CORLEY ELIZABETH
Form 4
February 05, 2018

FORM 4

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

OMB APPROVAL

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STATEMENT OF CHANGES IN BENEFICIAL OWNERSHIP OF SECURITIES

Filed pursuant to Section 16(a) of the Securities Exchange Act of 1934, Section 17(a) of the Public Utility Holding Company Act of 1935 or Section 30(h) of the Investment Company Act of 1940

(Print or Type Responses)

1. Name and Address of Reporting Person *
CORLEY ELIZABETH

(Last) (First) (Middle)

C/O MORGAN STANLEY, 1585 BROADWAY

(Street)

NEW YORK, NY 10036

(City) (State) (Zip)

2. Issuer Name **and** Ticker or Trading Symbol
MORGAN STANLEY [MS]

3. Date of Earliest Transaction (Month/Day/Year)
02/01/2018

4. If Amendment, Date Original Filed(Month/Day/Year)

5. Relationship of Reporting Person(s) to Issuer

(Check all applicable)

__X__ Director _____ 10% Owner
_____ Officer (give title below) _____ Other (specify below)

6. Individual or Joint/Group Filing(Check Applicable Line)
_X_ Form filed by One Reporting Person
___ Form filed by More than One Reporting Person

Table I - Non-Derivative Securities Acquired, Disposed of, or Beneficially Owned

1.Title of Security (Instr. 3)	2. Transaction Date (Month/Day/Year)	2A. Deemed Execution Date, if any (Month/Day/Year)	3. Transaction Code (Instr. 8)		4. Securities Acquired (A) or Disposed of (D) (Instr. 3, 4 and 5)			5. Amount of Securities Beneficially Owned Following Reported Transaction(s) (Instr. 3 and 4)	6. Ownership Form: Direct (D) or Indirect (I) (Instr. 4)	7. Nature of Indirect Beneficial Ownership (Instr. 4)
			Code	V	Amount	(A) or (D)	Price			
Common Stock	02/01/2018		A (1)		1,461.552	A	$ 0	1,461.552	D	

Reminder: Report on a separate line for each class of securities beneficially owned directly or indirectly.

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SEC 1474 (9-02)

Table II - Derivative Securities Acquired, Disposed of, or Beneficially Owned
(*e.g.*, puts, calls, warrants, options, convertible securities)

1. Title of Derivative Security (Instr. 3)	2. Conversion or Exercise Price of Derivative Security	3. Transaction Date (Month/Day/Year)	3A. Deemed Execution Date, if any (Month/Day/Year)	4. Transaction Code (Instr. 8)		5. Number of Derivative Securities Acquired (A) or Disposed of (D) (Instr. 3, 4, and 5)		6. Date Exercisable and Expiration Date (Month/Day/Year)		7. Title and Amount of Underlying Securities (Instr. 3 and 4)		8. Price of Derivative Security (Instr. 5)	9. Nu Deriv Secur Bene Owne Follo Repo Trans (Instr
				Code	V	(A)	(D)	Date Exercisable	Expiration Date	Title	Amount or Number of Shares		

Reporting Owners

Reporting Owner Name / Address	Relationships			
	Director	10% Owner	Officer	Other
CORLEY ELIZABETH C/O MORGAN STANLEY 1585 BROADWAY NEW YORK, NY 10036	X			

Signatures

/s/ Martin M. Cohen, Attorney-in-Fact	02/05/2018
**Signature of Reporting Person	Date

Explanation of Responses:

* If the form is filed by more than one reporting person, *see* Instruction 4(b)(v).

** Intentional misstatements or omissions of facts constitute Federal Criminal Violations. *See* 18 U.S.C. 1001 and 15 U.S.C. 78ff(a).

(1) Deferred stock units granted under the Morgan Stanley Directors' Equity Capital Accumulation Plan, which are convertible into shares of Common Stock at a ratio of 1 to 1.

Note: File three copies of this Form, one of which must be manually signed. If space is insufficient, *see* Instruction 6 for procedure.
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Other Non-Current Assets, net

Other non-current assets, net are stated at cost less accumulated amortization. Other non-current assets, net consisted of the following:

	December 31,	
	2011	2010
Unamortized financing costs (3 to 30 years)	$ 46,618	$ 35,267
Regulatory assets	88,993	92,939
Other	23,990	30,400
Total other non-current assets, net	$ 159,601	$ 158,606

Asset Retirement Obligation

We have determined that we are obligated by contractual or regulatory requirements to remove facilities or perform other remediation upon retirement of certain assets. Determination of the amounts to be recognized is based upon numerous estimates and assumptions, including expected settlement dates, future retirement costs, future inflation rates and the credit-adjusted risk-free interest rates. However, management was not able to reasonably measure the fair value of the asset retirement obligations as of December 31, 2011 or 2010 because the settlement dates were indeterminable. We will record an asset retirement obligation in the periods in which management can reasonably determine the settlement dates.

Accrued and Other Current Liabilities

Accrued and other current liabilities consisted of the following:

	December 31, 2011	2010
Interest payable	$142,616	$135,867
Customer advances and deposits	84,300	86,191
Accrued capital expenditures	196,789	87,260
Accrued wages and benefits	67,266	61,587
Taxes payable other than income taxes	77,073	27,067
Income taxes payable	14,422	7,390
Deferred income taxes	61	365
Other	46,675	56,833
Total accrued and other current liabilities	$629,202	$462,560

Deposits or advances are received from our customers as prepayments for natural gas deliveries in the following month and from our propane customers as security or prepayments for future propane deliveries. Prepayments and security deposits may also be required when customers exceed their credit limits or do not qualify for open credit.

Fair Value of Financial Instruments

The carrying amounts of cash and cash equivalents, accounts receivable and accounts payable approximate their fair value. Price risk management assets and liabilities are recorded at fair value.

Based on the estimated borrowing rates currently available to us and our subsidiaries for loans with similar terms and average maturities, the aggregate fair value and carrying amount of our debt obligations as of December 31, 2011 was $8.39 billion and $7.81 billion, respectively. As of December 31, 2010, the aggregate fair value and carrying amount of our debt obligations was $7.21 billion and $6.44 billion, respectively.

We have marketable securities, commodity derivatives and interest rate derivatives that are accounted for as assets and liabilities at fair value in our consolidated balance sheets. We determine the fair value of our assets and liabilities subject to fair value measurement by using the highest possible "level" of inputs. Level 1 inputs are observable quotes in an active market for identical assets and liabilities. We consider the valuation of marketable securities and commodity derivatives transacted through a clearing broker with a published price from the appropriate exchange as a Level 1 valuation. Level 2 inputs are inputs

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observable for similar assets and liabilities. We consider over-the-counter ("OTC") commodity derivatives entered into directly with third parties as a Level 2 valuation since the values of these derivatives are quoted on an exchange for similar transactions. Additionally, we consider our options transacted through our clearing broker as having Level 2 inputs due to the level of activity of these contracts on the exchange in which they trade. We consider the valuation of our interest rate derivatives as Level 2 as the primary input, the LIBOR curve, is based on quotes from an active exchange of Eurodollar futures for the same period as the future interest swap settlements. Level 3 inputs are unobservable. We currently do not have any recurring fair value measurements that are considered Level 3 valuations. During the period ended December 31, 2011, no transfers were made between any levels within the fair value hierarchy.

The following tables summarize the fair value of our financial assets and liabilities measured and recorded at fair value on a recurring basis as of December 31, 2011 and 2010 based on inputs used to derive their fair values:

	Fair Value Total	Fair Value Measurements at December 31, 2011	
		Level 1	Level 2
Assets:			
Marketable securities	$1,229	$1,229	$—
Interest rate derivatives	36,301	—	36,301
Commodity derivatives:			
Natural Gas:			
Basis Swaps IFERC/NYMEX	62,924	62,924	—
Swing Swaps IFERC	15,002	1,687	13,315
Fixed Swaps/Futures	214,572	214,572	—
Options – Puts	6,435	—	6,435
Forward Physical Swaps	699	—	699
Propane – Forwards/Swaps	9	—	9
Total commodity derivatives	299,641	279,183	20,458
Total Assets	$337,171	$280,412	$56,759
Liabilities:			
Interest rate derivatives	$(117,020)	$—	$(117,020)
Commodity derivatives:			
Natural Gas:			
Basis Swaps IFERC/NYMEX	(82,290)	(82,290)	—
Swing Swaps IFERC	(16,074)	(3,061)	(13,013)
Fixed Swaps/Futures	(148,111)	(148,111)	—
Options – Calls	(12)	—	(12)
Forward Physical Swaps	(712)	—	(712)
Propane — Forwards/Swaps	(4,131)	—	(4,131)
Total commodity derivatives	(251,330)	(233,462)	(17,868)
Total Liabilities	$(368,350)	$(233,462)	$(134,888)

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	Fair Value Total	Fair Value Measurements at December 31, 2010 Level 1	Level 2
Assets:			
Marketable securities	$2,032	$2,032	$—
Interest rate derivatives	20,790	—	20,790
Commodity derivatives:			
Natural Gas:			
Basis Swaps IFERC/NYMEX	15,756	15,756	—
Swing Swaps IFERC	1,682	1,562	120
Fixed Swaps/Futures	42,474	42,474	—
Options — Puts	26,241	—	26,241
Options — Calls	75	—	75
Propane – Forwards/Swaps	6,864	—	6,864
Total commodity derivatives	93,092	59,792	33,300
Total Assets	$115,914	$61,824	$54,090
Liabilities:			
Interest rate derivatives	$(18,338)	$—	$(18,338)
Commodity derivatives:			
Natural Gas:			
Basis Swaps IFERC/NYMEX	(17,372)	(17,372)	—
Swing Swaps IFERC	(3,768)	(3,520)	(248)
Fixed Swaps/Futures	(41,825)	(41,825)	—
Options — Puts	(7)	—	(7)
Options — Calls	(2,643)	—	(2,643)
Total commodity derivatives	(65,615)	(62,717)	(2,898)
Total Liabilities	$(83,953)	$(62,717)	$(21,236)

In conjunction with the MEP Transaction in 2010 (described in Note 11), we adjusted the investment in MEP to fair value based on the present value of the expected future cash flows (Level 3), resulting in a nonrecurring fair value adjustment of $52.6 million. Substantially all of our investment in MEP was transferred to ETE. See Note 11.

Contributions in Aid of Construction Costs

On certain of our capital projects, third parties are obligated to reimburse us for all or a portion of project expenditures. The majority of such arrangements are associated with pipeline construction and production well tie-ins. Contributions in aid of construction costs ("CIAC") are netted against our project costs as they are received, and any CIAC which exceeds our total project costs, is recognized as other income in the period in which it is realized.

Shipping and Handling Costs

Shipping and handling costs related to fuel sold are included in cost of products sold. Shipping and handling costs related to fuel consumed for compression and treating are included in operating expenses and are as follows:

	Years Ended December 31, 2011	2010	2009
Shipping and handling costs – recorded in operating expenses	$40,379	$43,321	$55,872

We do not separately charge propane shipping and handling costs to customers.

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Costs and Expenses

Costs of products sold include actual cost of fuel sold, adjusted for the effects of our hedging and other commodity derivative activities, storage fees and inbound freight on propane, and the cost of appliances, parts and fittings. Operating expenses include all costs incurred to provide products to customers, including compensation for operations personnel, insurance costs, vehicle maintenance, advertising costs, shipping and handling costs related to propane, purchasing costs and plant operations. Selling, general and administrative expenses include all partnership related expenses and compensation for executive, partnership, and administrative personnel.

We record the collection of taxes to be remitted to government authorities on a net basis.

Income Taxes

Energy Transfer Partners, L.P. is a limited partnership. As a result, our earnings or losses, to the extent not included in a taxable subsidiary, for federal and state income tax purposes are included in the tax returns of the individual partners. Net earnings for financial statement purposes may differ significantly from taxable income reportable to Unitholders as a result of differences between the tax basis and financial reporting basis of assets and liabilities, in addition to the allocation requirements related to taxable income under our Second Amended and Restated Agreement of Limited Partnership (the "Partnership Agreement").

As a limited partnership, we are generally not subject to income tax. We are, however, subject to a statutory requirement that our non-qualifying income (including income such as derivative gains from trading activities, service income, tank rentals and others) cannot exceed 10% of our total gross income, determined on a calendar year basis under the applicable income tax provisions. If the amount of our non-qualifying income exceeds this statutory limit, we would be taxed as a corporation. Accordingly, certain activities that generate non-qualifying income are conducted through taxable corporate subsidiaries ("C corporations"). These C corporations are subject to federal and state income tax and pay the income taxes related to the results of their operations. For the years ended December 31, 2011, 2010 and 2009, our non-qualifying income did not exceed the statutory limit.

Those subsidiaries which are taxable corporations follow the asset and liability method of accounting for income taxes, under which deferred income taxes are recorded based upon differences between the financial reporting and tax basis of assets and liabilities and are measured using the enacted tax rates and laws that will be in effect when the underlying assets are received and liabilities settled.

The effective tax rate differs from the statutory rate due primarily to Partnership earnings that are generally not subject to federal and state income taxes at the Partnership level.

The components of the federal and state income tax expense (benefit) of our taxable subsidiaries are summarized as follows:

	Years Ended December 31,		
	2011	2010	2009
Current expense (benefit):			
Federal	$(737)	$507	$(8,851)
State	15,407	8,591	9,662
Total	14,670	9,098	811
Deferred expense:			
Federal	3,718	6,325	11,541
State	427	113	425
Total	4,145	6,438	11,966
Total income tax expense	$18,815	$15,536	$12,777

As of December 31, 2011 and 2010, we had net deferred income tax liabilities of $125.9 million and $119.2 million, respectively, recorded in other non-current liabilities in our consolidated balance sheets. Substantially all of our deferred tax liability relates to property, plant and equipment, including $55.3 million and $49.2 million as of December 31, 2011 and 2010, respectively, and basis differences associated with our Class E Units of $72.2 million and $70.2 million as of December 31, 2011 and 2010, respectively. As of December 31, 2011 and 2010 we had deferred income tax liabilities of $0.1 million and $0.4 million, respectively, recorded in accrued and other liabilities in our consolidated balance sheet.

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Accounting for Derivative Instruments and Hedging Activities

For qualifying hedges, we formally document, designate and assess the effectiveness of transactions that receive hedge accounting treatment and the gains and losses offset related results on the hedged item in the statement of operations. The market prices used to value our financial derivatives and related transactions have been determined using independent third party prices, readily available market information, broker quotes and appropriate valuation techniques.

At inception of a hedge, we formally document the relationship between the hedging instrument and the hedged item, the risk management objectives, and the methods used for assessing and testing effectiveness and how any ineffectiveness will be measured and recorded. We also assess, both at the inception of the hedge and on a quarterly basis, whether the derivatives that are used in our hedging transactions are highly effective in offsetting changes in cash flows. If we determine that a derivative is no longer highly effective as a hedge, we discontinue hedge accounting prospectively by including changes in the fair value of the derivative in net income for the period.

If we designate a hedging relationship as a fair value hedge, we record the changes in fair value of the hedged asset or liability in cost of products sold in our consolidated statement of operations. This amount is offset by the changes in fair value of the related hedging instrument. Any ineffective portion or amount excluded from the assessment of hedge ineffectiveness is also included in the cost of products sold in the consolidated statement of operations.

Cash flows from derivatives accounted for as cash flow hedges are reported as cash flows from operating activities, in the same category as the cash flows from the items being hedged.

If we designate a derivative financial instrument as a cash flow hedge and it qualifies for hedge accounting, the change in the fair value is deferred in accumulated other comprehensive income ("AOCI") until the underlying hedged transaction occurs. Any ineffective portion of a cash flow hedge's change in fair value is recognized each period in earnings. Gains and losses deferred in AOCI related to cash flow hedges remain in AOCI until the underlying physical transaction occurs, unless it is probable that the forecasted transaction will not occur by the end of the originally specified time period or within an additional two-month period of time thereafter. For financial derivative instruments that do not qualify for hedge accounting, the change in fair value is recorded in cost of products sold in the consolidated statements of operations.

We manage a portion of our interest rate exposures by utilizing interest rate swaps and similar instruments. Certain of our interest rate derivatives are accounted for as either cash flow hedges or fair value hedges. For interest rate derivatives accounted for as either cash flow or fair value hedges, we report realized gains and losses and ineffectiveness portions of those hedges in interest expense. For interest rate derivatives not designated as hedges for accounting purposes, we report realized and unrealized gains and losses on those derivatives in "Gains (losses) on non-hedged interest rate derivatives" in the consolidated statements of operations. See Note 9 for additional information related to interest rate derivatives.

Allocation of Income (Loss)

For purposes of maintaining partner capital accounts, the Partnership Agreement specifies that items of income and loss shall generally be allocated among the partners in accordance with their percentage interests (see Note 6). Our net income (loss) for partners' capital and statement of operations presentation purposes is allocated to the General Partner and Limited Partners in accordance with their respective partnership percentages, after giving effect to priority income allocations for incentive distributions, if any, to our General Partner, the holder of the incentive distribution rights ("IDRs") pursuant to our Partnership Agreement, which are declared and paid following the close of each quarter. Earnings in excess of distributions are allocated to the General Partner and Limited Partners based on their respective ownership interests.

3. ACQUISITIONS AND RELATED TRANSACTIONS:

Pending Acquisition

On July 19, 2011, ETE entered into a Second Amended and Restated Agreement and Plan of Merger (the "SUG Merger Agreement") with Sigma Acquisition Corporation, a Delaware corporation and wholly-owned subsidiary of ETE ("Merger Sub"), and Southern Union Company, a Delaware corporation ("SUG"). The SUG Merger Agreement modifies certain terms of the Amended and Restated Agreement and Plan of Merger entered into by ETE, Merger Sub and SUG on July 4, 2011 (the “First Amended Merger Agreement”). Under the terms of the SUG Merger Agreement, Merger Sub will merge with and into SUG, with SUG continuing as the surviving entity and becoming a wholly-owned subsidiary of ETE (the “SUG Merger”), subject to certain conditions to closing.

Consummation of the SUG Merger is subject to customary conditions, including, without limitation: (i) the adoption of the Second Amended SUG Merger Agreement by the stockholders of SUG, (ii) the receipt of required approvals from the Federal Energy Regulatory Commission (the “FERC”), the Missouri Public Service Commission and, if required, the Massachusetts

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Department of Public Utilities, (iii) the effectiveness of a registration statement on Form S-4 relating to the ETE Common Units to be issued in the SUG Merger, and (iv) the absence of any law, injunction, judgment or ruling prohibiting or restraining the SUG Merger or making the consummation of the SUG Merger illegal. On July 28, 2011, the waiting period applicable to the SUG Merger under the Hart-Scott-Rodino Antitrust Improvements Act of 1976, as amended (the "HSR Act") expired. On September 23, 2011, the FERC issued a letter order authorizing the transfer of FERC-jurisdictional facilities resulting from the SUG Merger. On October 27, 2011, the registration statement on Form S-4 was declared effective by the SEC. On December 9, 2011, the special meeting of the SUG stockholders was held and the SUG stockholders voted to approve the SUG Merger. ETE and SUG have made filings with the Missouri Public Service Commission and expect to receive its approval of the SUG Merger in the first quarter of 2012.

On July 19, 2011, we entered into an Amended and Restated Agreement and Plan of Merger with ETE (the "Amended Citrus Merger Agreement"). The Amended Citrus Merger Agreement modifies certain terms of the Agreement and Plan of Merger entered into by ETP and ETE on July 4, 2011. Pursuant to the terms of the Second Amended SUG Merger Agreement, immediately prior to the effective time of the SUG Merger, ETE will assign and SUG will assume the benefits and obligations of ETE under the Amended Citrus Merger Agreement. If we do not consummate the Citrus Acquisition on or before April 17, 2012, or the Citrus Merger Agreement is terminated at any time on or before such time, we must redeem the notes at a redemption price equal to 101% of the aggregate principal amount of the notes, plus accrued and unpaid interest, if any, to, but excluding, the redemption date.

Under the Amended Citrus Merger Agreement, it is anticipated that SUG will cause the contribution to ETP of a 50% interest in Citrus Corp., which owns 100% of the Florida Gas Transmission pipeline system and is currently jointly owned by SUG and El Paso Corporation ("El Paso") (the "Citrus Acquisition"). The Citrus Acquisition will be effected through the merger of Citrus ETP Acquisition, L.L.C., a Delaware limited liability company and wholly-owned subsidiary of ETP, with and into CrossCountry Energy, LLC, a Delaware limited liability company and wholly-owned subsidiary of SUG that indirectly owns a 50% interest in Citrus Corp. ("CrossCountry"). In exchange for the interest in Citrus Corp., SUG will receive approximately $2.0 billion, consisting of approximately $1.9 billion in cash and $105 million of ETP common units, with the value of the ETP common units based on the volume-weighted average trading price for the ten consecutive trading days ending immediately prior to the date that is three trading days prior to the closing date of the Citrus Acquisition. In order to increase the expected accretion to be derived from the Citrus Acquisition, ETE has agreed to relinquish its rights to approximately $220 million of the incentive distributions from ETP that ETE would otherwise be entitled to receive over 16 consecutive quarters following the closing of the transaction.

The Amended Citrus Merger Agreement includes customary representations, warranties and covenants of ETP and ETE (including representations, warranties and covenants relating to SUG, CrossCountry and certain of CrossCountry's affiliates). Consummation of the Citrus Acquisition is subject to customary conditions, including, without limitation: (i) satisfaction or waiver of the closing conditions set forth in the SUG Merger Agreement, (ii) the receipt by ETP of any necessary waivers or amendments to its credit agreement, (iii) the amendment of our partnership agreement to reflect the agreed upon relinquishment by ETE of incentive distributions from ETP discussed above, and (iv) the absence of any order, decree, injunction or law prohibiting or making the consummation of the transactions contemplated by the Amended Citrus Merger Agreement illegal. The Amended Citrus Merger Agreement contains certain termination rights for both ETE and ETP, including among others, the right to terminate if the Citrus Acquisition is not completed by December 31, 2012 or if the SUG Merger Agreement is terminated.

Pursuant to the Amended Citrus Merger Agreement, ETE has granted ETP a right of first offer with respect to any disposition by ETE or SUG of Southern Union Gas Services, a subsidiary of SUG that owns and operates a natural gas gathering and processing system serving the Permian Basin in West Texas and New Mexico.

On November 17, 2011, CrossCountry filed a petition in the Court of Chancery in the State of Delaware seeking a declaratory judgment against El Paso that El Paso's right of first refusal under a Capital Stock Agreement ("CSA") governing the Citrus Corp. joint venture between CrossCountry and El Paso would not be triggered by the Citrus Acquisition. This petition was filed by CrossCountry following an exchange of letters between El Paso and SUG in which El Paso stated that it believed the Citrus Acquisition violated the provisions of the CSA related to transfers of equity interests with respect to Citrus Corp. On December 27, 2011, El Paso filed its answer to CrossCountry's petition and, in addition, El Paso brought third-party claims against ETP, ETE and SUG. El Paso’s third-party complaint against ETP seeks declaratory relief regarding El Paso’s rights under the CSA. Specifically, El Paso claims that the Citrus Acquisition violates its right of first refusal and seeks rescission of the Citrus Acquisition or, alternatively, damages. The parties are currently engaged in discovery and the case is scheduled to go to trial on April 26, 2012. ETP believes that El Paso’s assertions related to the Citrus Acquisition under the CSA are without merit.

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2012 Transaction

Propane Operations

On January 12, 2012, we contributed our propane operations, consisting of HOLP and Titan (collectively, the “Propane Business”) to AmeriGas. We received approximately $1.46 billion in cash and approximately 29.6 million AmeriGas common units. AmeriGas assumed approximately $71 million of existing HOLP debt. In connection with the closing of this transaction, we entered into a support agreement with AmeriGas pursuant to which we are obligated to provide contingent, residual support of $1.5 billion of intercompany indebtedness owed by AmeriGas to a finance subsidiary that in turn supports the repayment of $1.5 billion of senior notes issued by this AmeriGas finance subsidiary to finance the cash portion of the purchase price. Under a unitholder agreement with AmeriGas, we are obligated to hold the approximately 29.6 million AmeriGas common units that we received in this transaction until January 2013.

We have not reflected our Propane operations as discontinued operations as we will have a continuing involvement in this business as a result of the investment in AmeriGas that was transferred as consideration for the transaction.

2011 Transactions

LDH Acquisition

On May 2, 2011, ETP-Regency Midstream Holdings, LLC (“ETP-Regency LLC”), a joint venture owned 70% by the Partnership and 30% by Regency Energy Partners LP (“Regency”), acquired all of the membership interest in LDH Energy Asset Holdings LLC (“LDH”), from Louis Dreyfus Highbridge Energy LLC (“Louis Dreyfus”) for approximately $1.98 billion in cash (the “LDH Acquisition”), including working capital adjustments. The Partnership contributed approximately $1.38 billion to ETP-Regency LLC to fund its 70% share of the purchase price. Subsequent to closing, ETP-Regency LLC was renamed Lone Star.

Lone Star owns and operates a natural gas liquids storage, fractionation and transportation business. Lone Star’s storage assets are primarily located in Mont Belvieu, Texas, and its West Texas Pipeline transports NGLs through an intrastate pipeline system that originates in the Permian Basin in west Texas, passes through the Barnett Shale production area in north Texas and terminates at the Mont Belvieu storage and fractionation complex. Lone Star also owns and operates fractionation and processing assets located in Louisiana. The acquisition of LDH by Lone Star expands the Partnership’s asset portfolio by adding an NGL platform with storage, transportation and fractionation capabilities.

We accounted for the LDH Acquisition using the acquisition method of accounting. Lone Star’s results of operations are included in our NGL transportation and services segment. Regency’s 30% interest in Lone Star is reflected as noncontrolling interest.

The following table summarizes the assets acquired and liabilities assumed recognized as of the acquisition date:

Total current assets	$118,177
Property, plant and equipment[(1)]	1,419,591
Goodwill	432,026
Intangible assets	81,000
Other assets	157
	2,050,951
Total current liabilities	74,964
Other long-term liabilities	438
	75,402
Total consideration	1,975,549
Cash received	31,231
Total consideration, net of cash received	$1,944,318

(1) Property, plant and equipment (and estimated useful lives) consists of the following:

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Land and improvements	$30,759
Buildings and improvements (10 to 40 years)	3,123
Pipelines and equipment (20 to 65 years)	662,881
Natural gas liquids storage (40 years)	682,419
Linepack	704
Vehicles (3 to 20 years)	242
Furniture and fixtures (3 to 10 years)	49
Other (5 to 10 years)	8,526
Construction work-in-process	30,888
Property, plant and equipment	$1,419,591

Pro Forma Results of Operations

The following unaudited pro forma consolidated results of operations for the years ended 2011 and 2010 are presented as if the LDH Acquisition had been completed on January 1, 2010.

	Year Ended December 31,	
	2011	2010
Revenues	$6,959,029	$6,189,977
Net income	697,325	614,763
Net income attributable to partners	662,180	594,777
Basic net income (loss) per Limited Partner unit	$1.07	$1.08
Diluted net income (loss) per Limited Partner unit	$1.07	$1.07

The pro forma consolidated results of operations include adjustments to:

- include the results of Lone Star for all periods presented;
- include the incremental expenses associated with the fair value adjustments recorded as a result of applying the acquisition method of accounting;
- include incremental interest expense related to the financing of ETP’s proportionate share of the purchase price; and
- reflect noncontrolling interest related to Regency’s 30% interest in Lone Star.

The pro forma information is not necessarily indicative of the results of operations that would have occurred had the transactions been made at the beginning of the periods presented or the future results of the combined operations.

2010 Transactions

In March 2010, we purchased a natural gas gathering company, which provides dehydration, treating, redelivery and compression services on a 120-mile pipeline system in the Haynesville Shale for approximately $150.0 million in cash, excluding certain adjustments as defined in the purchase agreement. In connection with this transaction, we recorded customer contracts of $68.2 million and goodwill of $27.3 million.

2009 Transactions

In November 2009, we acquired all of the outstanding equity interests of a natural gas compression equipment business with operations in Arkansas, California, Colorado, Louisiana, New Mexico, Oklahoma, Pennsylvania and Texas, in exchange for our issuance of 1,450,076 Common Units having an aggregate market value of approximately $63.3 million on the closing date. In connection with this transaction, we received cash of $41.1 million, assumed total liabilities of $30.5 million, which includes $8.4 million in notes payable and recorded goodwill of $8.7 million.

In August 2009, we acquired Energy Transfer Group, L.L.C. (“ETG”), as described in Note 11. In connection with this transaction, we assumed liabilities of $33.5 million and recorded goodwill of $1.7 million.

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4. NET INCOME PER LIMITED PARTNER UNIT:

A reconciliation of net income and weighted average units used in computing basic and diluted net income per unit is as follows:

	Years Ended December 31,		
	2011	2010	2009
Net income attributable to partners	$668,974	$617,222	$791,542
General Partner’s interest in net income	433,148	387,729	365,362
Limited Partners’ interest in net income	235,826	229,493	426,180
Additional earnings allocated from General Partner	734	771	468
Distributions on employee unit awards, net of allocation to General Partner	(7,784)	(4,946)	(2,760)
Net income available to Limited Partners	$228,776	$225,318	$423,888
Weighted average Limited Partner units – basic	207,245,106	188,077,143	167,337,192
Basic net income per Limited Partner unit	$1.10	$1.20	$2.53
Weighted average Limited Partner units	207,245,106	188,077,143	167,337,192
Dilutive effect of unvested unit awards	909,197	640,253	431,789
Weighted average Limited Partner units, assuming dilutive effect of unvested unit awards	208,154,303	188,717,396	167,768,981
Diluted net income per Limited Partner unit	$1.10	$1.19	$2.53

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5. DEBT OBLIGATIONS:

Our debt obligations consist of the following:

	December 31, 2011	2010
ETP Senior Notes:		
5.65% Senior Notes due August 1, 2012	$400,000	$400,000
6.0% Senior Notes due July 1, 2013	350,000	350,000
8.5% Senior Notes due April 15, 2014	350,000	350,000
5.95% Senior Notes due February 1, 2015	750,000	750,000
6.125% Senior Notes due February 15, 2017	400,000	400,000
6.7% Senior Notes due July 1, 2018	600,000	600,000
9.7% Senior Notes due March 15, 2019	600,000	600,000
9.0% Senior Notes due April 15, 2019	650,000	650,000
4.65% Senior Notes due June 1, 2021	800,000	—
6.625% Senior Notes due October 15, 2036	400,000	400,000
7.5% Senior Notes due July 1, 2038	550,000	550,000
6.05% Senior Notes due June 1, 2041	700,000	—
Transwestern Senior Notes:		
5.39% Senior Notes due November 17, 2014	88,000	88,000
5.54% Senior Notes due November 17, 2016	125,000	125,000
5.64% Senior Notes due May 24, 2017	82,000	82,000
5.36% Senior Notes due December 9, 2020	175,000	175,000
5.89% Senior Notes due May 24, 2022	150,000	150,000
5.66% Senior Notes due December 9, 2024	175,000	175,000
6.16% Senior Notes due May 24, 2037	75,000	75,000
HOLP Senior Secured Notes:		
Senior Secured Notes with interest rates ranging from 7.26% to 8.87%	71,314	103,127
ETP Revolving Credit Facility	314,438	402,327
Other long-term debt	10,345	9,541
Unamortized discounts	(15,457)	(12,074)
Fair value adjustments related to interest rate swaps	11,647	17,260
	7,812,287	6,440,181
Current maturities	(424,117)	(35,265)
	$7,388,170	$6,404,916

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The following table reflects future maturities of long-term debt for each of the next five years and thereafter. These amounts exclude (i) maturities of long-term debt related to our Propane Business, which was contributed to AmeriGas in January 2012 (see Note 3), and (ii) $3.8 million in unamortized discounts and fair value adjustments related to interest rate swaps:

2012	$400,000
2013	350,000
2014	438,000
2015	750,000
2016	439,438
Thereafter	5,357,000
Total	$7,734,438

Long-term debt reflected on our consolidated balance sheet includes fair value adjustments related to interest rate swaps, which represent fair value adjustments that had been recorded in connection with fair value hedge accounting prior to the termination of the interest rate swap. As of December 31, 2011 long-term debt includes $11.6 million of fair value adjustments to interest rate swaps, which will be amortized as a reduction of interest expense until 2015.

ETP Senior Notes

The ETP Senior Notes were registered under the Securities Act of 1933 (as amended). The Partnership may redeem some or all of the ETP Senior Notes at any time, or from time to time, pursuant to the terms of the indenture and related indenture supplements related to the ETP Senior Notes. The balance is payable upon maturity. Interest on the ETP Senior Notes is paid semi-annually.

The 9.7% ETP Senior Notes contain a put option on March 15, 2012. The current market value of these notes is significantly in excess of the principal amount making a repurchase at par value uneconomic by the holder. However, if such repurchase were to occur, we would refinance any amounts paid on a long-term basis.

The ETP Senior Notes are unsecured obligations of the Partnership and the obligation of the Partnership to repay the ETP Senior Notes is not guaranteed by any of the Partnership's subsidiaries. As a result, the ETP Senior Notes effectively rank junior to any future indebtedness of ours or our subsidiaries that is both secured and unsubordinated to the extent of the value of the assets securing such indebtedness, and the ETP Senior Notes effectively rank junior to all indebtedness and other liabilities of our existing and future subsidiaries.

In May 2011, we completed a public offering of $800 million aggregate principal amount of 4.65% Senior Notes due June 1, 2021 and $700 million aggregate principal amount of 6.05% Senior Notes due June 1, 2041. We used the net proceeds of $1.48 billion to repay all of the borrowings outstanding under our revolving credit facility, to fund capital expenditures related to pipeline construction projects and for general partnership purposes. We may redeem some or all of the notes at any time and from time to time pursuant to the terms of the indenture subject to the payment of a "make-whole" premium. Interest will be paid semi-annually.

In January 2012, we completed a public offering of $1 billion aggregate principal amount of 5.20% Senior Notes due February 1, 2022 and $1 billion aggregate principal amount of 6.50% Senior Notes due February 1, 2042. We will use the net proceeds of $1.98 billion to fund the cash portion of the purchase price of the Citrus Acquisition and for general partnership purposes. We may redeem some or all of the notes at any time and from time to time pursuant to the terms of the indenture subject to the payment of a "make-whole" premium. Interest will be paid semi-annually. If we do not consummate the Citrus Acquisition on or before April 17, 2012, or the Citrus Merger Agreement is terminated on or before such date, we must redeem the $2.0 billion of senior notes at a redemption price equal to 101% of the aggregate principal amount of the notes, plus accrued and unpaid interest.

In January 2012, we announced a cash tender offer for up to $750 million aggregate principal amount of specified series of the ETP Senior Notes. The tender offer consisted of two separate offers: an Any and All Offer and a Maximum Tender Offer.

In the Any and All Offer, we offered to purchase, under certain conditions, any and all of our 5.65% Senior Notes due August 1, 2012, at a fixed price. Pursuant to the Any and All Offer, we purchased $292.0 million in aggregate principal amount on January 19, 2012.

In the Maximum Tender Offer, we offered to purchase, under certain conditions, certain series of outstanding ETP Senior Notes at a fixed spread over the index rate. Pursuant to this tender offer, on February 7, 2012, we purchased $200.0 million aggregate principal amount of our 9.7% Senior Notes due March 15, 2019, $200.0 million aggregate principal amount of our

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9.0% Senior Notes due April 15, 2019 and $58.1 million aggregate principal amount of our 8.5% Senior Notes due April 15, 2014.

Transwestern Senior Notes

The Transwestern notes are payable at any time in whole or pro rata in part, subject to a premium or upon a change of control event or an event of default, as defined. The balance is payable upon maturity. Interest is paid semi-annually.

HOLP Senior Secured Notes

All receivables, contracts, equipment, inventory, general intangibles, cash concentration accounts, and the capital stock of HOLP and its subsidiaries secure the HOLP Senior Secured Notes. Interest is paid quarterly or semiannually and principal payments are made in annual installments through 2020 except for a one time payment of $16.0 million due in 2013. Subsequent to our contribution of the Propane Business, this debt was assumed by AmeriGas.

Revolving Credit Facility

The indebtedness under ETP's revolving credit facility (the "ETP Credit Facility") is unsecured and not guaranteed by any of the Partnership's subsidiaries and has equal rights to holders of our current and future unsecured debt. The indebtedness under the ETP Credit Facility has the same priority of payment as our other current and future unsecured debt.

As of December 31, 2011, we had $314.4 million outstanding under the ETP Credit Facility, and the amount available for future borrowings was $2.16 billion taking into account letters of credit of $25.6 million. The weighted average interest rate on the total amount outstanding as of December 31, 2011 was 1.78%.

On October 27, 2011, we amended and restated the ETP Credit Facility to, among other things, (i) allow for borrowings of up to $2.5 billion; (ii) extend the maturity date from July 20, 2012 to October 27, 2016 (which may be extended by one year with lender approval); (iii) allow for an increase in the size of the credit facility to $3.75 billion (subject to obtaining lender commitments for the additional borrowing capacity); and (iv) to adjust the interest rates and commitment fees to current market terms. Following this amendment and based on our current ratings, the interest margin for LIBOR rate loans is 1.50% and the commitment fee for unused borrowing capacity is 0.25%.

Covenants Related to Our Credit Agreements

The agreements relating to the ETP Senior Notes contain restrictive covenants customary for an issuer with an investment-grade rating from the rating agencies, which covenants include limitations on liens and a restriction on sale-leaseback transactions.

The credit agreement relating to the ETP Credit Facility contains covenants that limit (subject to certain exceptions) the Partnership's and certain of the Partnership's subsidiaries' ability to, among other things:

- incur indebtedness;
- grant liens;
- enter into mergers;
- dispose of assets;
- make certain investments;
- make Distributions (as defined in such credit agreement) during certain Defaults (as defined in such credit agreement) and during any Event of Default (as defined in such credit agreement);
- engage in business substantially different in nature than the business currently conducted by the Partnership and its subsidiaries;
- engage in transactions with affiliates; and
- enter into restrictive agreements.

The credit agreement relating to the ETP Credit Facility also contains a financial covenant that provides that the Leverage Ratio, as defined in the ETP Credit Facility, shall not exceed 5.0 to 1 as of the end of each quarter, with a permitted increase to 5.5 to 1 during a Specified Acquisition Period, as defined in the ETP Credit Facility.

The agreements relating to the Transwestern senior notes contain certain restrictions that, among other things, limit the incurrence of additional debt, the sale of assets and the payment of dividends and specify a maximum debt to capitalization

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ratio.

Failure to comply with the various restrictive and affirmative covenants of our revolving credit facilities could require us to pay debt balances prior to scheduled maturity and could negatively impact the Operating Companies' ability to incur additional debt and/or our ability to pay distributions.

We were in compliance with all requirements, tests, limitations, and covenants related to our debt agreements as of December 31, 2011.

6. EQUITY:

Limited Partner interests are represented by Common and Class E Units that entitle the holders thereof to the rights and privileges specified in the Partnership Agreement. As of December 31, 2011, there were issued and outstanding 225,468,108 Common Units representing an aggregate 98.5% Limited Partner interest in us. There are also 8,853,832 Class E Units outstanding that are reported as treasury units, which units are entitled to receive distributions in accordance with their terms.

No person is entitled to preemptive rights in respect of issuances of equity securities by us, except that ETP GP has the right, in connection with the issuance of any equity security by us, to purchase equity securities on the same terms as equity securities are issued to third parties sufficient to enable ETP GP and its affiliates to maintain the aggregate percentage equity interest in us as ETP GP and its affiliates owned immediately prior to such issuance.

IDRs represent the contractual right to receive an increasing percentage of quarterly distributions of Available Cash (as defined in our Partnership Agreement) from operating surplus after the minimum quarterly distribution has been paid. Please read "Quarterly Distributions of Available Cash" below. ETP GP owns all of the IDRs.

Common Units

The change in Common Units was as follows:

	Years Ended December 31,		
	2011	2010	2009
Number of Common Units, beginning of period	193,212,590	179,274,747	152,102,471
Common Units issued in connection with public offerings	29,440,000	20,700,000	23,575,000
Common Units issued in connection with certain acquisitions	66,499	—	1,450,076
Common Units issued in connection with the Distribution Reinvestment Plan	353,679	—	—
Common Units issued in connection with the equity distribution program	1,951,715	5,194,287	1,891,691
Issuance of Common Units under equity incentive plans	443,625	317,386	255,509
Redemption of Common Units in connection with MEP Transaction (See Note 11)	—	(12,273,830)	—
Number of Common Units, end of period	225,468,108	193,212,590	179,274,747

Our Common Units are registered under the Securities Exchange Act of 1934 (as amended) and are listed for trading on the NYSE. Each holder of a Common Unit is entitled to one vote per unit on all matters presented to the Limited Partners for a vote. In addition, if at any time any person or group (other than our General Partner and its affiliates) owns beneficially 20% or more of all Common Units, any Common Units owned by that person or group may not be voted on any matter and are not considered to be outstanding when sending notices of a meeting of Unitholders (unless otherwise required by law), calculating required votes, determining the presence of a quorum or for other similar purposes under the Partnership Agreement. The Common Units are entitled to distributions of Available Cash as described below under "Quarterly Distributions of Available Cash."

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Public Offerings

The following table summarizes our public offerings of Common Units, all of which have been registered under the Securities Act of 1933 (as amended):

Date	Number of Common Units (1)	Price per Unit	Net Proceeds	Use of Proceeds
January 2009	6,900,000	$34.05	$225,354	(2)
April 2009	9,775,000	37.55	352,369	(3)
October 2009	6,900,000	41.27	275,979	(2)
January 2010	9,775,000	44.72	423,551	(2)(3)
August 2010	10,925,000	46.22	489,418	(2)(3)
April 2011	14,202,500	50.52	695,496	(3)
November 2011	15,237,500	44.67	660,241	(2)(3)

(1) Number of Common Units includes the exercise of the overallotment options by the underwriters.
(2) Proceeds were used to repay amounts outstanding under the ETP Credit Facility.
(3) Proceeds were used to fund capital expenditures and capital contributions to joint ventures, as well as for general partnership purposes.

Equity Distribution Program

In December 2010, we entered into an Equity Distribution Agreement with Credit Suisse Securities (USA) LLC (“Credit Suisse”). According to the provisions of this agreement, we may offer and sell from time to time through Credit Suisse, as our sales agent, Common Units having an aggregate offering price of up to $200.0 million. Sales of the units are made by means of ordinary brokers’ transactions on the NYSE at market prices, in block transactions or as otherwise agreed between us and Credit Suisse. Under the terms of this agreement, we may also sell Common Units to Credit Suisse as principal for its own account at a price agreed upon at the time of sale. Any sale of Common Units to Credit Suisse as principal would be pursuant to the terms of a separate agreement between us and Credit Suisse.

During 2011, we received proceeds from units issued pursuant to this agreement of approximately $96.3 million, net of commissions, which proceeds were used for general partnership purposes. Approximately $69.6 million of our Common Units remain available to be issued under the agreement based on trades initiated through December 31, 2011.

Previously, we had an Equity Distribution Agreement with UBS Securities LLC ("UBS"), which was similar to our existing agreement with Credit Suisse as described above. During 2010, we received proceeds from units issued pursuant to this agreement of approximately $214.3 million, net of commissions, which proceeds were used to repay amounts outstanding under our revolving credit facility.

Equity Incentive Plan Activity

As discussed in Note 7, we issue Common Units to employees and directors upon vesting of awards granted under our equity incentive plans. Upon vesting, participants in the equity incentive plans may elect to have a portion of the Common Units to which they are entitled withheld by the Partnership to satisfy tax-withholding obligations.

Distribution Reinvestment Program

In April 2011, we filed a registration statement with the SEC covering our Distribution Reinvestment Plan (the “DRIP”). The DRIP provides Unitholders of record and beneficial owners of our Common Units a voluntary means by which they can increase the number of ETP Common Units they own by reinvesting the quarterly cash distributions they would otherwise receive in the purchase of additional Common Units. The registration statement covers the issuance of up to 5,750,000 Common Units under the DRIP.

During 2011, distributions of approximately $15.0 million were reinvested under the DRIP resulting in the issuance of 353,679 Common Units.

Explanation of Responses:

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Class E Units

There are 8,853,832 Class E Units outstanding that are reported as treasury units. These Class E Units are entitled to aggregate cash distributions equal to 11.1% of the total amount of cash distributed to all Unitholders, including the Class E Unitholders, up to $1.41 per unit per year, with any excess thereof available for distribution to Unitholders other than the holders of Class E Units in proportion to their respective interests. The Class E Units are treated as treasury units for accounting purposes
because they are owned by our wholly-owned subsidiary, Heritage Holdings, Inc. Although no plans are currently in place, management may evaluate whether to retire some or all of the Class E Units at a future date.

Quarterly Distributions of Available Cash

The Partnership Agreement requires that we distribute all of our Available Cash to our Unitholders and our General Partner within forty-five days following the end of each fiscal quarter, subject to the payment of incentive distributions to the holders of IDRs to the extent that certain target levels of cash distributions are achieved. The term Available Cash generally means, with respect to any of our fiscal quarters, all cash on hand at the end of such quarter, plus working capital borrowings after the end of the quarter, less reserves established by the General Partner in its sole discretion to provide for the proper conduct of our business, to comply with applicable laws or any debt instrument or other agreement, or to provide funds for future distributions to partners with respect to any one or more of the next four quarters. Available Cash is more fully defined in our Partnership Agreement.

Our distributions of Available Cash from operating surplus, excluding incentive distributions, to our General Partner and Limited Partner interests are based on their respective interests as of the distribution record date. Incentive distributions allocated to our General Partner are determined based on the amount by which quarterly distribution to common Unitholders exceed certain specified target levels, as set forth in our Partnership Agreement.

Distributions declared during the periods presented below are summarized as follows:

Quarter Ended	Record Date	Payment Date	Rate
September 30, 2011	November 4, 2011	November 14, 2011	$0.89375
June 30, 2011	August 5, 2011	August 15, 2011	0.89375
March 31, 2011	May 6, 2011	May 16, 2011	0.89375
December 31, 2010	February 7, 2011	February 14, 2011	0.89375
September 30, 2010	November 8, 2010	November 15, 2010	$0.89375
June 30, 2010	August 9, 2010	August 16, 2010	0.89375
March 31, 2010	May 7, 2010	May 17, 2010	0.89375
December 31, 2009	February 8, 2010	February 15, 2010	0.89375
September 30, 2009	November 9, 2009	November 16, 2009	$0.89375
June 30, 2009	August 7, 2009	August 14, 2009	0.89375
March 31, 2009	May 8, 2009	May 15, 2009	0.89375
December 31, 2008	February 6, 2009	February 13, 2009	0.89375

On January 25, 2012, we declared a cash distribution for the three months ended December 31, 2011 of $0.89375 per Common Unit. We paid this distribution on February 14, 2012 to Unitholders of record at the close of business on February 7, 2012.

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The total amounts of distributions declared during the years ended December 31, 2011, 2010 and 2009 were as follows (all from Available Cash from our operating surplus and are shown in the period with respect to which they relate):

	Years Ended December 31,		
	2011	2010	2009
Limited Partners:			
Common Units	$762,350	$676,798	$629,263
Class E Units	12,484	12,484	12,484
General Partner interest	19,603	19,524	19,505
Incentive Distribution Rights	421,888	375,979	350,486
	$1,216,325	$1,084,785	$1,011,738

Accumulated Other Comprehensive Income

The following table presents the components of AOCI, net of tax:

	December 31,	
	2011	2010
Net gains on commodity related hedges	$6,455	$25,245
Unrealized gains on available-for-sale securities	114	918
Total AOCI, net of tax	$6,569	$26,163

7. UNIT-BASED COMPENSATION PLANS:

We have issued equity incentive plans for employees, officers and directors, which provide for various types of awards, including options to purchase ETP Common Units, restricted units, phantom units, Common Units, distribution equivalent rights ("DERs"), Common Unit appreciation rights, and other unit-based awards. As of December 31, 2011, an aggregate total of 2,788,181 ETP Common Units remain available to be awarded under our equity incentive plans.

Unit Grants

We have granted restricted unit awards to employees that vest over a specified time period, typically a five-year period at 20% per year, with vesting based on continued employment as of each applicable vesting date. Upon vesting, ETP Common Units are issued. These unit awards entitle the recipients of the unit awards to receive, with respect to each Common Unit subject to such award that has not either vested or been forfeited, a cash payment equal to each cash distribution per Common Unit made by us on our Common Units promptly following each such distribution by us to our Unitholders. We refer to these rights as "distribution equivalent rights."

Under our equity incentive plans, our non-employee directors each receive grants that vest ratably over three years and do not entitle the holders to receive distributions during the vesting period.

Award Activity

The following table shows the activity of the awards granted to employees and non-employee directors:

	Number of Units	Weighted Average Grant-Date Fair Value Per Unit
Unvested awards as of December 31, 2010	1,936,578	$43.95
Awards granted	1,386,251	48.35
Awards vested	(610,557)	44.07
Awards forfeited	(148,563)	42.74
Unvested awards as of December 31, 2011	2,563,709	46.37

During the years ended December 31, 2011, 2010 and 2009, the weighted average grant-date fair value per unit award granted

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was $48.35, $49.82 and $43.56, respectively. The total fair value of awards vested was $26.9 million, $16.5 million and $14.7 million, respectively based on the market price of ETP Common Units as of the vesting date. As of December 31, 2011, a total of 2,563,709 unit awards remain unvested, for which ETP expects to recognize a total of $79.4 million in compensation expense over a weighted average period of 1.9 years.

Related Party Awards

McReynolds Energy Partners, L.P., the general partner of which is owned and controlled by the President of the entity that indirectly owns our General Partner, awarded to certain officers of ETP certain rights related to units of ETE previously issued by ETE to such ETE officer. These rights include the economic benefits of ownership of these ETE units based on a five year vesting schedule whereby the officer will vest in the ETE units at a rate of 20% per year. As these ETE units are conveyed to the recipients of these awards upon vesting from a partnership that is not owned or managed by ETE or ETP, none of the costs related to such awards are paid by ETP or ETE unless this partnership defaults under its obligations pursuant to these unit awards. As these units were outstanding prior to these awards, these awards do not represent an increase in the number of outstanding units of either ETP or ETE and are not dilutive to cash distributions per unit with respect to either ETP or ETE.

We are recognizing non-cash compensation expense over the vesting period based on the grant-date fair value of the ETE units awarded the ETP employees assuming no forfeitures. For the years ended December 31, 2011, 2010 and 2009, we recognized non-cash compensation expense, net of forfeitures, of $2.0 million, $3.7 million and $6.4 million, respectively, as a result of these awards. As of December 31, 2011, rights related to 180,000 ETE common units remain outstanding, for which we expect to recognize a total of $1.0 million in compensation expense over a weighted average period of 1.0 years.

8. REGULATORY MATTERS, COMMITMENTS, CONTINGENCIES AND ENVIRONMENTAL LIABILITIES:

Regulatory Matters

On September 21, 2011, in lieu of filing a new general rate case filing under Section 4 of the NGA, Transwestern filed a proposed settlement with the FERC, which was approved by the FERC on October 31, 2011. Transwestern is required to file a new general rate case on October 1, 2014. However, shippers which were not parties to the settlement have the right to challenge the lawfulness of tariff rates that have become final and effective. The FERC may also investigate such rates absent shipper complaint.

Guarantee - Fayetteville Express Pipeline LLC

Fayetteville Express Pipeline LLC (“FEP”), a joint venture entity in which we own a 50% interest, had a credit agreement that provided for a $1.1 billion senior revolving credit facility (the “FEP Facility”). We guaranteed 50% of the obligations of FEP under the FEP Facility, with the remainder of FEP Facility obligations guaranteed by Kinder Morgan Energy Partners, L.P. (“KMP”). Amounts borrowed under the FEP Facility bore interest at a rate based on either a Eurodollar rate or a prime rate.

In July 2011, the FEP Facility was repaid with capital contributions from ETP and KMP totaling $390 million along with proceeds from a $600 million term loan credit facility maturing in July 2012 (which can be extended for one year at the option of FEP). Upon closing and funding of the term loan facility, the FEP Facility was terminated. FEP also entered into a $50 million revolving credit facility maturing in July 2015. FEP’s indebtedness under its new credit facilities is not guaranteed by ETP or KMP.

Contingent Residual Support Agreement - AmeriGas

In order to finance the cash portion of the purchase price of the Propane Transaction described in Note 3, AmeriGas Finance LLC ("Finance Company"), a wholly owned subsidiary of AmeriGas, issued $550 million in aggregate principal amount of 6.75% senior notes due 2020 and $1.0 billion in aggregate principal amount of 7.00% senior notes due 2022. AmeriGas borrowed $1.5 billion of the proceeds of the Senior Notes issuance from Finance Company through an intercompany borrowing having maturity dates and repayment terms that mirror those of the Senior Notes (the "Supported Debt").

In connection with the closing of the Propane Transaction, ETP entered into and delivered a Contingent Residual Support Agreement ("CRSA") with AmeriGas, Finance Company, AmeriGas Finance Corp. and UGI Corp., pursuant to which ETP will provide contingent, residual support of the Supported Debt as defined in the CRSA.

NGL Pipeline Regulation

We have interests in NGL pipelines located in Texas. We believe that these pipelines do not provide interstate service and that they are thus not subject to the jurisdiction of the FERC under the Interstate Commerce Act ("ICA") and the Energy Policy Act of 1992. Under the ICA, tariffs must be just and reasonable and not unduly discriminatory or confer any undue preference. We cannot guarantee that the jurisdictional status of our NGL facilities will remain unchanged; however, should they be found

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jurisdictional, the FERC's rate-making methodologies may limit our ability to set rates based on our actual costs, may delay or limit the use of rates that reflect increased costs and may subject us to potentially burdensome and expensive operational, reporting and other requirements. Any of the foregoing could adversely affect our business, revenues and cash flow.

Commitments

In the normal course of our business, we purchase, process and sell natural gas pursuant to long-term contracts and we enter into long-term transportation and storage agreements. Such contracts contain terms that are customary in the industry. We have several propane purchase and supply commitments, which are typically one year agreements with varying terms as to quantities, prices and expiration dates. We believe that the terms of these agreements are commercially reasonable and will not have a material adverse effect on our financial position or results of operations.

We have certain non-cancelable leases for property and equipment, which require fixed monthly rental payments and expire at various dates through 2029. Rental expense under these operating leases has been included in operating expenses in the accompanying statements of operations and totaled approximately $26.1 million, $21.1 million and $19.8 million for the years ended December 31, 2011, 2010 and 2009, respectively.

Future minimum lease commitments for such leases are:

Years Ending December 31:	
2012	$19,795
2013	18,874
2014	16,304
2015	16,220
2016	16,327
Thereafter	149,844

Amounts reflected above do not include future minimum lease commitments for our propane operations, which was deconsolidated in January 2012 in connection with the contribution of these operations described in Note 3.

Our joint venture agreements require that we fund our proportionate share of capital contributions to our unconsolidated affiliates. Such contributions will depend upon our unconsolidated affiliates' capital requirements, such as for funding capital projects or repayment of long-term obligations.

Litigation and Contingencies

We may, from time to time, be involved in litigation and claims arising out of our operations in the normal course of business. Natural gas and propane are flammable, combustible gases. Serious personal injury and significant property damage can arise in connection with their transportation, storage or use. In the ordinary course of business, we are sometimes threatened with or named as a defendant in various lawsuits seeking actual and punitive damages for product liability, personal injury and property damage. We maintain liability insurance with insurers in amounts and with coverage and deductibles management believes are reasonable and prudent, and which are generally accepted in the industry. However, there can be no assurance that the levels of insurance protection currently in effect will continue to be available at reasonable prices or that such levels will remain adequate to protect us from material expenses related to product liability, personal injury or property damage in the future.

We or our subsidiaries are a party to various legal proceedings and/or regulatory proceedings incidental to our businesses. For each of these matters, we evaluate the merits of the case, our exposure to the matter, possible legal or settlement strategies, the likelihood of an unfavorable outcome and the availability of insurance coverage. If we determine that an unfavorable outcome of a particular matter is probable and can be estimated, we accrue the contingent obligation, as well as any expected insurance recoverable amounts related to the contingency. As of December 31, 2011 and 2010, accruals of approximately $18.2 million and $10.2 million, respectively, were reflected on our balance sheets related to these contingent obligations. As new information becomes available, our estimates may change. The impact of these changes may have a significant effect on our results of operations in a single period. The outcome of these matters cannot be predicted with certainty and there can be no assurance that the outcome of a particular matter will not result in the payment of amounts that have not been accrued for the matter. Furthermore, we may revise accrual amounts prior to resolution of a particular contingency based on changes in facts and circumstances or changes in the expected outcome.

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No amounts have been recorded in our December 31, 2011 or 2010 consolidated balance sheets for contingencies and current litigation, other than amounts disclosed herein.

Environmental Matters

Our operations are subject to extensive federal, state and local environmental and safety laws and regulations that require expenditures to ensure compliance, including related to air emissions and wastewater discharges, at operating facilities and for remediation at current and former facilities as well as waste disposal sites. Although we believe our operations are in substantial compliance with applicable environmental laws and regulations, risks of additional costs and liabilities are inherent in the business of transporting, storing, gathering, treating, compressing, blending and processing natural gas, natural gas liquids and other products. As a result, there can be no assurance that significant costs and liabilities will not be incurred. Costs of planning, designing, constructing and operating pipelines, plants and other facilities must incorporate compliance with environmental laws and regulations and safety standards. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, the imposition of remedial obligations, the issuance of injunctions and the filing of federally authorized citizen suits. Moreover, there can be no assurance that other developments, such as increasingly stringent environmental laws, regulations and enforcement policies thereunder, and claims for damages to property or persons resulting from the operations, will not result in substantial costs and liabilities. We are unable to estimate any losses or range of losses that could result from such developments. Furthermore, we may revise accrual amounts prior to resolution of a particular contingency based on changes in facts and circumstances or changes in the expected outcome.

Environmental exposures and liabilities are difficult to assess and estimate due to unknown factors such as the magnitude of possible contamination, the timing and extent of remediation, the determination of our liability in proportion to other parties, improvements in cleanup technologies and the extent to which environmental laws and regulations may change in the future. Although environmental costs may have a significant impact on the results of operations for any single period, we believe that such costs will not have a material adverse effect on our financial position.

As of December 31, 2011 and 2010, accruals on an undiscounted basis of $13.7 million and $13.8 million, respectively, were recorded in our consolidated balance sheets as accrued and other current liabilities and other non-current liabilities related to environmental matters.

Based on information available at this time and reviews undertaken to identify potential exposure, we believe the amount reserved for environmental matters is adequate to cover the potential exposure for cleanup costs.

Transwestern conducts soil and groundwater remediation at a number of its facilities. Some of the cleanup activities include remediation of several compressor sites on the Transwestern system for contamination by polychlorinated biphenyls (“PCBs”). The costs of this work are not eligible for recovery in rates. The total accrued future estimated cost of remediation activities expected to continue through 2025 is $5.7 million, which is included in the aggregate environmental accruals discussed above. Transwestern received approval from the FERC for the continuation of rate recovery of projected soil and groundwater remediation costs not related to PCBs for the term of its rate case settlement.

Transwestern, as part of ongoing arrangements with customers, continues to incur costs associated with containing and removing potential PCBs. Future costs cannot be reasonably estimated because remediation activities are undertaken as claims are made by customers and former customers. However, such future costs are not expected to have a material impact on our financial position, results of operations or cash flows.

The U.S. Environmental Protection Agency’s (the “EPA”) Spill Prevention, Control and Countermeasures program regulations were recently modified and impose additional requirements on many of our facilities. We expect to expend resources on tank integrity testing and any associated corrective actions as well as potential upgrades to containment structures to comply with the new rules. Costs associated with tank integrity testing and resulting corrective actions cannot be reasonably estimated at this time, but we believe such costs will not have a material adverse effect on our financial position, results of operations or cash flows.

Petroleum-based contamination or other environmental wastes are known to be located on or adjacent to six sites on which HOLP presently has, or formerly had, retail propane operations. These sites were evaluated at the time of their acquisition. In all cases, remediation operations have been or will be undertaken by others, and in all six cases, HOLP obtained indemnification rights for expenses associated with any remediation from the former owners or related entities. We have not been named as a potentially responsible party at any of these sites, and we believe that our operations have not contributed to the environmental issues at these sites. Accordingly, no amounts have been recorded in our December 31, 2011 or 2010 consolidated balance sheets. Based on information currently available to us, the presence of contamination and remediation activities at these sites are not expected to have a material adverse effect on our financial condition or results of operations.

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On August 20, 2010, the EPA published new regulations under the federal Clean Air Act (“CAA”) to control emissions of hazardous air pollutants from existing stationary reciprocal internal combustion engines. The rule will require us to undertake certain expenditures and activities, likely including purchasing and installing emissions control equipment. In response to an industry group legal challenge to portions of the rule in the U.S. Court of Appeals for the D.C. Circuit and a Petition for Administrative Reconsideration to the EPA, on March 9, 2011, the EPA issued a new proposed rule and direct final rule effective on May 9, 2011 to clarify compliance requirements related to operation and maintenance procedures for continuous parametric monitoring systems. If no further changes to the standard are made as a result of comments to the proposed rule, we would not expect that the cost to comply with the rule’s requirements will have a material adverse effect on our financial condition or results of operations. Compliance with the final rule is required by October 2013.

On June 29, 2011, the EPA finalized a rule under the CAA that revised the new source performance standards for manufacturers, owners and operators of new, modified and reconstructed stationary internal combustion engines. The rule became effective on August 29, 2011. The rule modifications may require us to undertake significant expenditures, including expenditures for purchasing, installing, monitoring and maintaining emissions control equipment, if we replace equipment or expand existing facilities in the future. At this point, we are not able to predict the cost to comply with the rule’s requirements, because the rule applies only to changes we might make in the future.

Our pipeline operations are subject to regulation by the U.S. Department of Transportation (“DOT”) under the Pipeline Hazardous Materials Safety Administration (“PHMSA”), pursuant to which the PHMSA has established requirements relating to the design, installation, testing, construction, operation, replacement and management of pipeline facilities. Moreover, the PHMSA, through the Office of Pipeline Safety, has promulgated a rule requiring pipeline operators to develop integrity management programs to comprehensively evaluate their pipelines, and take measures to protect pipeline segments located in what the rule refers to as “high consequence areas.” Activities under these integrity management programs involve the performance of internal pipeline inspections, pressure testing or other effective means to assess the integrity of these regulated pipeline segments, and the regulations require prompt action to address integrity issues raised by the assessment and analysis. For the years ended December 31, 2011, 2010 and 2009, $18.3 million, $13.3 million and $31.4 million, respectively, of capital costs and $14.7 million, $15.4 million and $18.5 million, respectively, of operating and maintenance costs have been incurred for pipeline integrity testing. Integrity testing and assessment of all of these assets will continue, and the potential exists that results of such testing and assessment could cause ETP to incur even greater capital and operating expenditures for repairs or upgrades deemed necessary to ensure the continued safe and reliable operation of its pipelines; however, no estimate can be made at this time of the likely range of such expenditures.

Our operations are also subject to the requirements of the federal Occupational Safety and Health Act (“OSHA”), and comparable state laws that regulate the protection of the health and safety of employees. In addition, OSHA’s hazardous communication standard requires that information be maintained about hazardous materials used or produced in our operations and that this information be provided to employees, state and local government authorities and citizens. We believe that our operations are in substantial compliance with the OSHA requirements, including general industry standards, record keeping requirements, and monitoring of occupational exposure to regulated substances.

National Fire Protection Association Pamphlets No. 54 and No. 58, which establish rules and procedures governing the safe handling of propane, or comparable regulations, have been adopted as the industry standard in all of the states in which we operate. In some states, these laws are administered by state agencies, and in others, they are administered on a municipal level. With respect to the transportation of propane by truck, we are subject to regulations governing the transportation of hazardous materials under the Federal Motor Carrier Safety Act, administered by the DOT. We conduct ongoing training programs to help ensure that our operations are in compliance with applicable regulations. We believe that the procedures currently in effect at all of our facilities for the handling, storage and distribution of propane are consistent with industry standards and are in substantial compliance with applicable laws and regulations.

9. PRICE RISK MANAGEMENT ASSETS AND LIABILITIES:

Commodity Price Risk

We are exposed to market risks related to the volatility of natural gas, NGL and propane prices. To manage the impact of volatility from these prices, we utilize various exchange-traded and OTC commodity financial instrument contracts. These contracts consist primarily of futures, swaps and options and are recorded at fair value in the consolidated balance sheets.

We inject and hold natural gas in our Bammel storage facility to take advantage of contango markets (i.e., when the price of natural gas is higher in the future than the current spot price). We use financial derivatives to hedge the natural gas held in connection with these arbitrage opportunities. At the inception of the hedge, we lock in a margin by purchasing gas in the spot market or off peak season and entering into a financial contract to lock in the sale price. If we designate the related financial contract as a fair value hedge for accounting purposes, we value the hedged natural gas inventory at current spot

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market prices along with the financial derivative we use to hedge it. Changes in the spread between the forward natural gas prices designated as fair value hedges and the physical inventory spot price result in unrealized gains or losses until the underlying physical gas is withdrawn and the related designated derivatives are settled. Once the gas is withdrawn and the designated derivatives are settled, the previously unrealized gains or losses associated with these positions are realized. Unrealized margins represent the unrealized gains or losses from our derivative instruments using mark-to-market accounting, with changes in the fair value of our derivatives being recorded directly in earnings. These margins fluctuate based upon changes in the spreads between the physical spot price and forward natural gas prices. If the spread narrows between the physical and financial prices, we will record unrealized gains or lower unrealized losses. If the spread widens, we will record unrealized losses or lower unrealized gains. Typically, as we enter the winter months, the spread converges so that we recognize in earnings the original locked-in spread through either mark-to-market adjustments or the physical withdrawal of natural gas.

We are also exposed to market risk on natural gas we retain for fees in our intrastate transportation and storage segment and operational gas sales on our interstate transportation segment. We use financial derivatives to hedge the sales price of this gas, including futures, swaps and options. Certain contracts that qualify for hedge accounting, are designated as cash flow hedges of the forecasted sale of natural gas. The change in value, to the extent the contracts are effective, remains in AOCI until the forecasted transaction occurs. When the forecasted transaction occurs, any gain or loss associated with the derivative is recorded in cost of products sold in the consolidated statement of operations.

During the fourth quarter of 2011, our trading activities included the use of financial commodity derivatives to take advantage of market opportunities. These trading activities are a complement to our transportation and storage segment's operations and are accounted for in cost of products sold in our consolidated statements of operations. As a result of our trading activities and the use of derivative financial instruments in our transportation and storage segment, the degree of earnings volatility that can occur may be significant, favorably or unfavorably, from period to period. We attempt to manage this volatility through the use of daily position and profit and loss reports provided to our risk oversight committee, which includes members of senior management, and the limits and authorizations set forth in our commodity risk management policy.

Derivatives are utilized in our midstream segment in order to mitigate price volatility and manage fixed price exposure incurred from contractual obligations. We attempt to maintain balanced positions in our marketing activities to protect against volatility in the energy commodities markets; however, net unbalanced positions can exist. Long-term physical contracts are tied to index prices. System gas, which is also tied to index prices, is expected to provide most of the gas required by our long-term physical contracts. When third-party gas is required to supply long-term contracts, a hedge is put in place to protect the margin on the contract. To the extent that financial contracts are not tied to physical delivery volumes, we may engage in offsetting financial contracts to balance our positions. To the extent open commodity positions exist, fluctuating commodity prices can impact our financial position and results of operations, either favorably or unfavorably.

Our propane segment permitted customers to guarantee the propane delivery price for the next heating season. As we executed fixed sales price contracts with our customers, we entered into propane futures contracts to fix the purchase price related to these sales contracts, thereby locking in a gross profit margin. Additionally, we used propane futures contracts to secure the purchase price of our propane inventory for a percentage of our anticipated propane sales.

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The following table details our outstanding commodity-related derivatives:

	December 31, 2011		December 31, 2010	
	Notional Volume	Maturity	Notional Volume	Maturity
Mark to Market Derivatives				
Natural Gas:				
Basis Swaps IFERC/NYMEX (MMBtu) - trading (1)	(151,260,000)	2012-2013	—	—
Basis Swaps IFERC/NYMEX (MMBtu) - non-trading	(61,420,000)	2012-2013	(38,897,500)	2011
Swing Swaps IFERC (MMBtu)	92,370,000	2012-2013	(19,720,000)	2011
Fixed Swaps/Futures (MMBtu)	797,500	2012	(2,570,000)	2011
Forward Physical Contracts (MMBtu)	(10,672,028)	2012	—	—
Options — Calls (MMBtu)	—	—	(3,000,000)	2011
Propane:				
Forwards/Swaps (Gallons)	38,766,000	2012-2013	1,974,000	2011
Fair Value Hedging Derivatives				
Natural Gas:				
Basis Swaps IFERC/NYMEX (MMBtu)	(28,752,500)	2012	(28,050,000)	2011
Fixed Swaps/Futures (MMBtu)	(45,822,500)	2012	(39,105,000)	2011
Hedged Item — Inventory (MMBtu)	45,822,500	2012	39,105,000	2011
Cash Flow Hedging Derivatives				
Natural Gas:				
Fixed Swaps/Futures (MMBtu)	—	—	(210,000)	2011
Options – Puts (MMBtu)	3,600,000	2012	26,760,000	2011-2012
Options – Calls (MMBtu)	(3,600,000)	2012	(26,760,000)	2011-2012
Propane:				
Forwards/Swaps (Gallons)	—	—	32,466,000	2011

(1) Includes aggregate amounts for open positions related to Houston Ship Channel, Waha Hub, NGPL TexOk, West Louisiana Zone and Henry Hub locations.

We expect gains of $6.4 million related to commodity derivatives to be reclassified into earnings over the next 12 months related to amounts currently reported in AOCI. The amount ultimately realized, however, will differ as commodity prices change and the underlying physical transaction occurs.

Interest Rate Risk

We are exposed to market risk for changes in interest rates. In order to maintain a cost effective capital structure, we borrow funds using a mix of fixed rate debt and variable rate debt. We manage our current interest rate exposures by utilizing interest rate swaps to achieve a desired mix of fixed and variable rate debt. We also utilize forward starting interest rate swaps to lock in the rate on a portion of our anticipated debt issuances.

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We had the following interest rate swaps outstanding as of December 31, 2011 and 2010, none of which are designated as hedges for accounting purposes:

Term	Type [1]	Notional Amount Outstanding December 31, 2011	December 31, 2010
May 2012[2]	Forward starting to pay a fixed rate of 2.59% and receive a floating rate	$350,000	$—
August 2012[2]	Forward starting to pay a fixed rate of 3.51% and receive a floating rate	500,000	400,000
July 2013[2]	Forward starting to pay a fixed rate of 4.02% and receive a floating rate	300,000	—
July 2018	Pay a floating rate plus a spread of 4.01% and receive a fixed rate of 6.70%	500,000	500,000

(1) As of December 31, 2011, floating rates are based on 3-month LIBOR.

(2) Represents the effective date. These forward starting swaps have a term of 10 years with a mandatory termination date the same as the effective date.

Credit Risk

We maintain credit policies with regard to our counterparties that we believe minimize our overall credit risk. These policies include an evaluation of potential counterparties' financial condition (including credit ratings), collateral requirements under certain circumstances and the use of standardized agreements, which allow for netting of positive and negative exposure associated with a single or multiple counterparties.

Our counterparties consist primarily of petrochemical companies and other industrials, small to major oil and gas producers, midstream and power generation companies. This concentration of counterparties may impact our overall exposure to credit risk, either positively or negatively in that the counterparties may be similarly affected by changes in economic, regulatory or other conditions. Currently, management does not anticipate a material adverse effect on our financial position or results of operations as a result of counterparty nonperformance.

We utilize master-netting agreements and have maintenance margin deposits with certain counterparties in the OTC market and with clearing brokers. Payments on margin deposits are required when the value of a derivative exceeds our pre-established credit limit with the counterparty. Margin deposits are returned to us on the settlement date for non-exchange traded derivatives, and we exchange margin calls on a daily basis for exchange traded transactions. Since the margin calls are made daily with the exchange brokers, the fair value of the financial derivative instruments are deemed current and netted in deposits paid to vendors within other current assets in the consolidated balance sheets. The Partnership had net deposits with counterparties of $66.2 million and $52.2 million as of December 31, 2011 and 2010, respectively.

For financial instruments, failure of a counterparty to perform on a contract could result in our inability to realize amounts that have been recorded on our consolidated balance sheet and recognized in net income or other comprehensive income.

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Derivative Summary

The following table provides a balance sheet overview of the Partnership's derivative assets and liabilities as of December 31, 2011 and 2010:

	Fair Value of Derivative Instruments			
	Asset Derivatives		Liability Derivatives	
	2011	2010	2011	2010
Derivatives designated as hedging instruments:				
Commodity derivatives (margin deposits)	$77,197	$35,031	$(819)	$(6,631)
Commodity derivatives	—	6,589	—	—
	77,197	41,620	(819)	(6,631)
Derivatives not designated as hedging instruments:				
Commodity derivatives (margin deposits)	227,337	64,940	(251,268)	(72,729)
Commodity derivatives	708	275	(4,844)	—
Interest rate derivatives	36,301	20,790	(117,020)	(18,338)
	264,346	86,005	(373,132)	(91,067)
Total derivatives	$341,543	$127,625	$(373,951)	$(97,698)

The commodity derivatives (margin deposits) are recorded in "Other current assets" on our consolidated balance sheets. The remainder of the derivatives are recorded in "Price risk management assets/liabilities."

We disclose the non-exchange traded financial derivative instruments as price risk management assets and liabilities on our consolidated balance sheets at fair value with amounts classified as either current or long-term depending on the anticipated settlement date.

The following tables summarize the amounts recognized with respect to our derivative financial instruments for the periods presented:

	Change in Value Recognized in OCI on Derivatives (Effective Portion)		
	Years Ended December 31,		
	2011	2010	2009
Derivatives in cash flow hedging relationships:			
Commodity derivatives	$19,047	$60,764	$3,143
Interest rate derivatives	—	(1,366)	—
Total	$19,047	$59,398	$3,143

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	Location of Gain/(Loss) Reclassified from AOCI into Income (Effective Portion)	Amount of Gain/(Loss) Reclassified from AOCI into Income (Effective Portion)		
		Years Ended December 31,		
		2011	2010	2009
Derivatives in cash flow hedging relationships:				
Commodity derivatives	Cost of products sold	$37,703	$37,325	$9,924
Interest rate derivatives	Interest expense	—	(1,493)	287
Total		$37,703	$35,832	$10,211

	Location of Gain/(Loss) Reclassified from AOCI into Income (Ineffective Portion)	Amount of Gain (Loss) Recognized in Income on Ineffective Portion		
		Years Ended December 31,		
		2011	2010	2009
Derivatives in cash flow hedging relationships:				
Commodity derivatives	Cost of products sold	$283	$18	$—
Total		$283	$18	$—

	Location of Gain/(Loss) Recognized in Income on Derivatives	Amount of Gain (Loss) Recognized in Income representing hedge ineffectiveness and amount excluded from the assessment of effectiveness		
		Years Ended December 31,		
		2011	2010	2009
Derivatives in fair value hedging relationships (including hedged item):				
Commodity derivatives	Cost of products sold	$34,000	$16,210	$60,045
Total		$34,000	$16,210	$60,045

	Location of Gain/(Loss) Recognized in Income on Derivatives	Amount of Gain (Loss) Recognized in Income on Derivatives		
		Years Ended December 31,		
		2011	2010	2009
Derivatives not designated as hedging instruments:				
Commodity derivatives - Trading	Cost of products sold	$(29,777)	$—	$—
Commodity derivatives - Non-trading	Cost of products sold	$9,257	$11,584	$99,807
Interest rate derivatives	Gains (losses) on non-hedged interest rate derivatives	(77,409)	4,616	39,239
Total		$(97,929)	$16,200	$139,046

We recognized unrealized losses of $20.8 million, $47.4 million, and $18.6 million of unrealized losses on commodity derivatives not in fair value hedging relationships (including the ineffective portion of commodity derivatives in cash flow hedging relationships and amounts classified as trading activity) for the years ended December 31, 2011, 2010 and 2009, respectively. In addition, for the years ended December 31, 2011, 2010 and 2009, we recognized unrealized gains of $9.5 million, $17.4 million and $48.6 million, respectively, on commodity derivatives and related hedged inventory accounted for as fair value hedges.

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10. RETIREMENT BENEFITS:

We sponsor a 401(k) savings plan, which covers virtually all employees. Employer matching contributions are calculated using a formula based on employee contributions. We made matching contributions of $11.3 million, $9.8 million and $9.8 million to the 401(k) savings plan for the years ended December 31, 2011, 2010 and 2009, respectively.

11. RELATED PARTY TRANSACTIONS:

We previously held a 50% interest in Midcontinent Express Pipeline LLC ("MEP"), a joint venture with Kinder Morgan Energy Partners, L.P. (KMP). On May 26, 2010 we transferred a majority of our interest in MEP to ETE in exchange for 12,273,830 common units previously held by ETE. In conjunction with this transfer, we recorded a non-cash charge of approximately $52.6 million during 2010 to reduce the carrying value of our investment in MEP to its estimated fair value. As a part of this transaction, ETE transferred its interest in MEP to Regency in exchange for Regency Common Units. Along with this transaction ETE also transferred its option to purchase ETP's remaining 0.1% interest in MEP. On September 1, 2011, Regency exercised its option to acquire our remaining 0.1% interest in MEP for approximately $1.2 million in cash.

Regency became a related party on May 26, 2010 when ETE acquired all of the equity interest in the general partner of Regency. We provide Regency with certain natural gas sales and transportation services and compression equipment and Regency provides us with certain contract compression services. For the year ended December 31, 2011, we recorded revenue of $34.1 million, costs of products sold of $34.3 million and operating expenses of $2.5 million related to transactions with Regency. For the period from May 26, 2010 to December 31, 2010, we recorded revenue of $4.0 million, costs of products sold of $4.0 million and operating expenses of $0.5 million related to transactions with Regency.

We received $17.1 million, $6.3 million and $0.5 million in management fees from ETE for the provision of various general and administrative services for ETE’s benefit for the years ended December 31, 2011, 2010 and 2009, respectively. The increase recorded in the years ended December 31, 2011 and 2010 were the result of increased service fees related to the provision of various general and administrative services for Regency which was acquired by ETE in 2010. In addition, the management fees for the year ended December 31, 2011 include the provision of various general and administrative services for Regency. For the year ended December 31, 2011 we recorded from Regency $6.6 million for reimbursement of various general and administrative expenses incurred by us.

For the year ended December 31, 2011 revenue of $1.9 million and cost of products sold of $1.2 million are included in our consolidated statement of operations related to transactions with FEP, our unconsolidated affiliate. For the year ended December 31, 2010 revenue of $26.0 million and cost of products sold of $20.5 million are included in our consolidated statement of operations related to transactions with FEP, our unconsolidated affiliate.

Enterprise Products Partners L.P. ("Enterprise") is considered to be a related party to us due to Enterprise’s holdings of outstanding common units of ETE. We and Enterprise transport natural gas on each other’s pipelines, share operating expenses on jointly-owned pipelines and ETC OLP sells natural gas to Enterprise. Our propane operations routinely buy and sell product with Enterprise. Our propane operations purchase a portion of our propane requirements from Enterprise pursuant to an agreement that expires in 2015 and includes an option to extend the agreement for an additional year.

The following table presents sales to and purchases from Enterprise:

	Years Ended December 31,		
	2011	2010	2009
Natural Gas Operations:			
Sales	$654,129	$538,657	$414,333
Purchases	26,992	23,592	48,528
Propane Operations:			
Sales	10,613	15,527	19,961
Purchases	471,046	415,897	343,540

As of December 31, 2011 and 2010, Titan had forward mark-to-market derivatives for approximately 38.8 million and 1.7 million gallons of propane at a fair value liability of $4.1 million and a fair value asset of $0.2 million, respectively, with Enterprise. In addition, as of December 31, 2010, Titan had forward derivatives accounted for as cash flow hedges of 32.5 million gallons of propane at a fair value asset of $6.6 million with Enterprise. Our propane operations discontinued cash

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flow hedge accounting in July 2011; therefore, all of their forward derivatives are currently accounted for using mark-to-market accounting.

The following table summarizes the related party balances on our consolidated balance sheets:

	As of December 31,	
	2011	2010
Accounts receivable from related parties:		
Enterprise:		
Natural Gas Operations	$54,644	$36,736
Propane Operations	—	2,327
Other	27,109	14,803
Total accounts receivable from related parties:	$81,753	$53,866
Accounts payable from related parties:		
Enterprise:		
Natural Gas Operations	$2,198	$2,687
Propane Operations	27,770	22,985
Other	3,405	1,505
Total accounts payable from related parties:	$33,373	$27,177
Net imbalance receivable from (payable to) Enterprise	$(780)	$1,360

On January 18, 2012, Enterprise sold a significant portion of its ownership in ETE's common units. Subsequent to that transaction Enterprise owns less than 5% of ETE's outstanding common units.

Effective August 17, 2009, we acquired 100% of the membership interests of ETG, which owns all of the partnership interests of Energy Transfer Technologies, Ltd. ("ETT"). ETT provides compression services to customers engaged in the transportation of natural gas, including ETP. The membership interests of ETG were contributed to us by our Chief Executive Officer and by two entities, one of which is controlled by a director of our General Partner's general partner and the other of which is controlled by a member of ETP's management. In exchange, the former members acquired the right to receive (in cash or Common Units) future amounts to be determined based on the terms of the contribution arrangement. These contingent amounts are to be determined in 2014 and 2017, and the former members of ETG may receive payments contingent on the acquired operations performing at a level above the average return required by ETP for approval of its own growth projects during the period since acquisition. In addition, the former members may be required to make cash payments to us under certain circumstances. We have not accrued any contingent payments related to this agreement.

Subsequent to the acquisition of ETG, we pay $4.7 million in operating lease payments per year to the former owners for the use of compressor equipment through 2017.

12. REPORTABLE SEGMENTS:

Our financial statements reflect five reportable segments, which conduct their business exclusively in the United States of America, as follows:

- intrastate natural gas transportation and storage;
- interstate natural gas transportation;
- midstream;
- NGL transportation and services (See Note 3); and
- retail propane and other retail propane related operations.

Intersegment and intrasegment transactions are generally based on transactions made at market-related rates. Consolidated revenues and expenses reflect the elimination of all material intercompany transactions.

Revenues from our intrastate transportation and storage segment are primarily reflected in natural gas sales and gathering, transportation and other fees. Revenues from our interstate transportation segment are primarily reflected in gathering, transportation and other fees. Revenues from our midstream segment are primarily reflected in natural gas sales, NGL sales

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and gathering, transportation and other fees. Revenues from our NGL transportation and services segment are primarily reflected in NGL sales and gathering, transportation and other fees. Revenues from our retail propane and other retail propane related segment are primarily reflected in retail propane sales and other.

We previously reported segment operating income as a measure of segment performance. We have revised certain reports provided to our chief operating decision maker to assess the performance of our business to reflect Segment Adjusted EBITDA. We define Segment Adjusted EBITDA as earnings before interest, taxes, depreciation, amortization and other non-cash items, such as non-cash compensation expense, gains and losses on disposals of assets, the allowance for equity funds used during construction, unrealized gains and losses on commodity risk management activities, non-cash impairment charges, and other non-operating income or expense items. Unrealized gains and losses on commodity risk management activities includes unrealized gains and losses on commodity derivatives and inventory fair value adjustments (excluding lower of cost or market adjustments). Segment Adjusted EBITDA reflects amounts for less than wholly owned subsidiaries and unconsolidated affiliates based on the Partnership's proportionate ownership. Based on the change in our segment performance measure, we have recast the presentation of our segment results for the prior years to be consistent with the current year presentation.

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The following tables present the financial information by segment for the following periods:

	Years Ended December 31,		
	2011	2010	2009
Revenues:			
Intrastate transportation and storage:			
Revenues from external customers	$2,397,887	$2,075,217	$1,773,528
Intersegment revenues	276,270	1,215,688	618,016
	2,674,157	3,290,905	2,391,544
Interstate transportation – revenues from external customers	446,743	292,419	270,213
Midstream:			
Revenues from external customers	2,041,600	1,955,627	2,060,451
Intersegment revenues	551,783	1,213,687	380,709
	2,593,383	3,169,314	2,441,160
NGL transportation and services:			
Revenues from external customers	362,701	—	—
Intersegment revenues	34,400	—	—
	397,101	—	—
Retail propane and other retail propane related – revenues from external customers	1,468,082	1,419,646	1,292,583
All other:			
Revenues from external customers	133,427	141,918	20,520
Intersegment revenues	54,155	145,405	1,145
	187,582	287,323	21,665
Eliminations	(916,608)	(2,574,780)	(999,870)
Total revenues	$6,850,440	$5,884,827	$5,417,295
Cost of products sold:			
Intrastate transportation and storage	$1,774,006	$2,381,397	$1,393,295
Midstream	2,085,951	2,759,113	2,116,279
NGL transportation and services	218,283	—	—
Retail propane and other retail propane related	860,323	774,742	596,002
All other	155,374	235,614	16,350
Eliminations	(904,584)	(2,550,925)	(999,870)
Total cost of products sold	$4,189,353	$3,599,941	$3,122,056
Depreciation and amortization:			
Intrastate transportation and storage	$119,600	$116,992	$107,605
Interstate transportation	80,839	52,582	48,297
Midstream	111,226	85,942	70,845
NGL transportation and services	32,459	—	—
Retail propane and other retail propane related	82,310	81,947	83,476
All other	4,470	5,548	2,580
Total depreciation and amortization	$430,904	$343,011	$312,803

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	Years Ended December 31, 2011	2010	2009
Segment Adjusted EBITDA			
Intrastate transportation and storage	$667,294	$716,176	$768,934
Interstate transportation	373,409	220,027	228,705
Midstream	388,578	329,025	206,232
NGL transportation and services	88,197	—	—
Retail propane and other retail propane related	222,204	269,670	270,027
All other	2,881	5,990	3,492
Total Segment Adjusted EBITDA	1,742,563	1,540,888	1,477,390
Depreciation and amortization	(430,904)	(343,011)	(312,803)
Interest expense, net of interest capitalized	(474,113)	(412,553)	(394,274)
Gains (losses) on non-hedged interest rate derivatives	(77,409)	4,616	39,239
Income tax expense	(18,815)	(15,536)	(12,777)
Non-cash compensation expense	(37,457)	(27,180)	(24,032)
Allowance for equity funds used during construction	957	28,942	10,557
Unrealized gains (losses) on commodity risk management activities	(11,407)	(78,300)	29,980
Impairment of investments in affiliates	(5,355)	(52,620)	—
Losses on disposal of assets	(3,188)	(5,043)	(1,564)
Adjusted EBITDA attributable to noncontrolling interest	37,842	—	—
Proportionate share of unconsolidated affiliates' interest, depreciation and allowance for equity funds used during construction	(29,994)	(22,499)	(22,331)
Other, net	4,442	(482)	2,157
Net income	697,162	617,222	791,542
Less: Net income attributable to noncontrolling interest	28,188	—	—
Net income attributable to partners	$668,974	$617,222	$791,542

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	As of December 31, 2011	2010	2009
Total assets:			
Intrastate transportation and storage	$4,784,630	$4,894,352	$4,901,102
Interstate transportation	3,661,098	3,390,588	3,313,837
Midstream	2,665,610	1,842,370	1,523,538
NGL transportation and services	2,360,095	—	—
Retail propane and other retail propane related	1,783,770	1,791,254	1,784,353
All other	263,413	231,428	212,142
Total	$15,518,616	$12,149,992	$11,734,972

	Years Ended December 31, 2011	2010	2009
Additions to property, plant and equipment including acquisitions, net of contributions in aid of construction costs (accrual basis):			
Intrastate transportation and storage	$52,388	$117,295	$378,494
Interstate transportation	207,962	872,112	99,341
Midstream	836,841	404,669	95,081
NGL transportation and services	1,745,035	—	—
Retail propane and other retail propane related	66,053	64,520	62,953
All other	13,586	11,405	44,911
Total	$2,921,865	$1,470,001	$680,780

13. QUARTERLY FINANCIAL DATA (UNAUDITED):

Summarized unaudited quarterly financial data is presented below. The sum of net income per Limited Partner unit by quarter does not equal the net income per limited partner unit for the year due to the computation of income allocation between the General Partner and Limited Partners and variations in the weighted average units outstanding used in computing such amounts. HOLP’s and Titan’s businesses are seasonal due to weather conditions in their service areas. Propane sales to residential and commercial customers are affected by winter heating season requirements, which generally results in higher operating revenues and net income during the period from October through March of each year and lower operating revenues and either net losses or lower net income during the period from April through September of each year. Sales to commercial and industrial customers are less weather sensitive. ETC OLP’s business is also seasonal due to the operations of ET Fuel System and the HPL System. We expect margin related to the HPL System operations to be higher during the periods from November through March of each year and lower during the periods from April through October of each year due to the increased demand for natural gas during the cold weather. However, we cannot assure that management’s expectations will be fully realized in the future and in what time period due to various factors including weather, availability of natural gas in regions in which we operate, competitive factors in the energy industry, and other issues.

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	Quarter Ended March 31	June 30	September 30	December 31	Total Year
2011:					
Revenues	$1,687,577	$1,628,095	$1,715,316	$1,819,452	$6,850,440
Gross profit	693,120	619,467	639,790	708,710	2,661,087
Operating income	363,135	270,419	272,343	338,910	1,244,807
Net income	247,202	156,616	76,050	217,294	697,162
Limited Partners' interest in net income (loss)	139,663	42,336	(38,045)	91,872	235,826
Basic net income per limited partner unit (loss)	$0.71	$0.19	$(0.19)	$0.41	$1.10
Diluted net income per limited partner unit (loss)	$0.71	$0.19	$(0.19)	$0.41	$1.10
2010:					
Revenues	$1,871,981	$1,267,706	$1,290,644	$1,454,496	$5,884,827
Gross profit	647,116	496,849	513,233	627,688	2,284,886
Operating income	344,338	199,184	208,147	306,502	1,058,171
Net income	240,111	42,843	107,387	226,881	617,222
Limited Partners' interest in net income (loss)	140,112	(47,756)	10,341	126,796	229,493
Basic net income per limited partner unit (loss)	$0.74	$(0.26)	$0.05	$0.65	$1.20
Diluted net income per limited partner unit (loss)	$0.74	$(0.26)	$0.05	$0.65	$1.19

For the three months ended September 30, 2011 and June 30, 2010, distributions paid for the period exceeded net income attributable to partners by $229.2 million and $213.3 million, respectively. Accordingly, the distributions paid to the General Partner, including incentive distributions, further exceeded net income, and as a result, a net loss was allocated to the Limited Partners for the period.