enogex Partners L.P., a Delaware limited partnership (the “Partnership”), as part of its strategy to further develop its natural gas midstream assets and operations. OGE Energy intends to offer units, representing limited partner interests in the Partnership, to the public (the “Offering”). In connection with the Offering, Enogex Inc., an Oklahoma corporation, will be merged with and into a Delaware corporation, with the Delaware corporation continuing as the surviving entity, and the Delaware corporation will then convert to a Delaware limited liability company, to be named Enogex LLC. OGE Energy will then contribute a 25% membership interest in Enogex LLC to a wholly owned subsidiary of the Partnership. A wholly owned subsidiary of OGE Energy will retain the remaining 75% membership interest in Enogex LLC. At the completion of the Offering, a wholly owned subsidiary of OGE Energy will own a 63.9% limited partner interest and a 2% general partner interest in the Partnership, through its ownership of OGE Enogex GP LLC, the Partnership’s general partner (“General Partner”), and the Partnership’s wholly owned subsidiary will continue to own its 25% interest in Enogex LLC. The Partnership’s wholly owned subsidiary will serve as Enogex LLC’s managing member and will control its assets and operations. The operations of Enogex Inc. and its subsidiaries (collectively, the “Company”) consist of three related business segments: (i) the transportation and storage of natural gas, (ii) the gathering and processing of natural gas and (iii) the marketing of natural gas. The vast majority of the Company’s natural gas gathering, processing, transportation and storage assets are located in the major gas producing basins of Oklahoma. The Company is a wholly owned subsidiary of OGE Energy, which is an energy and energy services provider offering physical delivery and related services for both electricity and natural gas primarily in the south central United States. The Company has a transportation contract with its affiliate, Oklahoma Gas and Electric Company (“OG&E”), to transport natural gas to OG&E’s natural gas-fired electric generation facilities. The Company also provides natural gas storage services for OG&E. The Company has been providing natural gas storage services to OG&E since August 2002 when it acquired the Stuart Storage Facility.

At the closing of the Offering the following transactions are expected to occur:

- OGE Energy or its subsidiaries will contribute to the Partnership’s wholly owned subsidiary a 25% membership interest in Enogex LLC;
- The Partnership will issue to OGE Enogex Holdings LLC, a wholly owned subsidiary of OGE Energy, 3,280,605 common units and 10,780,605 subordinated units, collectively representing a 63.9% limited partner interest in the Partnership;
- The Partnership will issue to the General Partner a 2% general partner interest in the Partnership and all of the Partnership’s incentive distribution rights, which will entitle the General Partner to increasing percentages of the cash the Partnership distributes in excess of $0.3881 per unit per quarter;
- Enogex LLC expects to enter into a $250 million credit facility for working capital, capital expenditures and other corporate purposes, including acquisitions;
- The Partnership will enter into an omnibus agreement with its General Partner and OGE Energy and certain of its affiliates which will address, among other things, the Partnership’s and Enogex LLC’s reimbursement of expenses to OGE Energy for the payment of certain operating

expenses and the provision of various general and administrative services in connection with the Offering and the indemnification of the Partnership and Enogex LLC by OGE Energy Corp. for certain matters; and

- The Partnership will issue 7,500,000 common units to the public in the Offering, representing a 34.1% limited partner interest in the Partnership, and expects to contribute the proceeds to Enogex LLC in order to pay expenses associated with the offering and related formation transactions, allow for the anticipated repayment by Enogex LLC of a portion of its existing senior notes due 2010, including a make-whole premium, pay fees and expenses related to Enogex LLC's new credit facility and an issuance of new long-term debt and apply the remaining proceeds to fund future capital expenditures, working capital and other corporate purposes.

Enogex LLC also currently expects to refinance its $400 million 8.125% senior notes due 2010 with a combination of $300 million of new long-term debt and proceeds from the Offering that the Partnership expects to contribute to Enogex LLC for the anticipated repayment of that debt.

Basis of Presentation

The Condensed Consolidated Financial Statements included herein have been prepared by the Company, without audit, pursuant to the rules and regulations of the Securities and Exchange Commission. Certain information and footnote disclosures normally included in financial statements prepared in accordance with accounting principles generally accepted in the United States have been condensed or omitted pursuant to such rules and regulations; however, the Company believes that the disclosures are adequate to prevent the information presented from being misleading.

In the opinion of management, all adjustments necessary to fairly present the consolidated financial position of the Company at March 31, 2007 and December 31, 2006, the results of its operations for the three months ended March 31, 2007 and 2006, and the results of its cash flows for the three months ended March 31, 2007 and 2006, have been included and are of a normal recurring nature.

Due to seasonal fluctuations and other factors, the operating results for the three months ended March 31, 2007 are not necessarily indicative of the results that may be expected for the year ending December 31, 2007 or for any future period. The Condensed Consolidated Financial Statements and Notes thereto should be read in conjunction with the audited Consolidated Financial Statements and Notes thereto for the year ended December 31, 2006.

Principles of Consolidation

The consolidated financial statements include the accounts and operations of the Company and its subsidiaries. All significant intercompany transactions have been eliminated in consolidation.

Related Party Transactions

OGE Energy allocated operating costs to the Company of approximately $4.9 million and $5.2 million during the three months ended March 31, 2007 and 2006, respectively. OGE Energy allocates operating costs to its affiliates based on several factors. Operating costs directly related to specific affiliates are assigned to those affiliates. Where more than one affiliate benefits from certain expenditures, the costs are shared between those affiliates receiving the benefits. Operating costs incurred for the benefit of all affiliates are allocated among the affiliates, based primarily upon head-count, occupancy, usage or the "Distrigas" method. The Distrigas method is a three-factor formula that uses an equal weighting of payroll, net operating revenues and gross property, plant and equipment. OGE Energy adopted the Distrigas method in January 1996 as a result of a recommendation by the Oklahoma Corporation Commission ("OCC") Staff. OGE Energy believes this method provides a reasonable basis for allocating common expenses.

During the three months ended March 31, 2007 and 2006, the Company received approximately $8.6 million and $8.7 million, respectively, from its affiliate, Oklahoma Gas and Electric Company ("OG&E") for transporting gas to OG&E's natural gas-fired electric generation facilities. During each of the three months ended March 31, 2007 and 2006, the Company received approximately $3.2 million from OG&E for natural gas storage services. During the three months ended March 31, 2007 and 2006, the Company also recorded natural gas sales to OG&E of approximately $5.3 million and $15.3 million, respectively. Approximately $4.0 million and $5.4 million were recorded at March 31, 2007 and December 31, 2006, respectively, and are included in Accounts Receivable—Affiliates in the Condensed Consolidated Balance Sheets for these activities.

During the three months ended March 31, 2007 and 2006, the Company recorded interest income of approximately $2.5 million and $2.4 million, respectively, from OGE Energy for advances made by the Company to OGE Energy.

OGE Energy made no advances to the Company during the three months ended March 31, 2007 and 2006. The interest rate charged on advances to the Company from OGE Energy approximates OGE Energy's commercial paper rate.

During the three months ended March 31, 2007, the Company repurchased 35,967 shares of its common stock for approximately $10.0 million. In May 2007, the Company repurchased 88,574 shares of its common stock for approximately $25.0 million.

Price Risk Management Assets and Liabilities

In accordance with FASB Interpretation No. 39 (As Amended), "Offsetting of Amounts Related to Certain Contracts an interpretation of APB Opinion No. 10 and FASB Statement No. 105," fair value amounts recognized for forward, interest rate swap, currency swap, option and other conditional or exchange contracts executed with the same counterparty under a master netting arrangement may be offset. The reporting entity's choice to offset or not must be applied consistently. A master netting arrangement exists if the reporting entity has multiple contracts, whether for the same type of conditional or exchange contract or for different types of contracts, with a single counterparty that are subject to a contractual agreement that provides for the net settlement of all contracts through a single payment in a single currency in the event of default on or termination of any one contract. Offsetting the fair values recognized for forward, interest rate swap, currency swap, option and other conditional or exchange contracts outstanding with a single counterparty results in the net fair value of the transactions being reported as an asset or a liability in the consolidated balance sheet. The Company has presented the fair values of its contracts under master netting agreements using a net fair value presentation. If these transactions with the same counterparty were presented on a gross basis in the Condensed Consolidated Balance Sheets, current Price Risk Management assets and liabilities would be approximately $8.0 million and $6.5 million, respectively, at March 31, 2007, and non-current Price Risk Management assets and liabilities would be approximately $1.5 million and $0.9 million, respectively, at March 31, 2007. If these transactions with the same counterparty were presented on a gross basis in the

Condensed Consolidated Balance Sheets, current Price Risk Management assets and liabilities would be approximately $41.0 million and $9.2 million, respectively, at December 31, 2006, and non-current Price Risk Management assets and liabilities would be approximately $1.7 million and $1.1 million, respectively, at December 31, 2006.

2. Accounting Pronouncement

In February 2007, the FASB issued SFAS No. 159, "The Fair Value Option for Financial Assets and Financial Liabilities, including an amendment of FASB Statement No. 115," which permits all entities to choose, at specified election dates, to measure many financial instruments and certain other items at fair value that are not currently required to be measured at fair value. The decision about whether to elect the fair value option is applied instrument by instrument, is irrevocable unless a new election date occurs and is applied only to an entire instrument and not to only specified risks, specific cash flows or portions of that instrument. A business entity must report unrealized gains and losses on items for which the fair value option has been elected in earnings (or another performance indicator if the business entity does not report earnings) at each subsequent reporting date. Upfront costs and fees related to items for which the fair value option is elected must be recognized in earnings as incurred and not deferred. SFAS No. 159 also establishes presentation and disclosure requirements designed to facilitate comparisons between entities that choose different measurement attributes for similar types of assets and liabilities. SFAS No. 159 is effective as of the beginning of an entity's first fiscal year that begins after November 15, 2007. Early adoption is permitted as of the beginning of a fiscal year that begins on or before November 15, 2007, provided the entity also elects to apply the provisions of SFAS No. 157, "Fair Value Measurements." The Company will adopt this new standard effective January 1, 2008. Management has not yet determined what the impact of this new standard will be on its consolidated financial position or results of operations.

3. Stock-Based Compensation

On January 21, 1998, OGE Energy adopted a Stock Incentive Plan (the "1998 Plan"). In 2003, OGE Energy adopted, and its shareowners approved, a new Stock Incentive Plan (the "2003 Plan" and together with the 1998 Plan, the "Plans"). The 2003 Plan replaced the 1998 Plan and no further awards will be granted under the 1998 Plan. As under the 1998 Plan, under the 2003 Plan, restricted stock, stock options, stock appreciation rights and performance units may be granted to officers, directors and other key employees of the Company and its subsidiaries. OGE Energy has authorized the issuance of up to 2,700,000 shares under the 2003 Plan.

Effective January 1, 2006, OGE Energy adopted SFAS No. 123(R), "Share-Based Payment," using the modified prospective transition method. Under that transition method, the Company's compensation cost recognized in the first quarter of 2006 included: (i) compensation cost for all share-based payments granted prior to, but not yet vested as of January 1, 2006, based on the fair value calculated in accordance with the provisions of SFAS No. 123(R); and (ii) compensation cost for all share-based payments granted in the first quarter of 2006 based on the fair value calculated in accordance with the provisions of SFAS No. 123(R).

As a result of adopting SFAS No. 123(R) on January 1, 2006, the Company recorded compensation expense of approximately $0.3 million pre-tax ($0.2 million after tax) during the three months ended March 31, 2006 related to its portion of OGE Energy's share-based payments. Also, as a result of adopting SFAS No. 123(R), the Company recorded a cumulative effect adjustment of approximately $0.1 million pre-tax (less than $0.1 million after tax) on January 1, 2006 for outstanding non-vested share-based compensation grants at December 31, 2005. The Company determined that the cumulative effect adjustment was immaterial for presentation purposes and is, therefore, included in Other Operation and Maintenance Expense in the Condensed Consolidated Statement of Income. The Company recorded compensation expense of approximately $0.2 million pre-tax ($0.1 million after tax) during the three months ended March 31, 2007 related to its portion of OGE Energy's share-based payments.

During the three months ended March 31, 2007, OGE Energy awarded 122,044 performance units based on total shareholder return ("TSR") and 40,686 performance units based on earnings per share ("EPS") with a grant date fair value of $24.18 and $33.59, respectively, to certain employees of OGE Energy and its subsidiaries, of which 28,232 performance units based on TSR and 9,415 performance units based on EPS were awarded to certain employees of the Company. Also, during the three months ended March 31, 2007, OGE Energy converted 132,845 performance units based on a payout ratio of 169.25% of the target number of performance units granted in February 2004, of which 18,179 performance units related to the Company's employees. Of the performance units converted, two-thirds were settled in OGE Energy's common stock (20,513 shares) and one-third was paid in cash. Also, in January 2007, all of OGE Energy's outstanding stock options became fully vested.

OGE Energy issues new shares to satisfy stock option exercises. During the three months ended March 31, 2007, there were 286,339 shares of new common stock issued pursuant to OGE Energy's Stock Incentive Plan related to exercised stock options, of which 20,877 related to the Company's employees. OGE Energy received approximately $7.0 million and $1.9 million during the three months ended March 31, 2007 and 2006, respectively, related to exercised stock options.

4. Accumulated Other Comprehensive Loss

The components of total comprehensive income for the three months ended March 31, 2007 and 2006, respectively, are as follows:

	Three Months Ended March 31,	
	2007	**2006**
	(in millions)	
Net income	**$15.5**	$27.0
Other comprehensive income (loss), net of tax:		
Defined benefit pension plan:		
Net loss, net of tax	**0.1**	—
Defined benefit postretirement plans:		
Net loss, net of tax	**0.1**	—
Net transition obligation, net of tax	**0.1**	—
Deferred hedging gains (losses), net of tax	**(5.1)**	(0.5)
Total comprehensive income	**$10.7**	$26.5

The components of accumulated other comprehensive loss at March 31, 2007 and December 31, 2006 are as follows:

	March 31, 2007	December 31, 2006
	(in millions)	
Defined benefit pension plan:		
Net loss, net of tax ($9.2 and $9.3 pre-tax, respectively)	**$(5.6)**	$(5.7)
Prior service cost, net of tax ($0.5 and $0.5 pre-tax, respectively)	**(0.3)**	(0.3)
Defined benefit postretirement plans:		
Net loss, net of tax ($4.7 and $4.8 pre-tax, respectively)	**(2.0)**	(2.1)
Net transition obligation, net of tax ($0.7 and $0.8 pre-tax, respectively)	**(0.4)**	(0.5)
Prior service cost, net of tax ($0.5 and $0.5 pre-tax, respectively)	**(0.3)**	(0.3)
Deferred hedging gains (losses), net of tax ($0.1 and $8.1 pre-tax, respectively)	**(0.1)**	5.0
Total accumulated other comprehensive loss	**$(8.7)**	$(3.9)

5. Discontinued Operations

In March 2006, the Company announced that its wholly owned subsidiary, Enogex Gas Gathering, L.L.C. (“Gathering”), had entered into an agreement to sell certain gas gathering assets in the Kinta, Oklahoma, area. The Gathering assets included in the transaction were approximately 568 miles of gas gathering pipeline and 22 compressor units with current volumes of approximately 145 million cubic feet per day, all in eastern Oklahoma. The sale price was approximately $93 million. This transaction closed on May 1, 2006 and the Company recorded an after tax gain of approximately $34.1 million during the second quarter of 2006. The proceeds from the sale, were used, among other things, to reduce short-term debt levels and fund capital expenditures.

The Condensed Consolidated Financial Statements of the Company have been reclassified to reflect Gathering’s sale of certain gas gathering assets in Kinta, Oklahoma, as discontinued operations. Accordingly, revenues, costs and expenses and cash flows of the Gathering assets that were sold have been excluded from the respective captions in the Condensed Consolidated Financial Statements and have been separately reported as discontinued operations in the applicable financial statement captions. Summarized financial information for the discontinued operations as of March 31 is as follows:

Condensed Consolidated Statements of Income Data

	Three Months Ended March 31, 2007	2006
	(in millions)	
Operating revenues from discontinued operations	**$ —**	$6.6
Income from discontinued operations before taxes	**$ —**	$1.3

6. Income Taxes

The Company is a member of an affiliated group that files consolidated income tax returns in the U.S. federal jurisdiction and various state jurisdictions. With few exceptions the Company is no longer subject to U.S. Federal or state and local income tax examinations by tax authorities for years before 2001. Income taxes are allocated to each affiliate based on its separate taxable income or loss. The following schedule reconciles the statutory federal tax rate to the effective income tax rate:

	Three Months Ended March 31,	
	2007	**2006**
Statutory federal tax rate	**35.0%**	35.0%
State income taxes, net of federal income tax benefit	**3.5**	3.7
Medicare Part D subsidy	**(0.1)**	(0.2)
Other	**(0.6)**	(0.1)
Effective income tax rate as reported	**37.8%**	38.4%

The Company adopted the provisions of FASB Interpretation No. 48, "Accounting for Uncertainty in Income Taxes, an amendment of FASB Statement No. 109," on January 1, 2007. The Company did not record a cumulative effect of change in accounting principle as a result of the implementation of FIN No. 48 because the Company does not believe any unrecognized tax benefits existed at January 1, 2007. The Company will recognize accrued interest related to future unrecognized tax benefits in interest expense and recognize penalties in operating and maintenance expense.

The Company follows the provisions of SFAS No. 109, "Accounting for Income Taxes," which uses an asset and liability approach to accounting for income taxes. Under SFAS No. 109, deferred tax assets or liabilities are computed based on the difference between the financial statement and income tax bases of assets and liabilities using the enacted marginal tax rate. Deferred income tax expenses or benefits are based on the changes in the asset or liability from period to period.

7. Long-Term and Short-Term Debt

At March 31, 2007, the Company is in compliance with all of its debt agreements.

The Company has an intercompany borrowing agreement with OGE Energy whereby the Company has access to up to $200 million of OGE Energy's revolving credit amount. The following table shows OGE Energy's revolving credit agreement and available cash at March 31, 2007.

	Revolving Credit Agreement and Available Cash			
Entity	Amount Available	Amount Outstanding	Weighted-Average Interest Rate	Maturity
	(in millions)			
OGE Energy(A)	$600.0	$ —	—	December 6, 2011(B)
Cash	3.1	N/A	N/A	N/A
Total	$603.1	$ —	—	

(A) This bank facility is available to back up OGE Energy's commercial paper borrowings and to provide revolving credit borrowings. This bank facility can also be used as a letter of credit facility. At March 31, 2007, there were no outstanding commercial paper borrowings.

(B) In December 2006, OGE Energy amended and restated its revolving credit agreement. This credit facility has a five-year term with an option to extend the term for two additional one-year periods. Also, this credit facility has an additional option at the end of the two renewal options to convert the outstanding balance to a one-year term loan.

OGE Energy's ability to access the commercial paper market could be adversely impacted by a credit ratings downgrade or major market disruptions. Pricing grids associated with the back-up lines of credit could cause annual fees and borrowing rates to increase if an adverse ratings impact occurs. The impact of any future downgrades would result in an increase in the cost of short-term borrowings but would not result in any defaults or accelerations as a result of the rating changes.

8. Retirement Plans and Postretirement Benefit Plans

In September 2006, the FASB issued SFAS No. 158 which requires an employer to: (i) recognize the overfunded or underfunded status of a defined benefit postretirement plan (other than a multiemployer plan) as an asset or liability in its statement of financial position and to recognize changes in that funded status in the year in which the changes occur through comprehensive income of a business entity; and (ii) measure the fair value of the funded status of a plan as of the date of its year-end statement of financial position, with limited exceptions. The requirement to initially recognize the funded status of the defined benefit postretirement plan and the disclosure requirements were effective for the year ended December 31, 2006 for the Company. The requirement to measure plan assets and benefit obligations at fair value in accordance with SFAS No. 157 as of the date of the employer's fiscal year-end statement of financial position is effective for fiscal years ending after December 15, 2008. SFAS No. 158 also requires additional disclosures for defined benefit pension plans and other defined benefit postretirement plans.

The details of net periodic benefit cost of the pension plan (including the restoration of retirement income plan) and the postretirement benefit plans included in the Condensed Consolidated Financial Statements are as follows:

Net Periodic Benefit Cost

	Pension Plan and Restoration of Retirement Income Plan	
	Three Months Ended March 31,	
	2007	**2006**
	(in millions)	
Service cost	**$ 0.9**	$ 0.9
Interest cost	**0.6**	0.5
Return on plan assets	**(0.9)**	(0.8)
Amortization of net loss	**0.1**	0.2
Net periodic benefit cost	**$ 0.7**	$ 0.8

	Postretirement Benefit Plans	
	Three Months Ended March 31,	
	2007	**2006**
	(in millions)	
Service cost	**$0.2**	$0.1
Interest cost	**0.2**	0.2
Amortization of net loss	**—**	0.1
Amortization of recognized prior service cost	**0.1**	0.1
Net periodic benefit cost	**$0.5**	$0.5

Pension Plan Funding

OGE Energy previously disclosed in its Form 10-K for the year ended December 31, 2006 that it may contribute up to $50 million to its pension plan during 2007, of which approximately $4.4 million is expected to be allocated to the Company. In April 2007, OGE Energy contributed approximately $20 million to its pension plan, of which approximately $1.7 million was allocated to the Company. During the remainder of 2007, OGE Energy may contribute up to an additional $30 million to its pension plan, of which approximately $2.6 million is expected to be allocated to the Company. Any expected contributions to the pension plan during 2007 are discretionary contributions, anticipated to be in the form of cash, and are not required to satisfy the minimum regulatory funding requirement specified by the Employee Retirement Income Security Act of 1974, as amended.

9. Report of Business Segments

The Company's business is divided into three reportable segments, defined as components of the enterprise about which financial information is available and evaluated regularly by our management. Our reportable segments are strategic business units that offer different services. Each segment is managed separately based on similarities in economic characteristics, products and services, types of customers, methods of distribution and regulatory environment. These segments are as follows: (i) transportation and storage of natural gas, (ii) gathering and processing of natural gas, and (iii) marketing of natural gas. Intersegment revenues are recorded at prices comparable to those of unaffiliated customers and are affected by regulatory considerations. The following tables summarize the results of the Company's business segments for the three months ended March 31, 2007 and 2006.

Three Months Ended March 31, 2007	Transportation and Storage	Gathering and Processing	Marketing	Eliminations	Total
			(in millions)		
Operating revenues	**$ 59.1**	**$165.6**	**$461.4**	**$ (128.3)**	**$ 557.8**
Cost of goods sold	**29.1**	**123.7**	**459.5**	**(128.3)**	**484.0**
Gross margin on revenues	**30.0**	**41.9**	**1.9**	**—**	**73.8**
Other operation and maintenance	**10.4**	**16.0**	**1.4**	**—**	**27.8**
Depreciation	**4.4**	**6.9**	**—**	**—**	**11.3**
Taxes other than income	**3.4**	**0.9**	**0.2**	**—**	**4.5**
Operating income	**$ 11.8**	**$ 18.1**	**$ 0.3**	**$ —**	**$ 30.2**
Total assets	**$1,440.8**	**$844.6**	**$187.9**	**$(1,168.6)**	**$1,304.7**
Capital expenditures	**$ 7.2**	**$ 18.5**	**$ —**	**$ (0.2)**	**$ 25.5**

Three Months Ended March 31, 2006	Transportation and Storage	Gathering and Processing	Marketing	Eliminations	Total
			(in millions)		
Operating revenues	$ 64.6	$159.9	$677.1	$ (138.4)	$ 763.2
Cost of goods sold	23.8	121.7	670.9	(138.4)	678.0
Gross margin on revenues	40.8	38.2	6.2	—	85.2
Other operation and maintenance	10.8	15.4	2.4	—	28.6
Depreciation	4.5	5.7	—	—	10.2
Taxes other than income	3.4	0.7	0.2	—	4.3
Operating income	$ 22.1	$ 16.4	$ 3.6	$ —	$ 42.1
Total assets	$1,444.3	$748.2	$256.1	$(1,042.0)	$1,406.6
Capital expenditures	$ 1.7	$ 18.4	$ —	$ —	$ 20.1

10. Commitments and Contingencies

Except as set forth below and in Note 11, the circumstances set forth in Notes 13 and 14 to the Company's Consolidated Financial Statements for the year ended December 31, 2006 appropriately represent, in all material respects, the current status of the Company's material commitments and contingent liabilities.

Agreement with Cheyenne Plains Gas Pipeline Company, L.L.C.

Cheyenne Plains Gas Pipeline Company, L.L.C ("Cheyenne Plains") operates the Cheyenne Plains Pipeline that provides firm transportation services in Wyoming, Colorado and Kansas with a capacity of 730,000 decatherms/day ("Dth/day"). OGE Energy Resources LLC, ("OERI"), a wholly owned subsidiary of the Company, entered into a Firm Transportation Service Agreement ("FTSA") with Cheyenne Plains in 2004, for 60,000 Dth/day of firm capacity on the Cheyenne Plains Pipeline. The FTSA was for a 10-year term beginning with the in-service date of the Cheyenne Plains Pipeline in March 2005 with an annual demand fee of approximately $7.4 million. Effective March 1, 2007, OERI and Cheyenne Plains amended the FTSA to provide for OERI to turn back 20,000 Dth/day of its capacity beginning in January 2008 for the remainder of the term. OERI's new demand fee obligations, net of this turn back and other immaterial release agreements, are estimated at approximately $6.9 million in 2007; $5.9 million in 2008; $6.5 million for each of the years 2009 through 2014; and $1.6 million in 2015.

Agreement with Midcontinent Express Pipeline, LLC

On December 15, 2006, the Company announced that it had entered into a firm capacity lease agreement with Midcontinent Express Pipeline, LLC for a primary term of 10 years (subject to possible extensions) for certain capacity on the its system. The leased capacity provided for in this agreement is up to 500 million cubic feet ("MMcf") per day and is dependent on the shipper volumes that commit to the project. The Company's capacity will be a part of the proposed Midcontinent Express Pipeline ("MEP"), a joint venture between Kinder Morgan Energy Partners, L.P. and Energy Transfer Partners, L.P. In addition to the Company's leased capacity, the proposed MEP project includes a new pipeline originating near Bennington, Oklahoma and terminating in Butler, Alabama. Pending necessary regulatory approval, the MEP project is currently expected to be in service during the first quarter of 2009. Depending on the final capacity that MEP subscribes to pursuant to the agreement, the Company expects its revenues from this firm capacity lease agreement to be between $12 million and $30 million annually. The Company currently estimates that its capital expenditures related to this project during 2007 and 2008 will be between $65 million and $100 million. The Company's lease agreement with MEP is subject to certain contingencies including regulatory approval. Prior to such approval, the Company may incur expenditures of between approximately $20 million and $40 million primarily related to commitments for materials that can be sold or used in normal operations in the event the MEP project does not proceed. The amount not recovered or utilized for such expenditures is not expected to be material.

Agreement with Boardwalk's Gulf Crossing Project

In March 2007, the Company entered into a firm capacity lease agreement with Gulf Crossing Pipeline Company LLC for a primary term of seven years (subject to a possible extension) for certain capacity on the Company system. The leased capacity provided for in this agreement is up to 165 MMcf per day and is dependent on the shipper volumes that commit to the project. Boardwalk Pipeline Partners, LP, has announced plans to build the Gulf Crossing pipeline, which includes 355 miles of new interstate natural gas pipeline. It initially is expected to transport gas from the supply areas in Sherman, Texas, Bennington, Oklahoma, and Paris, Texas to the Perryville, Louisiana Hub. Depending on the final capacity that Gulf Crossing subscribes to pursuant to the agreement, the Company expects its revenues from this firm capacity lease agreement to be between $1.6 million and $5.7 million annually. The Company currently estimates that its capital expenditures related to this project during 2007 and 2008 will be between approximately $2 million and $5 million. The lease agreement with Gulf Crossing is subject to certain regulatory approval. Prior to such approval, the Company may incur expenditures of up to $5 million primarily related to commitments for material that can be sold or used in normal operations in the event the Gulf Crossing project does not proceed. The amount not recovered or utilized for such expenditures is not expected to be material. Subject to regulatory approvals, the Gulf Crossing project is expected to have a commercial operation date in late 2008. Gulf Crossing filed applications with the FERC on June, 19, 2007 requesting certificates of public convenience and necessity authorizing Gulf Crossing to construct, abandon and lease certain facilities relating to its Gulf Crossing pipeline. In a related application, the Company filed its FERC application on June 20, 2007 for issuance of a limited-jurisdiction certificate authorizing its lease of intrastate pipeline capacity to Gulf Crossing. Both the Company and Gulf Crossing have requested approval of the applications by November 2007.

Natural Gas Measurement Case

United States of America ex rel., Jack J. Grynberg v. Enogex Inc., Enogex Services Corporation and OG&E. (United States District Court for the Western District of Oklahoma, Case No. CIV-97-1010-L.) United States of America ex rel., Jack J. Grynberg v. Transok Inc. et al. (United States District Court for the Eastern District of Louisiana, Case No. 97-2089; United States District Court for the Western District of Oklahoma, Case No. 97-1009M.). On June 15, 1999, the Company was served with Plaintiff's complaint, which is a qui tam action under the False Claims Act. Plaintiff Jack J. Grynberg, as individual relator on behalf of the United States Government, alleges: (i) each of the named defendants have improperly or intentionally mismeasured gas (both volume and British thermal unit content) purchased from federal and Indian lands which have resulted in the under-reporting and underpayment of gas royalties owed to the Federal Government; (ii) certain provisions generally found in gas purchase contracts are improper; (iii) transactions by affiliated companies are not arms-length; (iv) excess processing cost deduction; and (v) failure to account for production separated out as a result of gas processing. Grynberg seeks the following damages: (a) additional royalties which he claims should have been paid to the Federal Government, some percentage of which Grynberg, as relator, may be entitled to recover; (b) treble damages; (c) civil penalties; (d) an order requiring defendants to measure the way Grynberg contends is the better way to do so; and (e) interest, costs and attorneys' fees.

In qui tam actions, the United States Government can intervene and take over such actions from the relator. The Department of Justice, on behalf of the United States Government, decided not to intervene in this action.

The plaintiff filed over 70 other cases naming over 300 other defendants in various Federal Courts across the country containing nearly identical allegations. The Multidistrict Litigation Panel entered its order in late 1999 transferring and consolidating for pretrial purposes approximately 76 other similar actions filed in nine other Federal Courts. The consolidated cases are now before the United States District Court for the District of Wyoming.

In October 2002, the court granted the Department of Justice's motion to dismiss certain of the plaintiff's claims and issued an order dismissing the plaintiff's valuation claims against all defendants. Various procedural motions have been filed. A hearing on the defendants' motions to dismiss for lack of subject matter jurisdiction, including public disclosure, original source and voluntary disclosure requirements was held in 2005 and the special master ruled that OG&E and all Enogex parties named in these proceedings should be dismissed. This ruling was appealed to the District Court of Wyoming.

On October 20, 2006, the District Court of Wyoming ruled on Grynberg's appeal, following and confirming the recommendation of the special master dismissing all claims against Enogex Inc., Enogex Services Corp., Transok, Inc. and OG&E, for lack of subject matter jurisdiction. Judgment was entered on November 17, 2006 and Grynberg filed his notice of appeal with the District Court of Wyoming. The defendants filed motions for attorneys' fees regarding issues of liability and Rule 11 motions on January 8, 2007. The defendants also filed for other legal costs on December 18, 2006. A hearing on these motions was held on April 24, 2007, at which time the judge in this matter took these motions under advisement. Grynberg has also filed appeals with the Tenth Circuit Court of Appeals. The Company intends to vigorously defend this action. At this time, the Company is unable to provide an evaluation of the likelihood of an unfavorable outcome and an estimate of the amount or range of potential loss to the Company.

Calpine Corporation Bankruptcy

Calpine Corporation, Calpine Energy Services, L.P., and several other affiliates (collectively "Calpine") voluntarily filed for Chapter 11 bankruptcy protection from creditors on December 20, 2005 (Case No. 05-60200 (BRL)) in the United States Bankruptcy Court, S.D. of New York. The Company provides natural gas transportation services to two Calpine-owned power generation plants in Oklahoma pursuant to long-term contracts. Calpine is continuing to operate the plants and request services pursuant to the contracts. The total unpaid amount due to the Company from Calpine is approximately $0.3 million which has been fully reserved on the Company's books. Negotiations continue as the parties are discussing potential amendments to the contracts that service the two Calpine plants as part of the bankruptcy restructuring plan.

Other

In the normal course of business, the Company is confronted with issues or events that may result in a contingent liability. These generally relate to lawsuits, claims made by third parties, environmental actions or the action of various regulatory agencies and income tax related items. When appropriate, management consults with legal counsel and other appropriate experts to assess the claim. If in management's opinion, the Company has incurred a probable loss as set forth by accounting principles generally accepted in the United States, an estimate is made of the loss and the appropriate accounting entries are reflected in the Company's Condensed Consolidated Financial Statements. Except as otherwise stated above, in Note 11 below and in Notes 13 and 14 of Notes to the Company's Consolidated Financial Statements for the year ended December 31, 2006, management, after consultation with legal counsel, does not currently anticipate that liabilities arising out of these pending or threatened lawsuits, claims and contingencies will have a material adverse effect on the Company's consolidated financial position, results of operations or cash flows.

11. Regulation

Except as set forth below, the circumstances set forth in Note 14 to the Company's Consolidated Financial Statements included for the year ended December 31, 2006 appropriately represent, in all material respects, the current status of any regulatory matters.

Pending Regulatory Matter

Market-Based Rate Authority

On December 22, 2003, OG&E and OERI filed a triennial market power update based on the supply margin assessment test. On May 13, 2004, the FERC directed all utilities with pending three year market-based reviews to revise the generation market power portion of their three year review to address the new interim tests. OG&E and OERI submitted a compliance filing to the FERC on February 7, 2005 that applied the interim tests to OG&E and OERI. In the compliance filing, OG&E and OERI passed the pivotal supplier screen but did not pass the market share screen in OG&E's control area. OG&E and OERI provided an explanation as to why their failure of the market share screen in OG&E's control area should not be viewed as an indication that they can exercise generation market power.

On June 7, 2005, the FERC issued an order on OG&E's and OERI's market-based rate filing. Because OG&E and OERI failed the market share screen for OG&E's control area, the FERC established hearing procedures to investigate whether OG&E and OERI may continue to sell power at market-based rates in OG&E's control area. The order established a rebuttable presumption that OG&E and OERI have the ability to exercise market power in OG&E's control area. OG&E and OERI were requested to provide additional information that demonstrates to the FERC that they cannot exercise market power in the first-tier markets as well. However, the order conditionally allows OG&E and OERI to sell power in first-tier markets subject to OG&E and OERI providing additional information that clearly shows that they pass the market share screen for the first-tier markets. OG&E and OERI provided that additional information on July 7, 2005. On August 8, 2005, OG&E and OERI informed the FERC that they will: (i) adopt the FERC default rate mechanism for sales of one week or less to loads that sink in OG&E's control area; and (ii) commit not to enter into any sales with a duration of between one week and one year to loads that sink in OG&E's control area. OG&E and OERI also informed the FERC that any new agreements for long-term sales (one year or longer in duration) to loads that sink in OG&E's control area will be filed with the FERC and that OG&E and OERI will not make such sales under their respective market based rate tariffs. On January 20, 2006, the FERC issued a Notice of Institution of Proceeding and Refund Effective Date for the purpose of establishing the date from which any subsequent market-based sales would be subject to refund in the event the FERC concludes after investigation that the rates for such sales are not just and reasonable. The refund effective date was March 27, 2006.

On March 21, 2006, the FERC issued an order conditionally accepting OG&E's and OERI's proposal to mitigate the presumption of market power in OG&E's control area. First, the FERC accepted the additional information related to first-tier markets submitted by OG&E and OERI, and concluded that OG&E and OERI satisfy the FERC's generation market power standard for directly interconnected first-tier control areas. Second, the FERC directed the Company to make certain revisions to its mitigation proposal and file a cost-based rate tariff for short-term sales (one week or less) made within OG&E's control area. The FERC also expanded the scope of the proposed mitigation to all sales made within OG&E's control area (instead of only to sales sinking to load within OG&E's control area). On April 20, 2006, the Company submitted: (i) a compliance filing containing the specified revisions to the Company's market-based rate tariffs and the new cost-based rate tariff; and (ii) a request for rehearing asking the FERC to reconsider its expanded mitigation directive contained in the March 21, 2006 order. On May 22, 2006, the FERC issued a tolling order that effectively provided the FERC additional time to consider the April 20, 2006 rehearing request. On

July 25, 2006 and August 25, 2006, pursuant to a FERC March 20, 2006 order, OG&E and OERI filed revisions to their market-based rate tariffs to allow them to sell energy imbalance service into the wholesale markets administered by the SPP at market-based rates. The FERC has not yet acted on OG&E's April 20, 2006, July 25, 2006 or August 25, 2006 filings. On February 6, 2007, OG&E and OERI submitted to the FERC a change in status report notifying the FERC that OG&E has placed into service OG&E's Centennial wind farm, a wind farm with a nameplate capacity rating of 120 MW. OG&E and OERI explained that adding this capacity was not material to the FERC's grant of market-based rate status to OG&E and OERI. On March 9, 2007, the FERC accepted OG&E's and OERI's change of status filing.

12. Fair Value of Financial Instruments

The following information is provided regarding the estimated fair value of the Company's financial instruments, including derivative contracts related to the Company's price risk management activities, which have significantly changed since December 31, 2006.

	March 31, 2007		December 31, 2006	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(in millions)			
Price Risk Management Assets				
Energy Trading Contracts	**$7.4**	**$7.4**	$39.1	$39.1
Price Risk Management Liabilities				
Energy Trading Contracts	**$5.3**	**$5.3**	$ 6.7	$ 6.7

The carrying value of the financial instruments on the Condensed Consolidated Balance Sheets not otherwise discussed above approximates fair value except for long-term debt which is valued at the carrying amount. The valuation of the Company's energy trading contracts was determined primarily based on quoted market prices. However, in certain instances where market quotes are not available, other valuation techniques or models are used to estimate market values. The valuation of instruments also considers the credit risk of the counterparties and the potential impact of liquidating the position in an orderly manner over a reasonable period of time. The fair value of the Company's long-term debt is based on quoted market prices and management's estimate of current rates available for similar issues with similar maturities.

OGE ENOGEX PARTNERS L.P.

BALANCE SHEET

JUNE 14, 2007

ASSETS	
CURRENT ASSETS	
Cash	**$2,000**
TOTAL ASSETS	**$2,000**
PARTNERS' EQUITY	
Limited partners' equity	**$1,960**
General partner equity	**40**
TOTAL PARTNERS' EQUITY	**$2,000**

The accompanying notes are an integral part of the Balance Sheet.

OGE ENOGEX PARTNERS L.P.

NOTES TO BALANCE SHEET

1. Nature of Operations

OGE Enogex Partners L.P., a Delaware limited partnership (the "Partnership"), was formed on May 30, 2007, by OGE Energy Corp., to further develop its natural gas midstream assets and operations. OGE Energy Corp. intends to offer common units representing limited partner interests, in the Partnership to the public (the "Offering"). In connection with the Offering, OGE Energy Corp.'s subsidiary, Enogex Inc., will be merged with and into a Delaware corporation that will then convert to a Delaware limited liability company, to be named Enogex LLC. OGE Energy Corp. will then contribute a 25% membership interest in Enogex LLC to a wholly owned subsidiary of the Partnership. A wholly owned subsidiary of OGE Energy Corp. will own the remaining 75% interest in Enogex LLC. At the completion of the Offering, a wholly owned subsidiary of OGE Energy Corp. will own a 63.9% limited partner interest in the Partnership and a 2% general partner interest in the Partnership, through its ownership of OGE Enogex GP LLC, the Partnership's general partner ("General Partner"), and the Partnership's wholly owned subsidiary will own a 25% interest in Enogex LLC. A wholly owned subsidiary of the Partnership will serve as Enogex LLC's managing member and will control its assets and operations.

The Partnership has adopted a December 31 fiscal year end. The General Partner contributed $40 and OGE Energy Corp. contributed $1,960 to the Partnership on June 14, 2007. There have been no other transactions involving the Partnership as at June 14, 2007.

2. Subsequent Events (unaudited)

At the closing of the Offering the following transactions are expected to occur:

- OGE Energy Corp. or its subsidiaries will contribute to the Partnership's wholly owned subsidiary a 25% membership interest in Enogex LLC;
- The Partnership will issue to OGE Enogex Holdings LLC, a wholly owned subsidiary of OGE Energy Corp., 3,280,605 common units and 10,780,605 subordinated units, collectively representing a 63.9% limited partner interest in the Partnership;
- The Partnership will issue to the General Partner a 2% general partner interest in the Partnership and all of the Partnership's incentive distribution rights, which will entitle the General Partner to increasing percentages of the cash the Partnership distributes in excess of $0.3881 per unit per quarter;
- Enogex LLC expects to enter into a $250 million credit facility for working capital, capital expenditures and other corporate purposes, including acquisitions;
- The Partnership will enter into an omnibus agreement with its General Partner and OGE Energy Corp. and certain of its affiliates which will address, among other things, the Partnership's and Enogex LLC's reimbursement of expenses to OGE Energy Corp. for the payment of certain operating expenses and the provision of various general and administrative services in connection with the Offering and the indemnification of the Partnership and Enogex LLC by OGE Energy Corp. and its affiliates of certain losses incurred prior to the Offering; and
- The Partnership will issue 7,500,000 common units to the public in the Offering, representing a 34.1% limited partner interest in the Partnership, and expects to contribute the proceeds to Enogex LLC in order to pay expenses associated with the offering and related formation transactions, allow for the anticipated repayment by Enogex LLC of a portion of its existing senior notes due 2010, including a make-whole premium, pay fees and expenses related to

Enogex LLC's new credit facility and apply the remaining proceeds to fund future capital expenditures, working capital and other corporate purposes.

Enogex LLC also currently expects to refinance its $400 million 8.125% senior notes due 2010 with a combination of $300 million of new long-term debt and proceeds from the Offering that the Partnership expects to contribute to Enogex LLC for the anticipated repayment of that debt.

OGE ENOGEX PARTNERS L.P.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Partners of OGE Enogex Partners L.P.:

We have audited the accompanying balance sheet of OGE Enogex Partners L.P. as of June 14, 2007. The balance sheet is the responsibility of the Partnership's management. Our responsibility is to express an opinion on this balance sheet based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the balance sheet is free of material misstatement. We were not engaged to perform an audit of the Company's internal control over financial reporting. Our audit included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes 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 balance sheet presentation. We believe that our audit provides a reasonable basis for our opinion.

In our opinion, the balance sheet referred to above presents fairly, in all material respects, the financial position of OGE Enogex Partners L.P. at June 14, 2007 in conformity with U.S. generally accepted accounting principles.

/s/ Ernst & Young LLP
Oklahoma City, Oklahoma
June 22, 2007

OGE ENOGEX GP LLC

BALANCE SHEET

JUNE 14, 2007

ASSETS	
CURRENT ASSETS	
Investment in OGE Enogex Operating LLC	**$1,000**
Investment in OGE Enogex Partners L.P.	**40**
TOTAL ASSETS	**$1,040**
MEMBER'S EQUITY	
Member's equity	**$1,040**
TOTAL MEMBER'S EQUITY	**$1,040**

The accompanying note is an integral part of the Balance Sheet.

OGE ENOGEX GP LLC

NOTE TO BALANCE SHEET

1. Nature of Operations

OGE Enogex GP LLC (the "Company"), a Delaware limited liability company, was formed on May 30, 2007 to become the general partner of OGE Enogex Partners L.P. (the "Partnership"). The Company is a wholly owned subsidiary of OGE Energy Corp. The Company has adopted a December 31 fiscal year end. On June 14, 2007, a subsidiary of OGE Energy Corp. contributed $1,040 to the Company in exchange for a 100% membership interest. The Company has invested $40 in the Partnership for a 2.0% general partner interest and $1,000 in OGE Enogex Operating LLC in exchange for a 100% membership interest. In conjunction with the expected initial public offering of the Partnership, the Company intends to distribute its 100% membership interest in OGE Enogex Operating LLC to the Partnership. There have been no other transactions involving the Company as of June 14, 2007. The Partnership anticipates filing a registration statement for an initial public offering of its common units.

OGE ENOGEX GP LLC

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Member of OGE Enogex GP LLC:

We have audited the accompanying balance sheet of OGE Enogex GP LLC as of June 14, 2007. The balance sheet is the responsibility of the Company's management. Our responsibility is to express an opinion on this balance sheet based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the balance sheet is free of material misstatement. We were not engaged to perform an audit of the Company's internal control over financial reporting. Our audit included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes 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 balance sheet presentation. We believe that our audit provides a reasonable basis for our opinion.

In our opinion, the balance sheet referred to above presents fairly, in all material respects, the financial position of OGE Enogex GP LLC at June 14, 2007 in conformity with U.S. generally accepted accounting principles.

/s/ Ernst & Young LLP
Oklahoma City, Oklahoma
June 22, 2007

APPENDIX A

AMENDED AND RESTATED AGREEMENT OF LIMITED PARTNERSHIP OF OGE ENOGEX PARTNERS L.P.

APPENDIX B

GLOSSARY OF SELECTED TERMS

Adjusted EBITDA. Net income from continuing operations before non-controlling interest, interest, income taxes and depreciation and amortization expense.

Adjusted operating surplus. With respect to any period, generated operating surplus with respect to such period (excluding any amounts attributable to the items included in clause (a)(1) of the definition of "operating surplus" in this Appendix B) as adjusted to:

(a) decrease operating surplus by:

(1) any net increase in working capital borrowings (including OGE Enogex Partners L.P.'s proportionate share of any net increases of certain subsidiaries it does not wholly own) with respect to that period;

(2) any net decrease made in subsequent periods in cash reserves for operating expenditures (including OGE Enogex Partners L.P.'s proportionate share of any net decreases of certain subsidiaries it does not wholly own) with respect to that period; and

(3) any net decrease in cash reserves for operating expenditures (including OGE Enogex Partners L.P.'s proportionate share of any net decreases of certain subsidiaries it does not wholly own) during that period not relating to an operating expenditure made during that period; and

(b) increase operating surplus by:

(1) any net decrease in working capital borrowings (including OGE Enogex Partners L.P.'s proportionate share of any net decreases of certain subsidiaries it does not wholly own) with respect to that period; and

(2) any net increase in cash reserves for operating expenditures (including OGE Enogex Partners L.P.'s proportionate share of any net increases of certain subsidiaries it does not wholly own) during that period required by any debt instrument for the repayment of principal, interest or premium.

APSC. Arkansas Public Service Commission.

Arrearage. The amount by which the minimum quarterly distribution for a quarter during the subordination period exceeds the distribution of available cash from operating surplus actually made for that quarter on a common unit, cumulative for that quarter and all prior quarters during the subordination period.

Available cash. With respect to any quarter ending prior to liquidation:

(a) the sum of:

(1) all of the cash and cash equivalents of OGE Enogex Partners L.P. and its subsidiaries (including OGE Enogex Partners L.P.'s proportionate share of cash and cash equivalents of certain subsidiaries it does not wholly own) on hand at the end of the quarter; and

(2) all additional cash and cash equivalents of OGE Enogex Partners L.P. and its subsidiaries (including OGE Enogex Partners L.P.'s proportionate share of cash and cash equivalents of certain subsidiaries it does not wholly own) on hand on the date of determination of available cash for that quarter resulting from working capital borrowings made after the end of that quarter; less

(b) the amount of cash reserves (including OGE Enogex Partners L.P.'s proportionate share of cash reserves of certain subsidiaries it does not wholly own) established by the general partner to:

(1) provide for the proper conduct of the business of OGE Enogex Partners L.P. and its subsidiaries (including reserves for future capital expenditures and for future credit needs of OGE Enogex Partners L.P. and its subsidiaries) after that quarter;

(2) comply with applicable law, any debt instrument or other agreements to which OGE Enogex Partners L.P. or any of its subsidiaries is a party or its assets are subject; or

(3) provide funds for minimum quarterly distributions to holders of common and subordinated units and the corresponding distributions on the 2% general partner and cumulative common unit arrearages for any one or more of the next four quarters;

provided, however, that the general partner may not establish cash reserves pursuant to clause (b)(3) immediately above for distributions to the subordinated units unless the general partner has determined that the establishment of reserves will not prevent OGE Enogex Partners L.P. from distributing the minimum quarterly distribution on all common units and any cumulative common unit arrearages thereon for the next four quarters; and *provided, further*, that disbursements made by OGE Enogex Partners L.P. or any of its subsidiaries or cash reserves established, increased or reduced after the end of that quarter but on or before the date of determination of available cash for that quarter will be deemed to have been made, established, increased or reduced, for purposes of determining available cash, within that quarter if the general partner so determines.

Barrel. One barrel of petroleum products equals 42 U.S. gallons.

Bcf. Billion cubic feet.

Bcf/d. Billion cubic feet of natural gas per day.

Btu. British thermal unit. When used in terms of volume, Btu refers to the amount of natural gas required to raise the temperature of one pound of water by one degree Fahrenheit at one atmospheric pressure.

Capital account. The capital account maintained for a partner under the partnership agreement. The capital account in respect of a general partner interest, a common unit, a subordinated unit, an incentive distribution right or other partnership interest will be the amount which that capital account would be if that general partner interest, common unit, subordinated unit, incentive distribution right or other partnership interest were the only interest in OGE Enogex Partners L.P. held by a partner.

Capital surplus. All amounts of available cash distributed by OGE Enogex Partners L.P. on any date from any source will be deemed to be distributed from operating surplus until the sum of all amounts of available cash distributed since the closing of the initial public offering equals the operating surplus from the closing of the initial public offering through the end of the quarter immediately preceding that distribution. Any remaining amounts of available cash distributed by OGE Enogex Partners L.P. will on that date be deemed to be capital surplus.

Central receipt point. A single receipt point into a gathering line where a producer aggregates the volumes from more than one well and delivers them into the gathering system at a single meter site.

CERCLA. Comprehensive Environmental Response, Compensation, and Liability Act of 1980.

Closing price. The last sale price on a day, regular way, or in case no sale takes place on that day, the average of the closing bid and asked prices on that day, regular way, as reported in the principal consolidated transaction reporting system for securities listed on the principal national securities exchange (other than the Nasdaq Stock Market) on which the units of that class are listed. If the units of that class are not listed on any national securities exchange (other than the Nasdaq Stock Market), the last quoted price on that day. If no quoted price exists, the average of the high bid and low asked prices on that day in the over-the-counter market, as reported by the Nasdaq Stock Market or any other system then in use. If on any day the units of that class are not quoted by any organization of that type, the average of the closing bid and asked prices on that day as furnished by a professional market maker making a market in the units of the class selected by the general partner. If on that day no market maker is making a market in the units of that class, the fair value of the units on that day as determined reasonably and in good faith by the general partner.

Condensate liquid. A natural gas liquid with a low vapor pressure, mainly composed of propane, butane, pentane and heavier hydrocarbon fractions.

Current market price. For any class of units listed on any national securities exchange as of any date, the average of the daily closing prices for the 20 consecutive trading days immediately prior to that date.

DOT. U.S. Department of Transportation.

EIA. Energy Information Administration.

EPA. U.S. Environmental Protection Agency.

Estimated maintenance capital expenditures. An estimate made in good faith by the board of directors of the general partner (with the concurrence of the conflicts committee of the general partner) of the average quarterly maintenance capital expenditures that OGE Enogex Partners L.P. will need to incur over the long term to maintain the asset base of OGE Enogex Partners L.P. and its subsidiaries (including OGE Enogex Partners L.P.'s proportionate share of assets of certain subsidiaries it does not wholly own) existing at the time the estimate is made.

FASB. Financial Accounting Standards Board.

FERC. Federal Energy Regulatory Commission.

Fractionation. The separation of the heterogenous mixture of extracted NGLs into individual components for end-use sale.

GAAP. Generally accepted accounting principles in the United States.

Gas imbalance. The difference between the actual amounts of natural gas delivered from or received by a pipeline system versus the amounts scheduled to be delivered or received.

Gross margin. Gross margin on revenues, which is revenues minus cost of goods sold.

Hazardous Liquid Pipeline Safety Act. Accountable Pipeline and Safety Partnership Act of 1996.

Hydrocarbon. An organic compound containing only carbon and hydrogen.

Incentive distribution right. A non-voting limited partner partnership interest issued to the general partner. The partnership interest will confer upon its holder only the rights and obligations specifically provided in the partnership agreement for incentive distribution rights.

Incentive distributions. The distributions of available cash from operating surplus initially made to the general partner that are in excess of the general partner's aggregate 2% general partner interest.

Interim capital transactions. The following transactions if they occur prior to liquidation:

(a) borrowings, refinancings or refundings of indebtedness (other than for working capital borrowings and other than for items purchased on open account in the ordinary course of business) and sales of debt securities by OGE Enogex Partners L.P. or any of its subsidiaries;

(b) sales of equity interests by OGE Enogex Partners L.P. or any of its subsidiaries;

(c) sales or other voluntary or involuntary dispositions of any assets of OGE Enogex Partners L.P. or any of its subsidiaries (other than sales or other dispositions of inventory, accounts receivable and other assets in the ordinary course of business, and sales or other dispositions of assets as a part of normal retirements or replacements);

(d) capital contributions received; or

(e) corporate reorganizations or restructurings.

LDC. Local distribution companies involved in the delivery of natural gas to consumers within a specific geographic area.

LNG. Liquefied natural gas.

Mcf. Thousand cubic feet of natural gas.

MMBtu. Million British thermal units.

MMBtu/d. Million British thermal units per day.

MMcf/d. Million cubic feet per day.

Natural gas. Hydrocarbon gas found in the earth, composed of methane, ethane, butane, propane and other gases.

NGLs. Natural gas liquids.

NGPA. Natural Gas Policy Act of 1978.

NGPSA. Natural Gas Pipeline Safety Act of 1968.

NOE. Notice of Enforcement Action.

OCC. Oklahoma Corporation Commission.

Operating expenditures. All cash expenditures of OGE Enogex Partners L.P. and its subsidiaries (including OGE Enogex Partners L.P.'s proportionate share of cash expenditures for certain subsidiaries it does not wholly own), including, but not limited to, taxes, reimbursements of the general partner, interest payments, repayment of working capital borrowings, maintenance capital expenditures and non-pro rata repurchases of units (other than those made with the proceeds of an interim capital transaction), provided that operating expenditures will not include:

(a) repayment of working capital borrowings deducted from operating surplus pursuant to clause (b)(4) of the definition of operating surplus when such repayment actually occurs;

(b) payments (including prepayments and prepayment penalties) of principal of and premium on indebtedness, other than working capital borrowings;

(c) actual maintenance capital expenditures;

(d) expansion capital expenditures;

(e) investment capital expenditures;

(f) payment of transaction expenses relating to interim capital transactions; or

(g) distributions to our partners (including distributions in respect of Class B units and the incentive distribution rights).

Operating surplus. With respect to any period prior to liquidation, on a cumulative basis and without duplication:

(a) the sum of:

(1) an amount equal to two times the amount needed for any one quarter for OGE Enogex Partners L.P. to pay a distribution on all of the units (including the general partner interest) and the incentive distribution rights of OGE Enogex Partners L.P. at the same per-unit amount as was distributed in the immediately preceding quarter;

(2) all cash receipts of OGE Enogex Partners L.P. and its subsidiaries (including OGE Enogex Partners L.P.'s proportionate share of cash receipts for certain subsidiaries it does not wholly own) after the closing of the initial public offering excluding interim capital transactions (provided that cash receipts from the termination of a commodity hedge contract or interest rate swap prior to its specified termination date will be included in operating surplus in equal quarterly installments over the scheduled life of such commodity hedge contract or interest rate swap);

(3) working capital borrowings (including OGE Enogex Partners L.P.'s proportionate share of working capital borrowings for certain subsidiaries it does not wholly own) made after the end of a quarter but on or before the date of determination of operating surplus for the quarter; and

(4) cash distributions paid on equity issued in connection with the construction or development of a capital improvement or replacement asset during the period beginning on the date that OGE Enogex Partners L.P. enters into a binding commitment to commence the construction or development of such capital improvement or replacement asset and ending on the earlier to occur of the date the capital improvement or replacement asset is placed into service and the date that it is abandoned or disposed of; less

(b) the sum of:

(1) estimated maintenance capital expenditures;

(2) all operating expenditures of OGE Enogex Partners L.P. and its subsidiaries (including OGE Enogex Partners L.P.'s proportionate share of operating expenditures of certain subsidiaries it does not wholly own) after the closing of this offering;

(3) the amount of cash reserves of OGE Enogex Partners L.P. and its subsidiaries (including OGE Enogex Partners L.P.'s proportionate share of cash reserves of certain subsidiaries it does not wholly own, including Enogex LLC) established by the general partner to provide funds for future operating expenditures; and

(4) all working capital borrowings (including OGE Enogex Partners L.P.'s proportionate share of working capital borrowings of certain subsidiaries it does not wholly own, including Enogex LLC) not repaid within twelve months after having been incurred or repaid within such twelve-month period with the proceeds of additional working capital borrowings.

OSHA. Occupational Safety and Health Act of 1970.

Park and loan transactions. Planned or managed gas imbalances related to the marketing of natural gas.

Pension Protection Act. Pension Protection Act of 2006.

RCRA. Resource Conservation and Recovery Act of 1976.

Recompletions. After the initial completion of a well, the action and techniques of reentering the well and redoing or repairing the original completion to restore the well's productivity.

Residue gas. The pipeline quality natural gas remaining after natural gas is processed.

SFAS. Statement of Financial Accounting Standard.

SOC. Statement of Operating Conditions.

Subordination period. The subordination period will extend from the closing of the initial public offering until the first to occur of:

(a) the first day of any quarter beginning after September 30, 2010 for which:

  (1) distributions of available cash from operating surplus on each of the outstanding common units and subordinated units and the corresponding distributions on the 2% general partner interest equaled or exceeded the minimum quarterly distribution for each of the three consecutive, non-overlapping four-quarter periods immediately preceding that date;

  (2) the adjusted operating surplus generated during each of the three consecutive, non-overlapping four-quarter periods immediately preceding that date equaled or exceeded the sum of the minimum quarterly distributions on all of the outstanding common units and subordinated units and the corresponding distributions on the 2% general partner interest during those periods on a fully diluted basis during those periods; and

  (3) there are no arrearages in payment of the minimum quarterly distribution on the common units;

(b) the first day after:

  (1) distributions of available cash from operating surplus on each of the outstanding common units and subordinated units and the corresponding distributions on the 2% general partner interest equaled or exceeded $0.50625 (150% of the minimum quarterly distribution) for each of the four consecutive quarters immediately preceding the date;

  (2) the "adjusted operating surplus" (as defined below) generated during each of the four consecutive quarters immediately preceding the date equaled or exceeded $0.50625 (150% of the minimum quarterly distribution) on each of the outstanding common units and subordinated units and unit equivalents representing the general partner interest during those periods; and

  (3) there are no arrearages in payment of the minimum quarterly distributions on the common units; and

(c) the date on which the general partner is removed as general partner of OGE Enogex Partners L.P. upon the requisite vote by the limited partners under circumstances where cause does not exist and no units held by the general partner and its affiliates are voted in favor of the removal.

TBtu. Trillion British thermal units.

TBtu/d. Trillion British thermal units per day.

TCEQ. Texas Commission on Environmental Quality.

Tcf. Trillion cubic feet of natural gas.

Throughput. The volume of natural gas being transported or passing through a pipeline, plant, terminal or other facility.

Units. Refers to the common units and subordinated units.

VaR. Value-at-risk.

Working capital borrowings. Borrowings that are made under a credit facility, commercial paper facility or similar financing arrangement, and in all cases are used solely for working capital purposes or to pay distributions to partners; provided that when incurred it is the intent of the borrower to repay such borrowings within 12 months from other than additional working capital borrowings.

Working gas. Natural gas storage capacity that can be used for system operations or is available to be sold to the market as firm or interruptible storage capacity or as the storage component of no notice service.

Workover. Operations on a completed production well to clean, repair and maintain the well for the purposes of increasing or restoring production.

OGE ENOGEX PARTNERS L.P.

7,500,000 Common Units
Representing Limited Partner Interests

PROSPECTUS

, 2007

UBS Investment Bank **Lehman Brothers**

PART II

INFORMATION NOT REQUIRED IN THE PROSPECTUS

Item 13. Other expenses of issuance and distribution.

Set forth below are the expenses (other than underwriting discounts and commissions and a structuring fee) expected to be incurred in connection with the issuance and distribution of the securities registered hereby. With the exception of the Securities and Exchange Commission registration fee, the NASD filing fee and the New York Stock Exchange listing fee, the amounts set forth below are estimates:

Securities and Exchange Commission registration fee	$ 5,561
NASD filing fee	18,613
New York Stock Exchange listing fee	36,000
Printing and engraving expenses	*
Legal fees and expenses	*
Accounting fees and expenses	*
Transfer agent and registrar fees	*
Miscellaneous	*
Total	$2,500,000

* To be provided by amendment.

Item 14. Indemnification of directors and officers.

The partnership agreement of OGE Enogex Partners L.P. provides that the partnership will, to the fullest extent permitted by law but subject to the limitations expressly provided therein, indemnify and hold harmless its general partner, any Departing Partner (as defined therein), any person who is or was an affiliate of the general partner, including the Guarantor and any Subsidiary Guarantor, or any Departing Partner, any person who is or was a member, partner, officer, director, fiduciary or trustee of the general partner, any Departing Partner, any Group Member (as defined therein) or any affiliate of the general partner, any Departing Partner or any Group Member, or any person who is or was serving at the request of the general partner, including the Guarantor and any Subsidiary Guarantor, or any affiliate of the general partner, or any Departing Partner or any affiliate of any Departing Partner as an officer, director, member, partner, fiduciary or trustee of another person, or any person that the general partner designates as a Partnership Indemnitee for purposes of the partnership agreement (each, a “Partnership Indemnitee”) from and against any and all losses, claims, damages, liabilities (joint or several), expenses (including legal fees and expenses), judgments, fines, penalties, interest, settlements or other amounts arising from any and all claims, demands, actions, suits or proceedings, whether civil, criminal, administrative or investigative, in which any Partnership Indemnitee may be involved, or is threatened to be involved, as a party or otherwise, by reason of its status as a Partnership Indemnitee, provided that the Partnership Indemnitee shall not be indemnified and held harmless if there has been a final and non-appealable judgment entered by a court of competent jurisdiction determining that, in respect of the matter for which the Partnership Indemnitee is seeking indemnification, the Partnership Indemnitee acted in bad faith or engaged in fraud, willful misconduct or gross negligence or, in the case of a criminal matter, acted with knowledge that the Partnership Indemnitee’s conduct was unlawful. This indemnification would under certain circumstances include indemnification for liabilities under the Securities Act. To the fullest extent permitted by law, expenses (including legal fees and expenses) incurred by a Partnership Indemnitee who is indemnified pursuant to the partnership agreement in defending any claim, demand, action, suit or proceeding shall, from time to time, be advanced by the partnership prior to a determination that the Partnership Indemnitee is not entitled to be indemnified upon receipt by the partnership of any undertaking by or on behalf of the Partnership Indemnitee to repay such amount if it shall be determined that the Partnership Indemnitee is not entitled to be indemnified under the partnership agreement. Any indemnification under these provisions will be only out of the assets of the partnership.

OGE Enogex Partners L.P. is authorized to purchase (or to reimburse its general partner for the costs of) insurance against liabilities asserted against and expenses incurred by its general partner, its affiliates and such other persons as the general partner may determine and described in the paragraph above in connection with their activities, whether or not they would have the power to indemnify such person against such liabilities under the provisions described in the paragraphs above. The general partner has purchased insurance covering its officers and directors against liabilities asserted and expenses incurred in connection with their activities as officers and directors of the general partner or any of its direct or indirect subsidiaries.

Any underwriting agreement entered into in connection with the sale of the securities offered pursuant to this registration statement will provide for indemnification of officers and directors of the general partner, including liabilities under the Securities Act.

Item 15. Recent sales of unregistered securities.

On March 30, 2007, in connection with the formation of OGE Enogex Partners L.P., or the Partnership, the Partnership issued to (a) OGE Enogex GP LLC the 2% general partner interest in the Partnership for $40 and (b) OGE Enogex Holdings LLC a 98% limited partner interest in the Partnership for $1,960 in an offering exempt from registration under Section 4(2) of the Securities Act. There have been no other sales of unregistered securities within the past three years.

Item 16. Exhibits and financial statement schedules.

(a) Exhibits.

The following documents are filed as exhibits to this registration statement:

1.1 Form of Underwriting Agreement+

3.1 Form of Amended and Restated Agreement of Limited Partnership of OGE Enogex Partners L.P. (included as Appendix A to this Prospectus)+

3.2 Certificate of Limited Partnership of OGE Enogex Partners L.P.*

3.3 Certificate of Formation of OGE Enogex GP LLC*

3.4 Limited Liability Company Agreement of OGE Enogex GP LLC*

4.1 Specimen Unit Certificate representing common units (included with Form of Amended and Restated Agreement of Limited Partnership of OGE Enogex Partners L.P.)+

5.1 Opinion of Jones Day relating to the legality of the securities being registered+

8.1 Opinion of Baker Botts L.L.P. relating to tax matters+

10.1 Form of OGE Enogex Partners L.P. Long-Term Incentive Plan+

10.2 Form of Credit Agreement+

10.3 Form of Omnibus Agreement+

10.4 Form of Contribution, Conveyance and Assumption Agreement+

10.5 Purchase Agreement, dated as of May 14, 1999, by and between Tejas Gas, LLC and Enogex Inc. (filed as Exhibit 2.01 to OGE Energy Corp.'s Form 10-Q for the quarter ended June 30, 1999 (File No. 1-12579))

10.6 Stock purchase agreement dated September 21, 2005 by and between Enogex Inc. and Atlas Pipeline Partners, L.P. (filed as Exhibit 10.01 to OGE Energy Corp.'s Form 8-K filed September 27, 2005 (File No. 1-12579))

10.7 Asset purchase agreement dated March 30, 2006, by and between Enogex Gas Gathering, L.L.C. and Hiland Operating, Inc. (filed as Exhibit 2.01 to OGE Energy Corp.'s Form 8-K filed April 4, 2006 (File No. 1-12579))

10.8 Intrastate Firm No-Notice, Load Following Transportation and Storage Services Agreement dated as of May 1, 2003 between Oklahoma Gas & Electric Company and Enogex Inc. [Confidential treatment has been requested for certain portions of this exhibit] (filed as Exhibit 10.24 to OGE Energy Corp.'s Form 10-K for the year ended December 31, 2004 (File No. 1-12579))

10.9 Capacity Lease Agreement dated as of December 11, 2006 by and between Enogex Inc. and Midcontinent Express Pipeline LLC [Confidential treatment has been requested for certain portions of this exhibit] (filed as Exhibit 10.30 to OGE Energy Corp.'s Form 10-K for the year ended December 31, 2006 (File No. 1-12579))

10.10 Firm Transportation Service Agreement (Rate Schedule FT) dated as of December 1, 2004 between OGE Energy Resources, Inc. and Cheyenne Plains Gas Pipeline Company, L.L.C. (filed as Exhibit 10.25 to OGE Energy Corp.'s Form 10-K for the year ended December 31, 2004 (File No. 1-12579))

10.11 Firm Transportation Service Agreement (Rate Schedule FT) dated as of April 14, 2004, amended and restated as of April 1, 2006, between OGE Energy Resources, Inc. and Cheyenne Plains Gas Pipeline Company, L.L.C.*

10.12 Firm Transportation Service Agreement (Rate Schedule FT) dated as of April 14, 2004, amended and restated as of March 1, 2007, between OGE Energy Resources, Inc. and Cheyenne Plains Gas Pipeline Company, L.L.C.*

10.13 Form of Executive Retention Agreement—2007 between Enogex Inc. and each of Patricia D. Horn, E. Keith Mitchell, Ramiro F. Rangel, Craig R. Jimenez, Jean C. Leger, Jr., Thomas L. Levescy*

21.1 Subsidiaries of OGE Enogex Partners L.P.+

23.1 Consent of Ernst & Young LLP*

23.2 Consent of Jones Day (contained in Exhibit 5.1)+

23.3 Consent of Baker Botts (contained in Exhibit 8.1)+

24.1 Power of Attorney*

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* Filed herewith.

\+ To be filed by amendment.

(b) Financial Statement Schedules.

Item 17. Undertakings.

The undersigned Registrant hereby undertakes:

(a) To provide to the underwriter(s) at the closing specified in the underwriting agreements, certificates in such denominations and registered in such names as required by the underwriter(s) to permit prompt delivery to each purchaser.

(b) Insofar as indemnification for liabilities arising under the Securities Act of 1933 may be permitted to directors, officers and controlling persons of the Registrant pursuant to the provisions described in Item 14, or otherwise, the Registrant has been advised that in the opinion of the Securities and Exchange Commission such indemnification is against public policy as expressed in the Act and is, therefore, unenforceable. In the event that a claim for indemnification against such liabilities (other than the payment by the Registrant of expenses incurred or paid by a director, officer or controlling person of the Registrant in the successful defense of any action, suit or proceeding) is asserted by such director, officer or controlling person in connection with the securities being registered, the Registrant will, unless in the opinion of its counsel the matter has been settled by controlling precedent, submit to a court of appropriate jurisdiction the question whether such indemnification by it is against public policy as expressed in the Act and will be governed by the final adjudication of such issue.

(c) For purpose of determining any liability under the Securities Act of 1933, the information omitted from the form of prospectus filed as part of this Registration Statement in reliance upon Rule 430A and contained in the form of prospectus filed by the Registrant pursuant to Rule 424(b)(1) or (4) or 497(h) under the Securities Act shall be deemed to be part of this Registration Statement as of the time it was declared effective.

(d) For the purpose of determining any liability under the Securities Act of 1933, each post-effective amendment that contains a form of prospectus shall be deemed to be a new registration statement relating to the securities offered therein, and the offering of such securities at that time shall be deemed to be the initial bona fide offering thereof.

SIGNATURES

Pursuant to the requirements of the Securities Act of 1933, as amended, the Registrant has duly caused this Registration Statement to be signed on its behalf by the undersigned, thereunto duly authorized, in the City of Oklahoma City in the State of Oklahoma on June 27, 2007.

OGE ENOGEX PARTNERS L.P.

By: OGE Enogex GP LLC
Its general partner

By: /s/ JAMES R. HATFIELD

Pursuant to the requirements of the Securities Act of 1933, as amended, this Registration Statement has been signed below by the following persons in the capacities and on the dates indicated.

Signature	Title	Date
* Peter B. Delaney	Chief Executive Officer and Director (Principal Executive Officer)	June 27, 2007
* James R. Hatfield	Senior Vice President and Chief Financial Officer and Director (Principal Financial Officer and Principal Accounting Officer)	June 27, 2007
* Danny P. Harris	Director	June 27, 2007
* Steven E. Moore	Director	June 27, 2007

* The undersigned by signing his name hereunto has hereby signed this registration statement on behalf of the above-named officers and directors on June 27, 2007, pursuant to a power of attorney executed on behalf of each such officer and director and filed with the Securities and Exchange Commission as Exhibit 24.1 hereto.

*By: /s/ JAMES R. HATFIELD
(Attorney-in-Fact)
June 27, 2007

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