Constellation Energy Partners LLC
Form 10-K
March 12, 2007
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-K

(Mark One)

þ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2006

OR

¨ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from to .

Commission File Number 001-33147

Constellation Energy Partners LLC

(Exact Name of Registrant as Specified in Its Charter)

Delaware **(State of organization)**	**11-3742489** **(I.R.S. Employer Identification No.)**
111 Market Place **Baltimore, Maryland** **(Address of Principal Executive Offices)**	**21202** **(Zip Code)**

Telephone Number: (410)468-3500

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

Title of each class	**Name of each exchange on which registered**
Common Units representing Class B Limited Liability Company Interests	NYSE Arca, Inc.

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

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ¨ No þ

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

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

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant s knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. þ

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of accelerated filer and large accelerated filer in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer ¨ Accelerated filer ¨ Non-accelerated filer þ

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act) Yes ¨ No þ

State the aggregate market value of the voting stock held by non-affiliates of the registrant: $135,119,250

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

Common Units outstanding on February 15, 2007: 11,093,894 units

Documents Incorporated by Reference: None

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PART I

Item 1. Business

Overview

We are a limited liability company that was formed by Constellation Energy Group, Inc. (Constellation) in 2005 to acquire oil and natural gas reserves. We are focused on the acquisition, development and production of oil and natural gas properties (E&P properties) as well as related midstream assets. Our primary business objective is to generate stable cash flows allowing us to make quarterly cash distributions to our unitholders and over time to increase our quarterly cash distributions. Currently, our estimated proved reserves are 100% natural gas and are located in the Robinson s Bend Field in Alabama s Black Warrior Basin. Our estimated proved reserves at December 31, 2006 were approximately 120.3 Bcf, approximately 81% of which were classified as proved developed. Our average proved reserve-to-production ratio is approximately 24 years based on our estimated proved reserves at January 1, 2006 and production for the year ended December 31, 2006. We currently own a 100% working interest (an approximate 75% average net revenue interest, calculated before the Torch Royalty NPI, or NPI, described below) in our Robinson s Bend Field producing properties, which had 467 producing natural gas wells as of December 31, 2006.

The Black Warrior Basin is one of the oldest and most prolific coalbed methane basins in the country. The multi-seam vertical wells in the basin range from 500 to 3,700 feet deep, with coal seams averaging a total of 25 to 30 feet of net pay per well. Coalbed methane wells are generally more shallow and produce less than conventional natural gas wells, require pumping units to remove the water from the wells, which we refer to as dewatering, and require fracturing to enhance production. These wells also tend to start producing gas and water immediately upon completion, and production increases as the well is dewatered. However, production rates from newly drilled and completed wells in the Robinson s Bend Field do not always increase as the formation dewaters. Once dewatered, coalbed methane wells often demonstrate fairly constant production rates for up to five years and then start on a decline to a final decline rate of as low as 4% to 6% per year. Typical wells produce over a period of 20 to over 50 years and on average have less favorable economic characteristics than conventional gas wells.

We completed our initial public offering on November 20, 2006 and our common units, representing Class B limited liability company interests, are listed on the NYSE Arca, Inc. under the symbol CEP.

In March 2007, we entered into a definitive purchase agreement to acquire certain coalbed methane properties located in the Cherokee Basin in Kansas and Oklahoma, as discussed in more detail in Note 18 to our consolidated financial statements.

Unless the context requires otherwise, any reference in this Annual Report on Form 10-K to Constellation Energy Partners, we, our, us, CEP, successor company or the Company means Constellation Energy Partners LLC and its subsidiaries. References in this Annual Report on Form 10-K to CCG and to CEPM are to Constellation Energy Commodities Group, Inc., and Constellation Energy Partners Management, LLC, respectively.

Business Strategies

Our primary business objective is to generate stable cash flows allowing us to make quarterly cash distributions to our unitholders and over time to increase the amount of our future quarterly distributions by executing our business strategy, which is to:

- make accretive acquisitions of E&P properties characterized by a high percentage of proved developed reserves with long-lived, stable production and low-risk drilling opportunities, which may include associated midstream assets such as gathering systems, compression, dehydrating and treating facilities and other similar facilities;
- increase reserves and production through what we believe to be low-risk development drilling; and
- reduce the volatility in our revenues resulting from changes in oil and natural gas commodity prices through hedging.

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Robinson s Bend Field

The Robinson s Bend Field was first drilled in the early 1990 s by Torch Energy Corporation (Torch Energy) and its affiliates to take advantage of certain tax credits. Therefore, most of our wells were drilled before 1992. The Robinson s Bend Field was owned and operated by Torch Energy until January 2003, when it was acquired by Everlast Energy LLC (Everlast) a company formed by a former Torch Energy executive. We acquired our initial properties in the Robinson s Bend Field from Everlast in June 2005.

The Robinson s Bend Field is located in western Tuscaloosa County and Pickens County, Alabama and encompasses a gross surface area of approximately 109 square miles. As of December 31, 2006, our interest in the Robinson s Bend Field operated with approximately 467 natural gas wells. The field has been primarily developed on 80-acre spacing. The State of Alabama has approved field-wide either 40-acre or 80-acre spacing. We are currently developing our properties in the field on both 40- and 80-acre spacing.

The field has seven compressor stations with 800-1,200 horse power compressors, approximately 170 miles of gas gathering lines (wells to header) and 25 miles of transportation lines (header to compressor). In addition, there are 152 miles of water gathering pipes and 28 miles of water transportation pipes.

One of our typical well sites consists of a single gas well and associated gas/water separators connected via subsurface piping. Gas flows from the wellhead to compressor facilities, where over 85% of the gas is routed to a natural gas pipeline operated by Southern Natural Gas Company (SONAT). The remaining natural gas is routed to the Enterprise Alabama Intrastate Pipeline from the Maxwell Crossing Module. Water produced from these wells is transferred via a facility pipeline to one of three wastewater treatment facilities, where particulates are removed by settling and the water is then discharged into the Black Warrior River in accordance with effluent standards established by the Alabama Department of Environmental Management (ADEM) and our National Pollutant Discharge Elimination System (NPDES) permits. In addition, there are three saltwater disposal wells that are not currently in use.

Proved Reserves

The following table reflects our internal estimates of net proved natural gas reserves based on the Securities and Exchange Commission (SEC) definitions that were used to prepare our financial statements for the periods presented. The Standardized Measure values shown in the table are not intended to represent the current market values of our estimated natural gas reserves.

	Predecessor Everlast Energy LLC	Successor Constellation Energy Partners LLC	
	As of December 31,	As of December 31,	
Reserve data:	**2004**	**2005**	**2006**
Estimated net proved reserves:			
Natural gas (Bcf)	162.2	112.0	120.3
Proved developed reserves (Bcf)	101.4	89.3	97.4
Proved undeveloped reserves (Bcf)	60.8	22.7	22.9
Proved developed reserves as a percent of total reserves	62%	80%	81%
Standardized Measure (in millions)[(a)]	$ 206.8	$ 295.4	$ 120.2
Natural gas price SONAT Gas Daily (price per MMBtu)[(b)]	$ 6.05	$ 10.06	$ 5.66

(a) Standardized Measure is the present value of estimated future net revenues to be generated from the production of proved reserves, determined in accordance with the rules and regulations of the SEC (using prices and costs in effect as of the date of estimation) without giving effect to non-property related expenses such as general and administrative expenses and debt service or to depreciation, depletion and amortization and discounted using an annual discount rate of 10%. Our Standardized Measure does not include future income taxes because we are not subject to income taxes. Standardized Measure does not give effect to derivative transactions and excludes reserves attributable to the NPI.

(b) Natural gas prices as of each period end were based on the SONAT Gas Daily Price, on the last business day of the relevant period.

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The data presented in the table above is based on our own internal estimates prepared for the predecessor and successor companies at the corresponding year ends and was used to prepare the financial statements presented elsewhere in this Annual Report on Form 10-K. Our 2005 estimates of proved reserves are lower than the 2004 estimates for Everlast, the predecessor company, because of the decision of CEP management to (i) reduce our future drilling program to 20 wells per year over the next six years, (ii) reflect our interpretation of well performance data from new wells drilled in the Robinson s Bend Field in 2004 and 2005, and (iii) reflect the impact of a revised refracture program. There was no drilling in the Robinson s Bend Field between 1994 and late 2003. While the performance data from new wells in the Robinson s Bend Field at December 31, 2005 was limited, we believe it provided relevant information for the purposes of estimating reserves. The revised 20-well drilling program reflects our current intention of how we plan to develop the properties in the future. Our estimate of reserves at December 31, 2005 is also approximately 5.8 Bcf lower than the December 31, 2004 estimates of proved reserves due to a reduction for estimated reserves attributed to the NPI. No corresponding adjustment was made to the December 31, 2006 because no amounts were due or paid in respect of the NPI at those times.

At December 31, 2006, and December 31, 2005, Netherland, Sewell & Associates, Inc. (NSAI), an independent petroleum engineering firm, prepared an estimate of all our proved reserves. NSAI also prepared an updated report at our request to provide a sensitivity of the estimates of the NSAI December 31, 2005 reserves based on our reduced drilling program, our revised refracture program and the elimination of estimated reserves attributable to the NPI. NSAI s estimates of our 2006 and 2005 proved reserves are materially consistent with our internal estimate.

Proved developed reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Proved undeveloped reserves are proved reserves that are expected to be recovered from new wells drilled to known reservoirs on undrilled acreage for which the existence and recoverability of such reserves can be estimated with reasonable certainty, or from existing wells on which a relatively major expenditure is required to establish production. The SEC provides a complete definition of proved reserves, proved developed reserves and proved undeveloped reserves in Rule 4-10(a) of Regulation S-X.

The data in the above table represents estimates only. Natural gas reserve engineering is an inherently subjective process of estimating underground accumulations of oil and natural gas that cannot be measured exactly. The accuracy of any reserve estimate is a function of the quality of available data and engineering, geological interpretation and judgment. Accordingly, reserve estimates may vary from the quantities of natural gas that are ultimately produced.

Future prices received for production and costs may vary, perhaps significantly, from the prices and costs assumed for purposes of these estimates. The Standardized Measures shown should not be considered the current market value of the reserves. The 10% discount factor used to calculate present value, which is required by Financial Accounting Standards Board (FASB) pronouncements, is not necessarily the most appropriate discount rate. The present value, no matter what discount rate is used, is materially affected by assumptions as to timing of future production, which may prove to be inaccurate.

Natural Gas Prices

We have generally sold our production in the Robinson s Bend Field based upon an index price reported in *Inside FERC s Gas Market Report* for the Southern Natural Gas Co., Louisiana Hub, which we refer to as the SONAT Inside FERC price. For the year ended December 31, 2006, the monthly index price varied between a low of $4.18 per MMBtu and a high of $11.67 per MMBtu.

We enter into derivative transactions in the form of hedging arrangements to reduce the impact of natural gas price volatility on our cash flow from operations. Currently, we use fixed price swaps to hedge New York Mercantile Exchange, or NYMEX , natural gas prices. By removing the price volatility from a significant portion of our natural gas production, we have mitigated, but not eliminated, the potential effects of fluctuating natural gas prices on our cash flow from operations for those periods.

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The following table summarizes, as of February 15, 2007, and for the periods indicated, our derivatives in place through December 31, 2009. Our fixed price swap transactions are settled based upon the NYMEX price of natural gas at Henry Hub on the final trading day of the month, and settlement occurs on the third day preceding the production month.

	2007	2008	2009
Hedged Volume (MMBtu)	4,199,996	3,500,004	3,300,000
Average Price ($/MMBtu)	$ 9.19	$ 8.91	$ 8.40

Production and Price History

The following table sets forth information regarding net production of natural gas and certain price and cost information for each of the periods indicated:

	Everlast Energy LLC		Constellation Energy Partners LLC	
	For the year ended December 31, 2004	For the period from January 1, 2005 to June 12, 2005	For the period from February 7, 2005 (inception) to December 31, 2005(a)	For the year ended December 31, 2006
Net Production:				
Total production (MMcf)	4,527	1,970	2,525	4,641
Average daily production (Mcf/d)	12,400	12,100	12,500	12,715
Average Sales Prices:				
Price per Mcf including hedges	$ 4.06	$ (1.23)(b)	$ 10.28(c)	$ 7.95(c)
Price per Mcf excluding hedges	$ 6.07	$ 6.54	$ 10.28	$ 7.43
Average Unit Costs Per Mcf:				
Field operating expenses(d)	$ 1.49	$ 1.75	$ 2.21	$ 1.94
Lease operating expenses	$ 1.16	$ 1.41	$ 1.66	$ 1.56
Production taxes	$ 0.33	$ 0.34	$ 0.55	$ 0.38
General and administrative expenses	$ 0.60	$ 0.30	$ 1.66	$ 0.99
Depreciation, depletion and amortization	$ 0.82	$ 0.85	$ 1.65	$ 1.60

(a) Until our acquisition of our initial properties in the Robinson s Bend Field from Everlast on June 13, 2005, we did not conduct any operations and therefore had no production.

(b) Price per Mcf including hedges includes mark-to-market losses of approximately $15.3 million on derivative transactions that did not qualify for hedge accounting treatment.

(c) We had no derivatives at December 31, 2005. In 2006, we entered into derivative transactions that hedged the future prices on a portion of our expected production from October 2006 through December 2006.

(d) Field operating expenses include lease operating expenses and production taxes.

Torch Royalty NPI

The NPI

The majority of our properties in the Robinson s Bend Field are subject to a non-operating net profits interest (NPI) held by Torch Energy Royalty Trust (the Trust). The NPI is a non-operating net revenue interest upon specified natural gas sales revenues from specified wells in the Robinson s Bend Field (the Trust Wells) reduced by specified associated expenditures. The units of the Trust are listed for trading on the New

York Stock Exchange (the NYSE). An affiliate of Torch Energy conveyed the NPI to the Trust in November 1993, together with net profits interests on three other properties. We acquired our properties in the Robinson s Bend Field from Everlast subject to the NPI. The NPI conveyance gives the Trust an ownership interest in specified properties in the Robinson s Bend Field.

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Not all of our wells within the Robinson s Bend Field are subject to the NPI. Under the NPI, the Trust is entitled to receive monthly payments. As of December 31, 2006, we owned a working interest in 467 producing wells in the Robinson s Bend Field, of which 421 were subject to the NPI:

- with respect to 393 wells, the lesser of (i) 95% of the net proceeds from such wells for the quarter and (ii) the net proceeds from the sale of 912.5 MMcf of natural gas for the quarter; and

- with respect to the remaining 28 wells that are subject to the NPI as of December 31, 2006, and all wells drilled thereafter on leases subject to the NPI other than wells drilled to replace damaged or destroyed wells, 20% of the net proceeds from such wells for the quarter.

Net proceeds is defined under the NPI as gross revenue from the sale of production attributable to the NPI less specified development, operating and other costs and taxes, in each case as calculated under the NPI documentation. After January 1, 2004, lease operating expenses and capital expenditures have also been deducted in calculating net proceeds under the NPI on the Robinson s Bend Field production. If permitted deductions exceed the gross revenue from the sale of production attributable to the NPI, the Trust is not entitled to a payment in respect of the NPI, and such excess, plus interest on such excess, is deducted from gross revenue attributable to future production in respect of the NPI. Payment of the net proceeds, if any, attributable to the NPI are made quarterly. Between July 1, 2003 and December 31, 2005, deductible expenses exceeded gross proceeds attributable to the Trust Wells, resulting in a cumulative deficit of approximately $69,000. The deficit was eliminated as a result of net proceeds attributable to the Trust Wells in January 2006, and we made a payment to the Trust in respect of the NPI of approximately $0.2 million in the aggregate for January through December 2006.

The Gas Purchase Contract

A gas purchase contract was executed in connection with the formation of the Trust in 1993, which established a minimum price for the purchase of the gas from the Trust Wells as well as a sharing arrangement when the applicable index price for gas increased over a specified sharing price. Torch Energy Marketing, Inc., an affiliate of the original sponsor of the Trust (TEMI) as buyer, and another affiliate of TEMI, as seller, entered into the gas purchase contract pursuant to which the parties were obligated to purchase and sell, as the case may be, all net production attributable to the properties subject to the NPI, including the Trust Wells, for an amount equal to the greater of (a) the minimum price of $1.70 per MMBtu, adjusted for inflation, and (b) 97% of a specified index price for natural gas, less certain specified permitted deductions for gathering, treating and transportation that are calculated monthly. The index price for Robinson s Bend Field production equals the SONAT Inside FERC Price. In addition, if 97% of the index price exceeds the sharing price specified in the gas purchase contract as adjusted for inflation, which we refer to as the sharing price, the purchase price for the gas is equal to the sharing price plus 50% of the difference between 97% of the index price and the sharing price. As a result, the purchaser is entitled to retain 50% of that difference between 97% of the index price and sharing price. The sharing price was $2.22, $2.18 and $2.13 per MMBtu in 2006, 2005 and 2004, respectively. Despite increases in recent years in spot prices for natural gas, the sharing arrangement under the gas purchase contract has had the effect of keeping the payments to the Trust significantly lower than if the NPI were calculated using the prevailing market price for production from the Trust Wells.

In connection with our acquisition of our initial properties in the Robinson s Bend Field from Everlast, our subsidiary, Robinson s Bend Marketing II, LLC, assumed TEMI s obligations under the gas purchase contract and our subsidiary, Robinson s Bend Production II, LLC, assumed the TEMI affiliate s obligations under the gas purchase contract, in each case in respect of the Robinson s Bend Field for production from and after June 13, 2005. As a result, we are obligated to sell and to purchase all production from the Trust Wells on the terms and conditions set forth in the gas purchase contract.

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Termination of the Gas Purchase Contract

The gas purchase contract, by its terms, automatically terminates on December 31, 2012 or upon the earlier termination of the Trust. The Trust will terminate upon the first to occur of:

- an affirmative vote to liquidate the Trust by holders of not less than 66 $^{2}/3$% of the outstanding Trust units; and

- such time as the ratio of the cash amounts received by the Trust from the NPI to administrative costs of the Trust is less than 1.2 to 1.0 for three consecutive quarters.

The Trust will also terminate on March 1 of any year if it is determined that the pre-tax future net cash flows, discounted at 10%, attributable to the estimated net proved reserves of the NPI (including the NPI on three other properties) on the preceding December 31 are equal to or less than $25.0 million. Based on reserve estimates at December 31, 2005, prepared by independent reserve engineers, the Trust has previously advised its investors in an SEC filing that, unless the Henry Hub spot price for natural gas on December 31, 2006 exceeded approximately $6.25 per MMBtu, the Trust would terminate on March 1, 2007. On December 30, 2005 and December 29, 2006, the Henry Hub spot prices for natural gas were $10.08 and $5.64 per MMBtu, respectively. On March 2, 2007, the Trust advised that the value of the pre-tax future net cash flows, discounted at 10%, attributable to the estimated net proved reserves of the NPI as of December 31, 2006, exceeded $25.0 million and therefore, the Trust did not terminate as of March 1, 2007.

If the Trust is terminated, the gas purchase contract will be terminated, and we will no longer be obligated to sell gas produced from our interest in the Robinson s Bend Field pursuant to the gas purchase contract. Notwithstanding the termination of the gas purchase contract, the NPI will continue to burden the Trust Wells, and it should continue to be calculated as if the gas purchase contract were still in effect, regardless of what proceeds may actually be received by us as the seller of the gas. The documents creating the NPI are not clear as to this point. However, if it is finally determined that the NPI is to be calculated based on the actual proceeds received for sale of the gas or otherwise without regard to the sharing arrangement, our obligations to the Trust for the NPI could be significantly higher, which would adversely affect our revenues, and results of operations and our ability to pay cash distributions.

In order to address to a limited extent, the risks of the potential adverse impact on our operating results from early termination, without the prior consent of our board of managers, of the sharing arrangement in respect of the calculation of amounts payable to the Trust for the NPI, Constellation Holdings, Inc. (CHI) contributed to us at the closing of our initial public offering $8.0 million for all of our Class D interests. This contribution will be returned to CHI in 24 special quarterly distributions over a period of approximately six years if the sharing arrangement remains in effect during that period. If the amounts payable by us to the Trust are not calculated based on continued applicability of the sharing arrangement through December 31, 2012, unless such change is approved in advance by our board of managers and our conflicts committee, the following will occur: the Class D interests will cease receiving the special quarterly cash distributions; and the Class D interests will only be returned the remaining undistributed amount of the original $8.0 million contribution under certain circumstances upon our liquidation. The effect of our retention and use of the unreturned amount is to provide us with cash that will reduce, but may not eliminate, the adverse impact of our reduced revenues from the termination of the sharing arrangement.

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Productive Wells

The following table sets forth information at December 31, 2006 relating to the productive wells in which we owned a working interest as of that date. Productive wells consist of producing wells and wells capable of production, including natural gas wells awaiting pipeline connections to commence deliveries. Gross wells are the total number of producing wells in which we have an interest, and net wells are the sum of our fractional working interests owned in gross wells.

	Natural Gas December 31, 2006	
	Gross	**Net**
Operated	467	467
Non-operated		
Total	467	467

Drilling Activity

The following table sets forth information with respect to wells completed by us or, for the period prior to June 13, 2005, by Everlast during the years ended December 31, 2004, 2005 and 2006, and wells commenced by us during the year ended December 31, 2006. The information should not be considered indicative of future performance, nor should it be assumed that there is necessarily any correlation between the number of productive wells drilled, quantities of reserves found or economic value. Productive wells are those that produce commercial quantities of natural gas, regardless of whether they produce a reasonable rate of return. No exploratory wells were drilled during the years ended December 31, 2004, 2005 or 2006.

	Year Ended December 31,			Wells in Progress as of December 31,
	2004	**2005**	**2006**	**2006**
Gross:				
Development				
Productive	9	18	31	
Dry				
Total	9	18	31	
Net:				
Development				
Productive	9	18	31	
Dry				
Total	9	18	31	

Development Costs

We drilled and completed 31 gross (31 net) wells during the year ended December 31, 2006. Those 31 wells developed 7.7 Bcf of natural gas previously categorized as proved undeveloped reserves or proved developed non-producing reserves and added 5.3 Bcf of estimated proved undeveloped reserves. We invested a total of $13.5 million in these and other activities on our properties in the Robinson s Bend Field.

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Developed and Undeveloped Acreage

The following table sets forth information as of December 31, 2006 relating to our leasehold acreage. We own a 100% working interest, or an approximate 75% net revenue interest, in all our developed acreage.

	Developed Acreage[a]		Undeveloped Acreage[b][e]	
	Gross[c]	Net[d]	Gross[c]	Net[d]
Total	32,000	32,000	28,000	27,200

(a) Developed acres are acres pooled within or assigned to productive wells/units.
(b) Undeveloped acres are acres on which wells have not been drilled or acres that have not been pooled into a productive unit.
(c) A gross acre is an acre in which a working interest is either fully or partially leased. The number of gross acres may include minerals not under lease as a result of leasing some but not all joint mineral owners under any given tract.
(d) A net acre is deemed to exist when the sum of the fractional ownership working interests in gross acres equals one. The number of net acres is the sum of the fractional working interests owned in gross acres expressed as whole numbers and fractions thereof.
(e) Reflects undeveloped acreage of approximately 6,000 acres that were held by production as of December 31, 2006. Such acreage was previously included in developed acreage.

Leases

We have approximately 850 leases in the Robinson s Bend Field. The typical oil and gas lease agreement covering our properties provides for the payment of royalties to the mineral owner for all natural gas produced from any wells drilled on or pooled with the leased property. There are other burdens affecting certain of the leases in the form of overriding royalty interests and the NPI. On our properties in the Robinson s Bend Field and adjoining areas, depending on the location of a particular well, the total lease burden is generally 25% corresponding to a 75% net revenue interest to us calculated before the NPI. In some instances, our lease net revenue interest may be as high as 83%.

Under the oil and gas lease agreements covering productive wells, such leases have been perpetuated beyond their stated lease term and will not expire unless and until associated production falls below commercially viable levels. Such leases are said to be held by production and do not require us to make lease payments beyond the royalty amount stipulated by each lease. The area held by production from a particular well is typically the applicable pooled unit for such well as specified under state law. Barring establishment of commercial production, most of these leases will expire by October 2010. Approximately 3%, 18% and 9% of our total net undeveloped acreage is held under leases that have remaining primary terms expiring in 2007, 2008 and 2009.

Operations

General

We have entered into a professional services agreement with Ironhorse Energy LP (Ironhorse), an independent company, to provide us with project management services for the operations of the Robinson s Bend Field. The owner of Ironhorse is the project manager for our activities in the Robinson s Bend Field, and he has over 25 years of experience in various producing areas.

Project Management

Ironhorse has responsibility for the overall operations of the field, directing field employees and contractors and executing the drilling program and other production enhancement opportunities. Field operations are conducted by employees of our subsidiary, Robinson s Bend Operating II, LLC, which employees operate the field under the direct supervision of Ironhorse. All other support services including geology, engineering, land administration and revenue accounting are provided by CEPM through a management services agreement that is described in Item 13. Certain Relationships and Related Transactions, and Manager Independence.

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Through the Ironhorse arrangement we operate 100% of our natural gas production in the Robinson s Bend Field. We approve the design and the development, maintenance, re-completion and workover for all of the wells on the field. Our professional services agreement and management services agreement provide us access to drilling, production and reservoir engineers, geologists and other specialists who will work to improve production rates, increase reserves and lower the cost of operating our properties. The ongoing drilling program is designed by us and implemented by Ironhorse. We do not own drilling rigs or other oil field services equipment used for drilling wells on our properties. Our site construction in the field for new wells is currently conducted by Sartain Contracting Company, and the drilling rigs are provided by and the wells are currently drilled by Pense Brothers Drilling Company, an established Black Warrior Basin drilling contractor. Cementing is currently conducted by Halliburton; Well Service, LLC currently provides well logging services, and Halliburton currently provides the design for and executes upon the well stimulation program.

The administration and operation of the Robinson s Bend Field may be divided into the following four functions:

Field Operations

Our day-to-day operations are currently conducted by field employees of Robinson s Bend Operations II, LLC under the supervision of Ironhorse. The field management team has extensive experience in the Black Warrior Basin and has been operating the Robinson s Bend Field since the early 1990s. This group is responsible for the operation of the existing production wells, pipelines, compressors and water handling facilities, as well as interaction with Alabama regulatory authorities with regard to permitting and compliance matters. In addition, they assist with the execution of the drilling program and the management of the contractors responsible for the drilling and completion of these wells.

Land Administration

Our lease positions are managed by CEPM under the management services agreement, with assistance from contract landmen. The landmen provide assistance with management of our current lease positions, acquisitions of new leases, permitting for drilling and laying pipelines as well as negotiating agreements with landowners for the use of their property. The land administration function is currently led by a CCG employee.

Geology and Engineering

In addition to our project management team, we are provided geologic and engineering assistance by CEPM, with access to CCG s in-house technical team including its contract engineers, geologists and consultants who have experience in drilling and producing coalbed methane reserves. As a result, our project management team has the ability to draw from a base of experienced and capable talent on an as needed basis to select drilling locations and completion approaches to improve productivity and generate and test new ideas to improve production and reserves from existing wells through the use of re-completions, optimizing compression and gathering systems and the like.

Revenue Accounting

Our revenue accounting function has been outsourced to Petroleum Financial, Inc., a Dallas-based revenue accounting firm. It manages the cash flow associated with our interest in the Robinson s Bend Field, including the payment of invoices, calculation and payment of royalties, calculation and payment of the NPI, receiving the revenues from gas sales and providing accounting information that is used to generate financial statements for us.

Marketing and Major Customers

While our production and marketing subsidiaries are successors-in-interest to a gas purchase contract dated October 1, 1993, and originally entered into by and among TEMI, Torch Royalty Company and Velasco Gas

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Company Ltd as it relates to our production from the Trust Wells, no gas produced by us is sold to unaffiliated third parties under this gas purchase contract. The primary purpose of the portion of the gas purchase contract to which we have succeeded is to provide the calculation of gross proceeds for purposes of determining any royalty amounts we owe in respect of the NPI.

TEMI is currently providing us with natural gas marketing services in connection with the gas produced from Robinson s Bend Field, including the Trust Wells, in exchange for a fee of $30,000 per month plus an incentive payment of 50% of any revenue created in excess of the revenue that would have been created if the gas had been sold at the SONAT Inside FERC Price for the relevant period. Under this arrangement, we determine acceptable purchasers, the type of the sales and the credit terms of the purchasers. TEMI does not take title to the gas or receive the sales proceeds. The marketing arrangement terminates on June 30, 2007. We are currently evaluating options for marketing services after the termination of the agreement.

For the year ended December 31, 2006, five customers accounted for 100% of our total sales volumes, specifically, Interconn Resources Inc., BP Energy Company, Enterprise Alabama, Conoco Phillips, and Coral Energy Resources, L.P. accounted for approximately 30%, 20%, 18%, 17% and 15%, respectively, of our sales. We are paid based on the SONAT Inside FERC Price, which is a liquid trading pricing point that has historically settled at an average premium of $0.02/MMBtu over the NYMEX Henry Hub monthly price for the year ended December 31, 2006.

Hedging Activity

We have entered into derivative transactions with an unaffiliated third party with respect to natural gas prices and interest rates to achieve more predictable cash flows and to reduce our exposure to short-term fluctuations in natural gas prices and interest rates. For a more detailed discussion of our derivative activities, please read Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations and Item 7A. Quantitative and Qualitative Disclosures about Market Risk in this Annual Report on Form 10-K.

Markets and Competition

We operate in a highly competitive environment for acquiring properties, marketing oil and natural gas and retaining trained personnel. Many of our competitors possess and employ financial, technical and personnel resources substantially greater than ours, which can be particularly important in the areas in which we operate. As a result, our competitors may be able to pay more for productive oil and natural gas properties and exploratory prospects and to evaluate, bid for and purchase a greater number of properties and prospects than our financial or personnel resources permit. Our ability to acquire additional prospects and to find and develop reserves in the future will depend on our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. There is substantial competition for capital available for investment in the oil and natural gas industry. Neither Constellation nor any of its affiliates is restricted from competing with us. Constellation or its affiliates may acquire, invest in or dispose of E&P properties or other assets in the future without any obligation to offer us the opportunity to purchase or own interests in those assets.

We are also affected by competition for drilling rigs, completion rigs and the availability of related equipment. In the past, the oil and natural gas industry has experienced shortages of drilling and completion rigs, equipment, pipe and personnel, which has delayed development drilling and other development and exploitation activities and has caused significant increases in the prices for this equipment and personnel. We are unable to predict when, or if, such shortages may occur or how they would affect our development and exploitation program. To date, however, we have not experienced the effects of such shortages that have affected our operations in the Robinson s Bend Field. In addition, over the past several years, our field employees have been working with the team of drilling and completion contractors that operate in the Black Warrior Basin and have developed relationships that should enable us to mitigate the risks associated with equipment availability.

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Title to Properties

At the time we acquired our interest in the Robinson s Bend Field, we obtained a title opinion or review on the most significant leases in the field. As a result, title opinions or reviews have been obtained on a significant portion of our properties.

In some instances and as is customary in the oil and natural gas industry, we conducted only a cursory review of the title to certain properties on which we do not have proved reserves. To the extent title opinions or other investigations reflect title requirements on those properties, we are typically responsible for curing any material title matters at our expense. We generally will not commence drilling operations on a property until we have cured or waived any such title matters or deemed the title risk sufficiently mitigated to justify proceeding with operations on such property.

We believe that we have satisfactory title to all of our material assets. Although title to these properties is subject to encumbrances in some cases, such as customary interests generally retained in connection with acquisition of real property, customary royalty interests and contract terms and restrictions, liens under operating agreements, liens related to environmental liabilities associated with historical operations, liens for current taxes and other burdens, easements, restrictions and minor encumbrances customary in the oil and natural gas industry and in the case of the Trust Wells, the NPI, we believe that none of these liens, restrictions, easements, burdens and encumbrances will materially detract from the value of these properties or from our interest in these properties or will materially interfere with our use in the operation of our business. In addition, we believe that we have obtained sufficient rights-of-way grants and permits from public authorities and private parties for us to operate our business in all material respects as described in this Annual Report on Form 10-K.

Environmental Matters and Regulation

General

Our operations are subject to stringent and complex federal, state and local laws and regulations governing environmental protection as well as the discharge of materials into the environment. These laws and regulations may, among other things:

- require the acquisition of various permits before drilling commences;
- restrict the types, quantities and concentration of various substances that can be released into the environment in connection with natural gas drilling, production and transportation activities;
- limit or prohibit drilling activities on lands lying within wilderness, wetlands and other protected areas;
- require remedial measures to mitigate pollution from former and ongoing operations, such as requirements to close pits and plug abandoned wells.

These laws, rules and regulations may also restrict the rate of natural gas production below the rate that would otherwise be possible. The regulatory burden on the natural gas industry increases the cost of doing business in the industry and consequently affects profitability. Additionally, Congress and federal and state agencies frequently revise environmental laws and regulations, and any changes that result in more stringent and costly waste handling, disposal and cleanup requirements for the natural gas industry could have a significant impact on our operating costs.

Environmental laws and regulations that could have a material impact on the natural gas industry include the following:

Waste Handling

The Resource Conservation and Recovery Act (RCRA) and comparable state statutes, regulate the generation, transportation, treatment, storage, disposal and cleanup of hazardous wastes and non-hazardous

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wastes. Under the auspices of the federal Environmental Protection Agency (EPA), the individual states administer some or all of the provisions of RCRA, sometimes in conjunction with their own, more stringent requirements. Drilling fluids, produced waters and most other wastes associated with the exploration, development and production of natural gas are currently regulated under RCRA s non-hazardous waste provisions. Certain of our operations are known to bring to the surface naturally occurring radioactive material (NORM) which is accumulated at our facilities and is subject to permitting and controls for storage, as well as requirements for proper disposal. We believe our operations are in substantial compliance with the radioactive materials license issued by the State of Alabama Department of Public Health to cover activities associated with NORM. Although we do not believe the current costs of managing any of our wastes are material under presently applicable laws, any future reclassification of natural gas exploration and production wastes as hazardous wastes, or more stringent regulation of NORM wastes, could increase our costs to manage and dispose of wastes.

Comprehensive Environmental Response, Compensation and Liability Act

The Comprehensive Environmental Response, Compensation and Liability Act (CERCLA), also known as the Superfund law, imposes joint and several liability, without regard to fault or legality of conduct, on classes of persons who are considered to be responsible for the release of a hazardous substance into the environment. These persons include the owner or operator of the site where the release occurred, and anyone who disposed or arranged for the disposal of a hazardous substance released at the site. Under CERCLA, such persons may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies. In addition, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment.

We currently own, lease or operate numerous properties that have been used for coalbed methane exploration and production for a number of years. Although we believe operating and waste disposal practices utilized in the past with respect to these properties were typical for the industry at the time, hazardous substances, wastes or hydrocarbons may have been released on or under the properties owned or leased by us, or on or under other locations, including off-site locations, where such substances have been taken for disposal. In addition, these properties have been operated by third parties or by previous owners or operators whose treatment and disposal of hazardous substances, wastes or hydrocarbons was not under our control. These properties and the substances disposed or released on them may be subject to CERCLA, RCRA and analogous state laws. Under such laws, we could be required to remove previously disposed substances and wastes, remediate contaminated property or perform remedial plugging or pit closure operations to prevent future contamination.

Water Discharges

The Federal Water Pollution Control Act (the Clean Water Act) and analogous state laws, impose restrictions and strict controls with respect to the discharge of pollutants, including spills and leaks of produced water and other natural gas wastes, into waters of the United States. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA or an analogous state agency. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with discharge permits or other requirements of the Clean Water Act and analogous state laws and regulations. We maintain permits issued pursuant to the Clean Water Act that authorize the discharge of produced waters and similar wastewaters generated as a result of our operations, in accordance with effluent standards established by ADEM. While we believe we are in substantial compliance with these permits and all other requirements of the Clean Water Act, we have several ponds used for the treatment and storage of wastewaters that were found to have leaked into the subsurface beneath the ponds at some time in the past. ADEM is aware of these leaks. We are in the process of replacing the liners beneath these treatment ponds and, under the supervision of ADEM, monitoring for the presence of chlorides in the subsurface to better determine what cleanup measures, if any, may be required by the ADEM. Based on present information, we do not believe

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we will incur material costs or penalties in connection with this matter, but there can be no assurance that significant costs will not be incurred if future data reveals elevated levels of chlorides beneath the ponds.

Air Emissions

The Clean Air Act, and comparable state laws, regulate emissions of various air pollutants through air emissions permitting programs and the imposition of other requirements. In addition, EPA and ADEM have developed, and continue to develop, stringent regulations governing emissions of toxic air pollutants at specified sources. We believe our operations are in substantial compliance with federal and state air emission standards. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with air permits or other requirements of the federal Clean Air Act and associated state laws and regulations.

OSHA and Other Laws and Regulation

We are subject to the requirements of the federal Occupational Safety and Health Act (OSHA) and comparable state statutes. The OSHA hazard communications standard, the EPA community right-to-know regulations under the Title III of CERCLA and similar state statutes require that we organize and/or disclose information about hazardous materials used or produced in our operations. We believe that we are in substantial compliance with these applicable requirements and with other OSHA and comparable requirements.

The Kyoto Protocol to the United Nations Framework Convention on Climate Change became effective in February 2005. Under the Protocol, participating nations are required to implement programs to reduce emissions of certain gases, generally referred to as greenhouse gases, that are suspected of contributing to global warming. The United States is not currently a participant in the Protocol, and Congress has not actively considered recent proposed legislation directed at reducing greenhouse gas emissions. However, there has been support in various regions of the country for legislation that requires reductions in greenhouse gas emissions, and some states have already adopted legislation addressing greenhouse gas emissions from various sources, primarily power plants. The oil and natural gas industry is a direct source of certain greenhouse gas emissions, namely carbon dioxide and methane, and future restrictions on such emissions could impact our future operations. Our operations are not adversely impacted by current state and local climate change initiatives and, at this time, it is not possible to accurately estimate how potential future laws or regulations addressing greenhouse gas emissions would impact our business.

Our operations in the Robinson s Bend Field are subject to the rules and regulations of the State Oil and Gas Board of Alabama Governing Coalbed Methane Gas Operations and these rules and regulations are found in the State Oil and Gas Board of Alabama Administrative Code. We believe we are in substantial compliance with these rules and regulations.

We believe that we are in substantial compliance with all existing environmental laws and regulations applicable to our current operations and that our continued compliance with existing requirements will not have a material adverse impact on our financial condition and results of operations. We have approximately $0.7 million accrued in our financial statements for our estimated exposure for environmental-related matters. We are not aware of any additional environmental issues or claims that will require material capital expenditures or that will otherwise have a material impact on our financial position or results of operations. However, we cannot predict how future environmental laws and regulations may impact our operations, and therefore cannot provide assurance that the passage of more stringent laws or regulations in the future will not have a negative impact on our financial condition, results of operations or ability to make distributions to our unitholders.

Employees

As of December 31, 2006, our subsidiary, Robinson s Bend Operations II, LLC, had 22 full-time field employees. None of these employees is subject to a collective bargaining agreement or an employment contract.

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Under the management services agreement, CEPM will provide or contract for other necessary services including land, engineering, regulatory, accounting, financial and other disciplines as needed. We reimburse CEPM for expenses it incurs on our behalf, including employee compensation expenses.

Offices

We are headquartered in Baltimore, Maryland where we share office space with Constellation. We also share office space with Constellation in Houston, Texas. In addition, we have a field office located in Buhl, Alabama. Our subsidiary, Robinson s Bend Production, LLC, owns both the land and office space in Buhl.

Available Information

Our internet address is http://www.constellationenergypartners.com. We make available free of charge on or through our website our Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and any amendments to these reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended (the Exchange Act), as soon as reasonably practicable after we electronically file such material with, or furnish it to the SEC. The SEC maintains an internet website that contains these reports at http://www.sec.gov. The public may read and copy any materials that we file with the SEC at the SEC s Public Reference Room at 100 F Street, NE, Washington, DC 20549. Information concerning the operation of the Public Reference Room may be obtained by calling the SEC at (800) 723-0330.

Item 1A. Risk Factors

Risks Related to Our Business

We may not have sufficient cash from operations to pay the initial quarterly distribution following establishment of cash reserves and payment of fees and expenses, including payments to CEPM, and future distributions to our unitholders may fluctuate from quarter to quarter.

We may not have sufficient cash flow from operations each quarter to pay the initial quarterly distribution of $0.4625 per common unit following establishment of cash reserves and payment of fees and expenses, including payments to CEPM. The amount of cash we can distribute on our common units principally depends upon the amount of cash we generate from our operations, which will fluctuate from quarter to quarter based on numerous factors generally described in this caption Risk Factors , including, among other things: the amount of natural gas we produce; the demand for and the price at which we are able to sell our natural gas production; the results of our hedging activity; the level of our operating costs, including reimbursements to CEPM under the management services agreement; the costs we incur to acquire E&P properties; whether we are able to continue our development and exploitation activities at economically attractive costs; the level of our interest expense, which depends on the amount of our indebtedness and the interest payable thereon; and the level of our capital expenditures.

In addition, the actual amount of cash we will have available for distribution will depend on other factors, some of which are beyond our control, including: our ability to make working capital borrowings under our reserve-based credit facility to pay distributions; our debt service requirements and restrictions on distributions contained in our reserve-based credit facility; fluctuations in our working capital needs; the timing and collectibility of receivables; prevailing economic conditions; the amount of our estimated maintenance capital expenditures; and the amount of cash reserves established by our board of managers for the proper conduct of our business, including the maintenance of our asset base and the payment of future cash distributions on our Class A and common units, management incentive interests and Class D interests. As a result of these factors, the amount of cash we distribute in any quarter to our unitholders may fluctuate significantly from quarter to quarter and may be significantly less than the initial quarterly distribution amount that we expect to distribute. If we do not achieve our expected operational results or cannot borrow the amounts needed, we may not be able to pay the

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full, or any, amount of the quarterly distribution, in which event the market price of our common units may decline substantially.

The amount of cash that we have available for distribution to our unitholders depends primarily upon our cash flow and not our profitability.

The amount of cash that we have available for distribution depends primarily on our cash flow, including cash from reserves and working capital or other borrowings, and not solely on our profitability, which is affected by non-cash items. As a result, we may be unable to pay distributions even when we record net income, and we may pay distributions during periods when we incur net losses.

Natural gas prices are very volatile, and if commodity prices decline significantly for a temporary or prolonged period, our cash from operations will decline and we may have to lower our quarterly distribution or may not be able to pay distributions at all.

Our revenue, profitability and cash flow depend upon the prices and demand for natural gas and a drop in prices can significantly affect our financial results and impede our growth. Changes in natural gas prices have a significant impact on the value of our reserves and on our cash flow. In particular, declines in commodity prices will reduce the value of our reserves, our cash flow, our ability to borrow money or raise capital and our ability to pay distributions. Prices for natural gas may fluctuate widely in response to relatively minor changes in the supply of and demand for natural gas, market uncertainty and a variety of additional factors that are beyond our control, such as: the domestic and foreign supply of and demand for natural gas; the price and level of foreign imports of oil and natural gas; the level of consumer product demand; weather conditions; overall domestic and global economic conditions; political and economic conditions in natural gas and oil producing countries, including those in West Africa, Middle East and South America; the ability of members of the Organization of Petroleum Exporting Countries to agree to and maintain oil price and production controls; the impact of U.S. dollar exchange rates on natural gas and oil prices; technological advances affecting energy consumption; domestic and foreign governmental regulations and taxation; the impact of energy conservation efforts; the costs, proximity and capacity of natural gas pipelines and other transportation facilities; and the price and availability of alternative fuels.

In the past, the prices of natural gas have been extremely volatile, and we expect this volatility to continue. If we raise our cash distribution level in response to increased cash flow during periods of relatively high commodity prices, we may not be able to sustain those distribution levels during periods of sustained lower commodity prices.

Unless we replace the reserves that we produce, our existing reserves and production will decline, which would adversely affect our cash from operations and our ability to make cash distributions to our unitholders.

Producing natural gas reservoirs generally are characterized by declining production rates that vary depending upon reservoir characteristics and other factors. Coalbed methane production generally declines at a shallow rate after initial increases in production as a consequence of the dewatering process. However, production rates from newly drilled and completed wells in the Robinson s Bend Field do not typically increase as the formation dewaters.

We estimate that, as of December 31, 2006, our average annual decline rate for proved developed producing reserves will be approximately 5% during the next fifteen years. Because total estimated proved reserves include our proved undeveloped reserves at December 31, 2006, we expect that our production will decline at this rate even if those proved undeveloped reserves are developed and the wells produce as expected. The rate of decline of our reserves and production reflected in our reserve report of December 31, 2006 will change if production from our existing wells declines in a different manner than we have estimated and can change when we drill additional wells, make acquisitions and under other circumstances. Thus, our future natural gas reserves and

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production and, therefore, our cash flow and income are highly dependent on our success in efficiently developing and exploiting our current reserves and economically finding or acquiring additional recoverable reserves. We may not be able to develop, find or acquire additional reserves to replace our current and future production at acceptable costs, which would adversely affect our business, financial condition and results of operations.

Our estimated reserves are based on many assumptions that may prove to be inaccurate. Any material inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves.

No one can measure underground accumulations of natural gas in an exact way. Natural gas reserve engineering requires subjective estimates of underground accumulations of natural gas and assumptions concerning future natural gas prices, production levels and operating and development costs. In addition, in the early stages of a coalbed methane project, it is difficult to predict the production curve of a coalbed methane field. As a result, estimated quantities of proved reserves, projections of future production rates and the timing of development expenditures may prove to be inaccurate. We have prepared the estimates of proved natural gas reserves included in this Annual Report on Form 10-K, and such estimates are different from the estimates that may be determined by an independent petroleum engineering firm. Over time, our internal engineers may make material changes to reserve estimates taking into account the results of actual drilling and production. Some of our reserve estimates are made without the benefit of a lengthy production history, which are less reliable than estimates based on a lengthy production history. Also, we make certain assumptions regarding future natural gas prices, production levels and operating and development costs that may prove incorrect. Any significant variance from these assumptions by actual figures could greatly affect our estimates of reserves, the economically recoverable quantities of natural gas attributable to any particular group of properties, the classifications of reserves based on risk of recovery and estimates of the future net cash flows. For example, if natural gas prices were to decline by $1.00 per Mcf, then the Standardized Measure of our proved reserves as of December 31, 2006 would decrease from approximately $120.2 million to approximately $79.9 million. Our Standardized Measure is calculated using unhedged natural gas prices and is determined in accordance with the rules and regulations of the SEC (except for the impact of income taxes as we are not a taxable entity). Numerous changes over time to the assumptions on which our reserve estimates are based, as described above, often result in the actual quantities of natural gas we ultimately recover being different from our reserve estimates.

The present value of future net cash flows from our proved reserves is not necessarily the same as the current market value of our estimated natural gas reserves.

We base the estimated discounted future net cash flows from our proved reserves on prices and costs in effect on the day of estimate. However, actual future net cash flows from our natural gas properties also will be affected by factors such as:

- the supply of and demand for natural gas;
- the actual prices we receive for natural gas;
- our actual operating costs in providing natural gas;
- the amount and timing of our capital expenditures;
- the amount and timing of actual production; and
- changes in governmental regulations or taxation.

The timing of both our production and our incurrence of expenses in connection with the development and production of natural gas properties will affect the timing of actual future net cash flows from proved reserves, and thus their actual present value. In addition, the 10% discount factor we use when calculating discounted future net cash flows may not be the most appropriate discount factor based on interest rates in effect from time

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to time and risks associated with us or the natural gas industry in general. Any material inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves, which could adversely affect our business, results of operations, financial condition and our ability to make cash distributions.

Future price declines may result in a write-down of our asset carrying values.

Lower natural gas prices may not only decrease our revenues, profitability and cash flows, but also reduce the amount of natural gas that we can produce economically. This may result in our having to make substantial downward adjustments to our estimated proved reserves. Substantial decreases in natural gas prices would render a significant number of our planned exploitation projects uneconomic. If this occurs, or if our estimates of development costs increase, production data factors change or drilling results deteriorate, accounting rules may require us to write down, as a non-cash charge to earnings, the carrying value of our natural gas properties for impairments. We are required to perform impairment tests on our assets periodically and whenever events or changes in circumstances warrant a review of our assets. To the extent such tests indicate a reduction of the estimated useful life or estimated future cash flows of our assets, the carrying value may not be recoverable and may, therefore, require a writedown of such carrying value. We may incur impairment charges in the future, which could result in a material reduction in our results of operations in the period taken and materially limit our ability to borrow funds under our reserve-based credit facility and our ability to make cash distributions to our unitholders.

We rely on third parties, including CEPM, for our management. If CEPM or these third parties fail to or inadequately perform, or if we cannot enter into other management contracts on satisfactory terms, our costs will increase and reduce our cash from operations and our ability to make cash distributions.

We rely on third parties for our management. While our board of managers has the right and responsibility to manage our affairs, we rely on third parties to manage the day-to-day aspects of our business. We have entered into a management services agreement with CEPM, a wholly owned subsidiary of Constellation. Pursuant to that agreement, we are required to use CEPM or its designee for legal, accounting, finance, tax and risk management services while we are consolidated with Constellation for accounting purposes. CEPM will also provide us with assistance in hedging our production and acquisition services in respect of opportunities for us to acquire long-lived, stable and proved oil and natural gas reserves. Constellation and its affiliates have no obligation to present us with potential acquisitions, and, if they fail to do so, we will need to either seek acquisitions on our own or retain a third party to seek acquisitions on our behalf. In the long term, without further acquisitions, we will not be able to replace or grow our reserves, which would reduce our cash from operations and our ability to make cash distributions.

In addition, we plan to target acquisitions in areas where we can work with third-party operators who have technical development expertise and experience in the particular natural gas field in which we are acquiring an interest and who will hold a working interest in such properties. If we cannot find suitable third-party operators or our operators fail to perform under their contracts, we will need to hire additional personnel to operate our properties. Doing so will increase our costs and could adversely affect our cash from operations and our ability to make cash distributions.

Our operations require substantial capital expenditures, which will reduce our cash available for distribution.

We will need to make substantial capital expenditures to maintain our asset base over the long term. These maintenance capital expenditures may include capital expenditures associated with drilling and completion of additional wells to offset the production decline from our producing properties or additions to our inventory of unproved properties or our proved reserves to the extent such additions maintain our asset base. These expenditures could increase as a result of:

- changes in our reserves;

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- changes in natural gas prices;
- changes in labor and drilling costs;
- our ability to acquire, locate and produce reserves;
- changes in leasehold acquisition costs; and
- government regulations relating to safety and the environment.

Our significant maintenance capital expenditures will reduce the amount of cash we have available for distribution to our unitholders. In addition, our actual maintenance capital expenditures will vary from quarter to quarter.

Each quarter we are required to deduct estimated maintenance capital expenditures from operating surplus, which may result in less cash available for distribution to unitholders than if actual maintenance capital expenditures were deducted.

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

We will be required to make substantial capital expenditures to increase our asset base. If we are unable to obtain needed capital or financing on satisfactory terms, our ability to make cash distributions may be diminished or our financial leverage could increase.

In order to increase our asset base, we will need to make expansion capital expenditures. If we do not make sufficient or effective expansion capital expenditures, we will be unable to expand our business operations and will be unable to raise the level of our future cash distributions. To fund our expansion capital expenditures and investment capital expenditures, we will be required to use cash from our operations or incur borrowings or sell additional common units or other securities. Such uses of cash from operations will reduce cash available for distribution to our unitholders. Our ability to obtain bank financing or to access the capital markets for future equity or debt offerings may be limited by our financial condition at the time of any such financing or offering and the covenants in our existing debt agreements, as well as by general economic conditions and contingencies and uncertainties that are beyond our control. Even if we are successful in obtaining the necessary funds, the terms of such financings could limit our ability to pay distributions to our unitholders. In addition, incurring additional debt may significantly increase our interest expense and financial leverage and issuing additional limited liability company interests may result in significant unitholder dilution and would increase the aggregate amount of cash required to maintain the then-current distribution rate, which could materially decrease our ability to pay distributions at the then-current distribution rate.

Furthermore, if our revenues or the borrowing base under our reserve-based credit facility decrease as a result of lower natural gas prices, operating difficulties, declines in reserves or for any other reason, we may have limited ability to obtain the capital necessary to increase or sustain our asset base. Our reserve-based credit facility restricts our ability to obtain new financing. If additional capital is needed, we may not be able to obtain debt or equity financing on terms favorable to us, or at all. If cash generated by operations or available under our

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reserve-based credit facility is not sufficient to meet our capital requirements, the failure to obtain additional financing could result in a curtailment of our operations relating to development of our prospects, which in turn could lead to a possible decline in our reserves, and could diminish our results of operations, financial condition and our ability to make cash distributions to our unitholders.

If we do not make acquisitions on economically acceptable terms, our future growth and ability to sustain or increase distributions will be limited.

Our ability to grow and to increase distributions to unitholders is partially dependent on our ability to make acquisitions that result in an increase in available cash per unit. We may be unable to make such acquisitions because we are:

- unable to identify attractive acquisition candidates or negotiate acceptable purchase contracts with them;
- unable to obtain financing for these acquisitions on economically acceptable terms; or
- outbid by competitors.

In any of these cases, our future growth and ability to increase distributions will be limited. Furthermore, even if we do make acquisitions that we believe will increase available cash per unit, these acquisitions may nevertheless result in a decrease in available cash per unit.

Our anticipated acquisition activities will subject us to certain risks.

Any acquisition involves potential risks, including, among other things: the validity of our assumptions about reserves, future production, revenues and costs, including synergies; an inability to integrate successfully the businesses we acquire; a decrease in our liquidity by using a significant portion of our available cash or borrowing capacity to finance acquisitions; a significant increase in our interest expense or financial leverage if we incur additional debt to finance acquisitions; the assumption of unknown liabilities, losses or costs for which we are not indemnified or for which our indemnity is inadequate; the diversion of management s attention to other business concerns; an inability to hire, train or retain qualified personnel to manage and operate our growing business and assets; the incurrences of other significant charges, such as impairment of goodwill or other intangible assets, asset devaluation or restructuring charges; unforeseen difficulties encountered in operating in new geographic areas; and customer or key employee losses at the acquired businesses.

Our decision to acquire a property will depend in part on the evaluation of data obtained from production reports and engineering studies, geophysical and geological analyses and seismic and other information, the results of which are often inconclusive and subject to various interpretations. Also, our reviews of acquired properties are inherently incomplete because it generally is not feasible to perform an in-depth review of the individual properties involved in each acquisition. Even a detailed review of records and properties may not necessarily reveal existing or potential problems, nor will it permit us to become sufficiently familiar with the properties to assess fully their deficiencies and potential. Inspections may not always be performed on every well, and environmental problems, such as ground water contamination, are not necessarily observable even when an inspection is undertaken.

If our acquisitions do not generate increases in available cash per unit, our ability to make cash distributions to our unitholders could materially decrease.

We may incur substantial additional debt in the future to enable us to pursue our business plan and to pay distributions to our unitholders.

Our business requires a significant amount of capital expenditures to maintain and grow production levels. Commodity prices have historically been volatile and we cannot predict the prices we will be able to realize for

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our production in the future. As a result, we may borrow significant amounts under our reserve-based credit facility in the future to enable us to pay quarterly distributions. Significant declines in our production or significant declines in realized natural gas prices for prolonged periods and resulting decreases in our borrowing base may force us to reduce or suspend distributions to our unitholders.

When we borrow to pay distributions, we are distributing more cash than we are generating from our operations on a current basis. This means that we are using a portion of our borrowing capacity under our reserve-based credit facility to pay distributions rather than to maintain or expand our operations. If we use borrowings under our reserve-based credit facility to pay distributions for an extended period of time rather than toward funding capital expenditures and other matters relating to our operations, we may be unable to support or grow our business. Such a curtailment of our business activities, combined with our payment of principal and interest on indebtedness incurred to pay distributions, will reduce our cash available for distribution on our units. If we borrow to pay distributions during periods of low commodity prices and commodity prices remain low, we may have to reduce our distribution in order to avoid excessive leverage.

Our reserve-based credit facility has substantial restrictions and financial covenants and we may have difficulty obtaining additional credit, which could adversely affect our operations and our ability to pay distributions to our unitholders.

We will depend on our reserve-based credit facility for future capital needs and to fund a portion of our distributions. The reserve-based credit facility restricts our ability to obtain additional financing, make investments, lease equipment, sell assets and engage in business combinations. We are also required to comply with certain financial covenants and ratios. Our ability to comply with these restrictions and covenants in the future is uncertain and will be affected by the levels of cash flow from our operations and events or circumstances beyond our control. Our failure to comply with any of the restrictions and covenants under our reserve-based credit facility could result in a default under the facility, which could cause all of our existing indebtedness to be immediately due and payable. Each of the following is an event of default:

- failure to pay any principal when due or any interest, fees or other amount prior to the expiration of certain grace periods;
- a representation or warranty made under the loan documents or in any report or other instrument furnished thereunder is incorrect when made;
- failure to perform or otherwise comply with the covenants in the credit facility or other loan documents, subject, in certain instances, to certain grace periods, which include covenants that:
  - Constellation and its affiliates maintain the right to elect our Class A managers; and
  - we obtain the approval of the administrative agent (such approval not to be unreasonably withheld or delayed) of any management services plan upon the termination of the management services agreement with CEPM;
- any event occurs that permits or causes the acceleration of the indebtedness;
- bankruptcy or insolvency events involving us or our subsidiaries;
- the entry of, and failure to pay, one or more adverse judgments in excess of $1.0 million or one or more non-monetary judgments that could reasonably be expected to have a material adverse effect and for which enforcement proceedings are brought or that are not stayed pending appeal;

specified events relating to our employee benefit plans that could reasonably be expected to result in liabilities in excess of $1.0 million in any year; and

a change of control, generally defined as the first date on which the following two conditions occur: (i) a decrease by Constellation Energy Partners Holdings, LLC (CEPH) and CEPM of their combined ownership of our outstanding membership interests to less than 25%, and (ii) the ownership by any

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person (other than a wholly-owned subsidiary of Constellation) of more than 35% of our outstanding membership interests.

The reserve-based credit facility limits the amounts we can borrow to a borrowing base amount, determined by the lenders in their sole discretion. The lenders can unilaterally adjust the borrowing base and the borrowings permitted to be outstanding under the reserve-based credit facility. Any increase in the borrowing base requires the consent of all the lenders. Outstanding borrowings in excess of the borrowing base must be repaid immediately, or we must pledge other natural gas and oil properties as additional collateral. We do not currently have any substantial unpledged properties, and we may not have the financial resources in the future to make any mandatory principal prepayments required under the reserve-based credit facility.

Our reserve-based credit facility may restrict us from borrowing to pay distributions on our outstanding units.

We are prohibited from borrowing under our reserve-based credit facility to pay distributions to unitholders if the amount of borrowings outstanding under our reserve-based credit facility reaches or exceeds 90% of the borrowing base. Our borrowing base is the amount of money available for borrowing, as determined semi-annually by our lenders in their sole discretion. The lenders will redetermine the borrowing base based on an engineering report with respect to our natural gas reserves, which will take into account the prevailing natural gas prices at such time. We anticipate that if, at the time of any distribution, our borrowings equal or exceed 90% of the then-specified borrowing base, our ability to pay distributions to our unitholders in any such quarter will be solely dependent on our ability to generate sufficient cash from our operations.

Our future debt levels may limit our flexibility to obtain additional financing and pursue other business opportunities.

We may incur substantial additional indebtedness in the future under our reserve-based credit facility or otherwise. Our future indebtedness could have important consequences to us, including:

- our ability to obtain additional financing, if necessary, for working capital, capital expenditures, acquisitions or other purposes may be impaired or such financing may not be available on favorable terms;
- covenants contained in our existing and future credit and debt arrangements will require us to meet financial tests that may affect our flexibility in planning for and reacting to changes in our business, including possible acquisition opportunities;
- we will need a substantial portion of our cash flow to make principal and interest payments on our indebtedness, reducing the funds that would otherwise be available for operations, future business opportunities and distributions to unitholders; and
- our debt level will make us more vulnerable than our competitors with less debt to competitive pressures or a downturn in our business or the economy generally.

Our ability to service our indebtedness will depend upon, among other things, our future financial and operating performance, which will be affected by prevailing economic conditions and financial, business, regulatory and other factors, some of which are beyond our control. If our operating results are not sufficient to service our current or future indebtedness, we will be forced to take actions such as reducing distributions, reducing or delaying business activities, acquisitions, investments and/or capital expenditures, selling assets, restructuring or refinancing our indebtedness, or seeking additional equity capital or bankruptcy protection. We may not be able to effect any of these remedies on satisfactory terms or at all.

Expense reimbursements due to CEPM under our management services agreement will reduce cash available for distribution to our unitholders.

Prior to making any distribution on the common units, we will reimburse CEPM for all expenses that it incurs on our behalf pursuant to the management services agreement. These expenses will include all costs

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incurred on our behalf in performing accounting and financial, risk management and acquisition services, including costs for providing corporate staff and support services to us. CEPM will charge on a fully allocated cost basis for services provided to us. This fully allocated cost basis is based on the percentage of time spent by personnel of CEPM and its affiliates on our matters and includes the compensation paid by CEPM and its affiliates to such persons and their allocated overhead. The allocation of compensation expense for such persons will be determined based on a good faith estimate of the value of each such person s services performed on our business and affairs, subject to the periodic review and approval of our audit or conflicts committee. The reimbursement of expenses to CEPM could adversely affect our ability to pay cash distributions to our unitholders.

If the Trust is terminated, the gas purchase contract with the Trust will be terminated and payment by us to the Trust in respect of the NPI may cease being calculated by the sharing arrangement. As a result, our royalty obligations under the NPI could increase, which could adversely affect our results of operations and our ability to pay cash distributions.

The gas purchase contract with the Trust terminates on the earlier to occur of December 31, 2012 and the termination of the Trust. The Trust will terminate upon the first to occur of (i) an affirmative vote of the holders of not less than 66 $^{2}/3$% of the outstanding Trust units to liquidate the Trust, and (ii) such time as the ratio of the cash amounts received by the Trust from the NPI to administrative costs of the Trust is less than 1.2 to 1.0 for three consecutive quarters. The Trust will also terminate on March 1 of any year if it is determined that the pre-tax future net cash flows, discounted at 10%, attributable to the estimated net proved reserves of the NPI on the preceding December 31 are less than $25.0 million. Based on natural gas reserve estimates at December 31, 2005 prepared by independent reserve engineers, the Trust has advised its investors that, unless the Henry Hub spot price for natural gas on December 31, 2006 exceeds approximately $6.25 per MMBtu, the Trust will terminate on March 1, 2007. The Henry Hub spot price for natural gas on December 30, 2005 and December 29, 2006 was $10.08 per MMBtu and $5.64 per MMBtu, respectively. Upon termination of the Trust, the gas purchase contract with TEMI, including the portion assigned to us, will terminate. Based upon our estimated production for the twelve months ending December 31, 2007 and the weighted average net realized sales price for our production used in calculating our Adjusted EBITDA for that twelve-month period, we estimate that, if the sharing arrangement in respect of the Trust was terminated as of January 1, 2007, our revenues would be reduced by approximately $5.0 million during such twelve-month period and the $8.0 million contributed to us for the Class D interests would offset such a shortfall for approximately 1.6 years, if production and prices were to remain constant throughout such period.

The royalty payment owed by us under the NPI is calculated based in part on gross proceeds as that term is defined in the gas purchase contract. Under the gas purchase contract, there is a sharing arrangement that permits us, as gas purchaser, to retain any excess of the market price we receive for production from the Trust Wells over the price under the sharing arrangement. This price under the sharing arrangement is equal to the sum of the sharing price set forth in the gas purchase contract, plus 50% of the amount by which 97% of the applicable spot index price exceeds the sharing price. Despite increases in recent years in the spot price for natural gas, this sharing arrangement has had the effect of keeping the royalty payments to the Trust in respect of the NPI significantly lower than the prevailing market price. If our payments to the Trust for the NPI ceased being calculated under the sharing arrangement, our royalty obligations under the NPI would be significantly higher based on current natural gas prices, which would reduce our revenues and could adversely affect our results of operations and our ability to pay cash distributions.

A group of investors in the Trust may seek to terminate the Trust, which termination could reduce our future revenues and adversely affect our results of operations and our ability to pay cash distributions.

In a filing with the SEC by a group that as of December 23, 2005 reported that it owned approximately 6.34% of the trust units then outstanding, such group reported that, among other actions it may take in the future, such group may . . . call a meeting of Unitholders to vote on . .. . termination of the Trust . . . . If the trust

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unitholders were to approve a termination of the Trust, whether upon a resolution submitted by such group or otherwise, the Trust would be terminated, which in turn would terminate the gas purchase contract.

The gas purchase contract on which the NPI is based contains a minimum price arrangement, which could have the effect of requiring a higher royalty payment in respect of the NPI than would be the case if the gas purchase contract did not have the minimum price arrangement. If the applicable index price falls below the minimum price, it could adversely affect our financial condition and results of operations and, as a result, our ability to pay cash distributions.

Pursuant to the gas purchase contract on which the NPI is based, we are required to pay at least $1.70 (adjusted for inflation annually, or approximately $1.80 during 2006) per MMBtu, which we refer to as the minimum price, for gas purchased from production in respect of the Trust Wells. If the applicable index price is less than the minimum price in any month, amounts payable under the gas purchase contract could be higher than the gross proceeds we would receive for the gas at market prices. As a result, the royalty obligation payable by us in respect of the NPI could exceed the gross proceeds we have received for the gas produced in respect of the NPI. If we have to pay a royalty under the NPI based upon the minimum price that exceeds the actual revenue received by us for the sale of such gas, based upon market prices, it could adversely affect our financial condition and results of operations and, as a result, our ability to pay cash distributions. The index price for the Trust Wells is the price reported in *Inside FERC s Gas Market Report* for the Southern Natural Gas Co., Louisiana Hub, which we refer to as the SONAT Inside FERC Price. For the years ended December 31, 2006 and 2005, the monthly index price varied between a low of $4.18 and a high of $11.67, and a low of $6.12 and a high of $14.01, respectively.

The gas purchase contract on which the NPI is based contains a sharing arrangement in the event the applicable spot index price for natural gas exceeds the sharing price, as calculated under the gas purchase contract. If the applicable spot index price for natural gas falls below the sharing price, it would have the effect of reducing the revenue we retain upon resale of the gas produced from the Trust Wells and could adversely affect our financial condition and results of operations and, as a result, our ability to pay cash distributions.

The gas purchase contract on which the NPI is based provides for a sharing arrangement in the event the index price in any month exceeds a price of $2.10 (adjusted for inflation annually, or approximately $2.22 during 2006 and $2.26 anticipated for 2007) per MMBtu, which we refer to as the sharing price. If 97% of the applicable spot index price is equal to or less than the sharing price, gas is purchased at the greater of (i) 97% of the index price per MMBtu and (ii) the minimum price described in the immediately preceding risk factor. If the index price exceeds the sharing price in any month, however, gas is purchased at the sharing price plus 50% of the excess of 97% of the applicable spot index price over the sharing price per MMBtu. In that case, gross proceeds payable under the gas purchase contract could be substantially less than the gross proceeds at market prices, as a result of which the royalty obligation payable by us in respect of the NPI could be substantially less than the gross proceeds we have received for the produced gas. For example, during 2005 and 2006, the amount payable under the gas purchase contract was, on average, approximately $3.37 per MMBtu and $2.63 per MMBtu, respectively, less than the net average market price realized for the sale of such gas. If during the term of the gas purchase contract, the index price is equal to or less than the sharing price, it could adversely affect our financial condition and results of operations and, as a result, our ability to pay cash distributions.

While TEMI s interest in the gas purchase contract was assigned to one of our subsidiaries in June 2005, TEMI remains a nominal party to that contract and has obligations thereunder and the potential ability to make elections or even breach its obligations, both of which could adversely affect our rights and interests.

TEMI is an original party to the gas purchase contract. In connection with our acquisition of the Robinson s Bend Field properties from Everlast in June 2005, one of our subsidiaries assumed from TEMI all of its rights in respect of the Trust Wells under the gas purchase contract. As TEMI remains a nominal party to the gas purchase

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contract, it may still have the ability to make elections or even breach its obligations under the contract in a manner that affects our rights in respect of the Robinson s Bend Field. Any such action by TEMI could adversely impact our rights and interests. If TEMI breaches its obligations under the gas purchase contract, the gas purchase contract may terminate, which could similarly result in a termination of the rights assigned to us. Also, if TEMI elects to terminate the minimum price commitment, we could be required to use the applicable spot index price without the sharing arrangement to calculate the amounts payable by us to the Trust for the NPI, which could cause the royalty obligation in respect of the NPI to increase. Any such increase in our royalty obligation under the NPI could reduce our revenues and adversely affect our financial condition and results of operations and, as a result, our ability to pay cash distributions.

We depend on certain key customers for sales of our natural gas. To the extent these and other customers reduce the volumes of natural gas they purchase from us and are not replaced by new customers, our revenues and cash available for distribution could decline.

For the year ended December 31, 2006, five customers accounted for 100% of our total sales volumes. Specifically, Interconn Resources Inc., BP Energy Company, Enterprise Alabama, ConocoPhillips and Coral Energy Resources, L.P. accounted for approximately 30%, 20%, 18%, 17% and 15%, respectively, of our total sales volumes. To the extent these and other customers reduce the volumes of natural gas that they purchase from us and are not replaced by new customers, our revenues and cash available for distribution could decline.

Our hedging activities could result in financial losses or could reduce our income, which may adversely affect our ability to pay distributions to our unitholders.

To achieve more predictable cash flow and to reduce our exposure to adverse fluctuations in the prices of natural gas, we have adopted a policy that contemplates hedging approximately 80% of our expected production volumes for up to five years. As a result, we will continue to have direct commodity price exposure on the unhedged portion of our production volumes. The extent of our commodity price exposure is related largely to the effectiveness and scope of our hedging activities. For example, the derivative instruments we utilize are generally based on posted market prices, which may differ significantly from the actual natural gas prices we realize in our operations.

Our actual future production may be significantly higher or lower than we estimate at the time we enter into hedging transactions for such period. If the actual amount is higher than we estimate, we will have greater commodity price exposure than we intended. If the actual amount is lower than the nominal amount that is subject to our derivative financial instruments, we might be forced to satisfy all or a portion of our derivative transactions without the benefit of the cash flow from our sale or purchase of the underlying physical commodity, resulting in a substantial diminution of our liquidity. As a result of these factors, our hedging activities may not be as effective as we intend in reducing the volatility of our cash flows, and in certain circumstances may actually increase the volatility of our cash flows. In addition, our hedging activities are subject to the following risks:

- a counterparty may not perform its obligation under the applicable derivative instrument;
- there may be a change in the expected differential between the underlying commodity price in the derivative instrument and the actual price received; and
- the steps we take to monitor our derivative financial instruments may not detect and prevent violations of our risk management policies and procedures.

We are exposed to trade credit risk in the ordinary course of our business activities.

We are exposed to risks of loss in the event of nonperformance by our customers and by counterparties to our hedging arrangements. Some of our customers and counterparties may be highly leveraged and subject to their own operating and regulatory risks. Even if our credit review and analysis mechanisms work properly, we may experience financial losses in our dealings with other parties. Any increase in the nonpayment or nonperformance by our customers and/or counterparties could reduce our ability to make distributions to our unitholders.

Certain of our undeveloped leasehold acreage is subject to leases that may expire in the near future.

As of December 31, 2006, we held natural gas leases in the Robinson s Bend Field that are still within their original lease term and are not currently held by production. Unless we establish commercial production on the properties subject to these leases, most of these leases will expire between January 2007 and October 2010. Leases covering approximately 939 net acres are scheduled to expire before December 31, 2007. If our leases expire, we will lose our right to develop the related properties.

Our business is difficult to evaluate because we have a limited operating history.

We were formed in February 2005 by Constellation to acquire E&P properties located in the Robinson s Bend Field from Everlast in June 2005. Our assembled management team may not be able to successfully oversee our business and effectively implement our operating and growth strategies. Our financial results cover periods during which the natural gas properties that we acquired were not under the control or management of our current management team and therefore may not be indicative of our future financial or operating results. Our success will depend upon management s ability to manage, operate and develop the properties that we currently own and those we may acquire in the future. Our failure to successfully manage, operate and develop these properties may have a significant adverse effect on our financial condition and results of operations.

Our identified drilling location inventories are scheduled out over several years, making them susceptible to uncertainties that could materially alter the occurrence or timing of their drilling, resulting in temporarily lower cash from operations, which may impact our ability to pay distributions.

Our management has specifically identified and scheduled drilling locations for our future multi-year drilling activities on our existing acreage. As of December 31, 2006, we had identified 120 gross proved undeveloped drilling locations and approximately 200 additional gross potential drilling locations. These identified drilling locations represent a significant part of our future development drilling program for the Robinson s Bend Field. Our ability to drill and develop these locations depends on a number of factors, including the availability of capital, seasonal conditions, regulatory approvals, natural gas prices, costs and drilling results. In addition, no proved reserves are assigned to any of the approximately 200 potential drilling locations we have identified and therefore, there may be greater uncertainty with respect to the likelihood of drilling and completing successful commercial wells at these potential drilling locations. Our final determination of whether to drill any of these drilling locations will be dependent upon the factors described above as well as, to some degree, the results of our drilling activities with respect to our proved drilling locations. Because of these uncertainties, we do not know if the numerous drilling locations we have identified will be drilled within our expected timeframe or will ever be drilled or if we will be able to produce natural gas from these or any other potential drilling locations. In addition, unless production is established within the spacing units covering the undeveloped acres on which some of the locations are identified, the leases for such acreage will expire. As such, our actual drilling activities may materially differ from those presently identified, which could have a significant adverse effect on our financial condition and results of operations.

Locations that we decide to drill may not yield oil and natural gas in commercially viable quantities.

The cost of drilling, completing and operating a well is often uncertain, and cost factors can adversely affect the economics of a well. Our efforts will be uneconomical if we drill dry holes or wells that are productive but do not produce enough to be commercially viable after drilling, operating and other costs. If we drill future wells that we identify as dry holes, our drilling success rate would decline, and may materially harm our business.

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Drilling for and producing oil and natural gas are high risk activities with many uncertainties that could adversely affect our financial condition or results of operations and, as a result, our ability to pay distributions to our unitholders.

Our drilling activities are subject to many risks, including the risk that we will not discover commercially productive reservoirs. Drilling for oil and natural gas can be uneconomic, not only from dry holes, but also from productive wells that do not produce sufficient revenues to be commercially viable. In addition, our drilling and producing operations may be curtailed, delayed or canceled as a result of other factors, including: the high cost, shortages or delivery delays of drilling rigs, equipment, labor and other services; unexpected operational events and drilling conditions; reductions in oil and natural gas prices; limitations in the market for oil and natural gas; adverse weather conditions; facility or equipment malfunctions; accidents; title problems; piping, casing or cement failures; compliance with environmental and other governmental requirements; unusual or unexpected geological formations; lost or damaged oilfield drillings and service tools; loss of drilling fluid circulation; formations with abnormal pressures; environmental hazards, such as gas leaks, oil spills, pipeline ruptures and discharges of toxic gases; fires or natural disasters; blowouts, craterings and explosions; and uncontrollable flows of natural gas or well fluids.

Any of these events can cause substantial losses, including personal injury or loss of life, damage to or destruction of property, natural resources and equipment, pollution, environmental contamination, loss of wells and regulatory penalties.

We ordinarily maintain insurance against various losses and liabilities arising from our operations; however, insurance against all operational risks is not available to us. Additionally, we may elect not to obtain insurance if we believe that the cost of available insurance is excessive relative to the perceived risks presented. Losses could therefore occur for uninsurable or uninsured risks or in amounts in excess of existing insurance coverage. The occurrence of an event that is not fully covered by insurance could adversely affect our business activities, financial condition, results of operations and our ability to make cash distributions to our unitholders.

Because we handle natural gas and other petroleum products in our business, we may incur significant costs and liabilities in the future resulting from a failure to comply with new or existing environmental regulations.

The operations of our wells, gathering systems, pipelines and other facilities are subject to stringent and complex federal, state and local environmental laws and regulations. These include, for example:

- the federal Clean Air Act, related federal regulations and comparable state laws and regulations that impose obligations related to air emissions;
- the federal Clean Water Act, related federal regulations and comparable state laws and regulations that impose obligations related to discharges of pollutants into regulated waters;
- RCRA, related federal regulations and comparable state laws and regulations that impose requirements for the handling and disposal of waste from our facilities; and
- CERCLA, also known as the Superfund law, and comparable state laws that regulate the cleanup of hazardous substances that may have been released at properties currently or previously owned or operated by us or at locations to which we have sent waste for disposal.

Moreover, the possibility exists that stricter laws, regulations or enforcement policies could significantly increase our compliance costs and the cost of any remediation that may become necessary. We may not be able to recover these costs from insurance.

Failure to comply with these laws and regulations may trigger a variety of administrative, civil and criminal enforcement measures, including the assessment of monetary penalties, the imposition of remedial requirements and the issuance of orders enjoining future operations. Certain environmental statutes, including RCRA,

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CERCLA, the federal Oil Pollution Act and analogous state laws and regulations, impose strict, joint and several liability for costs required to clean up and restore sites where hazardous substances have been disposed of or otherwise released into the environment.

We may incur significant costs and liabilities in the future resulting from an accidental release of hazardous substances into the environment.

There is an inherent risk that we may incur environmental costs and liabilities due to the nature of our business and the substances we handle. For example:

- there is the potential for an accidental release from one of our wells or gathering pipelines;
- certain of our operations are known to bring to the surface NORM that is accumulated at our facilities and is subject to permitting and controls for storage, as well as requirements for proper disposal; and
- several treatment ponds associated with the treatment and storage of produced waters and similar wastewaters have leaked into the subsurface and we are in the process of replacing the liners beneath these treatment ponds and, under the supervision of ADEM, monitoring for the presence of contaminants in the subsurface to better determine what cleanup, if any, may be required.

If a problem occurs with respect to any one of these, it could subject us to substantial liabilities arising from environmental cleanup and restoration costs, claims made by neighboring landowners and other third parties for personal injury and property damage, and fines or penalties for related violations of environmental laws or regulations.

Our operations expose us to significant costs and liabilities with respect to environmental and operational safety matters.

We may incur significant costs and liabilities as a result of environmental and safety requirements applicable to our natural gas exploration, production and transportation operations. These costs and liabilities could arise under a wide range of federal, state and local environmental and safety laws and regulations, including regulations and enforcement policies, which have tended to become increasingly strict over time. There is an inherent risk that we may incur environmental costs and liabilities due to the nature of our business and the substances that we handle. For instance, we must maintain permits and adhere to certain controls related to the storage and proper disposal of NORM that is produced periodically in connection with our natural gas drilling operations. In addition, as a result of leaks from ponds used for the treatment and storage of produced waters and similar wastewaters from our operations, we are in the process of replacing pond liners and are also conducting subsurface monitoring for chlorides under the supervision of the Alabama Department of Environmental Management. We may incur additional expenses, which could be material, in the future if our monitoring activities reveal that any contaminants exist in the subsurface beneath the ponds, and the agency requires cleanup of any such contaminants.

Failure to comply with environmental laws and regulations could result in the assessment of administrative, civil and criminal penalties, imposition of cleanup and site restoration costs and liens, and to a lesser extent, issuance of orders to limit or cease certain operations. In addition, certain environmental laws impose strict, joint and several liability, which could cause us to become liable for the conduct of others or for consequences of our own actions that were in compliance with all applicable laws at the time those actions were taken. Moreover, it is not uncommon for neighboring landowners and other third parties to file claims for damages as a result of environmental and other impacts.

Shortages of drilling rigs, supplies, oilfield services, equipment and crews could delay our operations and reduce our cash available for distribution.

Higher natural gas prices generally increase the demand for drilling rigs, supplies, services, equipment and crews, and can lead to shortages of, and increasing costs for, drilling equipment, services and personnel. Over the

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past three years, we (and Everlast) and other oil and natural gas companies have experienced higher drilling and operating costs. Shortages of, or increasing costs for, experienced drilling crews and equipment and services could restrict our ability to drill the wells and conduct the operations that we currently have planned. Any delay in the drilling of new wells or significant increase in drilling costs could reduce our revenues and cash available for distribution.

The coalbeds from which we produce natural gas frequently contain water that may hamper our ability to produce natural gas in commercial quantities or adversely affect our profitability.

Unlike conventional natural gas production, coalbeds frequently contain water that must be removed in order for the gas to desorb from the coal and flow to the wellbore. Our ability to remove and dispose of sufficient quantities of water from the coal seam will determine whether or not we can produce natural gas in commercial quantities. In addition, the cost of water disposal may be significant and may reduce our profitability.

We may face unanticipated water disposal costs.

Where water produced from our projects fails to meet the quality requirements of applicable regulatory agencies or our wells produce water in excess of the applicable volumetric permit limit, we may have to shut in wells, reduce drilling activities, or upgrade facilities for water handling or treatment. The costs to dispose of this produced water may increase if any of the following occur:

- we cannot obtain future permits from applicable regulatory agencies;
- water of lesser quality or requiring additional treatment is produced;
- our wells produce excess water; or
- new laws and regulations require water to be disposed of in a different manner.

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

Effective internal controls are necessary for us to provide reliable financial reports, prevent fraud and operate successfully as a public company. If we cannot provide reliable financial reports or prevent fraud, our reputation and operating results would be harmed. We cannot be certain that our efforts to develop and maintain our internal controls will be successful, that we will be able to maintain adequate controls over our financial processes and reporting in the future or that we will be able to comply with our obligations under Section 404 of the Sarbanes-Oxley Act of 2002. Any failure to develop or maintain effective internal controls, or difficulties encountered in implementing or improving our internal controls, could harm our operating results or cause us to fail to meet our reporting obligations. Ineffective internal controls could also cause investors to lose confidence in our reported financial information, which would likely have a negative effect on the trading price of our common units.

We may be unable to compete effectively with larger companies, which may adversely affect our ability to generate sufficient revenue to allow us to pay distributions to our unitholders.

The oil and natural gas industry is intensely competitive, and we compete with other companies that have greater resources. Our ability to acquire additional properties and to discover reserves in the future will be dependent upon CEPM s willingness and ability to evaluate and select suitable properties and our ability to consummate transactions in a highly competitive environment. Many of our larger competitors not only drill for and produce natural gas and oil, but also carry on refining operations and market petroleum and other products on a regional, national or worldwide basis. These companies may be able to pay more for natural gas properties and

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evaluate, bid for and purchase a greater number of properties than our financial or human resources permit. In addition, these companies may have a greater ability to continue drilling activities during periods of low natural gas prices and to absorb the burden of present and future federal, state, local and other laws and regulations. Our inability to compete effectively with larger companies could have a material adverse impact on our business activities, financial condition and results of operations, which could reduce the amount of cash we have available to pay distributions.

Due to our lack of asset and geographic diversification, adverse developments in our operating area would reduce our ability to make distributions to our unitholders.

We rely exclusively on sales of the natural gas that we produce. Furthermore, all of our assets are located in the Black Warrior Basin in Alabama. Due to our lack of diversification in asset type and location, an adverse development in the oil and gas business or this geographic area, would have a significantly greater impact on our results of operations and cash available for distribution to our unitholders than if we maintained more diverse assets and locations.

Seasonal weather conditions adversely affect our ability to conduct production activities in the Robinson s Bend Field.

Natural gas operations in the Robinson s Bend Field are adversely affected by seasonal weather conditions, primarily during hurricane season. We face the risk that power outages resulting from hurricanes and other strong storms will prevent us from operating our wells in an optimal manner.

We are subject to complex federal, state, local and other laws and regulations that could adversely affect the cost, manner or feasibility of conducting our operations.

Our natural gas exploration, production and transportation operations are subject to complex and stringent laws and regulations. In order to conduct our operations in compliance with these laws and regulations, we must obtain and maintain numerous permits, approvals and certificates from various federal, state and local governmental authorities. Failure or delay in obtaining regulatory approvals or drilling permits could have a material adverse effect on our ability to develop our properties, and receipt of drilling permits with onerous conditions could increase our compliance costs. In addition, regulations regarding conservation practices and the protection of correlative rights affect our operations by limiting the quantity of natural gas we may produce and sell.

We are subject to federal, state and local laws and regulations as interpreted and enforced by governmental authorities possessing jurisdiction over various aspects of the exploration, production and transportation of natural gas. The possibility exists that these new laws, regulations or enforcement policies could be more stringent and significantly increase our compliance costs. If we are not able to recover the resulting costs through insurance or increased revenues, our ability to make distributions to our unitholders could be adversely affected. Furthermore, we may be put at a competitive disadvantage to larger companies in our industry that can spread these additional costs over a greater number of wells and larger operating staff. Please read Item 1. Business-Operations-Environmental Matters and Regulation for more information on the laws and regulations that affect us.

Risks Related to Our Structure

Constellation and its affiliates own a controlling interest in us through their ownership of our Class A units and a majority of our common units.

Constellation indirectly owns approximately 53% of the outstanding common units and 100% of the outstanding Class A units. The percentages do not reflect any common units that may be issued under our long-term incentive plan. Accordingly, Constellation and its affiliates will be able to assert great influence in any vote

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of common unitholders, including the election of the three members of our board of managers that are elected by the common unitholders. As long as Constellation and its affiliates beneficially own a controlling interest in us, they will have the ability to control our management and affairs. In addition, CEPM, as the holder of all our Class A units will have the exclusive right to elect two members of our board of managers. Affiliates of Constellation may thus be able to cause a change of control of our company. This concentration of ownership may have the effect of preventing or discouraging transactions involving an actual or a potential change of control of our company, regardless of whether a premium is offered over then-current market prices.

Our limited liability company agreement limits and modifies our managers and officers fiduciary duties.

Our limited liability company agreement contains provisions that modify and limit our managers and officers fiduciary duties to us and our unitholders. For example, our limited liability company agreement provides that:

- our managers and officers will not have any liability to us or our unitholders for decisions made in good faith, which is defined so as to require that they believed the decision was in our best interests; and
- our managers and officers will not be liable for monetary damages to us or our unitholders for any acts or omissions unless there has been a final and non-appealable judgment entered by a court of competent jurisdiction determining that the managers or officers acted in bad faith or engaged in fraud or willful misconduct or, in the case of a criminal matter, acted with knowledge that such conduct was unlawful.

Members of our board of managers, our executive officers and Constellation and its affiliates, including CEPH and CEPM, may have conflicts of interest with us. Our limited liability company agreement limits the remedies available to our unitholders in the event they have a claim relating to conflicts of interest or the resolution of such a conflict of interest.

The two members of our board of managers appointed by CEPM, the holder of our Class A units, are officers of, and are affiliated with, Constellation. In addition, our executive officers also serve as managers, directors, officers or employees of Constellation or its other affiliates. Conflicts of interest may arise between us and our unitholders and members of our board of managers or our executive officers and Constellation and its affiliates, including CEPH and CEPM. These potential conflicts may relate to the divergent interests of these parties. Situations in which the interests of members of our board of managers or our executive officers and Constellation and its affiliates, including CEPH and CEPM, may differ from interests of owners of common units include, among others, the following situations:

- our limited liability company agreement gives our board of managers broad discretion in establishing cash reserves for the proper conduct of our business, which will affect the amount of cash available for distribution. For example, our board of managers will use its reasonable discretion to establish and maintain cash reserves sufficient to maintain our asset base;
- none of our limited liability company agreement, management services agreement nor any other agreement requires Constellation, CEPM or any of their affiliates to pursue a business strategy that favors us. Directors and officers of Constellation, CEPM and their subsidiaries (other than us) have a fiduciary duty while acting in the capacity as such a director or officer of Constellation, CEPM or such subsidiary to make decisions in the best interests of the Constellation stockholders, which may be contrary to our best interests;
- upon our request, CEPM, under the management services agreement, will recommend to our board of managers the timing and extent of our drilling program and related capital expenditures, asset purchases and sales, and financing alternatives (whether borrowings, issuances of additional limited liability company interests or a combination of the foregoing) and reserve adjustments, all of which will affect the amount of cash that we distribute to our unitholders;

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- we intend to rely on CEPM to provide us with opportunities for the acquisition of oil and natural gas reserves, however, neither Constellation nor CEPM has any obligation to provide us with such opportunities;

- in some instances our board of managers may cause us to borrow funds in order to permit us to pay cash distributions to our unitholders, even if the purpose or effect of the borrowing is to make management incentive distributions;

- our executive officers will not be compensated by us; instead, they will be compensated by CCG for serving as officers or employees of CCG;

- we intend to rely on CEPM and its affiliates to assist us in implementing our hedging policy;

- none of our executive officers or the members of our board of managers and Constellation and its affiliates, including CEPH and CEPM, are prohibited from investing or engaging in other businesses or activities that compete with us; and

- our board of managers is allowed to take into account the interests of parties other than us, such as Constellation or CEPM, in resolving conflicts of interest, which has the effect of limiting its fiduciary duty to our unitholders.

If in resolving conflicts of interest that exist or arise in the future our board of managers or officers, as the case may be, satisfy the applicable standards set forth in our limited liability company agreement for resolving conflicts of interest, a unitholder will not be able to assert that such resolution constituted a breach of fiduciary duty owed to us or to our unitholders by our board of managers and officers.

Our limited liability company agreement prohibits a unitholder (other than CEPM, CEPH and their affiliates) who acquires 15% or more of our common units without the approval of our board of managers from engaging in a business combination with us for three years. This provision could discourage a change of control that our unitholders may favor, which could negatively affect the price of our common units.

Our limited liability company agreement effectively adopts Section 203 of the Delaware General Corporation Law (the DGCL). Section 203 of the DGCL as it applies to us prevents an interested unitholder, defined as a person who owns 15% or more of our outstanding common units, from engaging in business combinations with us for three years following the time such person becomes an interested unitholder. Section 203 broadly defines business combination to encompass a wide variety of transactions with or caused by an interested unitholder, including mergers, asset sales and other transactions in which the interested unitholder receives a benefit on other than a pro rata basis with other unitholders. This provision of our limited liability company agreement could have an anti-takeover effect with respect to transactions not approved in advance by our board of managers, including discouraging takeover attempts that might result in a premium over the market price for our common units.

Our common unitholders do not have the right to vote for two of our managers, and the common units indirectly owned by Constellation give Constellation the ability to elect the remaining members of our board of managers.

CEPM, as the sole holder of our Class A units, has the sole right, voting as a separate class, to elect two of the five members of our board of managers and to fill any vacancy created by the death, resignation or removal of either of such managers. Each of the three remaining members of our board of managers are subject to annual election at a meeting of our common unitholders.

Since Constellation owns more than a majority of our outstanding common units, Constellation, in combination with CEPM as owner of the Class A units, is able to elect all of the members of our board of managers. In addition, since the removal of a manager elected by our common unitholders requires the approval

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of the holders of not less than a majority of our outstanding common units, our public common unitholders are unable to remove a member of our board of managers unless Constellation votes its common units in favor of such a removal.

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

Our limited liability agreement restricts the voting rights of common unitholders by providing that any units held by a person that owns 20% or more of any class of units then outstanding, other than Constellation, CEPM, their affiliates or transferees and persons who acquire such units with the prior approval of the board of managers, cannot vote on any matter. Our limited liability agreement also contains provisions limiting the ability of common unitholders to call meetings or to acquire information about our operations, as well as other provisions limiting common unitholders ability to influence the manner or direction of management.

If the holders of our common units vote to eliminate the special voting rights of the holders of our Class A units, our Class A units will convert into common units on a one-for-one basis and CEPM will have the option of converting the management incentive interests into common units at their fair market value, which may be dilutive to the common unitholders.

The holders of our Class A units have the right, voting as a separate class, to elect two of the five members of our board of managers, and any replacement of either of such members. This right can be eliminated upon a vote of the holders of not less than a 66 $^2/3$% of our outstanding common units. If such elimination is so approved and Constellation and its affiliates do not vote their common units in favor of such elimination, the Class A units will be converted into common units on a one-for-one basis and CEPM will have the right to convert its management incentive interests into common units based on the then fair market value of such interests, which may be dilutive to the common unitholders.

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

We may issue an unlimited number of limited liability company interests of any type, including common units and units with rights to cash distributions or in liquidation that are senior in order of priority to common units, without the approval of our unitholders.

The issuance of additional units or other equity securities may have the following effects:

- the common unitholders proportionate ownership interest in us may decrease;
- the amount of cash distributed on each common unit may decrease;
- the relative voting strength of each previously outstanding common unit may be diminished;
- the market price of the common units may decline; and
- the ratio of taxable income to distributions may increase.

Our limited liability company agreement provides for a limited call right that may require unitholders to sell their common units at an undesirable time or price.

If, at any time, any person owns more than 80% of the common units then outstanding, such person has the right, but not the obligation, which it may assign to any of its affiliates or to us, to acquire all, but not less than all, of the remaining common units then outstanding at a price not less than the then-current market price of the common units. As a result, unitholders may be required to sell their common units at an undesirable time or price

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and therefore may receive a lower or no return on their investment. Unitholders may also incur tax liability upon a sale of their common units.

The market price of our common units could be volatile due to a number of factors, many of which are beyond our control.

The market price of our common units could be subject to wide fluctuations in response to a number of factors, most of which we cannot control, including:

- changes in securities analysts recommendations and their estimates of our financial performance;
- the public s reaction to our press releases, announcements and our filings with the SEC;
- fluctuations in broader securities market prices and volumes, particularly among securities of natural gas and oil companies and securities of publicly traded limited partnerships and limited liability companies;
- changes in market valuations of similar companies;
- departures of key personnel;
- commencement of or involvement in litigation;
- variations in our quarterly results of operations or those of other natural gas and oil companies;
- variations in the amount of our quarterly cash distributions;
- future issuances and sales of our common units; and
- changes in general conditions in the U.S. economy, financial markets or the oil and natural gas industry.

In recent years, the securities markets have experienced extreme price and volume fluctuations. This volatility has had a significant effect on the market price of securities issued by many companies for reasons unrelated to the operating performance of these companies. Future market fluctuations may result in a lower price of our common units.

Unitholders may have liability to repay distributions.

Under certain circumstances, unitholders may have to repay amounts wrongfully returned or distributed to them. Under Section 18-607 of the Delaware Revised Limited Liability Company Act (the Delaware Act), we may not make a distribution to unitholders if the distribution would cause our liabilities to exceed the fair value of our assets. Delaware law provides that for a period of three years from the date of an impermissible distribution, members or unitholders who received the distribution and who knew at the time of the distribution that it violated Delaware law will be liable to the limited liability company for the distribution amount. A purchaser of common units who becomes a member or unitholder is liable for the obligations of the transferring member to make contributions to the limited liability company that are known to such purchaser of units at the time it became a member and for unknown obligations if the liabilities could be determined from our limited liability company agreement.

Constellation s interests in us may be transferred to a third party without common unitholder consent.

Constellation s affiliates may transfer their Class A units, common units, management incentive interests and Class D interests to a third party in a merger or in a sale of all or substantially all of their respective assets without the consent of our common unitholders. Furthermore, there is no restriction in our limited liability company agreement on the ability of Constellation to cause a transfer to a third party of its affiliates equity interest in CEPM, CEPH, CCG or CHI. The new owner of the Class A units and common units formerly owned by Constellation would then be in a position to replace a majority of our board of managers with its own choice, which could then replace some or all of our officers.

CEPH may sell common units in the future, which could reduce the market price of our outstanding common units.

As of February 15, 2007, CEPH controlled an aggregate of 5,918,894 common units. In addition, we have agreed to register for the sale common units held by CEPH. These registration rights allow CEPH to request registration of its common units and to include any of those common units in a registration of other securities by us. If CEPH were to sell a substantial portion of its common units, it could reduce the market price of our outstanding common units

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

Like all equity investments, an investment in our common units is subject to certain risks. In exchange for accepting these risks, investors may expect to receive a higher rate of return than would otherwise be obtainable from lower-risk investments. Accordingly, as interest rates rise, the ability of investors to obtain higher risk-adjusted rates of return by purchasing government-backed debt securities may cause a corresponding decline in demand for riskier investments generally, including yield-based equity investments such as publicly-traded limited liability company interests. Reduced demand for our common units resulting from investors seeking other more favorable investment opportunities may cause the trading price of our common units to decline.

Tax Risks to Unitholders

Our tax treatment depends on our status as a partnership for federal income tax purposes, as well as our not being subject to entity-level taxation by individual states. If the IRS were to treat us as a corporation for federal income tax purposes or we were to become subject to entity-level taxation for state tax purposes, taxes paid, if any, would reduce the amount of cash available for distribution.

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

If we were treated as a corporation for federal income tax purposes, we would pay federal income tax on our taxable income at the corporate tax rates, currently at a maximum rate of 35%, and would likely pay state income tax at varying rates. Distributions to unitholders would generally be taxed as corporate distributions, and no income, gain, loss, deduction or credit would flow through to the unitholders. Because a tax may be imposed on us as a corporation, our cash available for distribution to our unitholders could be reduced. Therefore, treatment of us as a corporation could result in a material reduction in the anticipated cash flow and after-tax return to our unitholders and therefore result in a substantial reduction in the value of our common units.

Current law or our business may change so as to cause us to be treated as a corporation for federal income tax purposes or otherwise subject us to entity-level taxation. In addition, because of widespread state budget deficits, several states are evaluating ways to subject partnerships and limited liability companies to entity-level taxation through the imposition of state income, franchise or other forms of taxation. If any state were to impose a tax upon us as an entity, the cash available for distribution to unitholders would be reduced. Our limited liability company agreement provides that if a law is enacted or existing law is modified or interpreted in a manner that subjects us to taxation as a corporation or otherwise subjects us to entity-level taxation for federal, state or local income tax purposes, the initial quarterly distribution amount and the Target Distribution amount (as defined in our limited liability company agreement) will be adjusted to reflect the impact of that law on us.

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Unitholders may be required to pay taxes on income from us even if they do not receive any cash distributions from us.

Unitholders are required to pay federal income taxes and, in some cases, state and local income taxes on their share of our taxable income, whether or not they receive cash distributions from us. Unitholders may not receive cash distributions from us equal to their share of our taxable income or even equal to the actual tax liability that results from their share of our taxable income.

A successful IRS contest of the federal income tax positions we take may adversely affect the market for our common units, and the costs of any contest will reduce cash available for distribution.

We have not requested a ruling from the IRS with respect to our treatment as a partnership for federal income tax purposes or any other matter that affects us. The IRS may adopt positions that differ from the positions we take. It may be necessary to resort to administrative or court proceedings to sustain some or all of the positions we take and a court may disagree with some or all of those positions. Any contest with the IRS may materially and adversely impact the market for our common units and the price at which they trade. In addition, our costs of any contest with the IRS will result in a reduction in cash available for distribution to our unitholders and thus will be borne indirectly by our unitholders.

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

Investment in units by tax-exempt entities, including employee benefit plans and individual retirement accounts (known as IRAs), and non-U.S. persons raises issues unique to them. For example, virtually all of our income allocated to organizations exempt from federal income tax, including individual retirement accounts and other retirement plans, will be unrelated business taxable income and will be taxable to such a unitholder. Distributions to non-U.S. persons will be reduced by withholding taxes imposed at the highest effective applicable tax rate, and non-U.S. persons will be required to file United States federal income tax returns and pay tax on their share of our taxable income.

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

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

Tax gain or loss on the disposition of our common units could be more or less than expected because prior distributions in excess of allocations of income will decrease a unitholder s tax basis in his common units.

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

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We will be considered to have terminated for tax purposes due to a sale or exchange of 50% or more of our interests within a twelve-month period.

We will be considered to have terminated for tax purposes if there is a sale or exchange of 50% or more of the total interests in our capital and profits within a twelve-month period. A constructive termination results in the closing of our taxable year for all unitholders and in the case of a unitholder reporting on a taxable year other than a fiscal year ending December 31, may result in more than 12 months of our taxable income or loss being includable in his taxable income for the year of termination. A constructive termination occurring on a date other than December 31 will result in us filing two tax returns (and unitholders receiving two Schedule K-1s) for one calendar year and the cost of the preparation of these returns will be borne by all unitholders.

Unitholders may be subject to state and local taxes and return filing requirements.

In addition to federal income taxes, unitholders will likely be subject to other taxes, including state and local taxes, unincorporated business taxes and estate, inheritance or intangible taxes that are imposed by the various jurisdictions in which we do business or own property now or in the future, even if the unitholder does not reside in any of those jurisdictions. Unitholders will likely be required to file foreign, state and local income tax returns and pay state and local income taxes in some or all of these jurisdictions. Further, unitholders may be subject to penalties for failure to comply with those requirements. We currently do business and own assets in Alabama and Maryland. We are registered to do business in Texas. As we make acquisitions or expand our business, we may do business or own assets in other states in the future. It is the responsibility of each unitholder to file all United States federal, foreign, state and local tax returns that may be required of such unitholder. In addition, if the unitholder sells his units, he may incur a tax liability in excess of the amount of cash received from the sale.

Forward-Looking Statements

This Annual Report on Form 10-K contains forward-looking statements that are subject to a number of risks and uncertainties, many of which are beyond our control, which may include statements about:

- the volatility of realized natural gas prices;
- the discovery, estimation, development and replacement of oil and natural gas reserves;
- our business and financial strategy;
- our drilling locations;
- technology;
- our cash flow, liquidity and financial position;
- the impact from the termination of the sharing arrangement before December 31, 2012;
- our production volumes;

our lease operating expenses, general and administrative costs and finding and development costs;

the availability of drilling and production equipment, labor and other services;

our future operating results;

our prospect development and property acquisitions;

the marketing of oil and natural gas;

competition in the oil and natural gas industry;

the impact of weather and the occurrence of natural disasters such as fires, floods, hurricanes, earthquakes and other catastrophic events and natural disasters;

governmental regulation of the oil and natural gas industry;

developments in oil-producing and natural gas producing countries; and

our strategic plans, objectives, expectations and intentions for future operations.

All of these types of statements, other than statements of historical fact included in this Annual Report on Form 10-K, are forward-looking statements. These forward-looking statements may be found in Item 1. Business; Item 1A. Risk Factors; Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations and other items within this Annual Report on Form 10-K. In some cases, forward-looking statements can be identified by terminology such as may, could, should, expect, plan, project, intend, anticipate, estimate, predict, potential, pursue, target, continue, the negative of such terms or other comparable terminology.

The forward-looking statements contained in this Annual Report on Form 10-K are largely based on our expectations, which reflect estimates and assumptions made by our management. These estimates and assumptions reflect our best judgment based on currently known market conditions and other factors. Although we believe such estimates and assumptions to be reasonable, they are inherently uncertain and involve a number of risks and uncertainties that are beyond our control. In addition, management s assumptions about future events may prove to be inaccurate. Management cautions all readers that the forward-looking statements contained in this Annual Report on Form 10-K are not guarantees of future performance, and we cannot assure any reader that such statements will be realized or the forward-looking events and circumstances will occur. Actual results may differ materially from those anticipated or implied in the forward-looking statements due to factors listed in the Risk Factors section and elsewhere in this Annual Report on Form 10-K. We do not intend to publicly update or revise any forward-looking statements as a result of new information, future events or otherwise. These cautionary statements qualify all forward-looking statements attributable to us or persons acting on our behalf.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

A description of our properties is included in Item 1. Business, and is incorporated herein by reference.

Our obligations under our credit facility are secured by mortgages on our natural gas properties, as well as a pledge of all ownership interests in our subsidiaries. See Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations Financing Activities Credit Facility , in this Annual Report on Form 10-K for additional information concerning our credit facility.

Item 3. Legal Proceedings

Although we may, from time to time, be involved in litigation and claims arising out of our operations in the normal course of business, we are not currently a party to any material legal proceedings. In addition, we are not aware of any legal or governmental proceedings against us, or contemplated to be brought against us, under various environmental protection statutes or other regulations to which we are subject.

Item 4. Submission of Matters to a Vote of Security Holders

No matters were submitted to a vote of security holders during the fourth quarter of 2006.

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PART II

Item 5. Market for Registrant s Common Equity, Related Unitholder Matters and Issuer Purchases of Equity Securities

Our common units are listed on the NYSE Arca under the symbol CEP. Our units began trading on November 15, 2006, in connection with our initial public offering. On February 15, 2007, there were 11,093,894 common units outstanding and approximately 1,500 unitholders. On February 15, 2007, the market price for our common units was $26.11 per unit, resulting in an aggregate market value of units held by non-affiliates of approximately $135.1 million. During the fourth quarter 2006, the high and low market price for our common units was $25.90 and $21.00, respectively.

Our limited liability company agreement requires that, within 45 days after the end of each quarter, beginning with the quarter ended December 31, 2006, we distribute all of our available cash to unitholders of record on the applicable record date. Available cash generally means, for any quarter ending prior to liquidation:

(a) the sum of:

(i) all cash and cash equivalents of the Company and its subsidiaries (or the Company s proportionate share of cash and cash equivalents in the case of subsidiaries that are not wholly-owned) on hand at the end of that quarter; and

(ii) all additional cash and cash equivalents of the Company and its subsidiaries (or the Company s proportionate share of cash and cash equivalents in the case of subsidiaries that are not wholly-owned) on hand on the date of determination of available cash for that quarter resulting from working capital borrowings made subsequent to the end of such quarter,

(b) less the amount of any cash reserves established by the board of managers (or the Company s proportionate share of cash reserves in the case of subsidiaries that are not wholly-owned) to:

(i) provide for the proper conduct of the business of the Company and its subsidiaries (including reserves for future capital expenditures including drilling and acquisitions and for anticipated future credit needs) subsequent to such quarter,

(ii) comply with applicable law or any loan agreement, security agreement, mortgage, debt instrument or other agreement or obligation to which the Company or any of its subsidiaries is a party or by which it is bound or its assets are subject; or

(iii) provide funds for distributions (1) to our unitholders or (2) in respect of our Class D interests or management incentive interests with respect to any one or more of the next four quarters;

provided, however, that the board of managers may not establish cash reserves pursuant to (iii) above if the effect of such reserves would be that the Company is unable to distribute the quarterly distribution on all Common Units and Class A Units with respect to such quarter; and provided further, that disbursements made by us or any of our subsidiaries or cash reserves established, increased or reduced after the end of that quarter, but on or before the date of determination of available cash for that quarter, shall be deemed to have been made, established, increased or reduced, for purposes of determining available cash, within that quarter if board of managers so determines.

On February 14, 2007, the Company paid a cash distribution of $0.2111 per common unit for the period on November 20, 2006 through December 31, 2006, to unitholders of record on February 7, 2007. This represented a prorated portion of our initial quarterly distribution of $0.4625 per common unit.

Use of Proceeds of Initial Public Offering

In the fourth quarter of 2006, we completed our initial public offering of an aggregate of 5,175,000 units representing Class B limited liability company interests (consisting of 4,500,000 units purchased by the

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underwriters November 20, 2006 and 675,000 units purchased by the underwriters on November 28, 2006 pursuant to their option to purchase additional units) at an initial public offering price of $21.00 per unit in a firm commitment underwritten initial public offering pursuant to Registration Statement on Form S-1 (File No. 333-134995) declared effective by the Securities and Exchange Commission on November 14, 2006. Citigroup and Lehman Brothers Inc. acted as joint lead-managing underwriters of the offering.

The aggregate initial public offering price for the units registered and sold in our initial public offering was approximately $108.7 million. Net proceeds (after underwriting discounts and offering expenses of approximately $10.7 million) were approximately $98.0 million. CHI contributed $8.0 million to us in exchange for the Class D interests. We borrowed $30.0 million under our reserve-based credit facility. Using the $8.0 million received from CHI, we reduced our borrowings under the reserve-based credit facility. Using the net proceeds and remaining cash on hand, a distribution of $122.8 million was made to CEPH as a reimbursement for capital expenditures incurred by CCG prior to the offering. The remaining proceeds were retained for working capital purposes.

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Common Unit Performance Graphs

The graph below compares CEP s cumulative total shareholder return on its common units from the period November 15, 2006 through December 31, 2006, with the cumulative total returns over the same period of the Russell 2000 index, the Dow Jones US Exploration & Production index and a customized peer group of five companies that includes: Atlas Energy Resources, Breitburn Energy Limited Liability Company, EV Energy Partners Limited Partnership, Legacy Reserves Limited Partnership and Linn Energy LLC. The graph assumes that the value of the investment in our common units, in each index, and in the peer group was $100 on November 15, 2006. Cumulative return is computed assuming reinvestment of dividends.

Item 6. Selected Financial Data

Set forth below is our selected historical consolidated financial data for the periods indicated for Constellation Energy Partners LLC. The historical financial data for the period ended December 31, 2006 and for the period from February 7, 2005 (inception) to December 31, 2005, and the balance sheet data as of December 31, 2006 and 2005 have been derived from our audited financial statements.

We were formed in February 2005 and had no principal operations prior to the completion of a $161.1 million acquisition of natural gas reserves and equipment from Everlast on June 13, 2005. The historical financial data for the period from January 1, 2005 through June 12, 2005 and the years ended December 31, 2004 and 2003 have been derived from Everlast s audited historical financial statements. The historical financial data as of

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and for the year ended December 31, 2002 have been derived from unaudited financial data of Torch Energy, the predecessor to Everlast.

You should read the following selected financial data in conjunction with Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations and our financial statements and the financial statements of Everlast and related notes appearing elsewhere in this Annual Report on Form 10-K.

Our only operations are in the Robinson s Bend Field, as were Everlast s. During each of the last three years, our properties in the Robinson s Bend Field were wholly-owned by us or Everlast. Our acquisition from Everlast resulted in a new basis for our properties in the Robinson s Bend Field for accounting purposes. In addition, new management, operating and accounting policies, and estimates were put into place after our acquisition from Everlast. Though the financial statements reflect the operation of the same properties in the Robinson s Bend Field, due to these differences, the financial statements for the periods prior to and after our purchase of our properties in the Robinson s Bend Field are not comparable. For that purpose, a black line has been placed between our and Everlast s financial statements. Our historical results of operations and period-to-period comparisons of results and certain financial data prior to and after our acquisition of our properties in the Robinson s Bend Field from Everlast may not be indicative of future results.

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The following table presents a non-GAAP financial measure, Adjusted EBITDA, which we use in our business. This measure is not calculated or presented in accordance with generally accepted accounting principles (GAAP). We explain this measure and reconcile it to net income, the most directly comparable financial measure calculated and presented in accordance with GAAP in Non-GAAP Financial Measure Adjusted EBITDA below.

	Predecessor				Successor	
	Torch Energy	Everlast Energy LLC			Constellation Energy Partners LLC	
	For the year ended December 31, 2002	For the year ended December 31, 2003	For the year ended December 31, 2004	For the period from January 1, 2005 to June 12, 2005	For the period from February 7, 2005 (inception) to December 31, 2005[(b)]	For the year ended December 31, 2006
	Unaudited (in 000 s)	As Restated[(a)]	As Restated[(a)] (in 000 s)		(in 000 s)	
Statement of Operations Data:						
Revenues:						
Gas sales	$ 8,710	$ 22,320	$ 27,494	$ 12,882	$ 25,957	$ 36,917
Loss from mark-to-market activities		(3,664)	(9,107)	(15,313)		
Total revenues	8,710	18,656	18,387	(2,431)	25,957	36,917
Operating expenses:						
Lease operating expenses	7,763	4,428	5,270	2,769	4,175	7,234
Production taxes	368	1,279	1,479	676	1,400	1,783
General and administrative	92	1,945	2,706	594	4,184	4,573
Depreciation, depletion and amortization	77	3,684	3,719	1,683	4,176	7,444
Accretion expense		73	86	46	78	141
Gain on asset sale	(4)					
Total operating expenses	8,296	11,409	13,260	5,768	14,013	21,175
Other expenses/(income):						
Interest expense		1,961	3,028	2,437	3	221
Interest (income)						(468)
Organization costs		299				
Total other expenses/(income)		2,260	3,028	2,437	3	(247)
Total expenses/(income)	8,296	13,669	16,288	8,205	14,016	20,928
Net income (loss)	$ 414	$ 4,987	$ 2,099	$ (10,636)	$ 11,941	$ 15,989
Other Financial Information (unaudited):						
Adjusted EBITDA	$	$ 10,193	$ 14,738	$ 8,795	$ 16,198	$ 23,025

(a) The financial statements of Everlast for 2003 and 2004 have been restated. Please read Note 2 to the historical consolidated financial statements included elsewhere in this Annual Report on Form 10-K.

(b) Until our acquisition of our properties in the Robinson s Bend Field from Everlast on June 13, 2005, we did not conduct any operations.

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	Predecessor				Successor	
	Torch Energy	Everlast Energy LLC			Constellation Energy Partners LLC	
	For the year ended December 31, 2002 Unaudited	For the year ended December 31, 2003 As Restated[(a)]	For the year ended December 31, 2004 As Restated[(a)]	For the period from January 1, 2005 to June 12, 2005[(b)]	For the period from February 7, 2005 (inception) to December 31, 2005[(b)]	For the year ended December 31, 2006
	(in 000 s)	(in 000 s)			(in 000 s)	
Balance Sheet Data (at period end):						
Cash and cash equivalents	$	$ 2,563	$ 2,012		$ 14,831	$ 7,485
Other current assets	39,014	1,812	4,562		6,097	18,602
Natural gas properties, net of accumulated depreciation, depletion and amortization	1,587	49,252	52,531		165,211	171,639
Other assets		590	1,579			5,971
Total assets	$ 40,601	$ 54,217	$ 60,684		$ 186,139	$ 203,697
Current liabilities	$ 43,812	$ 4,403	$ 4,482		$ 13,895	$ 9,007
Debt		26,000	67,500		63	22,000
Preferred units subject to mandatory redemption		16,752				
Other long-term liabilities		2,671	3,314		3,014	2,730
Class D interests						8,000
Members equity:						
Common members equity (deficit)	(3,211)	4,391	(14,612)		169,167	148,847
Accumulated other comprehensive income						13,113
Total members equity (deficit)	(3,211)	4,391	(14,612)		169,167	161,960
Total liabilities and members equity (deficit)	$ 40,601	$ 54,217	$ 60,684		$ 186,139	$ 203,697
Cash Flow Data:						
Net cash provided by operating activities	$ 109	$ 9,773	$ 4,906	$ 6,639	$ 23,313	$ 14,067
Net cash used in investing activities	(109)	(47,832)	(6,997)	(4,203)	(147,237)	(25,429)
Net cash provided by (used in) financing activities		40,622	1,540	(2,500)	138,755	4,016
Development of natural gas properties	(109)	(2,040)	(5,680)	(4,000)	(8,286)	(13,224)

(a) The financial statements of Everlast for 2003 and 2004 have been restated. Please read Note 2 to the historical consolidated financial statements included elsewhere in this Annual Report on Form 10-K.

(b) Until our acquisition of our properties in the Robinson s Bend Field from Everlast on June 13, 2005, we did not conduct any operations.

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Non-GAAP Financial Measure Adjusted EBITDA

We define Adjusted EBITDA as net income (loss) adjusted by:

- interest (income) expense;
- depreciation, depletion and amortization;
- write-off of deferred financing fees;
- impairment of long-lived assets;
- (gain) loss on sale of assets;
- (gain) loss from equity investment;
- accretion of asset retirement obligation;
- unrealized (gain) loss on natural gas derivatives; and
- realized loss (gain) on cancelled natural gas derivatives.

Adjusted EBITDA is a significant performance metric used by our management to indicate (prior to the establishment of any cash reserves by our board of managers) the cash distributions we expect to pay to our unitholders. Specifically, this financial measure indicates to investors whether or not we are generating cash flow at a level that can sustain or support an increase in our quarterly distribution rates. Adjusted EBITDA is also used as a quantitative standard by our management and by external users of our financial statements such as investors, research analysts and others to assess:

- the financial performance of our assets without regard to financing methods, capital structure or historical cost basis;
- the ability of our assets to generate cash sufficient to pay interest costs and support our indebtedness; and
- our operating performance and return on capital as compared to those of other companies in our industry, without regard to financing or capital structure.

Our Adjusted EBITDA should not be considered as a substitute for net income, operating income, cash flows from operating activities or any other measure of financial performance or liquidity presented in accordance with GAAP. Our Adjusted EBITDA excludes some, but not all, items that affect net income and operating income and these measures may vary among other companies. Therefore, our Adjusted EBITDA may not be comparable to similarly titled measures of other companies.

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The following table presents a reconciliation of net income (loss) to Adjusted EBITDA, our most directly comparable GAAP performance measure, for each of the periods presented:

	Predecessor Everlast Energy LLC			Successor Constellation Energy Partners LLC	
	For the year ended December 31, 2003	For the year ended December 31, 2004	For the period from January 1, 2005 to June 12, 2005	For the period from February 7, 2005 (inception) to December 31, 2005	For the year ended December 31, 2006
		(In 000 s)			(In 000 s)
Reconciliation of Net Income (Loss) to Adjusted EBITDA:					
Net income/(loss)	$ 4,987	$ 2,099	$ (10,636)	$ 11,941	$ 15,989
Adjusted by:					
Interest expense/(income), net[(a)]	1,961	3,028	2,437	3	(247)
Depreciation, depletion and amortization	3,684	3,719	1,683	4,176	7,444
Accretion of asset retirement obligation	73	86	46	78	141
Unrealized loss/(gain) on natural gas derivatives	(512)	(2,156)	15,265		(302)
Realized loss on cancelled natural gas derivatives		7,962			
Adjusted EBITDA	$ 10,193	$ 14,738	$ 8,795	$ 16,198	$ 23,025

(a) For the years ended December 31, 2004 and 2003, the return on the preferred units subject to mandatory redemption totaled approximately $0.4 million and $0.7 million, respectively. These amounts are included in interest expense in the accompanying income statements and were also treated as non-cash additions to net income when calculating the net cash provided by operating activities. As these amounts are already included in both interest expense and net cash provided by operating activities, they are not included in this line of the reconciliation.

Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations

The following discussion and analysis should be read in conjunction with the Item 6. Selected Financial Data and the accompanying financial statements and related notes included elsewhere in this Annual Report on Form 10-K. The following discussion contains forward-looking statements that reflect our future plans, estimates, forecasts, guidance, beliefs and expected performance. The forward-looking statements are dependent upon events, risks and uncertainties that may be outside our control. Our actual results could differ materially from those discussed in these forward-looking statements. Factors that could cause or contribute to such differences include, but are not limited to, market prices for natural gas, production volumes, estimates of proved reserves, capital expenditures, economic and competitive conditions, regulatory changes and other uncertainties, as well as those factors discussed below and elsewhere in this Annual Report on Form 10-K, particularly in Item 1A. Risk Factors and Forward-Looking Statements, all of which are difficult to predict. In light of these risks, uncertainties and assumptions, the forward-looking events discussed may not occur.

Overview

We are a limited liability company formed by Constellation on February 7, 2005 to acquire E&P properties. In June 2005, we acquired reserves in the Robinson s Bend Field from Everlast. Our primary business objective is to generate stable cash flows allowing us to make quarterly cash distributions to our unitholders and over time to increase the amount of our future quarterly distributions. Our strategies for achieving this objective are to:

make accretive acquisitions of E&P properties characterized by a high percentage of proved developed reserves with long-lived, stable production and low-risk drilling opportunities, which may include

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- associated midstream assets such as gathering systems, compression, dehydrating and treating facilities and other similar facilities;

- increase reserves and production through what we believe to be low-risk development drilling; and

- reduce the volatility in our revenues resulting from changes in oil and natural gas commodity prices through hedging.

Our future oil and natural gas reserves and production and, therefore, our cash flow and income are highly dependent on our success in efficiently developing our current reserves and economically finding, developing and acquiring additional recoverable reserves. We may not be able to find, develop or acquire additional reserves to replace our current and future production at acceptable costs, which would adversely affect our business, financial condition and results of operations and our ability to pay quarterly cash distributions to our unitholders.

Significant Operational Factors since December 31, 2005

- *Realized Prices*. Although we have continued to benefit from favorable natural gas prices and from our hedging program, our average realized prices declined from 2005. Our average realized price for 2006, including hedges, was $7.95 per Mcf.

- *Production*. Our production during 2006 was 4.6 Bcf or an average of 12,715 Mcf per day. Our December 2006 production was approximately 13,700 Mcf per day. The increased production volumes resulted from our successful drilling program, the addition of more compression to the field and an enhanced maintenance program.

- *Capital Expenditures and Drilling Results*. In 2006, we incurred $13.5 million in capital expenditures. We drilled and completed 31 wells with a 100% drilling success rate. On average, these wells came on-line producing 70 Mcf per day.

- *Natural Gas Reserves*. Our 2006 year-end reserves were 120.3 Bcf an approximate 7.4% increase from 112.0 Bcf in 2005. The increase was driven by our development drilling program, improved well performance and a reduction in the Torch NPI volumes were reduced from 5.8 Bcf to zero due to the lower December 31, 2006 natural gas price used to determine natural gas reserves under SEC guidelines. Based upon our six-year, 20 well per year drilling program, we estimate that we have 120 gross proved undeveloped locations and approximately 200 additional gross potential drilling locations left to develop in the Robinson s Bend Field.

- *Operating Expenses.* Our operating expenses declined in the fourth quarter of 2006, as we reduced discretionary costs associated with field maintenance programs that were implemented in 2005 after we acquired our initial properties in the Robinson s Bend Field.

In November 2006, we entered into a management services agreement with a subsidiary of Constellation to provide us with certain management, technical and administrative services. These services include legal, accounting and finance, engineering and technical, risk management, information technology, and tax services, as well as acquisition services related to opportunities to acquire oil and natural gas reserves and related midstream assets. The fees for services under the agreement will be determined on an annual basis and will be based on Constellation s cost to provide the services.

While we are consolidated with Constellation for accounting purposes, we will be required under the management services agreement to use Constellation for legal, accounting, finance, tax and risk management services. Constellation does not have any obligation to provide us with acquisition services under the management services agreement, but we expect that their ownership of our Class A units, common units and management incentive interests will provide them with an incentive to grow our business, by helping us to identify, evaluate and complete acquisitions that will be accretive to our distributable cash.

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Hedging Activities. We have implemented a hedging program that uses derivatives to reduce the impact of commodity price volatility on our anticipated cash flows. Our intention is to hedge approximately 80% of our forecasted production for a five year period. Our management, however, may modify the hedging percentages and strategies as it deems appropriate for market conditions and other business strategies. For 2007, we have hedged 4,199,996 MMBtu at a weighted average price of $9.19 per MMBtu.

NPI Agreement. As of December 31, 2006, 421 of our wells in the Robinson s Bend Field were subject to an NPI held by the Trust. Through the NPI, the Trust is entitled to a royalty payment, calculated as a percentage of the net revenue, that is, specified revenues reduced by specified associated expenditures, from the Trust Wells. Under the terms of the NPI and related contractual arrangements, the royalty payment we are required to make to the Trust under the NPI is calculated using a sharing arrangement with a pricing formula that has been below market and has had the effect of keeping the payments to the Trust significantly lower than if such payments had been calculated based on then prevailing market prices. Reserves attributable to the NPI are not included in our year-end 2006 estimate of proved reserves. The sharing arrangement may be terminated under specified circumstances that are beyond our control. If we lose the benefit of the sharing arrangement in respect of calculating payments under the NPI, the payments to the Trust could increase and our revenues could decrease in each case compared to the amounts if the sharing arrangement remained in effect.

Debt. We currently have $22.0 million outstanding under our secured revolving credit facility. The initial borrowing base is set at $75.0 million. The credit facility will mature in October 2010. The interest rate on the facility is the London interbank offered rate (LIBOR) plus an applicable margin between 1.25% and 2.00% per annum, based on utilization. We have entered into a swap agreement to fix our LIBOR rate at 4.74% for $16.5 million of our outstanding debt through October 2010.

Acquisition. We announced in March 2007 that we have entered into a definitive purchase agreement to acquire certain coalbed methane properties in the Cherokee Basin of Oklahoma and Kansas for approximately $115 million. The properties consist of over 550 producing wells currently producing 7,900 Mcf/day. The acquisition provides over 800 low-risk, low-cost drilling and recompletion opportunities on approximately 96,000 gross acres. We executed unit purchase agreements for a private placement of $60 million of equity securities to third party investors, consisting of 2,207,684 common units at a unit price of $26.12 per unit and 90,376 newly-created Class E units at a price of $25.84. The Class E units will convert into common units upon obtaining common unit holder approval. We have undertaken to obtain this approval by August 1, 2007. Constellation Energy Partners Holdings, LLC, the owner of a majority of the outstanding common units, will agree to vote its common units in favor of the conversion. We also have agreed to file a registration statement with the SEC registering for resale the common units and common units issuable upon conversion of the Class E units within 75 days after the closing. We believe that the proceeds from this equity private placement, together with funds available under our existing credit facility, will fully fund the purchase price of the acquisition. We anticipate that the private placement will close simultaneously with the acquisition of the assets in mid-April 2007. We expect to enter into derivative transactions to hedge the future expected production associated with this acquisition.

We face the challenge of natural gas production declines. As a given well s initial reservoir pressures are depleted, natural gas production decreases. We attempt to overcome this natural decline both by drilling on our properties and acquiring additional reserves. We will continue to focus on reducing our costs to add reserves through drilling and acquisitions, as well as the corresponding costs necessary to produce such reserves. Our ability to add reserves through drilling is dependent on our capital resources and can be limited by many factors, including our ability to timely obtain drilling permits and regulatory approvals. In accordance with our business

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plan, we intend to invest the capital necessary to maintain our production and operating capacity and our asset base over the long term.

Comparability of Financial Statements

Because of our limited operating history, our historical results of operations and period-to-period comparisons of these results and certain financial data may not be indicative of future results.

Our only operations are in the Robinson s Bend Field, which operations we acquired from Everlast in June 2005. During each of the last three years, our properties in the Robinson s Bend Field were wholly-owned by us or Everlast. The Everlast acquisition resulted in a new basis in our properties in the Robinson s Bend Field for accounting purposes. In addition, new management, operating and accounting policies, and reserve estimates were put into place after the Everlast acquisition. As a result, though the financial statements reflect the operation of the same Robinson s Bend Field properties, the financial statements for the periods prior to and after our purchase of our properties in the Robinson s Bend Field are not comparable. Our historical results of operations and period-to-period comparisons of results and certain financial data prior to and after our acquisition from Everlast may not be indicative of future results.

Some of the differences include:

Reserves and related estimates: Our estimate of proved reserves is based on the quantities of natural gas that engineering and geological analyses demonstrate, with reasonable certainty, to be recoverable from established reservoirs in the future under current operating and economic parameters. Our 2005 proved reserve estimate was 112.0 Bcf, which is lower than the 2004 estimates of proved reserves primarily because of the following factors:

A Reduction of 24.5 Bcf Based on Interpretation of Well Performance: The information on which we based this adjustment includes our interpretation of well performance data that was available at December 31, 2005 for new wells drilled and completed in the Robinson s Bend Field in 2004 and 2005. There was no drilling in the field between 1994 and late 2003. While the performance data at December 31, 2005 is from a limited number of new wells drilled in the field in 2004 and in 2005, we believed it provided relevant information for the purposes of estimating reserves and we interpreted the data and reflected the results of that analysis in our reserve estimates and assumptions. The majority of the 24.5 Bcf reduction in the reserve estimate at December 31, 2005 associated with our interpretation of the recent well performance data is in the proved developed non-producing (PDNP) category and the proved undeveloped (PUD) categories of reserves.

A Reduction of 15.4 Bcf Based on CEP s Planned Drilling Program: The 112.0 Bcf estimate also reflects our planned drilling program of 20 gross wells per year for the next six years. We use a six year time horizon for drilling program and reserves estimation purposes because it is consistent with what we use for internal capital expenditure planning purposes and because we believe that using a longer time horizon would create additional uncertainty with regard to capital budgeting, therefore potentially reducing our ability to prepare a reliable estimate of reserves. Everlast s drilling program, which was designed to provide maximum returns in a relatively short time period, was to drill and complete 197 gross wells within a five-year period. Our planned drilling program is designed to provide a steady and constant return by drilling an average of 20 wells per year over a six year period. Due to this difference in drilling programs, certain proved undeveloped reserves that were based on Everlast s accelerated drilling program and using NSAI s reserve assumptions cannot be included in our proved reserve estimates because, under our current drilling program, those reserves are scheduled to be drilled more than six years after the date of the reserve report and as such are outside the time horizon we use to prepare our internal estimates of proved reserves.

A Reduction of 5.8 Bcf for Reserves Attributed to the NPI: Our December 31, 2005 reserve estimates removed 5.8 Bcf of reserves that are attributed to the NPI using an overriding royalty interest approach. The estimated reserves attributed to the NPI at December 31, 2004 were zero due to the lower gas prices compared to December 31, 2005 prices.

We used our 112.0 Bcf proved reserve estimate to prepare our 2005 financial statements. We prepared the reserve estimate of 162.2 Bcf at December 31, 2004 that was used to prepare the 2004 financial statements of our predecessor, Everlast, using internal estimates.

We prepared the estimate of the 2004 proved reserves for financial statement purposes by starting with NSAI s December 31, 2005 proved reserve estimate, which was based upon Everlast s accelerated drilling program and reserve assumptions, and rolling that estimate back to December 31, 2004 by making appropriate adjustments for actual production, prices and development activity. The roll-back approach was necessary because the reserve report prepared by NSAI for Everlast for December 31, 2004 was not based on the SEC definition of proved reserves, which we use for financial statement preparation purposes.

Due to this inconsistency in the preparation of reserve reports for the periods presented, we have rolled back the estimate of reserves at December 31, 2005 to December 31, 2004 in preparing the financial statements of our predecessor for the year ended December 31, 2004. In preparing the roll-back to December 31, 2004, we did not adjust the estimated proved reserve volumes to reflect our reserve assumptions based upon our interpretation of recent well performance in the Robinson s Bend Field because these assumptions were based on recent information that was not available to Everlast when it was preparing the 2004 financials statements. In addition, we did not adjust the volumes to reflect our current drilling program of 20 gross wells per year for the next six years because this drilling program was not the drilling program adopted by Everlast in 2004. The previous reserve estimate was 173.4 Bcf at December 31, 2004.

Derivatives: Everlast s economic hedges did not qualify for hedge accounting treatment under Statement of Financial Accounting Standard (SFAS) No. 133, *Accounting for Derivative Instruments and Hedging Activities,* and are thus classified as losses on a mark-to-market basis in its statement of operations. From the acquisition of our properties in the Robinson s Bend Field until June 20, 2006, we did not enter into hedges in our own name. During that period, hedges were executed by CCG, which hedged its exposure to the variability in revenues from the forecasted sale of natural gas due to changes in natural gas prices by entering into hedges for its entire portfolio of natural gas properties, including our properties in the Robinson s Bend Field. Therefore, hedging gains and losses are not reflected in our financial statements included elsewhere in this Annual Report on Form 10-K. These gains and losses are reported in the financial statements of CCG. On June 20, 2006, we executed hedges for a portion of our expected production from currently producing wells from October 2006 through December 2009.

Depletion: Everlast used the full-cost method of accounting for natural gas properties, whereas we use the successful efforts method. Under the full-cost method used by Everlast, all costs related to the acquisition, exploration or development of natural gas properties were capitalized and depleted based on the production of proved reserves. Under the successful efforts method that we use, costs relating to the development of proved areas are capitalized when incurred and are depleted based on the production of either proved developed reserves or proved reserves, depending on the asset classification. Exploration costs, however, are expensed as incurred. Under both methods, capitalized costs are depleted on a units-of-production method.

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Results of Operations

We acquired our initial properties in the Robinson s Bend Field from Everlast on June 13, 2005. From February 7, 2005, the date of our formation, to June 12, 2005, we did not conduct any operations and had no production; therefore we had no revenues or operating expenses.

The following table sets forth the selected financial and operating data for the periods indicated:

	Predecessor Everlast Energy LLC		Successor Constellation Energy Partners LLC	
	For the year ended December 31, 2004[(a)]	For the period from January 1, 2005 to June 12, 2005	For the period from February 7, 2005 (inception) to December 31, 2005[(b)]	For the year ended December 31, 2006
	(In 000 s, except production, cost and price data)		(In 000 s, except production, cost and price data)	
Revenues:				
Gas Sales	$ 27,494	$ 12,882	$ 25,957	$ 36,917
Loss from mark-to-market activities	(9,107)	(15,313)		
Total Revenues	18,387	(2,431)	25,957	36,917
Operating expenses:				
Lease operating expenses	5,270	2,769	4,175	7,234
Production taxes	1,479	676	1,400	1,783
General and administrative expenses	2,706	594	4,184	4,573
Depreciation, depletion and amortization	3,719	1,683	4,176	7,444
Accretion expenses	86	46	78	141
Total operating expenses	13,260	5,768	14,013	21,175
Other expenses/(income):				
Interest expense	3,028	2,437	3	221
Interest (income)				(468)
Total other expenses/ (income)	3,028	2,437	3	(247)
Net income (loss)	$ 2,099	$ (10,636)	$ 11,941	$ 15,989
Net production:				
Total production (MMcf)	4,527	1,970	2,525	4,641
Average daily production (Mcf/d)	12,400	12,100	12,500	12,715
Average sales prices:				
Price per Mcf including hedges	$ 4.06	$ (1.23)[(c)]	$ 10.28[(d)]	$ 7.95[(d)]
Price per Mcf excluding hedges	$ 6.07	$ 6.54	$ 10.28	$ 7.43
Average unit costs per Mcf:				
Field operating expenses[(e)]	$ 1.49	$ 1.75	$ 2.21	$ 1.94

Lease operating expenses	$ 1.16	$ 1.41	$ 1.66	$ 1.56
Production taxes	$ 0.33	$ 0.34	$ 0.55	$ 0.38
General and administrative expenses	$ 0.60	$ 0.30	$ 1.66	$ 0.99
Depreciation, depletion and amortization	$ 0.82	$ 0.85	$ 1.65	$ 1.60

(a) The financial statements of Everlast for 2004 have been restated. Please read Note 2 to the historical consolidated financial statements included elsewhere in this Annual Report on Form 10-K.

(b) Until our acquisition of our properties in the Robinson s Bend Field from Everlast on June 13, 2005, we did not conduct any operations and, therefore, had no production.

(c) Price per Mcf including hedges includes mark-to-market losses of approximately $15.3 million on derivative transactions that did not qualify for hedge accounting treatment.

(d) We had no derivatives at December 31, 2005. In 2006, we entered into derivative transactions that hedged the future prices on a portion of our expected production from October 2006 through December 2006.

(e) Field operating expenses include lease operating expenses and production taxes.

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Revenue

Gas Sales

Our natural gas sales for the year ended December 31, 2006 were $36.9 million, at an average sales price of $7.95 per Mcf, including the impact of our hedges. Production for 2006 was 4.6 Bcf, which was higher than 2005 as a result of our development drilling program, the addition of compression to the field and improved field maintenance. We hedged approximately 74% of our production from October 2006 through December 2006. Our realized prices declined from 2005 to 2006 because of lower natural gas prices.

Our natural gas sales for the period from February 7, 2005 (inception) to December 31, 2005 were $26.0 million. For the period from February 7, 2005 (inception) to December 31, 2005, our total production was 2.5 Bcf, with an average sales price of $10.28 per Mcf. For the period from June 13, 2005 to December 31, 2005, gas prices increased substantially, particularly in October and November, due to natural gas shortages caused by hurricanes Katrina and Rita. The average realized sales price for those two months was $13.79 per Mcf, which was 49% higher than the prior two months.

Everlast s natural gas sales were $12.9 million for the period from January 1, 2005 to June 12, 2005. For that period, Everlast s production was 2.0 Bcf, with an average realized sales price of $6.54 per Mcf.

Everlast s natural gas sales were $27.5 million for the year ended December 31, 2004. Their sales revenues were impacted by the average natural gas price, which was $6.07 per Mcf for the year ended December 31, 2004, as total production remained relatively stable at approximately 4.5 Bcf.

Hedging and Mark-to-Market Activities

We did not have any mark-to-market derivatives for the year ended December 31, 2006.

We entered into cash flow hedges during 2006 and recognized income of approximately $0.3 million related to hedge ineffectiveness during the twelve months ended December 31, 2006.

We did not have any mark-to-market derivatives from February 7, 2005 (inception) to December 31, 2005. During such period, CCG utilized hedges to mitigate its natural gas price exposure across its portfolio of gas producing assets including our properties in the Robinson s Bend Field. Accordingly, the results of these hedges are not reflected on our financial statements. CCG also assumed certain of Everlast s hedges at the time of our acquisition from Everlast and managed such hedges as part of its portfolio of hedges.

Everlast entered into derivative instruments to economically hedge the market price fluctuations of its natural gas that did not qualify for hedge accounting under SFAS No. 133. Everlast s losses on its mark-to-market derivatives were $15.3 million for the period from January 1, 2005 to June 12, 2005, and $9.1 million for the year ended December 31, 2004. These losses were caused by the movement of market prices above the fixed price under the derivatives maintained by Everlast.

Expenses

Field Operating Expenses

Our field operating expenses generally consist of lease operating expenses, labor, vehicle expenses, supervision, transportation, minor maintenance, tools and supplies, as well as production and ad valorem taxes. Production taxes are a function of volumes and revenues generated from production. Ad valorem taxes vary by county and are based on the value of our wells, equipment and reserves. We assess our field operating expenses by monitoring the expenses in relation to the volume of production and the number of producing wells.

For the year ended December 31, 2006, field operating expenses were $9.0 million, or $1.94 per Mcf. Our total field operating costs increased $3.4 million from 2005 to 2006 primarily because of the acquisition of our

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properties in the Robinson s Bend Field in June 2005 and increased required and discretionary maintenance costs. The costs per unit decreased due to increased production volumes resulting from our drilling program, field maintenance and compression installation. Significant field operating expenses during this period included:

- Production taxes of $1.8 million, or $0.38 per Mcf (the current production tax rate is approximately 5% of gas sales);
- Field salaries and operating supervision costs of $1.7 million, or $0.36 per Mcf;
- Well servicing and workover costs $1.9 million, or $0.41 per Mcf;
- Power and fuel costs of $0.9 million, or $0.20 per Mcf;
- Maintenance and repair costs of $0.7 million, or $0.15 per Mcf;
- Gas marketing costs of $0.5 million, or $0.10 per Mcf;
- Insurance and bond costs of $0.3 million, or $0.06 per Mcf; and
- Miscellaneous operating costs of $1.2 million, or $0.27 per Mcf.

Our field operating expenses were $5.6 million for the period from February 7, 2005 (inception) to December 31, 2005, or an average of approximately $2.21 per Mcf of production during that period. Our field operating expenses increased over 2004 as a result of the effects of generally higher prevailing natural gas prices, which affected our production taxes and fuel costs.

For the period from February 7, 2005 (inception) to December 31, 2005, significant field operating expenses included:

- Production taxes of $1.4 million, or $0.55 per Mcf (the current production tax rate is approximately 5% of gas sales);
- Field salary costs and operating supervision costs of $1.3 million, or $0.52 per Mcf;
- Well servicing costs of $0.7 million, or $0.29 per Mcf;
- Power and fuel costs of $0.6 million, or $0.24 per Mcf;
- Maintenance and repair costs of $0.3 million, or $0.14 per Mcf;

Gas marketing costs of $0.4 million, or $0.16 per Mcf;

Insurance and bond costs of $0.2 million, or $0.07 per Mcf; and

Miscellaneous operating costs of $0.6 million, or $0.25 per Mcf.

Everlast s field operating expenses were $3.4 million, or $1.75 per Mcf, for the period from January 1, 2005 to June 12, 2005, and $6.7 million, or $1.49 per Mcf, for the year ended December 31, 2004.

For the period from January 1, 2005 to June 12, 2005, significant field operating expenses included:

Production taxes of $0.7 million, or $0.34 per Mcf;

Field salary costs of $0.6 million, or $0.29 per Mcf;

Well servicing and workover costs of $0.5 million, or $0.24 per Mcf;

Power and fuel costs of $0.4 million, or $0.19 per Mcf;

Maintenance and repair costs of $0.3 million, or $0.13 per Mcf;

Insurance and bond costs of $0.1 million, or $0.04 per Mcf; and

Miscellaneous operating expenses of $0.3 million, or $0.15 per Mcf.

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Field operating expenses for the year ended December 31, 2004 were $6.7 million. Production taxes remained level as the production tax rate was consistent and the total taxes were impacted by an increase in gas prices. In 2004, three recompletions were performed. Power and fuel costs for the year ended December 31, 2004 were $0.8 million, due to higher energy prices.

General and Administrative Expenses

General and administrative expenses include the costs of our employees, related benefits, field office expenses, professional fees, costs billed by CEPM under our management services agreement and other costs not directly associated with field operations. We monitor general and administrative expenses in relation to our production volumes and the number of producing wells.

Our general and administrative expenses were $4.6 million, or $0.99 per Mcf, for the year ended December 31, 2006. Our 2006 general and administrative expenses were higher than the period from February 7, 2005 (inception) to December 31, 2005, primarily due to increased expenses related to becoming a public company and a full year of costs for technical and administrative services from Constellation. Significant general and administrative costs during this period were:

- Audit fees of $1.4 million, or $0.30 per Mcf;
- Professional services of $1.2 million, or $0.27 per Mcf;
- Consulting fees of $1.0 million, or $0.21 per Mcf; and
- Landman consulting fees of $0.3 million, or $0.06 per Mcf, related to lease acquisition efforts.

Our general and administrative expenses were $4.2 million, or $1.66 per Mcf, for the period February 7, 2005 (inception) to December 31, 2005. Our costs increased in 2005 primarily because of consulting services from The Investment Company. For the period from February 7, 2005 (inception) to December 31, 2005, significant general and administrative costs were:

- Professional service and consulting fees of $3.7 million, or $1.45 per Mcf. $3.1 million, or $1.24 per Mcf, of this balance relates to the agreement with The Investment Company for consulting services associated with our acquisition of properties in the Robinson s Bend Field; and
- Fees incurred by CCG on our behalf of $0.4 million, or $0.15 per Mcf, for salaries and benefit costs of CCG employees dedicated to our operations.

Everlast s general and administrative expenses were $0.6 million for the period from January 1, 2005 to June 12, 2005.

For the period from January 1, 2005 to June 12, 2005, Everlast s significant general and administrative costs were:

- Corporate salaries of $0.3 million, or $0.13 per Mcf; and
- Professional service and consulting fees of $0.2 million, or $0.09 per Mcf.

General and administrative expenses for the year ended December 31, 2004 were $2.7 million. The expenses were primarily impacted by an increase in corporate salaries.

Depreciation, Depletion and Amortization Expense

Depreciation, depletion and amortization expenses include the depreciation, depletion and amortization of acquisition costs and equipment costs. Depletion is calculated using units-of-production. Assuming everything else remains unchanged, as natural gas production changes, depletion would change in the same direction.

Our depreciation, depletion and amortization expense for the year ended December 31, 2006 was $7.4 million, or $1.60 per Mcf. This reflects our basis in the assets as of December 2006 of $181.8 million, gross of

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accumulated depletion. As described above, we calculate depletion using units-of-production under the successful efforts method of accounting. Our depreciation, depletion and amortization expense increased from 2005 to 2006 primarily because of the acquisition of the properties from Everlast in June 2005, higher production rates and an increased basis in our assets because of additional capital expenditures.

Our depreciation, depletion and amortization expense for the period from February 7, 2005 (inception) to December 31, 2005, was $4.2 million and reflects the $161.1 million purchase price of our properties in the Robinson s Bend Field from Everlast on June 13, 2005. The combined effect of a higher basis and lower reserve estimates resulted in higher depreciation, depletion and amortization expense.

Everlast s depreciation, depletion and amortization expense was $1.7 million for the period from January 1, 2005 to June 12, 2005 and $3.7 million for the year ended December 31, 2004. As described above, Everlast calculated depletion based on units-of-production under the full cost method of accounting applied to capital costs of $63.8 million and $59.7 million as of June 12, 2005, and December 31, 2004, respectively. Everlast s production was constant for 2004 and the period from January 1, 2005 to June 12, 2005, and as a result, Everlast s depletion was relatively consistent for such periods.

Other Income (Expenses)

Our other income (expenses) for the year ended December 31, 2006 was $0.2 million, or $0.05 per Mcf. Interest income of $0.4 million was earned on the cash pool agreement with CCG. As of November 2006, we ceased participation in the cash pool and CCG retained the $12.4 million receivable. This was treated as a reduction of members equity for accounting purposes. Interest expense, net of capitalized amounts, was $0.2 million. The average interest rate on our outstanding debt of $22 million was 6.63%.

During the period from February 7, 2005 (inception) through December 31, 2005, our only debt outstanding was a $0.1 million note payable associated with an equipment lease. Our interest expense on the note payable was approximately $3,000 for this period.

For Everlast, interest expense includes all interest on notes payable, short-term and long-term debt, and accretion of the preferred return on Everlast s Series A and Series B Preferred Member units. Everlast s interest expense was $2.4 million for the period from January 1, 2005 to June 12, 2005 and $3.0 million for the year ended December 31, 2004, $1.3 million of the total annual interest expense related to the interest charged on Everlast s notes payable, short-term debt and long-term debt. For 2004, $2.6 million of the total annual interest expense related to the interest charged on Everlast s notes payable, short-term and long-term debt. At December 31, 2004, the weighted average interest rate on Everlast s floating rate debt was 6.1% and debt outstanding was $67.5 million. For 2004, the remaining $0.4 million of total annual interest expense related to the accretion of the preferred rate of return of 8% on Everlast s Series A and Series B Preferred Member units. The Series A and Series B Preferred Member units were redeemed by Everlast in April 2004. At June 12, 2005, the weighted average interest rate on Everlast s floating rate debt was 7.3% and debt outstanding was $65.0 million.

Liquidity and Capital Resources

During the year ended December 31, 2006, we utilized proceeds from our initial public offering, proceeds from bank borrowings and cash flow from operations as our primary sources of capital. In the fourth quarter of 2006, we completed our initial public offering of 5,175,000 units which provided proceeds after underwriting discounts and offering expenses of approximately $98.0 million. Using the net proceeds and cash on hand, a distribution of $122.8 million was made to CEPH, which was a reimbursement of capital expenditures incurred prior to the initial public offering by CCG on behalf of CEP. To date, our primary use of capital has been for the development of natural gas properties. As we pursue our growth strategy, we will be monitoring the capital resources available to us to meet our future financial obligations and planned capital expenditures. Our future success in growing reserves and production will be highly dependent on the capital resources available to us and our success in drilling for or acquiring additional reserves. Based upon our current expectations, we expect to continue to generate cash flow sufficient to support our projected maintenance capital expenditures and operations of our business.

In addition, our reserve-based credit facility may be used to help finance future expansion capital expenditures, such as drilling and recompletions beyond that required to maintain production, as well as acquisitions. We currently have $22.0 million of debt outstanding under the reserve-based credit facility and $53.0 million in unused borrowing capacity.

In each of the next two years, we expect to utilize our cash flow from operations and borrowings from our reserve-based credit facility to fund a portion of drilling expenditures. We expect to fund our 2007 and 2008 maintenance capital expenditures with cash flow from operations, while funding our 2007 and 2008 investment capital expenditures and any expansion capital expenditures that we might incur with borrowings under our reserve-based credit facility. We do not expect to incur expansion capital expenditures through the twelve-month period ending December 31, 2007, although that may change if expansion opportunities are available to us in that period. We also estimate that we will have sufficient cash flow from operations after funding our maintenance capital expenditures to enable us to make our quarterly cash distributions to unitholders through December 31, 2008. CEPM currently holds management incentive interests in us that represent the right to receive 15% of quarterly distributions of available cash from operating surplus after the Target Distribution (as defined in our limited liability company agreement) has been achieved and certain other tests have been met. The earliest that we could be required to make distributions in respect of the management incentive interests is after a period of twelve consecutive quarters following our initial public offering. We are not able to predict whether or when we will be required to make distributions in respect of the management incentive interests or, if we do make such distributions in the future, how much they will be.

In the event the cost of acquiring additional oil or natural gas properties exceed our existing capital resources, we expect that we will finance those acquisitions with a combination of expanded or new debt facilities or new equity issuances. The ratio of debt and equity issued will be determined by our management and our board of managers as deemed appropriate for our unitholders.

Reserve-Based Credit Facility

On October 31, 2006, we entered into a $200.0 million secured credit facility with a syndicate of commercial and investment banks, including The Royal Bank of Scotland plc, as administrative agent. The credit facility will mature on October 31, 2010. The amount available for borrowing at any one time is limited to the borrowing base, which is initially set at $75.0 million. The borrowing base will be re-determined semi-annually, and may be re-determined at our request more frequently, by the lenders in their sole discretion based on reserve reports prepared by our internal reserve engineers, together with, among other things, the natural gas and oil prices at such time. Any increase in the borrowing base will have to be approved by all of the lenders in the syndicate and any decrease in the borrowing base will have to be approved by lenders holding 66 $^{2}/_{3}$% of the commitments.

Our obligations under the credit facility are secured by mortgages on our natural gas properties, as well as a pledge of all ownership interests in our subsidiaries. We are required to maintain the mortgages on properties representing at least 65% of our proved producing and proved non-producing reserves. Additionally, the obligations under the credit facility are guaranteed by all of our operating subsidiaries and any future material subsidiaries.

Borrowings under the credit facility are available to us for acquisition, exploration, operation and maintenance of natural gas and oil properties, payment of expenses incurred in connection with the credit facility, working capital and general limited liability company purposes. A sub-limit of $20.0 million of the facility applies for letters of credit.

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At our election, interest will be determined by reference to:

- LIBOR plus an applicable margin between 1.25% and 2.00% per annum based on utilization; or
- a domestic bank rate plus an applicable margin between 0.25% and 1.00% per annum based on utilization.

Interest will generally be payable quarterly for domestic bank rate loans and at the applicable maturity date for LIBOR loans.

The credit facility contains various covenants that limit our ability to:

- incur indebtedness;
- grant certain liens;
- make certain loans, acquisitions, capital expenditures and investments;
- make distributions other than from available cash;
- merge or consolidate; or
- engage in certain asset dispositions, including a sale of all or substantially all of our assets.

The credit facility also contains covenants that, among other things, require us to maintain specified ratios or conditions as follows:

- debt to Adjusted EBITDA (defined as, for any period, the sum of consolidated net income for such period plus the following expenses or charges to the extent deducted from consolidated net income in such period: interest expense, depreciation, depletion, amortization, write-off of deferred financing fees, impairment of long-lived assets, (gain) loss on sale of assets, (gain) loss from equity investment, accretion of asset retirement obligation, unrealized (gain) loss on natural gas derivatives and realized (gain) loss on cancelled natural gas derivatives, and other similar charges) of not more than 3.5 to 1.0; and
- Adjusted EBITDA to cash interest expense of not less than 4.5 to 1.0; and
- consolidated current assets, including the unused amount of the total commitments but excluding current non-cash assets, to consolidated current liabilities, excluding non-cash liabilities, of not less than 1.0 to 1.0, all calculated pursuant to the requirements under SFAS No. 133 and 143 (including the current liabilities in respect of the termination of natural gas and interest rate swaps).

We have the ability to borrow under the credit facility to pay distributions to unitholders as long as there has not been a default or event of default and if the amount of borrowings outstanding under our credit facility is less than 90% of the borrowing base.

If an event of default exists under the credit facility, the lenders will be able to accelerate the maturity of the credit facility and exercise other customary rights and remedies. Each of the following is an event of default:

- failure to pay any principal when due or any interest, fees or other amount within certain grace periods;
- a representation or warranty made under the loan documents or in any report or other instrument furnished thereunder is incorrect when made;
- failure to perform or otherwise comply with the covenants in the credit facility or other loan documents, subject, in certain instances, to certain grace periods, which include covenants that:
  - Constellation and its affiliates maintain the right to elect our Class A Managers; and
  - we obtain the approval of the administrative agent (such approval not to be unreasonably withheld or delayed) of any management services plan upon the termination of the management services agreement with CEPM;

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- any event occurs that permits or causes the acceleration of the indebtedness;
- bankruptcy or insolvency events involving us or our subsidiaries;
- the entry of, and failure to pay, one or more adverse judgments in excess of $1.0 million or one or more non-monetary judgments that could reasonably be expected to have a material adverse effect and for which enforcement proceedings are brought or that are not stayed pending appeal;
- specified events relating to our employee benefit plans that could reasonably be expected to result in liabilities in excess of $1.0 million in any year; and
- a change of control, generally defined as the first date on which the following two conditions occur: (i) a decrease by CEPH and CEPM of their combined ownership of our outstanding membership interests to less than 25%, and (ii) the ownership by any person (other than a wholly- owned subsidiary of Constellation) of more than 35% of our outstanding membership interests.

At February 15, 2007, we believe that we are in compliance with the debt covenants contained in our credit facility.

We enter into hedging arrangements to reduce the impact of volatility of changes in the LIBOR interest rate on our interest payments for our reserve-based credit facility. Currently, we have an outstanding interest rate swap that fixes our LIBOR rate at 4.74% on $16.5 million of our outstanding debt through October 2010.

Cash Flow from Operations

Our net cash flow provided by operating activities was $14.1 million for the twelve months ended December 31, 2006. The major component of our cash flow for that period was net income of $16.0 million. In November 2006, we also paid $3.1 million to The Investment Company for consulting services associated with the acquisition of our properties in the Robinson s Bend Field. The major adjustments to net income were depreciation, depletion and amortization of $7.4 million, which was driven by our capitalized costs of $181.8 million.

Net cash provided by operating activities was $23.3 million for the period from February 7, 2005 (inception) to December 31, 2005. This cash flow is a result of relatively steady production in a rising natural gas price environment. As discussed above, CCG utilized portfolio hedges to mitigate its natural gas price exposure across its portfolio of gas producing assets. Therefore, we did not hedge the revenue from our production for the period from June 13, 2005 to December 31, 2005. If we had hedged 80% of our production for the period from June 13, 2005 through December 31, 2005, we estimate that our cash provided by operating activities would have been reduced by approximately $6.1 million, resulting in net cash provided by operating activities for that period of $17.2 million. The major component of our operating cash flow for the period from February 7, 2005 (inception) to December 31, 2005 was $26.0 million of gas sales resulting in net income of $11.9 million. The major adjustments to net income were depreciation, depletion and amortization of $4.2 million, which was driven by our capitalized costs of $168.7 million, and an increase in current liabilities of $8.6 million, of which $3.1 million relates to an agreement with The Investment Company for consulting services associated with the acquisition of our properties in the Robinson s Bend Field. The remaining $5.5 million increase in current liabilities was primarily the result of higher royalties payable due to higher gas prices and the remaining payable to Everlast related to the acquisition of our properties in the Robinson s Bend Field.

Net cash provided by operating activities of Everlast for the period from January 1, 2005 to June 12, 2005 was $6.6 million. The major component of Everlast s cash flow was $12.9 million of gas sales, resulting in a net loss of $10.6 million. The loss was primarily due to $15.3 million in losses from mark-to-market activities, which is one of the major adjustments to net income. Another major non-cash adjustment for the period was depreciation, depletion and amortization of $1.7 million, which was driven by Everlast s capitalized costs of $63.8 million.

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Our cash flow from operations is subject to many variables, the most significant of which is the volatility of natural gas prices. Natural gas prices are determined primarily by prevailing market conditions, which are dependent on regional and worldwide economic activity, weather and other factors beyond our control. Our future cash flow from operations will depend on our ability to maintain and increase production through our projected production, development and exploitation program and acquisitions, as well as the prices of natural gas and the extent and effectiveness of our planned hedging program.

We enter into hedging arrangements to reduce the impact of natural gas price volatility on our operations. By removing the price volatility from a significant portion of our natural gas production, we have mitigated, but not eliminated, the potential effects of changing prices on our cash flow from operations for those periods. While mitigating negative effects of falling commodity prices, these derivative contracts also limit the benefits we would receive from increases in commodity prices. It is our policy to enter into derivative contracts only with counterparties that are creditworthy financial institutions deemed by management as competent and competitive market makers.

The following table summarizes, for the periods indicated, our hedges currently in place through December 31, 2009. Currently, we use fixed-price swaps as our mechanism for hedging commodity prices.

Our derivative positions at February 15, 2007 were:

	For the quarter ended (in MMBtu)									
	March 31,		June 30,		Sept 30,		Dec 31,		Total	
	MMBtu	$/MMBtu	MMBtu	$/MMBtu	MMBtu	$/MMBtu	MMBtu	$/MMBtu	MMBtu	$/MMBtu
2007	974,999	$ 9.22	1,074,999	$ 9.13	1,074,999	$ 9.17	1,074,999	$ 9.25	4,199,996	$ 9.19
2008	875,001	$ 8.91	875,001	$ 8.91	875,001	$ 8.91	875,001	$ 8.91	3,500,004	$ 8.91
2009	825,000	$ 8.40	825,000	$ 8.40	825,000	$ 8.40	825,000	$ 8.40	3,300,000	$ 8.40
									11,000,000	

Investing Activities Acquisitions and Capital Expenditures

Our capital expenditures were $13.5 million for the twelve months ended December 31, 2006, which primarily relate to drilling, development of natural gas properties during the year. We drilled and completed 31 gross wells (31 net wells) during the twelve months. We paid Everlast $2.4 million, which was the remaining balance of the purchase price for the Robinson s Bend Field properties. In addition, we had $12.4 million of cash flows used in investing activities due to the cash pool with CCG. In February 2006, we entered into a cash pool arrangement with CCG. We administered and managed this cash pool arrangement. CCG could borrow from the pool at market interest rates. If we required cash, and CCG had an outstanding balance, CCG was required to immediately remit payment to us for the required cash amount. The cash pool arrangement was terminated in November 2006. At the termination of the arrangement, our net receivable balance of $12.4 million was canceled and CCG retained the funds in respect of that receivable. This was treated as a reduction of members equity for accounting purposes. The cash pool was recorded as an investment due from affiliate.

Our capital expenditures were $147.2 million for the period from February 7, 2005 (inception) to December 31, 2005. This includes $8.3 million for drilling, development of natural gas properties since we acquired our initial properties in the Robinson s Bend Field and $139.0 million for the acquisition of these properties from Everlast. The total acquisition price for the Robinson s Bend Field properties was $161.1 million. The difference between the $139.0 million and the total purchase price of $161.1 million primarily relates to $18.0 million of mark-to-market derivative liabilities assumed by CCG as part of the acquisition, plus other miscellaneous obligations. During this period, we drilled 9 gross (9 net) wells and completed 12 gross (12 net) wells.

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Everlast s capital expenditures for the period from January 1, 2005 to June 12, 2005 were $4.2 million. This includes $0.2 million of new lease acquisitions and $4.0 million of drilling, development of natural gas properties. During this period, Everlast drilled 9 gross (9 net) wells and completed 6 gross (6 net) wells.

We currently anticipate our capital budget will be between $8.9 and $10.7 million for the twelve months ending December 31, 2007, including interest expense of approximately $0.2 million. The capital budget, which primarily consists of capital for drilling, also includes amounts for infrastructure projects and equipment. The amount and timing of our capital expenditures is largely discretionary and within our control. If natural gas prices decline to levels below acceptable levels, we could choose to defer a portion of these planned capital expenditures until later periods. We routinely monitor and adjust our capital expenditures in response to changes in natural gas prices, drilling and acquisition costs, industry conditions and internally generated cash flow. Matters outside our control that could affect the timing of our capital expenditures include obtaining required permits and approvals in a timely manner and the availability of rigs and crews. Based upon current natural gas price expectations for the twelve months ending December 31, 2007, we anticipate that our cash flow from operations and available borrowing capacity under our reserve-based credit facility will exceed our planned capital expenditures and other cash requirements for the twelve months ending December 31, 2007. However, future cash flows are subject to a number of variables, including the level of natural gas production and prices. There can be no assurance that operations and other capital resources will provide cash in sufficient amounts to maintain planned levels of capital expenditures.

Financing Activities

Our net cash provided by financing activities was $4.0 million which relates to the proceeds from our initial public offering and the proceeds from our reserve-based credit facility. We borrowed $30.0 million from our reserve-based credit facility and immediately repaid $8.0 million with the proceeds from the issuance of our Class D units. Our initial public offering raised $109.3 million before underwriting discounts and expenses. We paid a dividend of $122.8 million to Constellation. We also repaid $63,000 in outstanding debt during September 2006. Debt issue costs associated with our credit facility were $1.2 million. The underwriting discounts and expenses associated with our initial public offering were approximately $10.7 million.

Net cash provided by financing activities was $138.8 million for the period February 7, 2005 (inception) to December 31, 2005. CCG contributed to us $138.8 million for its limited liability company interest in us.

As of December 31, 2005, we had $0.1 million of borrowings. We assumed this debt from Everlast, and it relates to a note payable issued in conjunction with the purchase of equipment.

Everlast repaid $2.5 million of debt for the period from January 1, 2005 to June 12, 2005. At June 12, 2005, they had $65.0 million of indebtedness outstanding. Everlast had no significant financing activities in 2004.

Contractual Obligations

At December 31, 2006, we had the following contractual obligations or commercial commitments:

	Payments Due By Year(1)(2)						
	2007	2008	2009	2010	2011	Thereafter	Total
				(In 000 s)			
Management Services Agreement	$ 1,443	$	$	$	$	$	$ 1,443
Reserve-Based Credit Facility				22,000			22,000
Support Services Agreement	240	140					380
Gas Marketing Services Agreement	180						180
Purchase Obligation	1,000						1,000
Total	$ 2,863	$ 140	$	$ 22,000	$	$	$ 25,003

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(1) This table does not include any liability associated with derivatives.
(2) This table does not include interest as interest rates are variable.

Off-Balance Sheet Arrangements

We have no guarantees or off-balance sheet debt to third parties, and we maintain no debt obligations that contain provisions requiring accelerated payment of the related obligations in the event of specified levels of declines in credit ratings.

Outlook

During 2007, we expect that our business will continue to be affected by the factors described in Item 1A., Risk Factors , as well as the following key industry and economic trends. Our expectation is based upon key assumptions and information currently available to us. To the extent that our underlying assumptions about or interpretations of available information prove to be incorrect, our actual results may vary materially from our expected results.

Production, Drilling, and Capital Expenditures

In 2007, we expect our net production to be between 4.8 Bcf and 5.3 Bcf. This is based on our estimates of the production decline rate on our existing wells and our 2007 drilling program, which includes 20 newly drilled wells in the Robinson s Bend Field. Excluding the impact of acquisitions, we expect to spend between $8.9 million and $10.7 million in capital expenditures in 2007.

Natural Gas Prices and Hedging Activities

Natural gas prices have been volatile over the past three years and even more so in the past twelve to eighteen months. We believe that this trend has been affected by the hurricanes in the late summer and fall of 2005, threats and existence of wars and terrorism in the Middle East and elsewhere, OPEC s management of oil reserves, levels of natural gas held in storage and growth in domestic natural gas demand. The currently high levels of natural gas in storage, resulting at least in part from relatively mild winters in 2005 and 2006 in the United States, have caused natural gas prices to decline from the higher levels prevailing during the later part of 2005 when gas prices increased substantially, particularly in October and November, due to natural gas shortages caused by hurricanes Katrina and Rita.

During 2007, we hedged an additional 500,000 MMBtu of our 2007 production. As of February 15, 2007, we had hedges for 4,199,996 MMBtu of our 2007 production at a weighted average sales price of $9.19 per MMBtu. During the year, we will evaluate adding hedge volumes for 2007, adding to our hedge levels for 2008 and 2009, and adding duration to our hedge portfolio beyond 2009. For accounting purposes, these hedges are being treated as cash flow hedges.

As described above, we have also hedged our exposure to changes in LIBOR on the interest payments associated with our $16.5 million of outstanding debt. For accounting purposes, this interest rate swap is being treated as a cash flow hedge.

Field Operating Expenses

Our field operating expenses include such items as lease operating expenses, labor, vehicle expenses, supervision, transportation, minor maintenance, tools and supplies, as well as production and ad valorem taxes. Due to the current environment of relatively high commodity prices, we anticipate that during 2007, service and labor costs, as well as costs of equipment and raw materials, will remain at or exceed the levels we experienced in 2005 and 2006. We currently expect our field operating expenses for 2007 to be between $8.1 million and $8.9

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million. We intend to monitor and manage these costs in an effort to mitigate their adverse impact on our results of operations. Our production taxes are directly correlated to our revenues, as they are approximately 5% of sales revenue before the impact of our hedging program.

General and Administrative Expenses

We expect that our general and administrative expenses will be between $4.6 million and $5.1 million in 2007. This amount includes $1.4 million that we expect CEPM to charge us under the management services agreement. These estimated general and administrative costs assume that we do not make any acquisitions in 2007, and that we do not reimburse CEPM under the management services agreement for any acquisition services.

Higher natural gas and oil prices have led to higher demand for drilling rigs, operating personnel and field supplies and services and have caused increases in the costs of these goods and services. To date, our realized sales prices for natural gas have more than offset the higher drilling and operating costs we have incurred since 2005. Given the inherent volatility of natural gas prices, which are influenced by many factors beyond our control, we plan our activities and budgets based on sales price assumptions that reflect our forward price curve. We focus our efforts on increasing natural gas reserves and maintaining natural gas production levels while controlling costs at a level that is appropriate for long-term operations. Our future cash flow from operations is dependent on our ability to manage our overall cost structure.

Critical Accounting Policies and Estimates

The discussion and analysis of our financial condition and results of operations are based upon our consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted in the United States of America. The preparation of these financial statements requires us to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, and related disclosure of contingent assets and liabilities. Certain accounting policies involve judgments and uncertainties to such an extent that there is reasonable likelihood that materially different amounts could have been reported under different conditions, or if different assumptions had been used. We evaluate our estimates and assumptions on a regular basis. We base our estimates on historical experience and various other assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities that are not readily apparent from other sources. Actual results may differ from these estimates and assumptions used in the preparation of our financial statements. Below, we have provided an expanded discussion of our more critical accounting policies, estimates and judgments. We believe these accounting policies reflect our more significant estimates and assumptions used in the preparation of the Consolidated Financial Statements. Please read Note 1 to the consolidated financial statements for a discussion of additional accounting policies and estimates made by management.

Natural Gas Properties

We follow the successful efforts method of accounting for our natural gas exploration, development and production activities. Leasehold acquisition costs are capitalized. If proved reserves are found on an undeveloped property, leasehold cost is transferred to proved properties. Under this method of accounting, costs relating to the development of proved areas are capitalized when incurred.

Depreciation and depletion of producing natural gas and oil properties is recorded based on the units-of-production method. Unit rates are computed for unamortized drilling and development costs using proved developed reserves and for unamortized leasehold costs using all proved reserves. SFAS No. 19, *Financial Accounting and Reporting by Oil and Gas Producing Companies*, requires that acquisition costs of proved properties be amortized on the basis of all proved reserves, developed and undeveloped, and that capitalized development costs (including wells and related equipment and facilities) be amortized on the basis of

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proved developed reserves. As more fully described in Note 16 to the consolidated financial statements, proved reserves are estimated by our internal reserve engineers, and are subject to future revisions when additional information becomes available.

As described in the footnotes to the consolidated financial statements, we follow SFAS No. 143, *Accounting for Asset Retirement Obligations*. Under SFAS No. 143, estimated asset retirement costs are recognized when the asset is placed in service, and are amortized over proved reserves using the units-of-production method. Asset retirement costs are estimated by our engineers using existing regulatory requirements and anticipated future inflation rates.

Geological, geophysical and dry hole costs on natural gas and oil properties relating to unsuccessful exploratory wells are charged to expense as incurred.

Natural gas properties are reviewed for impairment when facts and circumstances indicate that their carrying value may not be recoverable. We assess impairment of capitalized costs of proved natural gas properties by comparing net capitalized costs to estimated undiscounted future net cash flows using expected prices. If net capitalized costs exceed estimated undiscounted future net cash flows, the measurement of impairment is based on estimated fair value, which would consider estimated future discounted cash flows. As of December 31, 2006, the estimated undiscounted future cash flows for our proved natural gas and oil properties exceeded the net capitalized costs, and no impairment was required to be recognized.

Unproven properties that are individually significant are assessed for impairment and if considered impaired are charged to expense when such impairment is deemed to have occurred. Impairment is deemed to have occurred if a lease is going to expire prior to any planned drilling on the leased property.

Property acquisition costs are capitalized when incurred.

Everlast used the full-cost method of accounting. All costs related to the acquisition, exploration or development of oil and natural gas properties were capitalized into the full-cost pool. Such costs included those related to lease acquisitions, drilling and equipping of productive and nonproductive wells, delay rentals, geological and geophysical work and certain internal costs directly associated with the acquisition, exploration or development of oil and natural gas properties. Upon the sale or disposition of oil and natural gas properties, no gain or loss was recognized, unless such adjustments of the full-cost pool would significantly alter the relationship between capitalized costs and proved reserves.

Under the full-cost method of accounting, a full-cost ceiling test is required, wherein net capitalized costs of oil and gas properties cannot exceed the present value of estimated future net revenues from proved oil and natural gas reserves, discounted at 10%, less any related income tax effects.

Costs of acquiring undeveloped gas leases that are capitalized and not subject to amortization are assessed periodically to determine whether impairment has occurred. Appropriate valuation allowances are established when necessary. No such allowance was required during the period from January 1, 2005 to June 12, 2005, and for the year ended December 31, 2004.

Depreciation, depletion and amortization of oil and gas properties is computed using the units-of-production method based on estimated proved oil and gas reserves.

Natural Gas Reserve Quantities

Our estimate of proved reserves is based on the quantities of natural gas that engineering and geological analyses demonstrate with reasonable certainty to be recoverable from established reservoirs in the future under current operating and economic parameters. Management estimates the proved reserves attributable to our ownership in the Robinson s Bend Field based on various factors, including consideration of reserve reports prepared by NSAI, an independent reserve engineer. On an annual basis, our proved reserve estimates and the reserve report prepared by NSAI are reviewed by our audit committee of the board of managers.

Reserves and their relation to estimated future net cash flows impacts our depletion and impairment calculations. As a result, adjustments to depletion and impairment are made concurrently with changes to reserve estimates. We prepared our reserve estimates, and the projected cash flows derived from these reserve estimates, in accordance with SEC guidelines. The accuracy of our reserve estimates is a function of many factors including the following: the quality and quantity of available data, the interpretation of that data, the accuracy of various mandated economic assumptions and the judgments of the individuals preparing the estimates.

Our proved reserve estimates are a function of many assumptions, all of which could deviate significantly from actual results. As such, reserve estimates may materially vary from the actual quantities of natural gas, natural gas liquids and oil eventually recovered.

Net Profits Interest

A significant portion of our properties in the Robinson s Bend Field is subject to the NPI. The NPI represents an interest in production created from the working interest and is based on a contractual revenue calculation. We account for the NPI as an overriding royalty interest. This is consistent with our accounting for the NPI for reserve estimate purposes. Similar to royalty payments, our revenue excludes any payments made to the NPI holder. Everlast s financials have been restated to reflect this method of accounting.

Revenue Recognition

Sales of natural gas are recognized when natural gas has been delivered to a custody transfer point, persuasive evidence of a sales arrangement exists, the rights and responsibility of ownership pass to the purchaser upon delivery, collection of revenue from the sale is reasonably assured and the sales price is fixed or determinable. Natural gas is sold on a monthly basis. Most of the contracts pricing provisions are tied to a market index, with certain adjustments based on, among other factors, whether a well delivers to a gathering or transmission line, quality of natural gas, and prevailing supply and demand conditions, so that the price of the natural gas fluctuates to remain competitive with other available natural gas supplies. As a result, revenues from the sale of natural gas will suffer if market prices decline and benefit if they increase. We believe that the pricing provisions of our natural gas contracts are customary in the industry.

Gas imbalances occur when sales are more or less than the entitled ownership percentage of total gas production. Any amount received in excess is treated as a liability. If less than the entitled share of the production is received, the excess is recorded as a receivable. There were no gas imbalance positions at December 31, 2006, December 31, 2005, June 12, 2005, or December 31, 2004.

Hedging Activities

We implemented a hedging policy to hedge a portion of our expected natural gas production for a period of up to five years, as appropriate. On June 20, 2006, we entered into hedges for the first time since our formation on February 7, 2005. We account for these hedging activities as cash flow hedges pursuant to SFAS No. 133.

We use interest rate swaps to mitigate the impact of volatility of changes in the LIBOR interest rate on our interest payments for our debt. We account for these hedging activities as cash flow hedges pursuant to SFAS No. 133.

We record changes in the fair value of derivatives designated as hedges that are effective in offsetting the variability in cash flows of forecasted transactions in other comprehensive income until the forecasted transactions occur. At the time the forecasted transactions occur, we will reclassify the amounts recorded in other comprehensive income into earnings. We record the ineffective portion of changes in the fair value of derivatives used as hedges immediately in earnings. When amounts for hedging activities under SFAS No. 133 are reclassified from Accumulated other comprehensive income (loss) on the balance sheet to the income statement, we record settled natural gas swaps as Gas sales and settled interest rate swaps as Interest expense (income).

Accounting Standards Adopted

In April 2006, the Financial Accounting Standards Board (FASB) issued FASB Staff Position (FSP) FIN 46R-6, *Determining the Variability to Be Considered in Applying FASB Interpretation No. 46R.* FSP FIN 46R-6 addresses how a reporting enterprise should determine the variability to be considered in applying FIN No. 46R, *Consolidation of Variable Interest Entities, an interpretation of ARB No. 51.* The variability to be considered should be based on an analysis of the design of the entity and should consider the nature of the entity s risks and the purpose for which the entity was created. FSP FIN 46R-6 must be applied prospectively to all entities beginning July 1, 2006. We have determined that there was no impact on our financial results as a result of FSP FIN 46R-6.

In September 2006, the SEC issued Staff Accounting Bulletin (SAB) No. 108, *Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements*. SAB No. 108 provides interpretive guidance on how the effects of prior-year uncorrected misstatements should be considered when quantifying misstatements in the current year financial statements. SAB No. 108 requires registrants to quantify misstatements using both an income statement (rollover) and balance sheet (iron curtain) approach and evaluate whether either approach results in a misstatement that, when all relevant quantitative and qualitative factors are considered, is material. If prior year errors that had been previously considered immaterial now are considered material based on either approach, no restatement is required so long as management properly applied its previous approach and all relevant facts and circumstances were considered. If prior years are not restated, the cumulative effect adjustment is recorded in opening accumulated earnings (deficit) as of the beginning of the fiscal year of adoption. SAB No. 108 is effective for fiscal years ending on or after November 15, 2006, with earlier adoption encouraged. The adoption of SAB No. 108 did not have a material impact on our financial results.

Accounting Standards Issued But Not Effective

In September 2006, the FASB issued SFAS No. 157, *Fair Value Measurements*. SFAS No. 157 defines fair value, establishes a framework for measuring fair value and expands disclosures for fair value measurements. SFAS No. 157 is effective for all fair value measurements beginning January 1, 2008. We are currently assessing the potential impact of SFAS No. 157.

New Accounting Pronouncements Issued But Not Yet Adopted

As of December 31, 2006, there were a number of accounting standards and interpretations that had been issued, but not yet adopted by us. Based on our assessment of those standards, we do not believe there are any that could have a material impact on us.

Item 7A. Quantitative and Qualitative Disclosures about Market Risk

The primary objective of the following information is to provide forward-looking quantitative and qualitative information about our potential exposure to market risks. The term market risk refers to the risk of loss arising from adverse changes in natural gas prices and interest rates. The disclosures are not meant to be precise indicators of expected future losses, but rather indicators of reasonably possible losses. This forward-

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looking information provides indicators of how we view and manage our ongoing market risk exposures. All of our market risk sensitive instruments were entered into for purposes other than speculative trading.

Commodity Price Risk

Our major market risk exposure is in the pricing applicable to our natural gas production. Realized pricing is primarily driven by the SONAT Inside FERC Price and the spot market prices applicable to our natural gas production. Pricing for natural gas production has been volatile and unpredictable for several years, and we expect this volatility to continue in the future. The prices we receive for production depend on many factors outside our control.

We have entered into hedging arrangements with respect to a portion of our projected natural gas production through various transactions that hedge the future prices received. These arrangements are natural gas price swaps whereby we receive a fixed price for our production and pay a variable market price to the contract counterparty. These hedging activities are intended to support natural gas prices at targeted levels and to manage our exposure to natural gas price fluctuations. We do not hold or issue derivative instruments for speculative trading purposes. The table below presents the hypothetical sensitivity to changes in fair values arising from potential changes in the quoted market prices of the derivative commodity instruments used to mitigate these market risks. Any gain or loss on these derivative commodity instruments would be substantially offset by a corresponding gain or loss on the sale of the hedged natural gas production, which are not included in the table. These derivatives do not hedge all of our commodity price risk related to our forecasted sales of natural gas production and as a result, we are subject to commodity price risks on our remaining unhedged natural gas production.

		10 Percent Increase		10 Percent Decrease	
	Fair Value	**Fair Value**	**(Decrease)**	**Fair Value**	**Increase**
			(in 000 s)		
Impact of changes in commodity prices on derivative commodity instruments					
December 31, 2006	$ 13,285	$ 5,903	$ (7,382)	$ 20,667	$ 7,382

At the date of the acquisition of our properties in the Robinson s Bend Field from Everlast on June 13, 2005, we acquired certain fixed price swap liabilities that had approximately $18.0 million in unrealized losses with our counterparty. These derivatives were assigned to CCG. This resulted in a zero balance of the fair value of our derivative positions for 2005.

Interest Rate Risk

At December 31, 2006, we had debt outstanding of $22.0 million, which incurred interest at a fixed rate of 5.38% LIBOR plus an applicable margin between 1.25% and 2.00% based on utilization. We enter into hedging arrangements to reduce the impact of volatility of changes in the LIBOR interest rate on our interest payments for our debt. Currently, we have an outstanding interest rate swap that fixes the LIBOR rate at 4.74% on $16.5 million of our outstanding debt through October 2010. At December 31, 2006, the carrying value and fair value of our debt is $22.0 million.

The table below presents the hypothetical sensitivity to changes in fair values arising from potential changes in the quoted market prices of the derivative interest rate instruments used to mitigate these market risks.

		10 Percent Increase		10 Percent Decrease	
	Fair Value	**Fair Value**	**Increase**	**Fair Value**	**(Decrease)**
			(in 000 s)		
Impact of changes in LIBOR on derivative interest rate instruments					
December 31, 2006	$ 130	$ 169	$ 39	$ 91	$ (39)

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At December 31, 2005, we had debt outstanding of $63,000, which incurred interest at a fixed rate of 6.12%. In September 2006, this note payable was paid off.

Item 8. Financial Statements and Supplementary Data

The Report of Independent Registered Public Accounting Firm, Consolidated Financial Statements and supplementary financial data required to be filed under this item are presented on pages 86 through 118 of this Annual Report on Form 10-K, and are incorporated herein by reference.

Item 9. Changes in and Disagreements With Accountants on Accounting and Financial Disclosure

None.

Item 9A. Controls and Procedures

Evaluation of Disclosure Controls and Procedures. We carried out an evaluation, under the supervision and with the participation of our management, including the Chief Executive Officer and the Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934 (the Exchange Act)) as of December 31, 2006. Based upon the results of this evaluation, our Chief Executive Officer and our Chief Financial Officer concluded that our disclosure controls and procedures were effective as of December 31, 2006.

This annual report does not include a report on management s assessment regarding internal control over financial reporting or an attestation report of the Company s registered public accounting firm due to a transition period established by rules of the SEC for newly public companies.

Item 9B. Other Information

None.

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PART III

Item 10. Managers, Executive Officers and Corporate Governance

The following table shows information for members of our board of managers and our executive officers. Members of our board of managers are elected for one year terms, and our executive officers will hold office at the discretion of, and may be removed by, our board of managers in its discretion.

Name	Age	Position with Constellation Energy Partners LLC
Felix J. Dawson	39	Chief Executive Officer, President and Chairman
John R. Collins	49	Manager
Richard H. Bachmann	54	Independent manager
Richard S. Langdon	56	Independent manager
John N. Seitz	55	Independent manager
Angela A. Minas	42	Chief Financial Officer, Chief Accounting Officer and Treasurer

Felix J. Dawson is our Chief Executive Officer, President and Chairman of our board of managers. He also serves as Co-President and CEO of CCG and Senior Vice President of Constellation, positions to which he was appointed in August 2005 and October 2006, respectively. Mr. Dawson joined Constellation in April 2001, initially as Managing Director Co-Head Origination for CCG, and subsequently held positions as Managing Director Portfolio Management for CCG and Co-Chief Commercial Officer for CCG before obtaining his current position at CCG. Prior to joining Constellation, Mr. Dawson was Vice President Origination in Goldman Sachs Fixed Income Currency and Commodities division and was a key member of the Goldman Sachs team that worked in partnership with Constellation to develop its energy marketing and trading business. Mr. Dawson joined Goldman Sachs in 1997.

John R. Collins is a member of our board of managers. Mr. Collins also serves as Chief Risk Officer and Senior Vice President of Constellation, positions that he has held since December 2001 and January 2004, respectively. Mr. Collins also serves as a member of Constellation s Management Committee. Prior to joining Constellation, Mr. Collins was Managing Director Finance and Treasurer of Constellation Power Source Holdings, Inc. from January 2000 to December 2001. From February 1997 to December 2001, Mr. Collins served as the senior financial officer of CCG. Mr. Collins currently serves as the Chairman of the Board of the Committee of Chief Risk Officers, an energy industry association of risk management professionals.

Richard H. Bachmann is a member of our board of managers and our audit, compensation, conflicts, and nominating and governance committees and chairs our conflicts committee. Mr. Bachmann joined EPCO Inc., a privately held company, in 1999 as Executive Vice President, Chief Legal Officer and Secretary. Prior to joining EPCO Inc., Mr. Bachmann served as a partner in the law firms of Snell & Smith P.C. from 1993 to 1998 and Butler & Binion from 1988 to 1993. Mr. Bachmann currently serves as a director and as Executive Vice President, Chief Legal Officer and Secretary of various affiliates of EPCO Inc., including Enterprise Products GP, LLC, the general partner of Enterprise Products Partners L.P., a publicly traded midstream energy company, and EPE Holdings LLC, the general partner of Enterprise GP Holdings L.P., a publicly traded midstream energy company holding company.

Richard S. Langdon is a member of our board of managers and our audit, compensation, conflicts, and nominating and governance committees and chairs our audit committee. Mr. Langdon currently is the President and Chief Executive Officer of Matris Exploration Company, a privately held exploration and production company. From 1997 until 2002, Mr. Langdon served as Executive Vice President and Chief Financial Officer of EEX Corporation, a publicly traded exploration and production company that merged with Newfield Exploration Company in 2002. Prior to that, Mr. Langdon held various positions with the Pennzoil Companies from 1991 to 1996, including Executive Vice President International Marketing Pennzoil Products Company; Senior Vice President Business Development Pennzoil Company; and Senior Vice President Commercial & Control

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Pennzoil Exploration & Production Company. Langdon also serves as a director of Gasco Energy, Inc., a publicly traded exploration and production company.

John N. Seitz is a member of our board of managers and our audit, compensation, conflicts, and nominating and governance committees and chairs our compensation and nominating and governance committees. Mr. Seitz is also currently Vice Chairman of the Board of Endeavour International Corporation, a publicly traded oil and gas exploration and production company, and a director for Input Output, Inc., a publicly traded provider of seismic products and services. Mr. Seitz is also a member of the Compensation Committee for Input Output, Inc. In February 2004, Mr. Seitz co-founded Endeavour International Corporation and served as its co-Chief Executive Officer until September 2006. Prior to founding Endeavour International Corporation, Mr. Seitz served as Chief Executive Officer, President and Chief Operating Officer of Anadarko Petroleum Corporation from January 2002 to March 2003, and prior to being named Chief Executive Officer, President and Chief Operating Officer, Mr. Seitz was the Chief Operating Officer and President of Anadarko Petroleum Corporation beginning in 1999. Mr. Seitz also served as Anadarko Petroleum Corporation s Executive Vice President, Exploration and Production and as a member of its Board of Directors from 1997 to 1999.

Angela A. Minas has served as our Chief Financial Officer, Chief Accounting Officer and Treasurer, since September 2006. Ms. Minas also serves as Managing Director of CCG since August 2006. Prior to joining CCG, Ms. Minas held various positions with Science Applications International Corporation (SAIC), including the following: from January 2006 through July 2006, she served as Senior Vice President of Operations for the Commercial Business Services business unit; from January 2004 through December 2005, she served as Senior Vice President of Global Consulting; and from June 2002 through December 2003, she served as Vice President of US Consulting. From September 1997 until June 2002, Ms. Minas served as a partner of Arthur Andersen LLP, additionally serving as partner responsible for North American Oil & Gas Consulting from September 1999 until her departure from Arthur Andersen LLP.

Independence of Board of Managers

Each of Messrs. Bachmann, Langdon and Seitz is independent under the NYSE Arca listing standards. In addition, the audit, compensation and nominating and corporate governance committees are composed entirely of independent managers under NYSE Arca listing standards, SEC requirements and other applicable laws, rules and regulations. There are no transactions, relationships or other arrangements between us and our independent managers that need to be considered under the NYSE Arca listing standards in determining that such managers are independent.

Committees of the Board of Managers

Audit Committee

As described in the audit committee charter, the audit committee will be directly responsible for the appointment, compensation, retention and oversight of the work of the independent public accountants to audit our financial statements, including assessing the independent auditor s qualifications and independence, and will establish the scope of, and oversee, the annual audit. The committee will also approve any other services provided by public accounting firms. The audit committee will provide assistance to the board in fulfilling its oversight responsibility to the unitholders, the investment community and others relating to the integrity of our financial statements, our compliance with legal and regulatory requirements, the independent auditor s qualifications and independence and the performance of our internal audit function. The audit committee will oversee our system of disclosure controls and procedures and system of internal controls regarding financial, accounting, legal compliance and ethics that management and our board of managers established. In doing so, it will be the responsibility of the audit committee to maintain free and open communication between the committee and our independent auditors, the internal accounting function and management of our company.

The board of managers has determined that the chairman of the audit committee is an audit committee financial expert as that term is defined in the applicable rules of the SEC. The committee did not meet in 2006.

In February 2007, the committee met to review the audited financial statements with management. The committee recommended to the board of managers that the statements be included in the Annual Report on Form 10-K. In the meeting, they also discussed the matters required by Auditing Standards No. 61, reviewed auditor independence and reviewed the written disclosures required by ISB No. 1. Mr. Langdon is Chairman, and Messrs. Seitz and Bachmann are members.

Compensation Committee

As described in the compensation committee charter, the compensation committee will establish and review general policies related to our compensation and benefits. The compensation committee will determine and approve, or make recommendations to the board of managers with respect to, the compensation and benefits of our chief executive officer, our other executive officers and our board of managers.

The committee did not meet in 2006. In February 2007, the committee met to review the proposed 2007 compensation programs and to discuss the compensation, discussion, and analysis to be included in the Annual Report on Form 10-K. Mr. Seitz is Chairman, and Messrs. Bachmann and Langdon are members.

Conflicts Committee

The conflicts committee will review specific matters that the board of managers believes may involve conflicts of interest. The conflicts committee will determine if the resolution of the conflict of interest is fair and reasonable to our company. Any matters approved by the conflicts committee will be conclusively deemed to be fair and reasonable to our company and approved by all of our unitholders.

The committee did not meet in 2006. In February 2007, the committee met to discuss matters related to potential agreements between CCG and CEP. Mr. Bachmann is Chairman, and Messrs. Seitz and Langdon are members.

Nominating and Governance Committee

As described in the nominating and governance committee charter, the nominating and governance committee will nominate candidates to serve on our board of managers. The nominating and governance committee will also be responsible for monitoring a process to review manager, board and committee effectiveness, developing and implementing our corporate governance guidelines, committee members and committee chairpersons and otherwise taking a leadership role in shaping the corporate governance of our company.

The committee did not meet in 2006. In February 2007, the committee met to review corporate governance matters. Mr. Seitz is Chairman, and Messrs. Bachmann and Langdon are members.

Because we only recently became a public company, the nominating and corporate governance committee has not yet adopted procedures by which our unitholders may recommend nominees to our board of managers.

Constellation Energy Partners maintains on its website, www.*constellationenergypartners.com*, copies of the charters of each of the committees of its board of managers (except the conflicts committee which does not have a charter), as well as copies of its Corporate Governance Guidelines, its Code of Ethics for Chief Executive Officer, Chief Financial Officer and Principal Accounting Officer, and its Code of Business Conduct and Ethics. Copies of these documents are also available in print upon request of Constellation Energy Partner s Corporate Secretary. The Code of Business Conduct and Ethics provides guidance on a wide range of conduct, conflicts of interest and legal compliance issues for all of our managers, officers and employees, including the chief executive officer, chief financial officer and chief accounting officer. Constellation Energy Partners will post any

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amendments to, or waivers of, the Code of Business Conduct and Ethics applicable to its Chief Executive Officer, Chief Financial Officer or Principal Accounting Officer on its website.

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the Exchange Act requires our directors and executive officers, and persons who own more than 10% of a registered class of our equity securities, to file initial reports of ownership of our equity securities and reports of changes in ownership of our equity securities with the SEC. Such persons are also required by SEC regulation to furnish us with copies of all Section 16(a) forms they file. Based solely on our review of the copies of such forms furnished to us and written representations from our executive officers and directors, we believe that during 2006 all Section 16(a) reporting persons complied with all applicable filing requirements in a timely manner.

Certifications

The NYSE Arca requires the Chief Executive Officer of each listed company to certify annually that he is not aware of any violation by the company of the NYSE Arca s corporate governance listing standards, qualifying the certification to the extent necessary. We did not become a listed company until our initial public offering in November 2006 and did not therefore provide such a certification during 2006. In accordance with the rules of the NYSE Arca, we will provide such a certification within 30 days after our annual meeting. The certifications of our Chief Executive Officer and Chief Financial officer required by Sections 302 and 906 of the Sarbanes-Oxley Act have been included as exhibits to this Annual Report on Form 10-K.

Item 11. Executive Compensation

We were formed in February 2005 and did not begin operations until our acquisition of our initial properties in the Robinson s Bend Field from Everlast in June 2005. On May 9, 2006, we replaced our prior officers and board of directors with Mr. Dawson, who, at that time, was our only officer and manager. To date, all of our current officers and managers have been employees of Constellation or its affiliates, and they have received no additional compensation from us. CEPM will manage certain of our operations and activities through its officers and employees pursuant to the management services agreement under the direction of our board of managers and executive officers. We will reimburse CEPM for direct and indirect general and administrative expenses incurred on our behalf, including the compensation of executive officers as our board of managers may determine from time to time. We did not reimburse CEPM for the compensation of our executive officers that was paid by CCG for 2006. We will reimburse CEPM a fixed amount in 2007 for our Chief Executive Officer and Chief Financial Officer, as set forth in the table below.

The following table sets forth the compensation of our two named executive officers for 2007 for which we will reimburse CEPM. No reimbursable compensation was paid in 2006.

Name and Principal Position	Annual Salary
Felix J. Dawson, Chief Executive Officer and President	$ 150,000(1)(2)
Angela A. Minas, Chief Financial Officer, Chief Accounting Officer and Treasurer	$ 150,000(1)(2)

(1) Represents the fixed amount that we have agreed to pay for the services of these two named executive officers under the management services agreement and excludes the amount of any bonus to such officers paid by CCG, which bonus amount(s) we will not be required to reimburse CCG.

(2) Our executive officers may participate in the benefit plans of Constellation and its affiliates. There are no CEP benefit plans under which such officers may participate.

Employment Agreements

We have no employment agreements for specific terms with our officers or employees or those of our subsidiaries.

Compensation Discussion and Analysis

We do not directly employ any of the persons responsible for managing our business. Our two named executive officers are compensated by CCG under the compensation policies of Constellation. We reimburse CEPM for a portion of the compensation paid to our executive officers by CCG pursuant to our management services agreement. The elements of Constellation s and CCG s compensation program are intended to provide a total compensation package designed to drive performance and reward contributions in support of the business strategies of Constellation and its affiliates. A discussion of Constellation s compensation policies and programs can be found in the proxy statement relating to Constellation s 2007 annual meeting of shareholders to be filed by Constellation with the SEC, a copy of which will be available on the SEC s website at *www.sec.gov* or Constellation s website at *www.constellation.com*. For 2007, we have agreed to reimburse Constellation and CCG under the management services agreement for $150,000 in base salary for each of our named executive officers. Any other compensation, bonus, benefits, incentives, perquisites and other personal benefits paid by Constellation or CCG to our named executive officers will not be reimbursed. During 2006, our named executive officers were not specifically compensated for time expended with respect to our business or assets. Accordingly, we are not presenting any compensation information for historical periods.

We have a compensation committee that consists of three managers who are all independent under the independence standards established by NYSE Arca and SEC rules. The compensation committee will establish and review general policies related to our compensation and benefits. The compensation committee will determine and approve, or make recommendations to the board of managers with respect to, the compensation and benefits of our Chief Executive Officer and our other executive officers. We currently intend to pay no additional remuneration to employees of Constellation and its affiliates who also serve as our executive officers, provided that this compensation policy could change from time to time.

The compensation committee is authorized to retain at company expense any compensation survey, reports on the design and implementation of compensation programs or other services of compensation experts or consultants that it may find necessary in designing, implementing or administering compensation programs. No such experts were retained in 2006 or were consulted in relation to our 2007 compensation of our two named executive officers.

As described below, the Company has adopted a long-term incentive plan. This plan is intended to provide an incentive to our officers, key employees, consultants and managers and those of our affiliates. We expect that this plan will align the interests of those receiving grants with our intention to significantly increase the enterprise value of our company by allowing for increases in our quarterly distributions. This incentive program is expected to promote the expansion of our business via acquisitions and improved operational performance. No grants have been issued under the plan and no performance targets, financial measures or operational targets associated with potential grants have yet been developed.

Compensation of Managers

Officers or employees of Constellation and its affiliates who also serve as our managers will not receive additional compensation for serving as our managers. We will pay such independent managers an annual retainer of $40,000 and $2,500 per meeting fee for attending meetings of our board of managers (and committee meetings that occur on days when there is no board meeting). We may in the future grant independent managers awards under the long-term incentive plan that has been adopted by the Company. In addition, each independent manager will be reimbursed for out-of-pocket expenses in connection with attending meetings of our board of managers or committees thereof. Each manager will be indemnified by us for actions associated with being a manager to the full extent permitted under Delaware law. No compensation was paid to our managers in 2006.

Reimbursement of Expenses of CEPM

We reimburse CEPM on a quarterly basis for its costs in providing services to us, including all direct and indirect supervisory and management and expenses incurred by CEPM, pursuant to the management services agreement. Our limited liability company agreement provides that our board of managers has the right and the duty to review the services provided, and the costs charged, by CEPM under that agreement. These costs and expenses are deducted from cash available for distribution to our unitholders. These expenses include the cost of employee and officer compensation and benefits allocable to us and all other expenses necessary or appropriate to the performance of CEPM s obligations under the management services agreement. The limited liability company agreement provides that our board of managers approve the expenses that are allocable to us. There is no limit on the amount of expenses for which CEPM may be reimbursed.

Long-Term Incentive Plan

General. We adopted the Constellation Energy Partners LLC Long-Term Incentive Plan for officers, key employees, consultants and managers of us and our affiliates who perform services for us, whom we refer to as plan participants. The long-term incentive plan consists of common unit grants, restricted common units, phantom common units, common unit options and common unit appreciation rights. The long-term incentive plan permits the grant of awards covering an aggregate of 450,000 common units. The plan is administered by the compensation committee of our board of managers. We filed a registration statement with the SEC registering the units issuable under the long-term incentive plan. No grants of awards have been issued under this plan as of February 15, 2007.

Our board of managers in its discretion may terminate, suspend or discontinue the long-term incentive plan at any time with respect to any award that has not yet been granted. Our board of managers also has the right to alter or amend the long-term incentive plan or any part of the plan from time to time, including increasing the number of common units that may be granted subject to common unitholder approval as required by the exchange upon which the common units are listed at that time. The compensation committee of our board of managers in its discretion may waive any conditions or rights under, amend any terms of, or alter any award, provided, however, no change in any outstanding award may be made that would materially impair the rights of the participant without the consent of the participant.

Common Unit Grants. The long-term incentive plan permits the grant of common units. A common unit grant is a grant of common units that vest immediately upon issuance.

Restricted Common Units and Phantom Common Units. A restricted common unit is a common unit that is subject to forfeiture prior to the vesting of the award. A phantom common unit is a notional common unit that entitles the plan participant to receive a common unit upon the vesting of the phantom common unit or, in the discretion of the compensation committee, cash equivalent to the value of a common unit. The compensation committee may determine to make grants under the plan of restricted common units and phantom common units to plan participants containing such terms as the compensation committee shall determine. The compensation committee determines the period over which restricted common units and phantom common units granted to plan participants will vest. In addition to vesting based on the passage of time, the committee may condition the vesting of common units on performance criteria that may include the achievement of specified financial objectives.

Unless provided otherwise by the compensation committee in the applicable award agreement, upon a change in control, as defined in the plan, or such time prior thereto as established by the compensation committee, to the extent that we do not survive as an independent organization and any surviving or successor

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organization and/or any of its affiliates does not assume or continue the unvested restricted common units or phantom common units substantially on the same terms, then, immediately prior to the change in control (or any earlier date related to the change in control and established by the compensation committee) all outstanding unvested restricted common units or phantom common units shall automatically vest. In this regard, all restricted periods shall terminate and all performance criteria, if any, shall be deemed to have been achieved at the maximum level. Unless provided otherwise by the compensation committee in the applicable award agreement, any time-based restricted common units or phantom common units that vest upon a change in control shall be settled by (i) issuance of unrestricted common units based on the number of common units that were subject to the award on the date of grant of the award or (ii) payment of cash and/or other property equal to the fair market value, as defined in the plan, of a common unit on the payout date for each phantom common unit or restricted common unit or (iii) any combination of payouts under clauses (i) and (ii) of this sentence, as determined by the compensation committee. Unless provided otherwise by the compensation committee in the applicable award agreement, any performance-based restricted common units or phantom common units that vest upon a change in control shall be settled by (i) issuance of unrestricted common units based on the number of common units that were subject to the award as established on the date of grant of the award, prorated based on the number or complete months of the restricted period that have elapsed as of the payment date, and assuming that maximum performance was achieved or (ii) payment of cash and/or other property equal to the fair market value of a common unit on the payout date for each phantom common unit or restricted common unit which is payable under clause (i) of this sentence or (iii) any combination of payouts under clauses (i) and (ii) of this sentence, as determined by the compensation committee. Any accelerated payout will be made in a single payment within 30 days after the date of the change in control.

If a plan participant s employment with or services to us and our affiliates or membership on the board of managers terminates for any reason, the plan participant s unvested restricted common units and phantom common units will be automatically forfeited unless, and to the extent, the compensation committee provides otherwise in the applicable award agreement. Common units to be delivered in connection with the grant of restricted common units or upon the vesting of phantom common units may be common units acquired by us in the open market, common units already owned by us, common units acquired by us from any other person, common units newly issued by us or any combination of the foregoing. If we issue new common units in connection with the grant of common units, restricted common units or upon vesting of the phantom common units, the total number of common units outstanding will increase. The compensation committee, in its discretion, may grant tandem distribution rights with respect to restricted common units and tandem distribution equivalent rights with respect to phantom common units.

Common Unit Options and Common Unit Appreciation Rights. The long-term incentive plan permits the grant of options covering common units and the grant of common unit appreciation rights. A common unit appreciation right is an award that, upon exercise, entitles the participant to receive the excess of the fair market value of a common unit on the exercise date over the exercise price established for the common unit appreciation right. Such excess may be paid in common units, cash, or a combination thereof, as determined by the compensation committee in its discretion. The compensation committee is able to make grants of common unit options and common unit appreciation rights under the plan to plan participants containing such terms as the committee shall determine. Common unit options and common unit appreciation rights may not have an exercise price that is less than the fair market value of the common units on the date of grant. In general, common unit options and common unit appreciation rights granted will become exercisable over a period determined by the compensation committee.

Unless provided otherwise by the compensation committee in the applicable award agreement, upon a change in control, as defined in the plan, or such time prior thereto as established by the compensation committee, to the extent that we do not survive as an independent organization and surviving or successor organization and/or any of its affiliates does not assume or continue the unvested common unit options or common unit appreciation rights substantially on the same terms, then, immediately prior to the change in control (or any earlier date related to the change in control and established by the compensation committee) all

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outstanding unvested options and rights shall automatically vest and become exercisable in full. Any accelerated payout on account of a change in control will be made in a single payment within 30 days after the date of the change in control. If a plan participant s employment with or services to us or our affiliates or membership on the board of managers terminates for any reason, the plan participant s unvested common unit options and common unit appreciation rights will be automatically forfeited, unless and to the extent the compensation committee provides otherwise in the applicable award agreement. Except as otherwise provided in the terms of an award agreement pertaining to common unit options, if the plan participant ceases employment with or services to us or our affiliates prior to the lapse of any vested common unit option, the vested common unit option will lapse as follows:

(A) Termination Not For Retirement, Disability or Death any vested common unit option will lapse on the earlier of (i) 90 days after the effective date of any such termination that is not due to the participant s retirement (as defined in the plan), disability (as defined in the plan) or death or (ii) at the expiration of the common unit option; or

(B) Retirement, Disability or Death any vested common unit option will lapse on the earlier of (i) 60 months after the effective date of the plan participant s retirement (as defined in the plan), disability (as defined in the plan) or death or (ii) at the expiration of the common unit option.

The compensation committee, in its discretion, may grant tandem distribution equivalent rights with respect to common unit options and common unit appreciation rights.

Upon exercise of a common unit option (or a common unit appreciation right settled in common units), we will acquire common units on the open market or directly from any other person, use common units already owned by us, issue new common units or any combination of the foregoing. If we issue new common units upon exercise of the common unit options (or a common unit appreciation right settled in common units), the total number of common units outstanding will increase, and we will receive the proceeds from an optionee upon exercise of a common unit option. The availability of common unit options and common unit appreciation rights is intended to furnish additional compensation to plan participants and to align their economic interests with those of common unitholders.

Compensation Committee Interlocks and Insider Participation

None of our executive officers serves as a member of the board of directors or compensation committee of any entity that has one or more of its executive officers serving as a member of our board of managers or compensation committee.

Compensation Committee Report

The compensation committee of the board of managers has reviewed and discussed the *Compensation Discussion and Analysis* beginning on page 71 with management. Based on such review and discussions, the compensation committee recommended to the board of managers that the *Compensation Discussion and Analysis* be included in this Annual Report on Form 10-K.

John N. Seitz, Chairman

Richard H. Bachmann

Richard S. Langdon

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Unitholder Matters

The following table sets forth the beneficial ownership of our units held by:

each unitholder who is a beneficial owner of more than 5% of our outstanding units;

each of our managers and named executive officers; and

our managers and executive officers as a group.

The amounts and percentage of units beneficially owned are reported on the basis of the SEC rules governing the determination of beneficial ownership of securities. Under the SEC rules, a person is deemed to be a beneficial owner of a security if that person has or shares voting power, which includes the power to vote or to direct the voting of such security, and/or investment power, which includes the power to dispose of or to direct the disposition of such security. A person is also deemed to be a beneficial owner of any securities of which that person has a right to acquire beneficial ownership within 60 days. Under these rules, more than one person may be deemed a beneficial owner of the same securities and a person may be deemed a beneficial owner of securities as to which he has no economic interest.

Except as indicated by footnote, to our knowledge the persons named in the table below have sole voting and investment power with respect to all units shown as beneficially owned by them, subject to community property laws where applicable.

	Common Units Beneficially Owned		Class A Units Beneficially Owned		Percentage of Total Units Beneficially Owned
Name of Beneficial Owner	**Number**	**Percentage**	**Number**	**Percentage**	**Percentage**
Constellation Energy Group, Inc.[1]	5,918,894	53%	226,406	100%	54%
Constellation Energy Partners Holdings, LLC[2]	5,918,894	53%	226,406	100%	54%
Constellation Energy Partners Management, LLC[3]			226,406	100%	2%
Richard H. Bachmann					
John R. Collins					
Felix J. Dawson					
Richard S. Langdon					
Angela A. Minas					
John N. Seitz					
All managers and executive officers as a group (6 persons)					

(1) Constellation Energy Group, Inc., through its direct and indirect ownership of Constellation Enterprises, Inc., Constellation Holdings, Inc. and Constellation Power Source Holdings, Inc., is the ultimate parent company of Constellation Energy Partners Holdings, LLC and Constellation Energy Partners Management, LLC and may, therefore, be deemed to beneficially own the common units held by Constellation Energy Partners Holdings, LLC and the Class A units held by Constellation Energy Partners Management, LLC. The address of Constellation Energy Group, Inc. is 750 East Pratt Street, Baltimore, MD 21202.

(2) Constellation Energy Partners Holdings, LLC is the parent company of Constellation Energy Partners Management, LLC and may, therefore, be deemed to beneficially own the Class A units held by Constellation Energy Partners Management, LLC. The address of Constellation Energy Partners Holdings, LLC is 111 Market Place, Baltimore, MD 21202.

(3) The address of Constellation Energy Partners Management, LLC is 111 Market Place, Baltimore, MD 21202.

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Equity Compensation Plan Information

The following table reflects our equity compensation plan information as of December 31, 2006:

Plan Category	Number of securities to be issued upon exercise of outstanding options, warrants, and rights	Weighted-average exercise price of outstanding options, warrants, and rights	Number of securities remaining available for future issuance under equity compensation plans
Equity compensation plans not approved by security holders		$	450,000
Total		$	450,000

See Item 11. *Executive Compensation Long-Term Incentive Plan* for a description of the material features of our long-term incentive plan.

Item 13. Certain Relationships and Related Transactions, and Manager Independence

Constellation owns a significant number of our units. CEPM owns all of our 226,406 Class A units, representing a 2% limited liability company interest in us, and all of the management incentive interests; CEPH owns 5,918,894 common units, representing an approximate 52% limited liability company interest in us; and CHI owns all of our Class D interests.

Our board of managers has established a conflicts committee to review specific matters that the board believes may involve conflicts of interest, including transactions with related persons such as Constellation or its affiliates. The conflicts committee determines if the resolution of the conflict of interest is fair and reasonable to our company. Our limited liability company agreement provides that members of the conflicts committee may not be officers or employees of our company, or directors, officers or employees of any of our affiliates, and must meet the independence standards for service on an audit committee of a board of directors as established by NYSE Arca and SEC rules. Any matters approved by the conflicts committee will be conclusively deemed to be fair and reasonable to our company and approved by all of our unitholders. However, the board is not required by the terms of our limited liability company agreement to submit the resolution of a potential conflict of interest to the conflicts committee, and may itself resolve such conflict of interest if the board determines that (i) the terms of the related person transaction are no less favorable to us that those generally being provided to or available from unrelated third parties or (ii) the transaction is fair and reasonable to us, taking into account the totality of the relationships between the parties involved. Any matters approved by the board in this manner will be deemed approved by all of our unitholders.

Distributions and Payments to CCG, CEPH, CEP Equity II LLC, CHI and CEPM

The following summarizes the distributions and payments to be made by us to CCG, CEPH, CEP Equity II LLC, CHI and CEPM in connection with the ongoing operation and any liquidation of Constellation Energy Partners LLC.

Initial Public Offering	CEPM and CEPH received 226,406 Class A units; 5,918,894 common units and the management incentive interest in the restructuring carried out in conjunction with our initial public offering in November 2006. In addition, CHI contributed $8.0 million to us in exchange for all of the Class D interests.

On October 30, 2006, we received $475,000 from CEP Equity II LLC in exchange for the Floyd Shale Rights.

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As a result of our initial public offering, we distributed all our cash in excess of $3.9 million, including the cash pool balance, which was $12.4 million, to CCG.

In November 2006, in connection with our initial public offering, we distributed $122.8 million to CEPH as a reimbursement for capital expenditures incurred by CCG prior to our initial public offering.

Distributions of available cash to CEPM and CEPH	We will generally make cash distributions 98% to common unitholders, including CEPH, and 2% to CEPM in respect of its Class A units. In addition, if distributions exceed the Target Distribution (as defined in our limited liability company agreement) and certain other requirements are met, CEPM will be entitled in respect of its management incentive interests to 15% of distributions above the Target Distribution.

Assuming we have sufficient available cash to pay the initial quarterly distribution on all of our outstanding units for four quarters, but no distributions in excess of the full initial quarterly distribution, CEPM would receive an annual distribution of approximately $0.42 million on its Class A units and CEPH would receive an annual distribution of approximately $12.2 million on its common units.

Distributions to CHI	For each full calendar quarter during the period commencing January 1, 2007 and ending on December 31, 2012 that the sharing arrangement in respect of the calculation of amounts payable to the Trust for the NPI remains in effect, we will distribute to CHI, in respect of its Class D interests, $333,333.33, as a partial return of the $8.0 million capital contribution made for the Class D interests, which payment will be made concurrently with the quarterly cash distribution to our common and Class A unitholders for that quarter. Unless the special distribution right has been terminated earlier, the Class D interests will be cancelled upon the payment of the final distribution of $333,333.41 to CHI for the quarter ending December 31, 2012. If the amounts payable by us to the Trust are not calculated based on the sharing arrangement through December 31, 2012, unless such change is approved in advance by our board of managers and our conflicts committee, the special distribution right for future quarters will terminate. In the case of such early termination, CHI will only have the right under specific circumstances upon our liquidation to receive the unpaid portion of the $8.0 million capital contribution that has not then been distributed to CHI in such special distributions. If the special distribution right is terminated during a quarter, the special distribution in respect of the Class D interests will be prorated for that quarter based upon the ratio of the number of days in such quarter prior to the effective date of such termination to 90.
Payments to CEPM	Pursuant to our management services agreement with CEPM, if CEPM provides us acquisition services with respect to a particular opportunity, we will be obligated to reimburse CEPM for the costs it incurs in providing such acquisition services to us. In addition, subject to the arrangements relating to acquisition services described

	below in Management Services Agreement, CEPM will be entitled to be reimbursed on a quarterly basis for all supervisory and management costs incurred by it in performing services for us.
Conversion of Class A units and management incentive interests	Generally, if the common unitholders vote to eliminate the special voting rights of the holder of our Class A units, the Class A units will be converted into common units on a one for one basis and CEPM will have the right to elect to convert its management incentive interests into common units at fair market value.

Should CEPM s Class A units and its management incentive interests convert into common units, CEPM will receive cash distributions on its common units as described above in Distributions and Payments to CCG, CEPH, CEP Equity II LLC, CHI and CEPM.

Liquidation	Upon our liquidation, the unitholders, including CEPH, as a common unitholder, CEPM, as the holder of the Class A units and CHI, as the holder of our Class D interests that are then outstanding, will be entitled to receive liquidating distributions according to their respective capital account balances.

Transactions with Affiliates

Initial Public Offering

In November 2006, we completed our initial public offering. In our restructuring, CEPM and CEPH received consideration of 226,406 Class A units; 5,918,894 common units; and the management incentive interests.

Class D Contribution

In November 2006, in conjunction with our initial public offering, CHI contributed $8.0 million to us in exchange for the Class D interests.

Sale of Floyd Shale Rights

On October 30, 2006, we sold to an affiliate of Constellation, CEP Equity II, LLC, an undivided mineral interest in our properties in the Robinson s Bend Field for depths below 100 feet below the base of the lowest producing coal seam for $475,000. We refer to this mineral interest as the Floyd Shale Rights. The Floyd Shale Rights were not material to our business and no value was assigned to them in our historical financial statements included elsewhere in this Annual Report on Form 10-K. The Floyd Shale Rights did not fit our investment strategy, given the uncertainty of encountering commercial quantities of oil and natural gas.

Omnibus Agreement

At the closing of our initial public offering, we entered into an omnibus agreement with CCG. Under the omnibus agreement, CCG indemnified us against certain liabilities relating to:

- for a period of six years and 30 days after our initial public offering, any of our income tax liabilities, or any income tax liability attributable to our operation of our properties, in each case relating to periods prior to the closing of our initial public offering;

- legal actions pending against Constellation or us at the time of our initial public offering;

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- events and conditions associated with the ownership by Constellation or its affiliates of the Floyd Shale Rights; and

- for a period of one year after our initial public offering, any miscalculation in the amount payable to the Trust in respect of the NPI for any period prior to the initial public offering, provided (i) that such miscalculation relates to amount(s) payable no more than four years prior to our initial public offering and (ii) the aggregate amount payable by CCG pursuant to this bullet point does not exceed $500,000.

Management Services Agreement

In connection with our initial public offering, we entered into a management services agreement with CEPM that governs our relationship with them regarding the following matters:

- CEPM s provision to us of certain supervisory and management services, including financial, acquisition and hedging and other risk management services;

- reimbursement of supervisory and management costs incurred by CEPM in performing services for us.

Financial, Acquisition and Other Services

While we are consolidated with Constellation for accounting purposes, we will be required under the management services agreement to use CEPM or its designee for legal, accounting, audit, tax, financial and risk management services. No other aspect of the management services agreement will be exclusive. Upon our request, CEPM will also provide us with engineering, geological, geophysical, property management and project management services.

CEPM may provide us with acquisition services upon our request, but is not obligated to do so. As a result, CEPM will have no commitment to offer us any particular E&P property, whether from CEPM or its other affiliates or a third-party. In connection with the acquisition services, we may acquire E&P properties with long-lived proved reserves in any of the following types of transactions:

- drop-downs, or acquisitions directly by us from CCG or its affiliates of properties previously acquired or developed by CCG or its affiliates;

- joint transactions in which CCG or its affiliates contemporaneously acquires from unaffiliated third parties E&P properties that do not fit our risk profile; and

- purchases made by us from unaffiliated third parties.

If CEPM provides us acquisition services with respect to a particular opportunity, we will be obligated to reimburse CEPM for the costs it incurs in providing those acquisition services to us.

Competition

None of CEPM, Constellation, CCG or any of their affiliates will be restricted under the management services agreement from competing with us. CEPM, Constellation, CCG and any of their affiliates may acquire or dispose of any assets, including, among other things, E&P properties, in the future without any obligation to offer us the opportunity to purchase those assets.

Reimbursement of Costs

Subject to the arrangements relating to acquisition services described above, CEPM will be entitled to be reimbursed on a quarterly basis for all supervisory and management costs incurred by it in performing services for us. These costs and expenses will be deducted from cash available for distribution to our unitholders. For 2007, we expect these costs to be approximately $1.4 million.

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Review by Our Board of Managers

Except with respect to exclusive arrangements under the management services agreement during the period in which we are consolidated with Constellation for accounting purposes, our board of managers will have the right to evaluate CEPM s performance thereunder and, if considered desirable by our board of managers, arrange for third parties to provide some or all of the services to be provided pursuant to the management services agreement.

Standard of Care

In exercising its powers and discharging its duties under the management services agreement, CEPM is required to act in good faith, and is to exercise that degree of care, diligence and skill that a reasonably prudent advisor or manager, as the case may be, would exercise in comparable circumstances.

Indemnification

The management services agreement provides that, except arising out of our gross negligence, willful misconduct or a breach of the agreement, CEPM must indemnify us for any damages, liabilities, costs and expenses (including reasonable attorneys fees) arising from the rendering of CEPM s services under the management services agreement. We will indemnify CEPM for damages, liabilities, costs and expenses (including reasonable attorneys fees) arising from our gross negligence, willful misconduct or breach of this agreement.

Term and Termination

The management services agreement is in effect for continuous one-year terms, with the initial term ending on December 31, 2007. The management services agreement may be terminated by us or CEPM at any time and for any reason upon six months advance notice to the other party; provided that we may not terminate the management services agreement while we are consolidated with Constellation for accounting purposes.

Amendments

The management services agreement may not be amended without the prior approval of the conflicts committee of our board of managers if the proposed amendment will, in the reasonable discretion of our board of managers, adversely affect holders of our common units.

Trademark License

Constellation granted a limited license to us for the use of certain trademarks in connection with our business. The license will terminate upon the elimination of the right of the holder or holders of our Class A Units to elect the Class A managers pursuant to our limited liability company agreement. Constellation will indemnify us from any third-party claims alleging trademark infringement that may arise out of our use of the Constellation trademarks under the license.

Gas Purchase Contract

While our production and marketing subsidiaries are successors-in-interest to a gas purchase contract dated October 1, 1993, and originally entered into by and among TEMI, Torch Royalty Company and Velasco Gas Company Ltd as it relates to our production from the Trust Wells, no gas produced by us is sold to unaffiliated third parties under this gas purchase contract. The primary purpose of the portion of the gas purchase contract to which we have succeeded is to provide the calculation of gross proceeds for purposes of determining any royalty amounts we owe in respect of the NPI. Please read Item 1. Business Natural Gas Data Torch Royalty NPI.

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Cash Pool Arrangement

In February 2006, we entered into a cash pool arrangement with CCG. This cash pool arrangement was administered and managed by us. CCG could borrow from the pool at market interest rates. If we required cash, and CCG had an outstanding balance, CCG was required to immediately remit payment to us for the required cash amount. In November 2006, our participation in the cash arrangement was terminated and the outstanding receivable of $12.4 million from CCG was cancelled and CCG retained the funds. This was treated as a reduction of members equity for accounting purposes.

Manager Independence

For a discussion of the independence of the members of our board of managers and its committees, please read Item 10. Directors, Executive Officers and Corporate Governance-Independence of Board of Managers.

Indemnification

CCG has granted us an indemnification related to matters associated with a potential liability associated with the termination of a lease in Tuscaloosa County, Alabama. The lease was originally executed in November 2003. We did not drill any wells on the lease and it was not held by production. This unconditional indemnification was granted in March 2007 by CCG to cover any potential payments or expenses associated with the termination of the lease.

Credit Support Fee Agreement

In March 2007, we entered into a credit support fee agreement with CEG where CEG would guarantee credit support up to $25.0 million for certain financial hedges that we enter into with The Royal Bank of Scotland plc (RBS). The guarantee will be in full force until our obligations to RBS under the hedge agreements are secured under our revolving credit facility, or March 31, 2008. In March 2007, we also entered into a credit support fee agreement with CEG where CEG would guarantee credit support up to $11.5 million for certain financial hedges that we enter into with BNP Paribas (BNP). The guarantee will be in full force until our obligations to BNP under the hedge agreements are secured under our revolving credit facility, or September 30, 2008. We will pay CEG $0.2 million for the credit support. The hedge positions are contemplated in connection with an acquisition.

Item 14. Principal Accountant Fees and Services

In connection with our initial public offering, in 2006 we engaged our principal accountant, PricewaterhouseCoopers LLP to audit our financial statements for the period from February 7, 2005 (inception) through December 31, 2005. PricewaterhouseCoopers also performed audit services for the fiscal year ended December 31, 2006. The amounts shown below in Audit Fees relate to all periods mentioned above with the exception of the audit related fees billed in connection with the initial public offering which is listed separately below.

Audit Fees. The aggregate fees billed for the financial statement audit or services provided in connection with statutory or regulatory filings were $1,601,247.

Audit-Related Fees. The aggregate audit-related fees billed by PricewaterhouseCoopers were $313,495. Audit-related services consisted of services related to the initial public offering.

Tax Fees. The aggregate fees related to the preparation of K-1 statements were $235,000.

All Other Fees. There were no other fees billed by our principal accountant for services other than those described above.

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Audit Committee Pre-Approval Policies and Practices

Prior to our initial public offering in November 2006, we were a wholly-owned subsidiary of Constellation and did not have a separate audit committee. Following our initial public offering, our audit committee must pre-approve any audit and permissible non-audit services performed by our independent registered public accounting firm. Additionally, the audit committee has oversight responsibility to ensure the independent registered public accounting firm is not engaged to perform certain enumerated non-audit services, including but not limited to bookkeeping, financial information system design and implementation, appraisal or valuation services, internal audit outsourcing services and legal services. In February 2007, the audit committee adopted an audit and non-audit services pre-approval policy, which sets forth the procedures and the conditions pursuant to which services proposed to be performed by the independent registered public accounting firm must be approved. Pursuant to the policy, the chairman of the audit committee has been delegated the authority to specifically pre-approve services, which pre-approval is subsequently reviewed with the committee.

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PART IV

It em 15. Exhibits, Financial Statement Schedules and Reports on Form 8-K

(a) The following documents are filed as a part of this Annual Report on Form 10-K:

1. Financial Statements:

Reports of Independent Registered Public Accounting Firm dated March 1, 2007 and June 12, 2006 of PricewaterhouseCoopers LLP

Consolidated Statements of Operations and Comprehensive Income (Loss) Constellation Energy Partners LLC for the three years ended December 31, 2006

Consolidated Balance Sheets Constellation Energy Partners LLC at December 31, 2006 and December 31, 2005

Consolidated Statements of Cash Flows Constellation Energy Partners LLC for the three years ended December 31, 2006

Consolidated Statements of Changes in Members Equity and Comprehensive Income Constellation Energy Partners LLC for the three years ended December 31, 2006

Notes to Consolidated Financial Statements

2. Financial Statement Schedules:

Schedule II Valuation and Qualifying Accounts

Schedules other than Schedule II are omitted as not applicable or not required

3. Exhibits Required by Item 601 of Regulation S-K.

Exhibit Number	Description
*3.1	Certificate of Formation of Constellation Energy Partners LLC, as amended
3.2	Second Amended and Restated Operating Agreement of Constellation Energy Partners LLC (incorporated herein by reference to Exhibit 3.1 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on November 28, 2006)
10.1	Credit Agreement dated as of October 31, 2006 by and among Constellation Energy Partners LLC, as borrower, The Royal Bank of Scotland plc, as administrative agent, RBS Securities Corporation, as lead arranger and sole bookrunner, BNP Paribas and Wachovia Bank N.A., as co-syndication agents and the lenders from time to time party thereto (incorporated herein by reference to Exhibit 10.1 to Amendment No. 4 to the Registration Statement on Form S-1 (File No. 333-134995) filed by Constellation Energy Partners LLC on November 2, 2006 (Amendment No. 4))
10.2	Management Services Agreement dated as of November 20, 2006 by and between Constellation Energy Partners LLC and Constellation Energy Partners Management, LLC (incorporated herein by reference to Exhibit 10.2 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on November 28, 2006)
10.3	Omnibus Agreement dated as of November 20, 2006 by and among Constellation Energy Partners LLC, Constellation Energy Commodities Group, Inc., Robinson s Bend Production II, LLC, Robinson s Bend Operating II, LLC and Robinson s Bend Marketing II, LLC (incorporated herein by reference to Exhibit 10.1 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on November 28, 2006)

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Exhibit Number	Description
10.4	Net Overriding Royalty Conveyance dated as of November 22, 1993 but effective as of October 1, 1993, pursuant to Part I thereof, from Velasco Gas Company, Ltd. to Torch Energy Advisors Incorporated, and pursuant to Part II thereof, from Torch Energy Advisors Incorporated to the Torch Energy Royalty Trust (incorporated herein by reference to Exhibit 10.4 to Amendment No. 2 to the Registration Statement on Form S-1 (File No. 333-134995) filed by Constellation Energy Partners LLC on September 29, 2006 (Amendment No. 2))
10.5	Oil and Gas Purchase Agreement dated as of October 1, 1993 by and among Torch Energy Marketing, Inc., Torch Royalty Company and Velasco Gas Company Ltd. (incorporated herein by reference to Exhibit 10.5 to Amendment No. 2)
10.6	Letter agreement dated as of June 13, 2005 by and between Robinson s Bend Marketing II, LLC and Torch Energy TM, Inc. (incorporated herein by reference to Exhibit 10.6 to Amendment No. 2)
10.7	International Swap Dealers Association, Inc. Master Agreement and Schedule dated as of June 16, 2006 between The Royal Bank of Scotland, plc and Constellation Energy Resources LLC (incorporated herein by reference to Exhibit 10.7 to Amendment No. 2)
10.8	Confirmation, dated June 28, 2006, effective June 20, 2006, between The Royal Bank of Scotland, plc and Constellation Energy Resources LLC (incorporated herein by reference to Exhibit 10.8 to Amendment No. 2)
10.9	Asset Purchase and Sale Agreement dated as of May 12, 2005 by and among Everlast Energy LLC, RB Marketing Company LLC, Robinson s Bend Operating Company LLC and CBM Equity IV, LLC (incorporated herein by reference to Exhibit 10.9 to Amendment No. 2)
10.10	Letter agreement as of October 24, 2006 by and among The Investment Company LLC, Constellation Energy Commodities Group, Inc. and Robinson s Bend Production II, LLC (incorporated herein by reference to Exhibit 10.10 to Amendment No. 4)
10.11	Trademark License Agreement dated as of November 20, 2006 by and between Constellation Energy Group, Inc. and Constellation Energy Partners LLC (incorporated herein by reference to Exhibit 10.3 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on November 28, 2006)
10.12	Constellation Energy Partners LLC Long-Term Incentive Plan (incorporated herein by reference to Exhibit 10.1 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on November 20, 2006)
*12.1	Computation of Ratio of Earnings to Fixed Charges
21.1	List of subsidiaries of Constellation Energy Partners LLC (incorporated herein by reference to Exhibit 21.1 to the Registration Statement on Form S-1 (File No. 333-134995) filed by Constellation Energy Partners LLC on June 14, 2006)
*23.1	Consent of PricewaterhouseCoopers LLP
*23.2	Consent of Netherland, Sewell & Associates, Inc.
*31.1	Certification of Chairman of the Board, Chief Executive Officer and President of Constellation Energy Partners LLC pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
*31.2	Certification of Chief Financial Officer, Chief Accounting Officer and Treasurer of Constellation Energy Partners LLC pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

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Exhibit Number	Description
*32.1	Certification of Chairman of the Board, Chief Executive Officer and President of Constellation Energy Partners LLC pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
*32.2	Certification of Chief Financial Officer, Chief Accounting Officer and Treasurer of Constellation Energy Partners LLC pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

* Filed herewith

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REPORTS OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Unitholders and Board of Managers of Constellation Energy Partners LLC:

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of operations and comprehensive income (loss), of cash flows, and of changes in member s equity present fairly, in all material respects, the financial position of Constellation Energy Partners LLC (formerly Constellation Energy Resources LLC and CBM Equity IV Holdings, LLC) and its subsidiaries (CEP) (Successor Company) at December 31, 2006 and 2005, and the results of their operations and their cash flows for the year ended December 31, 2006 and the period from February 7, 2005 (inception) to December 31, 2005 in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Company s management. Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

/s/ PricewaterhouseCoopers LLP

PricewaterhouseCoopers LLP

Houston, Texas

March 12, 2007

To the Unitholders and Board of Managers of Constellation Energy Partners LLC:

In our opinion, the accompanying consolidated balance sheet and the related consolidated statements of operations and comprehensive income (loss), cash flows, and changes in members equity present fairly, in all material respects, the financial position of Everlast Energy LLC and its subsidiaries (Everlast) (Predecessor Company) at December 31, 2004 and the results of their operations and their cash flows for the period from January 1, 2005 to June 12, 2005, and for the year ended December 31, 2004 in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of Everlast s management. Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As discussed in Note 2, Everlast has restated its financial statements for the year ended December 31, 2004.

/s/ PricewaterhouseCoopers LLP

PricewaterhouseCoopers LLP

Baltimore, Maryland

June 12, 2006

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CONSTELLATION ENERGY PARTNERS LLC and SUBSIDIARIES and

EVERLAST ENERGY LLC and SUBSIDIARIES

Consolidated Statements of Operations and Comprehensive Income (Loss)

	Successor CEP		Predecessor Everlast	
	For the year ended December 31, 2006	For the period from February 7, 2005 (inception) to December 31, 2005	For the period from January 1, 2005 to June 12, 2005	For the year ended December 31, 2004 As Restated (see Note 2)
	(In 000 s except unit data)		(In 000 s except unit data)	
Revenues				
Gas sales	$ 36,917	$ 25,957	$ 12,882	$ 27,494
Loss from mark-to-market activities (see Note 4)			(15,313)	(9,107)
Total revenues	36,917	25,957	(2,431)	18,387
Expenses:				
Operating expenses:				
Lease operating expenses	7,234	4,175	2,769	5,270
Production taxes	1,783	1,400	676	1,479
General and administrative	4,573	4,184	594	2,706
Depreciation, depletion, and amortization	7,444	4,176	1,683	3,719
Accretion expense	141	78	46	86
Total operating expenses	21,175	14,013	5,768	13,260
Other expense/(income)				
Interest expense	221	3	2,437	3,028
Interest (income)	(468)			
Total other expenses/(income)	(247)	3	2,437	3,028
Total expenses	20,928	14,016	8,205	16,288
Net income (loss)	$ 15,989	$ 11,941	$ (10,636)	$ 2,099
Other comprehensive income	13,113			
Comprehensive income (loss)	$ 29,102	$ 11,941	$ (10,636)	$ 2,099
Earnings per unit (see Note 1)				
Earnings per unit Basic	$ 1.41	$ 1.05		

Units outstanding Basic	11,320,300	11,320,300
Earnings per unit Diluted	$ 1.41	$ 1.05
Units outstanding Diluted	11,320,300	11,320,300

See accompanying notes to consolidated financial statements.

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CONSTELLATION ENERGY PARTNERS LLC and SUBSIDIARIES and

EVERLAST ENERGY LLC and SUBSIDIARIES

Consolidated Balance Sheets

	December 31, 2006	December 31, 2005
	(In 000 s)	
ASSETS		
Current assets		
Cash and cash equivalents	$ 7,485	$ 14,831
Accounts receivable	9,609	5,824
Prepaid expenses	317	62
Risk management assets	8,654	
Other	22	211
Total current assets	26,087	20,928
Natural gas properties (See Note 7)		
Natural gas properties, equipment and facilities	181,995	168,675
Material and supplies	1,264	712
Less accumulated depreciation, depletion and amortization	(11,620)	(4,176)
Net natural gas properties	171,639	165,211
Other assets		
Debt issue costs (net of accumulated amortization of $48 at December 31, 2006)	1,138	
Other non-current assets	72	
Risk management assets	4,761	
Total assets	$ 203,697	$ 186,139
LIABILITIES AND MEMBERS EQUITY		
Liabilities		
Current liabilities		
Accounts payable	$ 66	$ 4,799
Payable to affiliate	2,836	380
Accrued liabilities	3,017	5,483
Environmental liabilities	721	
Royalty payable	2,367	3,233
Total current liabilities	9,007	13,895
Other liabilities		
Asset retirement obligation	2,730	2,524
Environmental liabilities		490
Debt	22,000	63
Total other liabilities	24,730	3,077
Total liabilities	33,737	16,972
Commitments and contingencies (Notes 10 and 14)		
Class D Interests	8,000	

Members equity		
Class A units, 226,406 shares authorized, issued and outstanding	2,977	
Class B units, 11,093,894 shares authorized, issued and outstanding	145,870	
Common members equity		169,167
Accumulated other comprehensive income	13,113	
Total members equity	161,960	169,167
Total liabilities and members equity	$ 203,697	$ 186,139

See accompanying notes to consolidated financial statements.

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CONSTELLATION ENERGY PARTNERS LLC and SUBSIDIARIES and

EVERLAST ENERGY LLC and SUBSIDIARIES

Consolidated Statements of Cash Flows

	Successor CEP		Predecessor Everlast	
	For the year ended December 31, 2006	For the period from February 7, 2005 (inception) to December 31, 2005	For the period from January 1, 2005 to June 12, 2005	For the year ended December 31, 2004 As Restated (see Note 2)
	(In 000 s)		(In 000 s)	
Cash flows from operating activities:				
Net income (loss)	$ 15,989	$ 11,941	$ (10,636)	$ 2,099
Adjustments to reconcile net income (loss) to cash provided by operating activities:				
Expenses paid by CCG on behalf of CEP	370	64		
Depreciation, depletion and amortization	7,444	4,176	1,683	3,719
Amortization of debt issuance costs	48		237	685
Accretion of return on preferred member units				432
Accretion of plugging and abandonment liability	141	78	46	86
Hedge ineffectiveness	(302)			
Changes in Assets and Liabilities:				
Increase (decrease) in net mark-to-market activities			15,265	(2,156)
Increase in accounts receivable	(3,785)	(1,289)	(707)	(2,278)
(Increase) decrease in prepaid expenses	(255)	(62)	(131)	246
(Increase) decrease in other assets	117	(211)	(7,035)	
Increase in deposit on sale of properties			7,025	
Increase (decrease) in accounts payable	(4,733)	1,323	807	993
Increase in payable to affiliate	2,456	380		
Increase (decrease) in accrued liabilities	(2,557)	5,054	(25)	372
Increase (decrease) in royalty payable	(866)	1,859	110	708
Net cash provided by operating activities	14,067	23,313	6,639	4,906
Cash flows from investing activities:				
Acquisition of natural gas properties	(261)	(138,951)	(201)	(1,304)
Development of natural gas properties	(13,224)	(8,286)	(4,000)	(5,680)
Investment in affiliate cash pool	(12,419)			
Other, net	475		(2)	(13)
Net cash used in investing activities	(25,429)	(147,237)	(4,203)	(6,997)
Cash flows from financing activities:				
Members (distributions) contributions	(122,750)	138,770		(21,102)
Preferred members redemptions				(17,184)
Proceeds from issuance of debt	30,000			48,000
Repayment of debt	(8,063)	(15)	(2,500)	(6,500)
Proceeds from issuance of common stock	109,340			
Initial public offering issue costs	(3,325)			

Debt issue costs	(1,186)			(1,674)
Net cash provided by (used in) financing activities	4,016	138,755	(2,500)	1,540
Net (decrease) increase in cash	(7,346)	14,831	(64)	(551)
Cash and cash equivalents, beginning of period	14,831		2,012	2,563
Cash and cash equivalents, end of period	$ 7,485	$ 14,831	$ 1,948	$ 2,012
Supplemental disclosures of cash flow information:				
Non-cash items				
Assumption of receivables from Everlast by CEP	$	$ 4,536	$	$
Assumption of liabilities from Everlast by CEP		3,640		
Acquisition costs related to accrual for asset retirement obligation		2,446		
Acquisition costs related to payable to Everlast		2,361		
Derivative liabilities assumed by CEP as part of the acquisition and then subsequently assumed by CCG		18,003		
Direct costs related to the acquisition of the properties paid by CCG on behalf of CEP		389		
Expenses paid by CCG on behalf of CEP	370	64		
Termination of cash pool arrangement	12,419			
Cash paid during the period for interest	$ 3	$ 3	$ 2,196	$ 1,484

See accompanying notes to consolidated financial statements.

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CONSTELLATION ENERGY PARTNERS LLC and SUBSIDIARIES and

EVERLAST ENERGY LLC and SUBSIDIARIES

Consolidated Statements of Changes in Members Equity

	Members Equity	Class A Units	Class A Amount	Class B Units	Class B Amount	Accumulated Other Comprehensive Income	Total Members Equity
			(In 000 s, except unit data)				
CEP (Successor)							
Contributions	$ 157,226		$		$	$	$ 157,226
Net income	11,941						11,941
Balance, December 31, 2005	169,167						169,167
Contributions	571						571
Distributions	(122,951)						(122,951)
Cash in exchange for Floyd Shale rights	475						475
Issuance of common units	(44,133)	226,406	2,910	11,093,894	142,563		101,340
Issue costs	(3,325)						(3,325)
Termination of cash pool	(12,419)						(12,419)
Change in fair value of commodity hedges						15,097	15,097
Cash gains on settlement of commodity hedges						(2,114)	(2,114)
Change in fair value of interest rate hedges						130	130
Net income	12,615		67		3,307		15,989
Balance, December 31, 2006	$	226,406	$ 2,977	11,093,894	$ 145,870	$ 13,113	$ 161,960
Everlast (Predecessor) (as restated, see Note 2)							
Balance, December 31, 2003	4,391						4,391
Distributions	(21,102)						(21,102)
Net income	2,099						2,099
Balance, December 31, 2004	$ (14,612)		$		$	$	$ (14,612)

See accompanying notes to consolidated financial statements.

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CONSTELLATION ENERGY PARTNERS LLC AND SUBSIDIARIES

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

DECEMBER 31, 2004, 2005 and 2006

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Organization and Basis of Presentation

CBM Equity IV Holdings, LLC was organized as a limited liability company on February 7, 2005 under the laws of the State of Delaware and had no principal operations prior to our acquisition of our properties in the Robinson s Bend Field (the Properties) from Everlast Energy LLC (Everlast) on June 13, 2005. On May 10, 2006, CBM Equity IV Holdings, LLC changed its name to Constellation Energy Resources LLC. On July 18, 2006, Constellation Energy Resources LLC changed its name to Constellation Energy Partners LLC (CEP). CEP is a consolidated subsidiary of Constellation Energy Commodities Group, Inc. (CCG), which is owned by Constellation Energy Group (NYSE: CEG). CEP completed its initial public offering on November 20, 2006, and is traded on the NYSE Arca under the symbol CEP . The company is currently focused on the development, exploitation and acquisition of natural gas properties in the Robinson s Bend Field located in the Black Warrior Basin in Alabama (the Field). CEP acquired the natural gas properties, including equipment and a natural gas gathering facility and water treatment plant at the Properties from Everlast effective June 13, 2005.

The accompanying financial statements for CEP include the accounts of CEP and its wholly-owned subsidiaries, Robinson s Bend Production II, LLC (Production), Robinson s Bend Operating II, LLC (Operating) and Robinson s Bend Marketing II, LLC (Marketing) (collectively, the Entities). All significant intercompany accounts and transactions have been eliminated in consolidation. CEP s natural gas production is related to the Properties acquired as of June 13, 2005.

Everlast was organized as a limited liability company on November 20, 2002 under the laws of the State of Delaware. Everlast was primarily engaged in the acquisition, development and production of gas reserves and operation of gas wells in the Field from January 7, 2003 to June 12, 2005.

CEP s and Everlast s only operations were derived from the Properties. During the last three years, the Properties were wholly-owned by either CEP or Everlast. CEP s purchase of the Properties from Everlast resulted in a new basis of accounting. In addition, new management, new assumptions and new accounting policies were put into place. Though the financial statements represent the operation of the same Properties, due to these differences the financial statements for the periods prior to and after CEP s purchase of the Properties are not comparable. For that purpose, a black line has been placed between the CEP and Everlast financial statements.

Accounting policies used by CEP and Everlast conform to accounting principles generally accepted in the United States of America. Unless otherwise indicated, CEP and Everlast follow the same significant accounting policies.

CEP and Everlast both operated the Properties as one business segment, the exploration, development and production of natural gas. Management of both CEP and Everlast evaluated performance based on one business segment as there are not different economic environments within the operation of the Properties.

Certain reclassifications have been made to prior years reported amounts in order to conform with the current year presentation. These reclassifications did not impact our net income, members equity or cash flows.

Cash and Cash Equivalents

All highly liquid investments with original maturities of three months or less are considered cash equivalents by both CEP and Everlast.

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CONSTELLATION ENERGY PARTNERS LLC AND SUBSIDIARIES

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Concentration of Credit Risk and Accounts Receivable

Financial instruments that potentially subject CEP and Everlast to a concentration of credit risk consist of cash and cash equivalents, accounts receivable and derivative financial instruments. Both CEP and Everlast place their cash with high credit quality financial institutions. CEP and Everlast place their derivative financial instruments with financial institutions and other firms that their managements believes have high credit ratings. Substantially all of CEP s and Everlast s accounts receivable are due from purchasers of natural gas. Natural gas sales are generally unsecured. As CEP generally has fewer than 10 customers for its natural gas sales, CEP routinely assesses the financial strength of its customers. Bad debt expense is recognized on an account-by-account review after all means of collection have been exhausted and recovery is not probable. There has been no bad debt expense for any of the periods presented herein. Neither CEP nor Everlast have any off-balance-sheet credit exposure related to customers.

For the year ended December 31, 2006, five customers accounted for approximately 30%, 20%, 18%, 17% and 15%, respectively, of the gas sales revenues related to the Properties. For the period from February 7, 2005 (inception) to December 31, 2005, five customers accounted for approximately 31%, 20%, 20%, 17%, and 12%, respectively, of the gas sales revenues related to the Properties. For the year ended December 31, 2004, five customers accounted for approximately 31%, 20%, 16%, 15% and 11%, respectively, of the gas sales revenues related to the Properties.

Natural Gas Properties

CEP

Natural Gas Properties

CEP follows the successful efforts method of accounting for its natural gas exploration, development and production activities. Leasehold acquisition costs are capitalized. If proved reserves are found on an undeveloped property, leasehold cost is transferred to proved properties. Under this method of accounting, costs relating to the development of proved areas are capitalized when incurred.

Depreciation and depletion of producing natural gas and oil properties is recorded at the field level, based on the units-of-production method. Unit rates are computed for unamortized drilling and development costs using proved developed reserves and for unamortized leasehold costs using all proved reserves. Statement of Financial Accounting Standards (SFAS) No. 19, *Financial Accounting and Reporting by Oil and Gas Producing Companies*, requires that acquisition costs of proved properties be amortized on the basis of all proved reserves, developed and undeveloped, and that capitalized development costs (including wells and related equipment and facilities) be amortized on the basis of proved developed reserves. As more fully described in Note 16, proved reserves are estimated by CCG s internal reserve engineers, and are subject to future revisions when additional information becomes available.

As described in Note 11, CEP follows SFAS No. 143, *Accounting for Asset Retirement Obligations*. Under SFAS No. 143, estimated asset retirement costs are recognized when the asset is placed in service, and are amortized over proved reserves using the units-of-production method. Asset retirement costs are estimated by CEP s engineers using existing regulatory requirements and anticipated future inflation rates.

Geological, geophysical and dry hole costs on oil and natural gas properties relating to unsuccessful exploratory wells are charged to expense as incurred.

Natural gas properties are reviewed for impairment when facts and circumstances indicate that their carrying value may not be recoverable. CEP assesses impairment of capitalized costs of proved natural gas properties

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CONSTELLATION ENERGY PARTNERS LLC AND SUBSIDIARIES

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

by comparing net capitalized costs to estimated undiscounted future net cash flows using expected prices. If net capitalized costs exceed estimated undiscounted future net cash flows, the measurement of impairment is based on estimated fair value, which would consider estimated future discounted cash flows. As of December 31, 2006 and 2005, the estimated undiscounted future cash flows for CEP s proved natural gas and oil properties exceeded the net capitalized costs, thus no impairment was required to be recognized.

Unproven properties that are individually significant are assessed for impairment and if considered impaired are charged to expense when such impairment is deemed to have occurred. Impairment is deemed to have occurred if a lease is going to expire prior to any planned drilling on the leased property.

Property acquisition costs are capitalized when incurred.

Support Equipment and Facilities

Support equipment and facilities consist of CEP s water treatment facility, gas lines, roads and other various support equipment. Items are capitalized when acquired and depleted using the units-of-production method over the total proved developed reserves.

Materials and Supplies

Materials and supplies consist of well equipment, parts and supplies. They are valued at the lower of cost or market, using either the specific identification or first-in first-out method, depending on the inventory type. Materials and supplies are capitalized as used in the development or support of the Properties.

Everlast

Everlast used the full-cost method of accounting for its natural gas properties. All of Everlast s properties and assets were located in the Black Warrior Basin in Alabama; therefore its costs were capitalized in one cost center. Under the full-cost method, all costs related to the acquisitions, exploration or development of oil and natural gas properties are capitalized into the full-cost pool . Such costs include those related to lease acquisitions, drilling and equipping of productive and nonproductive wells, delay rentals, geological and geophysical work and certain internal costs directly associated with the acquisition, exploration or development of oil and natural gas properties. Upon the sale or disposition of oil and natural gas properties, no gain or loss is recognized, unless such adjustments of the full-cost pool would significantly alter the relationship between the capitalized costs and proved reserves.

Under the full-cost method of accounting, a full-cost ceiling test is required wherein net capitalized costs of oil and natural gas properties cannot exceed the present value of estimated future net revenues from proved oil and natural gas reserves, discounted at 10%, less any related income tax effects.

Costs of acquiring undeveloped gas leases that are capitalized and not subject to amortization (see Note 7) are assessed periodically to determine whether impairment has occurred. Appropriate valuation allowances are established when necessary. No such allowance was required during the period from January 1, 2005 to June 12, 2005, and for the year ended December 31, 2004.

Depreciation, depletion and amortization of natural gas properties was computed using the units-of-production method based on estimated proved gas reserves.

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CONSTELLATION ENERGY PARTNERS LLC AND SUBSIDIARIES

AND EVERLAST ENERGY LLC AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Natural Gas Reserve Quantities

CEP

CEP s estimate of proved reserves is based on the quantities of natural gas that engineering and geological analyses demonstrate, with reasonable certainty, to be recoverable from established reservoirs in the future under current operating and economic parameters. Management calculated reserves based on various factors, including consideration of an independent reserve engineers report on proved reserves and economic evaluation of all of CEP s properties on a well-by-well basis. The process used to complete the internal estimates of proved reserves at December 31, 2006 and 2005 is described in detail in Note 16.

Reserves and their relation to estimated future net cash flows impact CEP s depletion and impairment calculations. As a result, adjustments to depletion and impairment are made concurrently with changes to reserve estimates. The accuracy of CEP s reserve estimates is a function of many factors including the following: the quality and quantity of available data, the interpretation of that data, the accuracy of various mandated economic assumptions and the judgments of the individuals preparing the estimates.

CEP s proved reserve estimates were a function of many assumptions, all of which could deviate significantly from actual results. As such, reserve estimates may materially vary from the ultimate quantities of natural gas, natural gas liquids and oil eventually recovered.

Everlast

Everlast s estimates of proved reserves were based on the quantities of natural gas and oil that engineering and geological analyses demonstrated, with reasonable certainty, to be recoverable from established reservoirs in the future under current operating and economic parameters. The proved reserve estimate of 162.2 Bcf for 2004 was used to prepare the 2004 financial statements. CEP prepared the estimates internally by starting with a December 31, 2005 proved reserve estimate that was prepared by Netherland, Sewell & Associates, Inc. (NSAI) based on the prior accelerated drilling program and reserve assumptions and rolling that back to year end 2004 by making appropriate adjustments for actual production, prices and development activity. The roll back was necessary because the reserve report prepared by NSAI for Everlast for year end 2004 was not considered to be based on the Securities and Exchange Commission (SEC) definition of proved reserves, which CEP uses for financial statement preparation purposes.

Due to this inconsistency in the preparation of reserve reports for the periods presented, CEP has adopted the roll back approach of reserves at December 31, 2005 to year end 2004 in preparing the financial statements for year end 2004.

Changes to reserve estimates affect estimated future net cash flows, depletion and impairment calculations. The accuracy of Everlast s reserve estimates was a function of: the quality and quantity of available data, the interpretation of that data, the accuracy of various mandated economic assumptions and the judgments of the individuals preparing the estimates.

Everlast s proved reserve estimates were a function of many assumptions, all of which could deviate significantly from actual results. As such, reserve estimates may materially vary from the ultimate quantities of natural gas eventually recovered.

Deposit on Sale of Properties

As of June 12, 2005, Everlast had a restricted cash balance of $7.0 million. This account was cash held in escrow and was restricted until the purchase of the Properties by CEP was completed. It was released on June 13, 2005 to Everlast.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Derivatives and Hedging Activities

CEP

CEP uses derivative financial instruments to achieve a more predictable cash flow from its natural gas production by reducing its exposure to price fluctuations. Additionally, CEP uses derivative financial instruments in the form of interest rate swaps to mitigate its interest rate exposure.

SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities*, as amended, requires that all derivative instruments be recorded in the consolidated balance sheet as either an asset or a liability measured at fair value with changes in fair value recognized in earnings unless specific hedge accounting criteria are met. CEP elected to designate these contracts as cash-flow hedges for accounting purposes. The fair value of its derivative contracts are recorded on its balance sheet as Risk management assets and Accumulated other comprehensive income. Changes in the fair value of the cash flow hedges are reflected on the consolidated statements of operations and comprehensive income (loss) as other comprehensive income. When amounts for hedging activities under SFAS No. 133 are reclassified from Accumulated other comprehensive income (loss) on the balance sheet to the income statement, we record settled natural gas swaps as Gas sales and settled interest rate swaps as Interest expense (income).

Everlast

During 2004 and 2005, Everlast entered into certain over-the-counter contracts to economically hedge the cash flow of the forecasted sale of gas production. SFAS No. 133*, Accounting for Derivative Instruments and Hedging Activities*, as amended, requires that all derivative instruments be recorded in the consolidated balance sheet as either an asset or a liability measured at fair value with changes recognized in earnings unless specific hedge accounting criteria are met. Everlast did not elect to document and designate these contracts as hedges for accounting purposes. Thus, the changes in the fair value and ultimate settlement of these over-the-counter contracts are reflected in Everlast s earnings as loss from mark-to-market activities for the period from January 1, 2005 to June 12, 2005 and for the year ended December 31, 2004.

Net Profits Interest

Certain of the Properties are subject to a net profits interest (NPI). The NPI represents an interest in production created from the working interest and is based on a contracted revenue calculation (see Note 12). CEP accounts for the NPI as an overriding royalty interest. This is consistent with how CEP accounts for the NPI for reserves purposes. Any payments made to the NPI holder are reflected as a reduction in revenue. Everlast financials have been changed to reflect this method of accounting. For a discussion of restatements, see Note 2.

Revenue Recognition

Sales of natural gas are recognized when natural gas has been delivered to a custody transfer point, persuasive evidence of a sales arrangement exists, the rights and responsibility of ownership pass to the purchaser upon delivery, collection of revenue from the sale is reasonably assured and the sales price is fixed or determinable. Natural gas is sold on a monthly basis. Most of CEP s and Everlast s sales contracts pricing provisions are tied to a market index, with certain adjustments based on, among other factors, whether a well delivers to a gathering or transmission line, quality of natural gas, and prevailing supply and demand conditions, so that the price of the natural gas fluctuates to remain competitive with other available natural gas supplies. As a result, revenues from the sale of natural gas will suffer if market prices decline and benefit if they increase. CEP believes that the pricing provisions of its natural gas contracts are customary in the industry.

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CONSTELLATION ENERGY PARTNERS LLC AND SUBSIDIARIES

AND EVERLAST ENERGY LLC AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Gas imbalances occur when sales are more or less than the entitled ownership percentage of total gas production. CEP and Everlast use the entitlements method when accounting for gas imbalances. Any amount received in excess is treated as a liability. If less than the entitled share of the production is received, the excess is recorded as a receivable. There were no gas imbalance positions at December 31, 2006 or 2005, June 12, 2005 or December 31, 2004.

Income Taxes

As of November 20, 2006, the Company is treated as a partnership for federal and state income tax purposes. As such, it is not a taxable entity and does not directly pay federal and state income tax. Its taxable income or loss, which may vary substantially from the net income or net loss reported in the consolidated statements of income, is includable in the federal and state income tax returns of each member. Accordingly, no recognition has been given to federal and state income taxes for the operations of the Company except as described below. The aggregate difference in the basis of net assets for financial and tax reporting purposes cannot be readily determined as we do not have access to information about each member s tax attributes in the Company.

Until the completion of the initial public offering on November 20, 2006, CEP was a single-member liability company that was a disregarded entity for federal income tax purposes under Regulation 301.7701-3(b). That means, for Federal income tax purposes, CEP was accounted for as a division of CCG and did not file separate tax returns. Under Constellation Energy tax sharing practices, no provision for income taxes was made in CEP s financial statements because the taxable income or loss of CEP was included in the income tax return of CCG, the single corporate member, until the completion of the initial public offering on November 20, 2006. If CEP were a separate taxpayer, income taxes for the year ended November 19, 2006 and the period from February 7, 2005 (inception) to December 31, 2005, would have been $4.6 million and $4.7 million, respectively. After completion of the initial public offering on November 20, 2006, no provision for income taxes was made in CEP s consolidated financial statements because the taxable income or loss of CEP was included in the income tax returns of the individual members. As of November 19, 2006 and 2005, the income tax basis of CEP s assets was $165.4 million and $170.1 million, respectively.

No provision for incomes taxes was made in Everlast s consolidated financial statements because the taxable income or loss of Everlast was included in the income tax returns of the individual members. As of June 12, 2005 and December 31, 2004, the income tax basis of Everlast s assets was $53.8 million and $55.9 million, respectively.

Use of Estimates

Estimates and assumptions are made when preparing financial statements under accounting principles generally accepted in the United States of America. These estimates and assumptions affect various matters, including:

- reported amounts of revenue and expenses in the Consolidated Statement of Operations and Other Comprehensive Income (Loss) during the reported periods of CEP and Everlast,

- reported amounts of assets and liabilities in the Consolidated Balance Sheets at the dates of the financial statements of CEP and Everlast,

- disclosure of quantities of reserves and use of those reserve quantities for depreciation, depletion and amortization, and disclosure of contingent assets and liabilities at the date of the financial statements of CEP and Everlast.

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These estimates involve judgments with respect to numerous factors that are difficult to predict and are beyond management s control. As a result, actual amounts could materially differ from these estimates.

Earnings per Unit

Basic earnings per unit (EPS) is computed by dividing net earnings attributable to unitholders by the weighted average number of units outstanding during each period. However, because our initial public offering was completed in November 2006, the number of shares issued following the initial public offering is utilized for the 2005 period presented. Diluted EPS reflects the potential dilution of common equivalent units that could occur if securities or other contracts to issue common units were exercised or converted into common units. CEP s basic and diluted EPS are the same in each of the year ended December 31, 2006 and the period from February 7, 2005 (inception) to December 31, 2005, as there were no dilutive common unit equivalents.

Comprehensive Income (Loss)

Comprehensive income (loss) includes net earnings (loss) as well as unrealized gains and losses on derivative instruments.

Class D Interests

Due to their contingently redeemable feature, the Class D interests are treated as preferred units subject to contingent redemption in accordance with SEC Accounting Series Release No. 268, *Presentation in Financial Statements of Redeemable Preferred Stocks*.

Environmental Cost

We record liabilities at their undiscounted amounts on our balance sheet in other current and long-term liabilities when our environmental assessments indicate that remediation efforts are probable and the costs can be reasonably estimated. Estimates of our liabilities are based on currently available facts, existing technology and presently enacted laws and regulations taking into consideration the likely effects of other societal and economic factors, and include estimates of associated legal costs. These amounts also consider prior experience in remediating contaminated sites, other companies clean-up experience and data released by the Federal Environmental Protection Agency (EPA) or other organizations. Our estimates are subject to revision in future periods based on actual costs or new circumstances. We capitalize costs that benefit future periods and we recognize a current period charge in operation and maintenance expense when clean-up efforts do not benefit future periods.

Other Contingencies

We recognize liabilities for other contingencies when we have an exposure that, when fully analyzed, indicates it is both probable that an asset has been impaired or that a liability has been incurred and the amount of impairment or loss can be reasonably estimated. Funds spent to remedy these contingencies are charged against the associated reserve, if one exists, or expensed. When a range of probable loss can be estimated, we accrue the most likely amount or at least the minimum of the range of probable loss.

Accounting Standards Adopted

In April 2006, the Financial Accounting Standards Board (FASB) issued FASB Staff Position (FSP) FIN 46R-6, *Determining the Variability to Be Considered in Applying FASB Interpretation No. 46R*. FSP FIN

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46R-6 addresses how a reporting enterprise should determine the variability to be considered in applying FASB Interpretation (FIN) No. 46R, *Consolidation of Variable Interest Entities, an interpretation of ARB No. 51*. The variability to be considered should be based on an analysis of the design of the entity and should consider the nature of the entity s risks and the purpose for which the entity was created. FSP FIN 46R-6 must be applied prospectively to all entities beginning July 1, 2006. CEP has determined that there was no impact on its financial results as a result of FSP FIN 46R-6.

In September 2006, the SEC issued Staff Accounting Bulletin (SAB) No. 108, *Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements*. SAB No. 108 provides interpretive guidance on how the effects of prior-year uncorrected misstatements should be considered when quantifying misstatements in the current year financial statements. SAB No. 108 requires registrants to quantify misstatements using both an income statement (rollover) and balance sheet (iron curtain) approach and evaluate whether either approach results in a misstatement that, when all relevant quantitative and qualitative factors are considered, is material. If prior year errors that had been previously considered immaterial now are considered material based on either approach, no restatement is required so long as management properly applied its previous approach and all relevant facts and circumstances were considered. If prior years are not restated, the cumulative effect adjustment is recorded in opening accumulated earnings (deficit) as of the beginning of the fiscal year of adoption. SAB No. 108 is effective for fiscal years ending on or after November 15, 2006, with earlier adoption encouraged. The impact the adoption of SAB No. 108 had no material impact on CEP s financial statements.

Accounting Standards Issued but not Effective

In September 2006, the FASB issued SFAS No. 157, *Fair Value Measurements.* SFAS No. 157 defines fair value, establishes a framework for measuring fair value and expands disclosures for fair value measurements. SFAS No. 157 is effective for all fair value measurements beginning January 1, 2008. CEP is currently assessing the potential impact of SFAS No. 157.

2. RESTATEMENT OF EVERLAST FINANCIAL STATEMENTS

The financial statements as of December 31, 2004 and for the year ended December 31, 2004 which were prepared and issued by the predecessor entity, Everlast, have been restated for the following:

- to correct depletion expense that was recorded based on incorrect reserve quantities and future development costs;

- to include the impact of cost escalation for plugging and abandoning wells in the calculation of asset retirement obligations;

- to correct for costs recorded in the wrong periods;

- to correct the misclassification of revenues related to a long-term, fixed price natural gas sales contract accounted for as a derivative contract;

- to expense operating costs originally capitalized;

to capitalize and amortize deferred financing costs originally expensed;

to capitalize certain property costs originally expensed; and

to account for a net profits interest as an overriding royalty interest.

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In 2004, Everlast recorded depletion expense based on a depletion base that understated future development costs that are required to be included in the depletion base under the full cost method. In addition, recorded depletion expense was based on reserve estimates that incorrectly included certain proved undeveloped reserves. For purposes of reserve determination, it is inappropriate to include proved undeveloped reserves that are not immediately adjoining currently producing wells. The original year-end proved reserves for 2004 were adjusted to remove these proved undeveloped reserves. In 2004, Everlast s original accounting was based on a proved reserve estimate of 173.4 Bcf, while the revised accounting was based on a proved reserve estimate of 162.2 Bcf. This adjustment resulted in additional depletion expense and a reduction of net income of $76,000 for the year ended December 31, 2004 and an increase in accumulated depletion of $0.8 million at December 31, 2004.

In 2004, the cost estimates associated with plugging and abandoning wells should have been computed based on estimates of future costs, including inflation through the period in which the actual cash outflows would be incurred. The impact of correcting the expense to include all such future costs in the asset retirement obligation results in an increase in the asset retirement obligation along with an associated asset retirement asset of $0.8 million at December 31, 2004, and additional accretion expense and reduction of net income of $70,000 for the year ended December 31, 2004.

As part of CEP s cut-off procedures, CEP identified certain costs incurred in 2004 which should have been included in expenses and liabilities in different periods. Recording these costs in the correct periods resulted in additional liabilities of $108,000 and an increase in oil and gas properties of $51,000 at December 31, 2004 and a reduction of net income of $37,000 for the year ended December 31, 2004.

In 2004, Everlast completed a modification of its line of credit and wrote-off all deferred financing costs associated with the previous facility. In accordance with the guidance in EITF 98-14, *Debtors Accounting for Changes in Line-of-Credit or Revolving-Debt Agreements*, certain of these debt issuance costs should have continued to be capitalized and amortized over the life of the modified revolving credit agreement because one of the financial institutions was a participant in both the original credit facility, as well as the modified one. This adjustment resulted in an increase of $0.2 million in capitalized loan costs at December 31, 2004 and a reduction in interest expense and an increase in net income of $0.2 million for the year ended December 31, 2004.

Everlast expensed certain capital costs in 2003 that should have been capitalized. Accordingly, in the restated financial statements, $0.5 million has been recorded to increase properties being amortized at December 31, 2004. This increased depletion expense by $13,000 in the year ended December 31, 2004. The impact of these corrections decreased net income by $13,000 in 2004.

Certain of the Properties are subject to an NPI (see Notes 1 and 12). In 2004, Everlast determined its reserves as if the NPI were an overriding royalty interest. This was inconsistent with how the NPI was reflected in the statement of operations for those years. Generally accepted accounting principles require that the determination of reserves be consistent with the financial statement reporting. CEP believes that treatment of the NPI as an overriding royalty interest for both financial statement and reserve reporting is appropriate in the circumstances. As a result, the statement of operations has been restated to account for the NPI as an overriding royalty interest which resulted in an increase in revenues and a corresponding increase in expenses of $2.1 million for the year ended December 31, 2004. This restatement had no impact on net income for 2004. In addition, because reserves in this period were determined as if the NPI were an overriding royalty interest this adjustment had no impact on reserves.

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The following is a summary of the effects of these adjustments on Everlast s balance sheet as of December 31, 2004, and on the statements of operations, cash flows and members equity for the year ended December 31, 2004.

Statements of Operations

For the year ended December 31, 2004	As Previously Reported	Adjustments (In 000 s)	As Restated
Revenues:			
Gas sales	$ 25,363	$ 2,131	$ 27,494
Loss from mark-to-market activities	(9,107)		(9,107)
Total revenues	16,256	2,131	18,387
Expenses:			
Operating expenses:			
Lease operating expenses	3,682	1,588	5,270
Production taxes	921	558	1,479
General and administrative	2,689	17	2,706
Depreciation, depletion, and amortization	3,643	76	3,719
Accretion expense	16	70	86
Total operating expenses	10,951	2,309	13,260
Other expenses:			
Interest expense, net	2,803	225	3,028
Total other expenses	2,803	225	3,028
Total expenses	13,754	2,534	16,288
Net income	$ 2,502	$ (403)	$ 2,099

Balance Sheet

December 31, 2004	As Previously Reported	Adjustments (In 000 s)	As Restated
Natural gas properties and related equipment (full cost)	$ 58,813	$ 1,121	$ 59,934
Accumulated depreciation, depletion and amortization	(6,644)	(759)	(7,403)
Net natural gas properties	52,169	362	52,531
Loan costs (net of accumulated amortization)	1,378	201	1,579
Total assets	60,121	563	60,684
Accounts payable	1,793	108	1,901

Royalty payable	2,037	(8)	2,029
Total current liabilities	4,382	100	4,482
Asset retirement obligation	210	842	1,052
Total liabilities	74,354	942	75,296
Total members capital (deficit)	(14,233)	(379)	(14,612)

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Statements of Cash Flows

For the year ended December 31, 2004	As Previously Reported	Adjustments	As Restated
		(In 000 s)	
Net cash provided by operating activities	$ 4,654	$ 252	$ 4,906
Net cash used in investing activities	(6,947)	(50)	(6,997)
Net cash provided by (used in) financing activities	1,742	(202)	1,540
Cash and cash equivalents, beginning of period	2,563		2,563
Cash and cash equivalents, end of period	$ 2,012	$	$ 2,012

Statement of Members Equity

	As Previously Reported	Adjustments	As Restated
		(In 000 s)	
Balance, December 31, 2003	$ 21,553	$ (17,162)	$ 4,391
Distributions	(38,287)	17,185	(21,102)
Net income	2,502	(403)	2,099
Balance, December 31, 2004	$ (14,232)	$ (380)	$ (14,612)

The information in the tables above reflects the correction of errors in the 2004 Everlast financial statements. The information in the tables above does not, however, reflect the impact of Everlast s adoption of SFAS No. 150, *Accounting for Certain Financial Instruments with Characteristics of Both Liabilities and Equity* in 2003. See discussion of the adoption of SFAS No. 150 in Note 5.

3. ACQUISITIONS AND DIVESTITURES

On October 30, 2006 CEP received $475,000 from an affiliate of Constellation Energy Group for the sale of the Floyd Shale Rights. These rights are an undivided mineral interest in our properties in the Robinson s Bend Field for depths generally below 100 feet below the base of the lowest producing coal seam. The proceeds of $475,000 were treated as a capital contribution from CCG.

On June 13, 2005, CEP acquired the Properties consisting of 424 producing wells, land, tangible wellhead equipment, production facilities, and other support equipment in Alabama from Everlast for $141.3 million in cash plus the assumption of $19.8 million of net liabilities. Of the cash amount, $2.4 million was payable to Everlast as of December 31, 2005. The outstanding balance was remitted to Everlast on January 31, 2006.

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The following table represents the fair value of the assets acquired and liabilities assumed at the date of the acquisition:

	(In 000 s)
Accounts receivable	$ 4,536
Natural gas properties and equipment	135,741
Support equipment and facilities	24,935
Material and supplies	372
Accounts payable	(1,114)
Accrued liabilities	(802)
Royalty payable	(1,374)
Asset retirement obligation	(2,387)
Mark-to-market derivative liabilities	(18,003)
Environmental liabilities	(490)
Debt	(78)
Net cash consideration	$ 141,336

As part of the acquisition, the hedges were novated to CCG, on behalf of CEP, at a cost of $0.019 per hedged MMBtu or $0.2 million. The fair market value of the derivative liabilities at the time of the novation was $18.0 million and was capitalized as part of CEP s purchase price. The derivatives were then assigned to CCG in exchange for equity in CEP.

The following unaudited pro forma information presents the financial information of CEP as if the acquisition of the Properties had occurred on February 7, 2005 (inception).

	As Reported	Pro Forma
	(In 000 s)	
Gas sales	$ 25,957	$ 36,497
Net income	$ 11,941	$ 7,325

4. DERIVATIVE AND FINANCIAL INSTRUMENTS

Hedging Activities

CEP has hedged a portion of its expected natural gas sales from currently producing wells through December 2009. The value of its cash flow hedges included in Accumulated other comprehensive income was a net unrecognized gain on derivative activities of $13.3 million at December 31, 2006. CEP expects that $8.7 million will be reclassified from Accumulated other comprehensive income to the income statement in the next twelve months. There was approximately $0.3 million of income as a result of hedge ineffectiveness for the year ended December 31, 2006.

At December 31, 2006, CEP had debt outstanding of $22.0 million. CEP entered into hedging arrangements in the form of an interest rate swap to reduce its impact of volatility of changes in the Libor interbank offered rate (LIBOR) on $16.5 million of the outstanding debt through October 2010. The interest rate swap has a termination date that corresponds to the maturity date of the debt. This swap was designated as a cash flow hedge of the risk associated with changes in the designated benchmark interest rate (in this case, LIBOR) related to forecasted

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payments associated with interest on the reserve-based credit facility. CEP has accounted for the interest rate swap under the long-haul method under SFAS No. 133. There was no ineffectiveness identified. The value of CEP s cash flow hedges included in Accumulated other comprehensive income was a net unrecognized gain of approximately $130,000 at December 31, 2006.

Mark-to-Market Activities

Everlast entered into various derivative instruments to economically hedge the market price fluctuations of natural gas.

In 2004, in connection with the Restated Credit Agreement (see Note 6), Everlast terminated derivative instruments that were below specified gas prices for a total cost of $8.0 million. Everlast was required to hedge at least 80% of its estimated gas production through 2007 and 50% of its estimated gas production in years 2008 and 2009 at or above specific gas prices. The terminated hedges were replaced by floating to fixed gas swaps.

Fair Value of Financial Instruments

The fair value of a financial instrument represents the amount at which the instrument could be exchanged in a current transaction between willing parties, other than in a forced sale or liquidation. Significant differences can occur between the fair value and carrying amount of financial instruments that are recorded at historical amounts. The amounts on the Consolidated Balance Sheets for CEP and Everlast approximate fair value for the following financial instruments because of their short term nature: cash and cash equivalents, accounts receivable, other current assets, current liabilities and deferred credits, natural gas derivative instruments, and other liabilities. CEP believes the carrying value of long-term debt approximates its fair value because the fixed interest rates on the debt approximated market interest rates for debt with similar terms.

5. EVERLAST PREFERRED UNIT ISSUANCE

On January 6, 2003, Everlast closed a transaction pursuant to which it issued and sold to Greenhill Capital Resources, L.P., Greenhill Capital Resources (Cayman), L.P., Greenhill Resources (Executives), L.P., and Greenhill Capital, L.P. (collectively, Greenhill); Eos Resources, L.P., Eos Resources SBIC II L.P., Eos Resources SBIC III, L.P. (collectively, Eos); and Tgoff Energy LLC (Tgoff) (Tgoff together with Greenhill and Eos, the Investors) 1.5 million of Everlast s Series A Preferred Units and 50,000 of Everlast s Series B Preferred Units (Preferred Units) for cash of $15.5 million. As additional consideration, Everlast issued an aggregate of 1,125,000 shares of its common units to the Investors, which represented 100% of the outstanding common units at such time.

A preferred return on the Preferred Units was equal to 8% per annum compounded quarterly. In April 2004, Everlast redeemed the outstanding Preferred Series A and Preferred Series B units for $17.2 million. Everlast treated the redemption as retirement of the units and recognized no gain or loss upon redemption.

At December 31, 2004, Everlast had $0, of preferred units outstanding that were subject to mandatory redemption. Effective July 1, 2003, Everlast adopted SFAS No. 150, *Accounting for Certain Financial Investments with Characteristics of Both Liabilities and Equity*. As a result, the preferred units were classified as units subject to mandatory redemption in the liability section of Everlast s balance sheets. In addition, Everlast began accounting for the preferred units return as interest expense which totaled $0.4 million for the year ended December 31, 2004.

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6. DEBT

Reserve-Based Credit Facility

On October 31, 2006, CEP entered into a $200.0 million secured revolving credit facility with a syndicate of commercial and investment banks, including The Royal Bank of Scotland plc, as administrative agent. The credit facility will mature on October 31, 2010. The amount available for borrowing at any one time is limited to the borrowing base, which is initially set at $75.0 million. The borrowing base will be re-determined semi-annually, and may be re-determined at our request more frequently, by the lenders in their sole discretion based on reserve reports prepared by reserve engineers, together with, among other things, the natural gas and oil prices at such time. Any increase in the borrowing base will have to be approved by all of the lenders in the syndicate and any decrease in the borrowing base will have to be approved by lenders holding 66 2/3% of the commitments.

CEP s obligations under the credit facility are secured by mortgages on our natural gas properties, as well as a pledge of all ownership interests in our subsidiaries. CEP is required to maintain the mortgages on properties representing at least 65% on its proved producing and proved non-producing reserves. Additionally, the obligations under the credit facility are guaranteed by all of CEP s operating subsidiaries and any future material subsidiaries.

At CEP s election, interest will be determined by reference to:

- LIBOR plus an applicable margin between 1.25% and 2.00% per annum based on utilization; or

- a domestic bank rate plus an applicable margin between 0.25% and 1.00% per annum based on utilization.

Interest will generally be payable quarterly for domestic bank rate loans and at the applicable maturity date for LIBOR loans.

The credit facility contains covenants that, among other things, require CEP to maintain, as of the last day of each fiscal quarter, a ratio of Adjusted EBITDA (as defined in the credit agreement) to cash interest expense, each measured for the preceding quarter, of not less than 4.5 to 1.0; a ratio of total indebtedness to Adjusted EBITDA of not more than 3.5 to 1.0; and a ratio of current assets to current liabilities of not less than 1.0 to 1.0. In addition, a default by CEP could result in an acceleration of any indebtedness in excess of $1.0 million and would constitute an event of default under the credit agreement that would prohibit CEP from making distributions. Debt issue costs were approximately $1.1 million and will be amortized over the life of the facility.

As of December 31, 2006, CEP had $22.0 million in outstanding debt under the reserve-based credit facility.

Other

On December 31, 2005, CEP had $63,000 in outstanding debt. This debt was an installment note securitized by a piece of equipment and was assumed as part of the acquisition of the Properties. It had an annual interest rate of 6.12% and matured on March 31, 2008. On September 10, 2006, CEP paid off the note payable for $50,497. In April 2003, Everlast entered into this five year note for the purchase of equipment. Upon acquisition of the Properties by CEP, the Equipment Note was assumed by CEP.

On April 26, 2004, Everlast entered into the First Amendment to the Credit Agreement (the Amendment). This Amendment provided for an increase in Everlast s borrowing base to $46.5 million and provided for a

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limited consent and waiver from the lenders allowing Everlast to repurchase, on a one-time basis, all of its outstanding Preferred Series A and Preferred Series B units. Everlast immediately borrowed $17.0 million under the amended credit facility of which $16.7 million was used to redeem the outstanding Preferred Series A and Preferred Series B units.

Effective October 15, 2004, Everlast entered into an amended and restated credit agreement (Everlast s Restated Credit Agreement) with Wells Fargo and other lenders, with Wells Fargo serving as administrative agent. Proceeds from Everlast s Restated Credit Agreement were used to fully refinance Everlast s previous bank indebtedness. As required by Everlast s Restated Credit Agreement, Everlast economically hedged approximately 80% of estimated gas production generated from the Torch Acquisition through 2007 and 50% of the estimated gas production in 2008 and 2009. In accordance with Everlast s Restated Credit Agreement, the Banks were paid various underwriting, administrative and advisory fees totaling $1.0 million.

The total commitment amount under Everlast s Restated Credit Agreement was $100.0 million with a borrowing base at December 31, 2004 of $50.0 million (Borrowing Base) and a maturity date of October 15, 2007. Borrowings under Everlast s Restated Credit Agreement as of December 31, 2004 were $47.5 million. Everlast s Restated Credit Agreement bore interest at the Base Rate (which was the higher of the lender s Prime Rate or the Federal Funds Rate plus 0.50%) plus an applicable margin or at LIBOR (reserve adjusted) plus an applicable margin, at Everlast s choice.

The applicable margin for borrowings under Everlast s Restated Credit Agreement was computed based on Borrowing Base utilization and ranged from 0.75% to 1.75% for Base Rate loans and 1.75% to 2.75% for LIBOR loans.

Everlast was subject to various commitment and other fees associated with Everlast s Restated Credit Agreement above. At June 12, 2005 and December 31, 2004, there was $0.5 million and $0.6 million of accrued interest and fees payable, respectively.

In connection with Everlast s Restated Credit Agreement, on October 15, 2004 Everlast entered into a $20.0 million subordinated term credit agreement (Everlast s Term Credit Agreement) from Wells Fargo Energy Capital (WFEC). Everlast s Term Credit Agreement matures on October 15, 2008. Everlast s Term Credit Agreement bore interest at the Base Rate plus 6.25%. Proceeds under Everlast s Term Credit Agreement were distributed to the members. In accordance with Everlast s Term Credit Agreement, the Banks were paid various underwriting, administrative and advisory fees totaling $0.4 million.

On June 13, 2005, as part of the acquisition of the Properties, Everlast instructed CEP to wire $45.1 million of the purchase price for the Properties to Wells Fargo to pay off the Restated Credit Agreement, and to wire $20.5 million of the purchase price for the Properties to WFEC to pay off the Term Credit Agreement. Everlast had no outstanding debt after these events.

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7. NATURAL GAS PROPERTIES

Natural gas properties consist of the following:

	December 31, 2006	December 31, 2005
	(In 000 s)	
Natural gas properties and related equipment (successful efforts method)		
Property (acreage) costs		
Proved property	$ 181,747	$ 168,327
Unproved property	88	188
Total property costs	181,835	168,515
Materials and supplies	1,264	712
Land	160	160
Total	183,259	169,387
Less: Accumulated depreciation, depletion and amortization	(11,620)	(4,176)
Natural gas properties and equipment, net	$ 171,639	$ 165,211

8. BENEFIT PLANS

Eligible employees of CEP participate in pension, postretirement, other post employment and savings plans sponsored and administered by Constellation Energy Group. Contributions by Constellation Energy Group were approximately $24,000 and $1,000 for the year ended December 31, 2006 and the period from February 7, 2005 (inception) to December 31, 2005, respectively. In 2007, CEP will use ADP and other outsource benefit providers for payroll and other benefit services for the employees located at the field office in Alabama.

Everlast employees who had been employed at least twelve months were eligible to participate in the Everlast Energy LLC qualified defined contribution plan. Contributions under the plan were determined annually by the Board of Directors of Everlast and were $37,000 for the period January 1, 2005 through June 12, 2005 and $27,000 for the year ended December 31, 2004, respectively.

9. RELATED PARTY TRANSACTIONS

Prior to the initial public offering, CEP was owned and managed by CCG. CCG has performed various management tasks on behalf of CEP, including the operation and accounting functions. The costs to perform these management tasks were calculated by taking the percentage of time CCG employees were engaged with CEP business multiplied by their annual salary. CCG also processed the payroll and 401(k) transactions on behalf of CEP. These costs charged to CEP were calculated by taking the field employees total salary multiplied by a corporate overhead allocation percentage. Finally, CCG hired outside consultants to augment its current workforce specifically for the management of CEP. The full cost of these consultants was allocated to CEP. These costs totaled approximately $1.1 million and $0.4 million for the year ended December 31, 2006 and the period February 7, 2005 (inception) to December 31, 2005, respectively. CEP had a related party payable to CCG of $2.8 million and $0.4 million as of December 31, 2006 and 2005, respectively. This related party payable balance is included in current liabilities in the accompanying balance sheets.

In November 2006, CEP entered into a management services agreement with CEPM to provide or contract for other necessary services including operations, land, engineering, regulatory, accounting, finance and other

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disciplines as needed. CEP will reimburse CEPM on a quarterly basis for expenses it incurs on our behalf, including employee compensation expenses. A total of $0.1 million in costs were invoiced during 2006 under this agreement.

During the year ended December 31, 2006, CCG paid $0.6 million of additional expenses on CEP s behalf in exchange for additional equity in CEP. These expenses included legal fees, fees for consultants hired by CEP and various other expenses.

In February 2006, CEP entered into a cash pool arrangement with CCG. This cash pool arrangement was administered and managed by CEP. CCG could borrow from the pool at market interest rates. If CEP required cash, and CCG had an outstanding balance, CCG was required to immediately remit payment to CEP for the required cash amount. Upon the completion of its initial public offering, CEP ceased its participation in the cash pool arrangement and CCG retained the $12.4 million receivable balance. This was treated as a reduction of members equity for accounting purposes.

Prior to the initial public offering, due to the affiliate relationship described above, the financial position, results of operations and cash flows of CEP may differ from those that would have been achieved had CEP operated autonomously or as an entity independent of the ultimate parent and its subsidiaries.

On October 30, 2006, CEP received $475,000 from an affiliate of Constellation Energy Group for the sale of the Floyd Shale Rights. These rights are an undivided mineral interest in our properties in the Robinson s Bend Field for depths generally below 100 feet below the base of the lowest producing coal seam.

Everlast had a loan to one of its officers outstanding at June 12, 2005 for a total of $17,000 that was subsequently paid off after the CEP acquisition of the Properties.

10. COMMITMENTS AND CONTINGENCIES

In the course of its normal business affairs, CEP is subject to possible loss contingencies arising from federal, state and local environmental, health, and safety laws and regulations and third-party litigation. As of December 31, 2006 and 2005, other than the matter discussed below, there are no matters which, in the opinion of management, will have a material adverse effect on the financial position, results of operations or cash flows of CEP.

The Robinson s Bend Field is subject to a NPI held by Torch Energy Royalty Trust (the Trust) (See Note 12). The royalty payment to the Trust is calculated using a sharing arrangement with a pricing formula that has been below market and has had the effect of keeping our payments to the Trust lower than if such payments had been calculated based on prevailing market prices. If the sharing agreement were to terminate, CEP s payments to the Trust will increase and CEP s revenue will decrease. CEP is uncertain of the financial impact of the NPI over the life of the Robinson s Bend Field as it has volumetric and price risk variables. However, in order to address a portion of the risk of the potential adverse impact on CEP s operating results from a termination of the sharing arrangement, Constellation Holdings, Inc. (CHI) contributed $8.0 million to CEP in exchange for all of CEP s Class D interests at the closing of its initial public offering to be used to protect the distributions to the common unit holders in the event the sharing arrangement is terminated. This contribution will be returned to CHI in 24 special quarterly distributions as long as the sharing agreement remains in effect for the distribution period.

For our 2007 drilling program, CEP has committed to purchase approximately $1.0 million in pipe from a vendor.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

11. ASSET RETIREMENT OBLIGATION

CEP and Everlast follow SFAS No. 143, *Accounting for Asset Retirement Obligations.* SFAS No. 143 requires that the fair value of a liability for an asset retirement obligation (ARO) be recognized in the period in which it is incurred if a reasonable estimate of fair value can be made. The associated asset retirement cost (ARC) is capitalized as part of the carrying amount of the long-lived asset. Subsequently, the ARC is allocated to expense using a systematic and rational method over the asset s useful life. The ARO s recorded by CEP and Everlast relate to the plugging and abandonment of natural gas wells, and decommissioning of the gas gathering and processing facilities.

Inherent in the fair value calculation of ARO are numerous assumptions and judgments including the ultimate settlement amounts, inflation factors, credit adjusted discount rates, timing of settlement and changes in the legal, regulatory, environmental and political environments. To the extent future revisions to these assumptions impact the fair value of the existing ARO, a corresponding adjustment is made to the gas property balance.

The following table is a reconciliation of the ARO:

	December 31, 2006	December 31, 2005
	(In 000 s)	
Asset retirement obligation, beginning balance	$ 2,524	$
Liabilities incurred from acquisition of the properties		2,387
Liabilities incurred	65	59
Accretion expense	141	78
Asset retirement obligation, ending balance	$ 2,730	$ 2,524

At December 31, 2006 and 2005, there were no assets legally restricted for purposes of settling existing ARO s. Additional retirement obligations increase the liability associated with new natural gas wells and other facilities as these obligations are incurred.

12. NET PROFITS INTEREST

Certain of the Properties are subject to a non-operating NPI. The holder of the NPI, the Trust, does not have the right to receive production from the Properties. Instead, the Trust only has the right to receive a specified portion of the future contractual cash flows from specified wells as defined by the Net Overriding Royalty Conveyance Agreement. CEP records the NPI as an overriding royalty interest net in revenue in the Consolidated Statements of Operations. As discussed in Note 2, the Everlast financial statements have been corrected to reflect this method of accounting.

Amounts due to the Trust with respect to NPI are comprised of the sum of the Net Proceeds and the Infill Net Proceeds, which are described below.

The Net Proceeds equal the lesser of (i) 95% of the net proceeds from 393 producing wells at the Properties and (ii) the net proceeds from the sale of 912.5 MMcf of natural gas for the quarter. Net proceeds equal gross proceeds, currently calculated by reference to the gas purchase contract (for a description of the gas purchase contract, please read Item 1. Business Natural Gas Data Torch Royalty NPI The Gas Purchase

Contract),

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less specified costs attributable to the Properties. The specified costs deducted for purposes of calculating net proceeds for purposes of clause (i) of the first sentence of this paragraph (the NPI Net Proceeds Calculation) include: (a) delay rentals, shut-in royalties and similar payments, (b) property, production, severance and similar taxes and related audit charges, (c) specified refunds, interest or penalties paid to purchasers of hydrocarbons or governmental agencies, (d) certain liabilities for environmental damage, personal injury and property damage, (e) certain litigation costs, (f) costs of environmental compliance, (g) specified operating costs incurred to produce hydrocarbons, (h) specified development costs (including costs to increase recoverable reserves or the timing of recovery of such reserves), (i) costs of specified lease renewals and extensions and unitization costs, and (j) the unrecovered portion, if any, of the foregoing costs for preceding time periods plus interest on such unrecovered portion at a rate equal to the base rate (compounded quarterly) as announced from time to time by Citibank, N.A. The specified costs deducted for purposes of calculating net proceeds for purposes of clause (ii) of the first sentence of this paragraph include: (a) property, production, severance and similar taxes, (b) specified refunds, interest or penalties paid to purchasers of hydrocarbons or governmental agencies, and (c) the unrecovered portion, if any, of the foregoing costs for preceding time periods plus interest on such unrecovered portion at a rate equal to the base rate (compounded quarterly) as announced from time to time by Citibank, N.A. Net proceeds are calculated quarterly and any negative balance (expenses in excess of revenues) within the net proceeds calculation accumulates and is charged interest as described above.

The following represent the Net NPI Proceeds Calculation for the periods from January 1, 2004 to December 31, 2006:

	Successor CEP		Predecessor Everlast	
	For the year ended December 31, 2006	For the period February 7, 2005 (inception) to December 31, 2005	For the period January 1, 2005 to June 12, 2005	For the year ended December 31, 2004
	(In 000 s)		(In 000 s)	
Gross Proceeds	$ 7,564	$ 6,098	$ 3,034	$ 7,241
NPI Costs				
Water Handling	2,142	1,300	1,020	2,450
Gathering fees	1,105	828	455	1,102
COPAS	1,680	952	666	1,567
Severance Tax	583	532	231	547
LOE Charge	2,117	977	605	1,634
Capital Expenditures	129	60	168	709
Interest on Previous Negative Balances	12	59	20	32
Total NPI Costs	7,768	4,708	3,165	8,041
Net NPI Proceeds (Deficit)	$ (204)	$ 1,390	$ (131)	$ (800)

The cumulative Net NPI Proceeds balance must be greater than $0 before any payments are made to the Trust. The cumulative Net Proceeds Deficits were $0.3 million, $0.1 million, $1.4 million and $1.3 million for the year ended December 31, 2006, periods ended December 31, 2005 and June 12, 2005 and the year ended December 31, 2004. As a result, no payments were made to the Trust with respect to the NPI for any periods presented. With respect to production for the year ended December 31, 2006, CEP paid the Trust a total of $0.2 million.

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The calculation of the Infill Net Proceeds uses the same methodology as the NPI Net Proceeds Calculation described above except that the proceeds and costs are attributable, not to the NPI Net Proceeds Wells, but to the remaining wells that are subject to the NPI and that have been drilled since the Trust was formed and wells that will be drilled (other than wells drilled to replace damaged or destroyed wells), in each case on leases subject to the NPI. The NPI in the Infill Wells entitles the Trust to receive 20% of the Infill Net Proceeds. There has never been a payout on the Infill Net Proceeds.

13. ENVIRONMENTAL LIABILITY

CEP is subject to costs resulting from an increasing number of federal, state and local laws and regulations designed to protect human health and the environment. These laws and regulations can result in increased capital, operating and other costs as a result of compliance, remediation, containment and monitoring obligations. As of December 31, 2006 accrued environmental obligations were $0.7 million, which were classified as current on CEP s balance sheet. At December 31, 2005 accrued environmental obligations were $0.7 million, of which $0.2 million was current and $0.5 million was noncurrent.

14. OTHER CONTINGENCIES

On June 7, 2006, CCG and a subsidiary of CEP entered into an agreement with The Investment Company LLC (TIC) pursuant to which CCG agreed to pay TIC $3.1 million for consulting services associated with the acquisition of the Properties upon CEP s completion of its initial public offering on or before January 31, 2007. The fair value of this option also approximated $3.1 million. Accordingly, $3.1 million, was recorded in accrued liabilities as of December 31, 2005 as resolution of this matter related to a claim for prior service that was finalized prior to the issuance of the consolidated financial statements for those periods. The corresponding charge is reflected as General and administrative expense in the CEP Statement of Operations for the period ending December 31, 2005. At the completion of CEP s initial public offering in November 2006, the $3.1 million was paid to TIC.

15. INITIAL PUBLIC OFFERING

In the fourth quarter of 2006, CEP completed its initial public offering of an aggregate of 5,175,000 units representing Class B limited liability company interests (consisting of 4,500,000 units purchased by the underwriters on November 20, 2006 and 675,000 units purchased by the underwriters on November 28, 2006 pursuant to their option to purchase additional units) at an initial public offering price of $21.00 per unit in a firm commitment underwritten initial public offering pursuant to Registration Statement on Form S-1 (File No. 333-134995) declared effective by the Securities and Exchange Commission on November 14, 2006. Citigroup and Lehman Brothers Inc. acted as joint lead-managing underwriters of the offering.

The aggregate initial public offering price for the units registered and sold in our initial public offering was approximately $108.7 million. Net proceeds (after underwriting discounts and offering expenses of approximately $10.7 million) were approximately $98.0 million. Using the net proceeds and cash on hand, a distribution of $122.8 million was made to Constellation Energy Partners Holdings, LLC (CEPH) as a reimbursement for capital expenditures incurred by CCG prior to this offering. Affiliates of CCG own approximately 54% of the outstanding limited liability company interests in of CEP.

16. SUPPLEMENTAL INFORMATION ON GAS PRODUCING ACTIVITIES (UNAUDITED)

The Supplementary Information on Gas Producing Activities is presented as required by SFAS No. 69, *Disclosures about Oil and Gas Producing Activities.* The supplemental information includes capitalized costs

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related to gas producing activities; costs incurred for the acquisition of gas producing activities, exploration and development activities and the results of operations from gas producing activities.

Supplemental information is also provided for per unit production costs; gas production and average sales prices; the estimated quantities of proved gas reserves; the standardized measure of discounted future net cash flows associated with proved gas reserves and a summary of the changes in the standardized measure of discounted future net cash flows associated with proved gas reserves.

Costs

The following table sets forth capitalized costs at December 31, 2006 and December 31, 2005:

	December 31, 2006	December 31, 2005
	(In 000 s)	
Capitalized costs at the end of the period:[(a)]		
Natural gas properties and related equipment (successful efforts method)		
Property (acreage) costs		
Proved property	$ 181,747	$ 168,327
Unproved property	88	188
Total property costs	181,835	168,515
Materials and supplies	1,264	712
Land	160	160
Total	183,259	169,387
Less: Accumulated depreciation, depletion and amortization	(11,620)	(4,176)
Net capitalized cost	$ 171,639	$ 165,211

(a) Capitalized costs include the cost of equipment and facilities for our natural gas producing activities. Proved property costs include capitalized costs for leaseholds holding proved reserves; development wells and related equipment and facilities (including uncompleted development well costs); and support equipment. Unproved property costs include capitalized costs for natural gas leaseholds where proved reserves do not exist.

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The following table sets forth costs incurred for gas producing activities for the year ended December 31, 2006, the period from February 7, 2005 (inception) to December 31, 2005, for the period from January 1, 2005 to June 12, 2005, and for the year ended December 31, 2004:

Gas (Mmcf)	Successor CEP		Predecessor Everlast	
	For the year ended December 31, 2006	For the period February 7, 2005 (inception) to December 31, 2005	For the period January 1, 2005 to June 12, 2005	For the year ended December 31, 2004
	(In 000 s)		(In 000 s)	
Costs incurred for the period:				
Acquisition of properties				
Proved	$	$ 158,707	$ 201	$ 1,310
Unproved	85	188		
Exploration costs				
Development costs	13,400	7,851	3,998	5,674
Total costs incurred	$ 13,485	$ 166,746	$ 4,199	$ 6,984

Results of Operations

The revenues and expenses associated directly with gas producing activities are reflected in the Consolidated Statements of Operations. Substantially all of CEP s and Everlast s operations are gas producing activities, and those gas activities are located in a single geographic location.

Net Proved Gas Reserves

The following table sets forth information with respect to changes in CEP s and Everlast s proved (i.e., proved developed and undeveloped) reserves. This information excludes reserves related to royalty and net profit interests.

Successor	Predecessor
CEP	Everlast

	For the year ended December 31, 2006	For the period February 7, 2005 (inception) to December 31, 2005	For the period January 1, 2005 to June 12, 2005	For the year ended December 31, 2004
	(In 000 s)		(In 000 s)	
Beginning Balance	112,025		162,215	163,745
Extensions and discoveries				824
Purchases of reserves in place		160,245		
Sales of reserves in place				
Revisions of previous estimates	12,952	(45,695)		2,173
Production	(4,641)	(2,525)	(1,970)	(4,527)
Ending Balance	120,336	112,025	160,245	162,215
Total developed reserves	97,387	89,272		101,352

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Reserves and Related Estimates

CEP s estimate of proved reserves is based on the quantities of natural gas that engineering and geological analyses demonstrate, with reasonable certainty, to be recoverable from established reservoirs in the future under current operating and economic parameters.

CEP s 2006 and 2005 proved reserve estimates were 120.3 Bcf and 112.0 Bcf. For both years, NSAI, an independent petroleum engineering firm, prepared an estimate of CEP s proved reserves. NSAI also prepared an updated report at our request to provide a sensitivity of the estimates of the NSAI year-end 2005 reserves based on our reduced drilling program, our revised refracture program and the elimination of estimated reserves attributable to the NPI. NSAI s estimates of our 2006 and 2005 proved reserves were materially consistent with our internal estimate report.

CEP s 2006 estimates of proved reserves increased primarily due to our successful development drilling program and a lower year-end natural gas price which results in zero reserves being attributed to the Torch NPI. CEP s 2005 estimates of proved reserves were lower than our predecessor s estimates of proved reserves primarily because of the following factors:

A Reduction of 24.5 Bcf Based on Interpretation of Well Performance: The information on which CEP based this adjustment included its interpretation of well performance data that was available at December 31, 2005 for new wells drilled and completed in the Robinson s Bend Field in 2004 and 2005. There was no drilling in the field between 1994 and late 2003. While the performance data at year-end 2005 was from a limited number of new wells drilled in the field in 2004 and 2005, CEP believes it provided relevant information for the purposes of estimating reserves and CEP interpreted the data and reflected the results of that analysis in its reserve estimates and assumptions. The majority of the 24.5 Bcf reduction in the reserve estimate at December 31, 2005 associated with CEP s interpretation of the recent well performance data was in the proved developed non-producing (PDNP) category and the proved undeveloped (PUD) categories of reserves.

A Reduction of 15.4 Bcf Based on CEP s Planned Drilling Program: The 112.0 Bcf estimate also reflected CEP s planned drilling program of 20 gross wells per year for the next six years. CEP used a six year time horizon for drilling program and reserves estimation purposes because it was consistent with what CEP used for internal capital expenditure planning purposes and because CEP believed that using a longer time horizon would create additional uncertainty with regard to capital budgeting, therefore potentially reducing its ability to prepare a reliable estimate of reserves. Everlast s drilling program, which was designed to provide maximum returns in a relatively short time period, was to drill and complete 197 gross wells within a five-year period. CEP s planned drilling program is designed to provide a steady and constant return by drilling an average of 20 wells per year over a six year period. Due to this difference in drilling programs, certain proved undeveloped reserves that were based on the predecessor s accelerated drilling program and using NSAI s reserve assumptions cannot be included in CEP s proved reserve estimates because under CEP s current drilling program those reserves are scheduled to be drilled more than six years after the date of the reserve report and as such are outside the time horizon CEP uses to prepare its internal estimates of proved reserves.

A Reduction of 5.8 Bcf for Reserves Attributed to the NPI: CEP s December 31, 2005 reserve estimates removed 5.8 Bcf of reserves that are attributed to the NPI using an overriding royalty interest approach. The estimated reserves attributed to the NPI at December 31, 2004 were zero due to the lower gas prices compared to December 31, 2005 prices.

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The 2004 proved reserve estimate for the predecessor company was 162.2 Bcf. This was the estimate of proved reserves used in the 2004 predecessor company financial statements. CEP prepared the estimate of 2004 proved reserves for financial statement purposes by starting with NSAI s December 31, 2005 net proved reserve estimate, which was prepared based upon the predecessor s accelerated drilling program and reserve assumptions, and rolling back the estimate to year-end 2004 by making appropriate adjustments for actual production, prices and development activity. The roll-back approach was necessary because the reserve report prepared by NSAI for Everlast as of year-end 2004 was not based on the SEC definition of proved reserves, included different assumptions than those used by NSAI in preparing 2005 proved reserves estimate.

Due to this inconsistency in the preparation of reserve reports for the periods presented, CEP adopted the roll-back approach of reserves at December 31, 2005 to year-end 2004 in preparing the financial statements for year-end 2004. In preparing the roll-back to year-end 2004, CEP did not adjust the estimated proved reserve volumes to reflect its reserve assumptions based upon its interpretation of recent well performance in the Robinson s Bend Field because these assumptions were based on recent information that was not available to Everlast when it was preparing the 2004 financials statements. In addition, CEP did not adjust the volumes to reflect its current drilling program of 20 gross wells per year for the next six years because this drilling program was not the drilling program adopted by Everlast in 2004. The previous reserve estimate was 173.4 Bcf at December 31, 2004.

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Gas Reserves, Including a Reconciliation of Changes Therein

The following table sets forth the standardized measure of the discounted future net cash flows attributable to CEP s and Everlast s proved gas reserves. Certain information concerning the assumptions used in computing the valuation of proved reserves and their inherent limitations are discussed below.

Future cash inflows are calculated by applying year-end prices of gas, relating to the proved reserves, to the year-end quantities of those reserves. Future cash inflows exclude the impact of CEP s hedging program and Everlast s mark-to-market derivatives. Future development and production costs represent the estimated future expenditures (based on year-end costs) to be incurred in developing and producing the proved reserves, assuming continuation of existing economic conditions. In addition, asset retirement obligations are included within future production and development costs. There are no future income tax expenses because CEP and Everlast are both non-taxable entities.

The assumptions used to compute estimated future cash inflows do not necessarily reflect expectations of actual revenues or costs or their present value. In addition, variations from expected production rates could result directly or indirectly from factors outside of CEP s control, such as unexpected delays in development, changes in prices or regulatory or environmental policies. The reserve valuation further assumes that all reserves will be disposed of by production; however, if reserves are sold in place, additional economic considerations could also affect the amount of cash eventually realized.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The following table summarizes the standardized measure of estimated discounted future cash flows from the natural gas properties:

	Successor CEP		Predecessor Everlast
	For the year ended December 31, 2006	For the period February 7, 2005 (inception) to December 31, 2005	For the year ended December 31, 2004
	(In 000 s)		(In 000 s)
Future cash inflows	$ 677,866	$ 1,125,857	$ 984,758
Future production costs	(257,502)	(234,512)	(235,003)
Future estimated development costs	(64,673)	(60,283)	(93,041)
Future net cash flows	355,691	831,062	656,714
10% annual discount for estimated timing of cash flows	(235,504)	(535,627)	(449,946)
Standardized measure of discounted estimated future net cash flows related to proved gas reserves	$ 120,187	$ 295,435	$ 206,768

The following table summarizes the principal sources of change in the standardized measure of estimated discounted future net cash flows:

	Successor CEP		Predecessor Everlast
	For the year Ended December 31, 2006	For the period February 7, 2005 (inception) to December 31, 2005	For the year ended December 31, 2004
	(In 000 s)		(In 000 s)
Beginning of the period	$ 295,435	$	$ 194,189
Sales and transfers of natural gas, net of production costs	(40,064)		(21,582)
Net changes in prices and production costs related to future production	(193,499)		7,790
Development costs incurred during the period	12,292		3,970
Changes in extensions and discoveries			500
Revisions of previous quantity estimates	18,435	(54,899)	3,742
Purchase of reserves in place		350,047	

Accretion discount	29,624		19,469
Other	(2,036)	287	(1,310)
Standardized measure of discounted future net cash flows related to proved gas reserves	$ 120,187	$ 295,435	$ 206,768

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17. SUPPLEMENTAL QUARTERLY FINANCIAL DATA (Unaudited)

	2006 Quarters Ended			
	March 31,	June 30,	September 30, (In 000 s)	December 31,
Total revenue	$ 9,747	$ 7,858	$ 8,549	$ 10,763
Operating expenses	4,269	4,017	4,468	3,848
General and administrative expenses	1,095	1,636	714	1,128
Net income	$ 4,432	$ 2,353	$ 3,531	$ 5,673
Net income per unit[a]				
	2005 Quarters Ended			
	March 31,[b]	**June 30,**	**September 30, (In 000 s)**	**December 31,**
Total revenue	$	$ 1,377	$ 9,548	$ 15,032
Operating expenses		786	3,769	5,274
General and administrative expenses		3,275	56	853
Net (loss) income	$	$ (2,684)	$ 5,721	$ 8,904
Net income per unit[a]				

(a) CEP completed its initial public offering during the fourth quarter of 2006. There were no outstanding units prior to this offering; therefore, net income (loss) per unit information is not meaningful to present.

(b) CEP acquired its initial properties in the Robinson s Bend Field from Everlast on June 13, 2005. From February 7, 2005 (the inception of CEP) to June 12, 2005, CEP did not conduct any operations and had no production, therefore, CEP had no revenues or operating expenses until June 2005.

18. SUBSEQUENT EVENTS

Distribution

On February 14, 2007, CEP paid a distribution for the fourth quarter of 2006 to the unitholders of record at February 7, 2007, prorated from the date of CEP s initial public offering on November 20, 2006. The distribution was paid to holders of common units and Class A units at a rate of $0.2111 per unit.

Indemnification

CCG has granted CEP an indemnification related to matters associated with a potential liability associated with the termination of a lease in Tuscaloosa County, Alabama. The lease was originally executed in November 2003. CEP did not drill any wells on the lease and it was not held by production. This unconditional indemnification was granted in March 2007 by CCG to cover any potential payments or expenses associated with the termination of the lease.

Credit Support Fee Agreement

In March 2007, CEP entered into a credit support fee agreement with CEG where CEG would guarantee credit support up to $25.0 million for certain financial hedges that CEP enters into with The Royal Bank of Scotland plc (RBS). The guarantee will be in full force until CEP s obligations to RBS under the hedge agreements are secured under its revolving credit facility, or March 31, 2008. In March 2007, CEP also entered into a credit support fee agreement with CEG where CEG would guarantee credit support up to $11.5 million for certain financial hedges that CEP enters into with BNP Paribas (BNP). The guarantee will be in full force until CEP s obligations to BNP under the hedge agreements are secured under its revolving credit facility, or September 30, 2008. CEP will pay CEG $0.2 million for the credit support. The hedge positions are contemplated in connection with an acquisition

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Acquisition

CEP announced in March 2007 that it has entered into a definitive purchase agreement to acquire certain coalbed methane properties in the Cherokee Basin of Oklahoma and Kansas for approximately $115 million. The properties consist of over 550 producing wells currently producing 7,900 Mcf/day. The acquisition provides over 800 low-risk, low-cost drilling and recompletion opportunities on approximately 96,000 gross acres. CEP executed unit purchase agreements for a private placement of $60 million of equity securities to third party investors, consisting of 2,207,684 common units at a unit price of $26.12 per unit and 90,376 newly-created Class E units at a price of $25.84. The Class E units will convert into common units upon obtaining common unit holder approval. CEP has undertaken to obtain this approval by August 1, 2007. CEPH, the owner of a majority of the outstanding common units, will agree to vote its common units in favor of the conversion. CEP also has agreed to file a registration statement with the SEC registering for resale the common units and common units issuable upon conversion of the Class E units within 75 days after the closing. CEP believes that the proceeds from this equity private placement, together with funds available under its existing credit facility, will fully fund the purchase price of the acquisition. CEP anticipates that the private placement will close simultaneously with the acquisition of the assets in mid-April 2007. CEP expects to enter into derivative transactions to hedge the future expected production associated with this acquisition.

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SCHEDULE II

CONSTELLATION ENERGY PARTNERS LLC

VALUATION AND QUALIFYING ACCOUNTS

Years Ended December 31, 2006, 2005 and 2004

(In 000 s)

Description	Balance at Beginning of Period	Charged to Costs and Expenses	Deductions	Charged to Other Accounts	Balance at End of Period
2006					
Environmental reserves	$ 721				$ 721
2005					
Environmental reserves	$ 0			721	$ 721
2004					
Environmental reserves	$ 0				$ 0

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SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, Constellation Energy Partners LLC, the Registrant, has duly caused this Report to be signed on its behalf by the undersigned, thereunto duly authorized.

CONSTELLATION ENERGY PARTNERS LLC

(REGISTRANT)

Date: February 28, 2007 By /s/ FELIX J. DAWSON

Felix J. Dawson

Chairman of the Board, Chief Executive

Officer and President

Pursuant to the requirements of the Securities Exchange Act of 1934, this Report has been signed below by the following persons on behalf of Constellation Energy Partners LLC, the Registrant, and in the capacities and on the dates indicated.

Signature	Title	Date
Principal executive officer and manager:		
By /s/ FELIX J. DAWSON **Felix J. Dawson**	Chairman of the Board, Chief Executive Officer and President	March 12, 2007
Principal financial and accounting officer:		
By /s/ ANGELA A. MINAS **Angela A. Minas**	Chief Financial Officer, Chief Accounting Officer and Treasurer	March 12, 2007
Managers:		
/s/ RICHARD H. BACHMANN **Richard H. Bachmann**	Manager	March 12, 2007
/s/ JOHN R. COLLINS **John R. Collins**	Manager	March 12, 2007
/s/ RICHARD S. LANGDON **Richard S. Langdon**	Manager	March 12, 2007
/s/ JOHN N. SEITZ **John N. Seitz**	Manager	March 12, 2007

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EXHIBIT INDEX

Exhibit Number	Description
*3.1	Certificate of Formation of Constellation Energy Partners LLC, as amended
3.2	Second Amended and Restated Operating Agreement of Constellation Energy Partners LLC (incorporated herein by reference to Exhibit 3.1 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on November 28, 2006)
10.1	Credit Agreement dated as of October 31, 2006 by and among Constellation Energy Partners LLC, as borrower, The Royal Bank of Scotland plc, as administrative agent, RBS Securities Corporation, as lead arranger and sole bookrunner, BNP Paribas and Wachovia Bank N.A., as co-syndication agents and the lenders from time to time party thereto (incorporated herein by reference to Exhibit 10.1 to Amendment No. 4 to the Registration Statement on Form S-1 (File No. 333-134995) filed by Constellation Energy Partners LLC on November 2, 2006 (Amendment No. 4))
10.2	Management Services Agreement dated as of November 20, 2006 by and between Constellation Energy Partners LLC and Constellation Energy Partners Management, LLC (incorporated herein by reference to Exhibit 10.2 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on November 28, 2006)
10.3	Omnibus Agreement dated as of November 20, 2006 by and among Constellation Energy Partners LLC, Constellation Energy Commodities Group, Inc., Robinson s Bend Production II, LLC, Robinson s Bend Operating II, LLC and Robinson s Bend Marketing II, LLC (incorporated herein by reference to Exhibit 10.1 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on November 28, 2006)
10.4	Net Overriding Royalty Conveyance dated as of November 22, 1993 but effective as of October 1, 1993, pursuant to Part I thereof, from Velasco Gas Company, Ltd. to Torch Energy Advisors Incorporated, and pursuant to Part II thereof, from Torch Energy Advisors Incorporated to the Torch Energy Royalty Trust (incorporated herein by reference to Exhibit 10.4 to Amendment No. 2 to the Registration Statement on Form S-1 (File No. 333-134995) filed by Constellation Energy Partners LLC on September 29, 2006 (Amendment No. 2))
10.5	Oil and Gas Purchase Agreement dated as of October 1, 1993 by and among Torch Energy Marketing, Inc., Torch Royalty Company and Velasco Gas Company Ltd. (incorporated herein by reference to Exhibit 10.5 to Amendment No. 2)
10.6	Letter agreement dated as of June 13, 2005 by and between Robinson s Bend Marketing II, LLC and Torch Energy TM, Inc. (incorporated herein by reference to Exhibit 10.6 to Amendment No. 2)
10.7	International Swap Dealers Association, Inc. Master Agreement and Schedule dated as of June 16, 2006 between The Royal Bank of Scotland, plc and Constellation Energy Resources LLC (incorporated herein by reference to Exhibit 10.7 to Amendment No. 2)
10.8	Confirmation, dated June 28, 2006, effective June 20, 2006, between The Royal Bank of Scotland, plc and Constellation Energy Resources LLC (incorporated herein by reference to Exhibit 10.8 to Amendment No. 2)
10.9	Asset Purchase and Sale Agreement dated as of May 12, 2005 by and among Everlast Energy LLC, RB Marketing Company LLC, Robinson s Bend Operating Company LLC and CBM Equity IV, LLC (incorporated herein by reference to Exhibit 10.9 to Amendment No. 2)
10.10	Letter agreement as of October 24, 2006 by and among The Investment Company LLC, Constellation Energy Commodities Group, Inc. and Robinson s Bend Production II, LLC (incorporated herein by reference to Exhibit 10.10 to Amendment No. 4)

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Exhibit Number	Description
10.11	Trademark License Agreement dated as of November 20, 2006 by and between Constellation Energy Group, Inc. and Constellation Energy Partners LLC (incorporated herein by reference to Exhibit 10.3 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on November 28, 2006)
10.12	Constellation Energy Partners LLC Long-Term Incentive Plan (incorporated herein by reference to Exhibit 10.1 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on November 20, 2006)
*12.1	Computation of Ratio of Earnings to Fixed Charges
21.1	List of subsidiaries of Constellation Energy Partners LLC (incorporated herein by reference to Exhibit 21.1 to the Registration Statement on Form S-1 (File No. 333-134995) filed by Constellation Energy Partners LLC on June 14, 2006)
*23.1	Consent of PricewaterhouseCoopers LLP
*23.2	Consent of Netherland, Sewell & Associates, Inc.
*31.1	Certification of Chairman of the Board, Chief Executive Officer and President of Constellation Energy Partners LLC pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
*31.2	Certification of Chief Financial Officer, Chief Accounting Officer and Treasurer of Constellation Energy Partners LLC pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
*32.1	Certification of Chairman of the Board, Chief Executive Officer and President of Constellation Energy Partners LLC pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
*32.2	Certification of Chief Financial Officer, Chief Accounting Officer and Treasurer of Constellation Energy Partners LLC pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

* Filed herewith