Constellation Energy Partners LLC
Form S-1/A
October 16, 2006
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As filed with the Securities and Exchange Commission on October 13, 2006

Registration No. 333-134995

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

AMENDMENT NO. 3 TO

FORM S-1

REGISTRATION STATEMENT

UNDER THE SECURITIES ACT OF 1933

Constellation Energy Partners LLC

(Exact name of registrant as specified in its charter)

Delaware	**1311**	**11-3742489**
(State or other jurisdiction of incorporation or organization)	**(Primary Standard Industrial Classification Code Number)**	**(I.R.S. Employer Identification Number)**

111 Market Place

Baltimore, Maryland 21202

(410) 468-3500

(Address, including zip code, and telephone number, including area code, of registrant s principal executive offices)

Felix J. Dawson

Chief Executive Officer

Constellation Energy Partners LLC

111 Market Place

Baltimore, Maryland 21202

(410) 468-3500

(Name, address, including zip code, and telephone number, including area code, of agent for service)

Copies to:

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(713) 220-4200	**New York, New York 10103**
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Approximate date of commencement of proposed sale to the public: As soon as practicable after this Registration Statement becomes effective.

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

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

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

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

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

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The information in this prospectus is not complete and may be changed. We may not sell these securities until the registration statement filed with the Securities and Exchange Commission is effective. This prospectus is not an offer to sell these securities and is not soliciting an offer to buy these securities in any state where the offer or sale is not permitted.

SUBJECT TO COMPLETION, DATED OCTOBER 13, 2006

P R O S P E C T U S

6,275,000 Common Units

Representing Class B Limited Liability Company Interests

We are offering 6,275,000 common units representing Class B limited liability company interests in us. This is our initial public offering, and no public market currently exists for our common units. We have granted the underwriters an option to purchase up to 941,250 additional common units to cover over-allotments. We currently estimate that the initial public offering price will be between $ and $ per common unit. We have applied to list our common units on NYSE Arca under the symbol CEP.

Investing in our common units involves risks. See Risk Factors beginning on page 23.

These risks include the following:

- We may not have sufficient cash from operations to pay our initial quarterly distribution following establishment of cash reserves and payment of fees and expenses, including payments to affiliates of Constellation Energy Group, Inc., or Constellation.

- If commodity prices decline significantly, our cash from operations will decline, and we may have to reduce our quarterly cash distributions or may not be able to pay cash distributions at all.

- 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 you.

We will rely on an affiliate of Constellation to identify and evaluate for us prospective oil and natural gas properties for acquisition. Constellation and its affiliates have no obligation to present us with such potential acquisitions, and, if they fail to do so, we may not be able to replace or increase our reserves, which would adversely affect our cash from operations and our ability to make cash distributions to you.

Our operations require substantial capital expenditures, which will reduce our cash available for distribution. We may be unable to obtain needed capital or financing on satisfactory terms, which could lead to a decline in our reserves and production.

Constellation and its affiliates will own a controlling interest in us through their ownership of all of our Class A limited liability company interests and 57% of our outstanding common units. Constellation and its affiliates have conflicts of interest with us and no fiduciary duties to us. The ultimate resolution of these conflicts of interest may result in favoring the interests of Constellation and its other affiliates over yours and may be to our detriment.

We benefit from a gas purchase contract that will be terminated if a third-party royalty trust is terminated. The termination of the royalty trust is an event that is beyond our control.

You will experience immediate and substantial dilution of $10.59 per common unit.

You may be required to pay taxes on your share of our income even if you do not receive any cash distributions from us.

	Per Common Unit	Total
Initial public offering price	$	$
Underwriting discount(1)	$	$
Proceeds to Constellation Energy Partners LLC (before expenses)	$	$

(1) Excludes a structuring fee of $ to be paid to Citigroup Global Markets Inc. and Lehman Brothers Inc.

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

The underwriters expect to deliver the common units to purchasers on or about , 2006.

Citigroup **Lehman Brothers**

UBS Investment Bank **Wachovia Securities**

Scotia Capital

, 2006

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We are a limited liability company focused on the acquisition, development and exploitation of oil and natural gas properties as well as related midstream assets. Our 112.0 Bcf of estimated proved reserves are 100% natural gas and are located in the Robinson s Bend Field in Alabama s Black Warrior Basin.

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

Until , 2006 (25 days after the date of this prospectus), all dealers that buy, sell or trade our common units, whether or not participating in this offering, may be required to deliver a prospectus. This is in addition to the dealers obligation to deliver a prospectus when acting as underwriters and with respect to their unsold allotments or subscriptions.

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SUMMARY

This summary highlights information contained elsewhere in this prospectus. You should read the entire prospectus carefully, including the historical and pro forma consolidated financial statements and the notes to those financial statements. The information presented in this prospectus assumes an initial public offering price of $ per common unit (the mid-point of the price range on the cover of this prospectus), and that the underwriters option to purchase additional common units is not exercised, in each case unless otherwise noted. You should read Risk Factors for information about important factors to consider before buying the common units. We include a glossary of some of the terms used in this prospectus in Appendix B. We have prepared the estimates of proved natural gas reserves described in this prospectus, including the reserve estimates contained in the financial statements included elsewhere in this prospectus. As described in more detail under the caption Summary Reserve and Operating Data, in preparing the estimates as of December 31, 2005 included in the financial statements for the year ended December 31, 2005 and the estimates included elsewhere in this prospectus, we made certain downward adjustments to the reserve estimates as of December 31, 2005 prepared by Netherland, Sewell & Associates, Inc., or NSAI. In preparing the reserve estimates as of December 31, 2004 and 2003 used to prepare the financial statements of our predecessor for 2004 and 2003, we made other adjustments to the reserve estimates as of December 31, 2005 prepared by NSAI to rollback those estimates for actual production, prices and development as described in more detail under the caption Business Natural Gas Data Proved Reserves. We have removed from our reserve and Standardized Measure estimates in this prospectus estimated amounts attributable to the Torch Royalty NPI by treating the NPI as an overriding royalty interest. The number of common units referred to in this prospectus are after giving pro forma effect to a split of the outstanding limited liability company interests in us into 295,690 Class A units, 8,214,010 common units and the management incentive interests to be effected prior to the closing of this offering.

References in this prospectus to Constellation Energy Partners, we, our, us, CEP or like terms refer to Constellation Energy Partners LLC and its subsidiaries. References in this prospectus to CEPM are to Constellation Energy Partners Management, LLC, a newly formed Delaware limited liability company. References in this prospectus to CCG are to Constellation Energy Commodities Group, Inc., a Delaware corporation. References in this prospectus to CEPH are to Constellation Energy Partners Holdings, LLC, a newly formed Delaware limited liability company. References to CHI are to Constellation Holdings, Inc., a Delaware corporation. References in this prospectus to Constellation are to Constellation Energy Group, Inc., a Maryland corporation. We refer to our Class A limited liability company interests as the Class A units, our Class B limited liability company interests as the common units, our Class C limited liability company interests as the management incentive interests and our Class D limited liability company interests as the Class D interests.

Constellation Energy Partners LLC

We are a limited liability company that was formed by Constellation in February 2005 to acquire coalbed methane reserves and production. We are focused on the acquisition, development and exploitation of oil and natural gas properties, or 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, which we acquired in June 2005. The Robinson s Bend Field is located in Alabama s Black Warrior Basin. Our estimated proved reserves at December 31, 2005 were approximately 112.0 Bcf, approximately 80% of which were classified as proved developed producing. Our estimated proved reserves at December 31, 2005 had estimated future net revenues discounted at 10%, which we refer to as the Standardized Measure, of approximately $295.4 million. Standardized Measure is an accounting term that should not be confused with fair market value. Our average proved reserve-to-production ratio is approximately 25 years based on our estimated proved reserves at December 31, 2005 and annualized production for the six months ended December 31, 2005. We currently own a 100% working interest (an approximate 75% average net revenue interest, calculated before the Torch Royalty NPI described below) in our Robinson s Bend Field producing properties, which had 436 producing natural gas wells as of December 31, 2005.

The Black Warrior Basin is one of the oldest and most prolific coalbed methane basins in the country, with over 2,750 producing coalbed methane wells. These multi-seam vertical wells range from 500 to 3,700 feet deep, with coal seams averaging a total of 25 to 30 feet of thickness, or net pay, per well. Coalbed methane wells are generally more shallow than other 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 5% to 6% per year. A typical well produces over a period of 20 to over 50 years. For a further description of the characteristics of coalbed methane production, please read Business Description of Our Properties and Projects Characteristics of Coalbed Methane.

On June 20, 2006, we executed part of a commodity price risk management program that is intended to reduce the volatility in our revenues due to commodity price changes, which in turn should provide greater stability to our future cash flows. Pursuant to this program, we have hedged the future prices of approximately 78% of our expected production from October 2006 through December 2009 from currently producing wells. Under our broader hedge program, we plan to adopt a policy that contemplates hedging the sales prices for approximately 80% of our expected production from currently producing wells for a period of up to five years, as appropriate, based primarily on our intent to stabilize cash flows and our view of prevailing and expected market conditions for natural gas. In determining our initial quarterly distribution, or IQD, we have taken into account the resulting impact of these hedges. Please read Cash Distribution Policy and Restrictions on Distributions.

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 producing reserves with long-lived, stable production and step-out development opportunities, which may include associated midstream assets such as gathering systems, compression, dehydrating and treating facilities and other similar facilities;
- identify and work with third-party operators who have experience in regions in which we seek to acquire an ownership interest and who will hold an ownership interest in our properties;
- increase reserves and production through what we believe to be low-risk development and exploitation drilling; and
- reduce the volatility in our revenues resulting from changes in oil and natural gas commodity prices through hedging.

Competitive Strengths

We believe we are positioned to successfully execute our business strategies because of the following competitive strengths from which we benefit:

- our relationship with Constellation;

operational and technical support from Constellation;

low-risk development drilling operations;

predictable, long-lived reserves;

control of operations; and

large undeveloped acreage base;

Our Relationship With Constellation

We believe that one of our principal strengths is our relationship with Constellation, an integrated energy company with 2005 revenues of approximately $17.1 billion and total assets of approximately $19.2 billion as of June 30, 2006. Constellation s common stock trades on The New York Stock Exchange under the symbol CEG. Constellation is engaged in numerous aspects of the energy industry, including, through CCG, oil and natural gas exploration and production, or E&P, natural gas transportation, natural gas storage and physical and financial natural gas trading.

A principal component of our business strategy is to grow our asset base and production through the acquisition of E&P properties characterized by long-lived, stable production. Constellation, through CCG, has a track record of successfully acquiring developed and undeveloped E&P properties. CCG is currently developing several other E&P projects in various locations with unconventional production, including coalbed methane, tight sands and shale. As CCG continues to develop the E&P properties that comprise these projects, and potentially other undeveloped E&P properties that it may acquire in the future, it is possible these projects will have characteristics of properties suitable for us and our business strategies. Constellation views us as an integral component of the growth strategy for its upstream oil and natural gas business and intends to use us as its primary vehicle to develop a portfolio of long-lived, proved producing E&P properties. However, Constellation has no obligation or commitment to do so, and may act in a manner that is beneficial to its interests and detrimental to ours.

We will enter into a management services agreement with CEPM, an indirect wholly owned subsidiary of Constellation. Pursuant to that agreement, CEPM will provide us with legal, accounting, finance, tax, property management, engineering and risk management services and may provide us with acquisition services in respect of opportunities for us to acquire long-lived, stable and proved oil and natural gas reserves. While neither Constellation nor CEPM has any obligation to provide us with acquisition services under the management services agreement, 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.

We will reimburse CEPM for the reasonable costs of the services it provides to us. Our board of managers has the right and the duty to review the services provided, and the costs charged, by CEPM under the management services agreement. Our board of managers may in the future cause us to hire additional personnel to supplement or replace some or all of the services provided by CEPM, as well as employ third-party service providers. If we were to take such actions, they could increase the overall costs of our operations. For a description of the services that CEPM will provide to us and our obligation to reimburse CEPM for the costs it incurs in providing those services, please read Certain Relationships and Related Party Transactions Agreements Governing the Transactions Management Services Agreement.

While our relationship with Constellation and its subsidiaries is a significant strength, it is also a source of potential conflicts. For example, none of Constellation or any of its affiliates is restricted from competing with us, and each of our executive officers and our Class A managers also serves as a manager, director, officer or employee of Constellation or its other affiliates. Constellation or its affiliates may acquire, invest in or dispose of E&P or other assets in the future without any obligation to offer us the opportunity to purchase or own interests in those assets. The ultimate resolution of the conflicts of interest that exist or arise as a result of either our relationship with Constellation and its other affiliates or the status of our executive officers or our Class A managers as managers, directors, officers or employees of Constellation or its other affiliates may result in the interests of Constellation or its affiliates being favored over your interests and may be to our detriment. Please read Conflicts of Interest and Fiduciary Duties.

In December 2005, Constellation entered into an Agreement and Plan of Merger with FPL Group, Inc., a Florida corporation whose common stock trades on The New York Stock Exchange under the symbol FPL. FPL Group, Inc. is also an integrated energy company with 2005 revenues of $11.8 billion and total assets of $33.8 billion as of June 30, 2006. The merger agreement contains numerous conditions that must be satisfied or waived before the merger is consummated, and there can be no assurance that it will be consummated.

Cash Distribution Policy

Our board of managers has adopted a cash distribution policy to pay a regular quarterly distribution of $0.425 per unit on our outstanding common and Class A units while reinvesting in our business a portion of our operating cash flow. We intend to pay our first cash distribution on or about February 14, 2007 for the period from the closing of this offering through December 31, 2006. We will adjust our first distribution based on the actual length of that period. Thereafter, we intend to pay a distribution on a quarterly basis. Declaration and payment of distributions is at the discretion of our board of managers, and we cannot assure you that we will not reduce or eliminate our distributions.

In general, it is our policy to distribute all of our available cash after paying our operating expenses and retaining an amount of funds that our board of managers estimates is adequate for the proper conduct of our business, including the maintenance of our asset base. If we continue this policy, we will be dependent on our ability to raise debt and equity from the capital markets to grow our asset base, and we cannot assure you of our ability to access such markets. If our board of managers underestimates the amounts necessary to maintain our asset base or we fail to invest those funds effectively, our board of managers will likely need to reduce the amount of our distributions. In an effort to reduce the uncertainty regarding our distributions, our board of managers intends to increase our distributions per unit only if it believes that (i) we have sufficient reserves and liquidity for the proper conduct of our business, including the maintenance of our asset base, and (ii) we can maintain such increased distribution level for a sustained period.

You may not receive distributions in the intended amounts described above, or at all. Please read Risk Factors Risks Related to Our Business. If we had completed the transactions contemplated in this prospectus on January 1, 2005, pro forma available cash generated during the year ended December 31, 2005 would have been approximately $8.6 million. If we had completed the transactions contemplated in this prospectus on July 1, 2005, pro forma available cash generated during the twelve months ended June 30, 2006 would have been approximately $8.3 million. These amounts of pro forma cash available for distribution would have been sufficient to allow us to pay approximately 34% and 33%, respectively, of the initial quarterly distribution, or IQD, on our Class A and common units for these periods. For a calculation of our ability to make distributions based on our pro forma results for the year ended December 31, 2005 and the twelve months ended June 30, 2006, please read the information included under the caption Cash Distribution Policy and Restrictions on Distributions Unaudited Pro Forma Available Cash to Pay Distributions.

Pursuant to the terms of our limited liability company agreement, our board of managers has the discretionary authority to cause us to borrow funds from our reserve-based credit facility to make up a shortfall in cash available for distribution such as the estimated shortfall amounts discussed above. Under our reserve-based credit facility that we expect to enter into prior to or at the closing of this offering, we expect to be able to incur debt to pursue our business plan and to pay distributions to our unitholders, provided that our borrowings do not reach or exceed 90% of the borrowing base and that we are not then in default. For a description of our borrowing parameters and covenants, please read Cash Distribution Policy and Restrictions on Distributions.

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Torch Royalty NPI

The majority of our properties in the Robinson s Bend Field are subject to a non-operating net profits interest, or NPI, held by Torch Energy Royalty Trust, or 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 associated expenditures, from specified wells in the Robinson s Bend Field, or Trust Wells. As of December 31, 2005, we owned a working interest in 436 producing wells in the Robinson s Bend Field, of which 404 wells were subject to the NPI. We estimate that, as of December 31, 2005, approximately 5.8 Bcf of proved reserves were attributable to the NPI on the Trust Wells, which we have excluded from our estimate of proved reserves attributable to our interests in the Robinson s Bend Field.

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 resulted in below-market prices and has had the effect of keeping our payments to the Trust significantly lower than if such payments had been calculated based on then prevailing market prices. No amounts were due to the Trust in 2005 in respect of the NPI. We paid the Trust approximately $0.2 million in the aggregate for January 2006 through August 2006 production from the Trust Wells in respect of the NPI.

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, our payments to the Trust will increase and our revenues will decrease. For a further description of the NPI and the related contractual arrangements, as well as the circumstances under which the sharing arrangement may be terminated, please read Business Natural Gas Data Torch Royalty NPI.

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, CHI will contribute to us at the closing of this 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 the 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 $8.0 million contribution under certain circumstances upon our liquidation. The effect of our retention and use of the unreturned portion of the $8.0 million is to provide us with cash that will reduce, but not eliminate, the adverse impact of our reduced revenues from the termination of the sharing arrangement. For a further description of this special distribution right, please read Cash Distribution Policy and Restrictions on Distributions and Certain Relationships and Related Party Transactions Distributions and Payments to CCG, CEPH, CEP Equity II LLC, CHI and CEPM Operational Stage.

Risk Factors

An investment in our common units involves risks associated with our business, regulatory and legal matters, our limited liability company structure and the tax characteristics of our common units. Please read carefully the risks under the caption Risk Factors immediately following this Summary beginning on page 23.

The Transactions and Limited Liability Company Structure

General. We are a Delaware limited liability company formed in February 2005 to own natural gas properties that were acquired in June 2005 in the Black Warrior Basin of Alabama.

Conversion of Interests and Formation of CEPM. Immediately prior to the closing of this offering, the limited liability company interests in us held by CEPH will be converted into 295,690 Class A units, 8,214,010 common units and the management incentive interests. Immediately after such conversion, CEPH will contribute the 295,690 Class A units and the management incentive interests to CEPM in exchange for all of the limited liability company interests in CEPM.

Class D Interests Contribution. For a description of the Class D interests, the special cash distribution rights associated with those interests and the effects thereon of termination of the sharing arrangement without the prior consent of our board of managers, please read Cash Distribution Policy and Restrictions on Distributions and Certain Relationships and Related Party Transactions Distributions and Payments to CCG, CEPH, CEP Equity II LLC, CHI and CEPM Operational Stage.

Distribution of Floyd Shale Rights. In connection with this offering, we will sell to an affiliate of Constellation, CEP Equity II, LLC, 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. We refer to this mineral interest as the Floyd Shale Rights. The Floyd Shale Rights are not material to our business and no value has been assigned to them in our historical financial statements included elsewhere in this prospectus. The Floyd Shale Rights do not fit our investment strategy, given the uncertainty of encountering commercial quantities of oil or natural gas. We will receive $475,000 in return for this sale of the Floyd Shale Rights.

Reserve-Based Credit Facility. Prior to this offering, we plan to enter into a new reserve-based credit facility under which we expect our initial borrowing base will be $100.0 million. At the closing of this offering, we plan to borrow $30.0 million under that facility to fund part of a distribution currently estimated to be $136.0 million to CEPH as reimbursement for capital expenditures made by CCG prior to this offering.

Management of Constellation Energy Partners LLC. Our board of managers will manage our operations and activities, and CEPM, through its affiliates and employees, will carry out the directions of our board of managers pursuant to a management services agreement. This agreement is not terminable by us while we are consolidated with Constellation for accounting purposes. Thereafter, the management services agreement is terminable by either us or CEPM upon six months notice. CEPM will be reimbursed for its costs in providing services to us and will be entitled to be reimbursed for all direct and indirect expenses incurred on our behalf. Constellation and its affiliates will also be entitled to distributions on our Class A units, common units they own, management incentive interests and Class D interests. For more information about our management, please read Management Our Board of Managers and Executive Officers and Certain Relationships and Related Party Transactions.

Elimination of Special Voting Rights of Class A Units; Conversion of Class A Units and Management Incentive Interests Into Common Units. 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 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 at the then fair market value of such interests. For a further description of the right of common unitholders to eliminate the voting rights of the Class A units and the conversion of Class A units and management incentive interests into common units, please read The Limited Liability Company Agreement Election of Members of Our Board of Managers Elimination of Special Voting Rights of Class A Units.

Principal Executive Offices and Internet Address

Our principal executive offices are located at 111 Market Place, Baltimore, Maryland 21202, and our telephone number is (410) 468-3500. Our website is located at http://www.constellationenergypartners.com. We expect to make our periodic reports and other information filed with or furnished to the Securities and Exchange Commission, or SEC, available, free of charge, through our website, as soon as reasonably practicable after those

reports and other information are electronically filed with or furnished to the SEC. Information on our website or any other website is not incorporated by reference into this prospectus and does not constitute a part of this prospectus.

Organizational Chart

The following diagram depicts our organizational structure after giving effect to this offering and the related transactions.

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The Offering

Units offered by us	6,275,000 common units; or 7,216,250 common units if the underwriters exercise their option to purchase additional common units in full.
Units outstanding after this offering	14,489,010 common units, which does not include any common units that may be issued under the long-term incentive plan that we expect to adopt prior to the closing of this offering. 295,690 Class A units, all of which will be owned by CEPM.
Use of proceeds	The following table sets forth the estimated sources and uses of the funds we expect to receive from the sale of common units in this offering and related transactions. The actual sources and uses of these funds may differ from those set forth below. Please read Use of Proceeds.

Sources of Funds:	
Estimated proceeds, net of estimated underwriting discounts and commissions and offering expenses, received from this offering[(a)]	$ 113.8 million
Contribution for the Class D interests	$ 8.0 million
Borrowings under our new reserve-based credit facility	$ 30.0 million
Uses of Funds:	
Distribution to CEPH[(a)(b)]	$ 136.0 million
Reduction of borrowings under our new reserve-based credit facility	$ 8.0 million
Working capital	$ 7.8 million

(a) Assumes an initial public offering price of $20.00 per common unit, the mid-point of the price range set forth on the cover page of this prospectus and after deducting estimated underwriting discounts and commissions of $8.5 million and estimated offering expenses of $3.2 million.

(b) If the price exceeds the mid-point of the price range, we will distribute the excess net proceeds to CEPH. If the price is less than the mid-point of the price range, we will reduce the size of the special distribution to CEPH in an amount equal to the reduction in net proceeds.

We intend to use the net proceeds from any exercise of the underwriters option to purchase additional units from us to purchase an equivalent number of common units from CEPH.

Cash distributions	We intend to make an IQD of $0.425 per common unit to the extent we have sufficient available cash from operations after we establish appropriate cash reserves and pay fees and expenses, including

payments to CEPM for reimbursement of costs and expenses it incurs on our behalf. We refer to this cash as available cash, and we define its meaning in more detail in our limited liability company agreement, in How We Make Cash Distributions Distributions of Available Cash Definition of Available Cash and in the glossary of terms found in Appendix B. Our board of managers has broad discretion in establishing cash reserves. The cash reserves that our board of managers may establish in its discretion include reserves for future cash distributions on the common units, Class A units and management incentive interests and to pay special cash distributions to the holders of our Class D interests. These reserves, which could be substantial, will reduce the amount of cash available for distribution to you.

Our board of managers has adopted a policy that it will raise our quarterly cash distribution only when it believes that we (i) have sufficient reserves and liquidity for the proper conduct of our business, including the maintenance of our asset base, and (ii) can maintain such increased distribution level for a sustained period. While this is our current policy, our board of managers may alter such policy in the future when and if it determines such alteration to be appropriate. Our limited liability company agreement requires that, within 45 days after the end of each calendar quarter beginning with the quarter ending December 31, 2006, we distribute all of our available cash to holders of record of our limited liability company interests on the applicable record date.

We will adjust the IQD for the period from the closing of this offering through December 31, 2006, based on the actual length of the period.

The amount of available cash in any quarter may be greater or less than the aggregate amount associated with payment of the IQD on all of our common units and Class A units. In general, we will pay any cash distributions we make in the following manner:

first, 98% to the holders of our common units and 2% to the holders of our Class A units, pro rata, until each unitholder has received $0.48875 (that is, the $0.425 IQD plus $0.06375), which aggregate amount we refer to as the Target Distribution; and

thereafter, any amount distributed in respect of any quarter in excess of the Target Distribution will be distributed 98% to the holders of our common units, pro rata, and 2% to the holder of our Class A units until distributions become payable in respect of our management incentive interests as described under Management incentive interests below.

The holder of our Class A units will be entitled to 2% of our cash distributions without any obligation to make future capital contributions to us.

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Management incentive interests	We refer to a distribution in respect of the management incentive interests as a management incentive distribution. CEPM will initially hold all of the management incentive interests.

Payments to the holder of our management incentive interests will be subject to the satisfaction of certain requirements. The first requirement is the 12-Quarter Test. The 12-Quarter Test requires that, for the 12 full, consecutive, non-overlapping calendar quarters that begin with the first calendar quarter in respect of which we pay per unit cash distributions from operating surplus to holders of Class A and common units in an amount equal to or greater than the Target Distribution (we refer to such 12-quarter period as the First MII Earnings Period):

- we pay cash distributions from operating surplus to holders of our outstanding Class A and common units in an amount that on average exceeds the Target Distribution on all of the outstanding Class A and common units over the First MII Earnings Period;

- we generate adjusted operating surplus (which is defined in How We Make Cash Distributions and in the glossary included as Appendix B) during the First MII Earnings Period that on average is in an amount at least equal to 100% of all distributions on the outstanding Class A and common units up to the Target Distribution plus 117.65% of all such distributions in excess of the Target Distribution; and

- we do not reduce the amount distributed per unit in respect of any such 12 quarters.

The second requirement is the 4-Quarter Test. The 4-Quarter Test requires that, for each of the last four full, consecutive, non-overlapping calendar quarters in the First MII Earnings Period:

- we pay cash distributions from operating surplus to the holders of our outstanding Class A and common units that exceed the Target Distribution on all of the outstanding Class A and common units;

- we generate adjusted operating surplus in an amount at least equal to 100% of all distributions on the outstanding Class A and common units up to the Target Distribution plus 117.65% of all such distributions in excess of the Target Distribution; and

- we do not reduce the amount distributed per unit in respect of any of such four quarters.

If the 12-Quarter Test and the 4-Quarter Test have been met, then: (i) we will make a one-time management incentive distribution (contemporaneously with the distribution paid in respect of the Class A and common units for the twelfth calendar quarter in the First MII Earnings Period) to the holder of our management incentive interests equal to 17.65% of the sum of the cumulative amounts, if any, by which quarterly cash distributions per unit paid on the outstanding Class A and common units during the First MII Earnings Period exceeded the Target Distribution on all of the outstanding Class A and common units (we refer to this one-time management incentive distribution as an EP MID); and (ii) for each calendar quarter after the First MII Earnings Period, the holders of our Class A units, common units and management incentive interests will receive 2%, 83% and 15%, respectively, of cash distributions from available cash from operating surplus that we pay for such quarter in excess of the Target Distribution.

If the 12-Quarter Test is not met, management incentive distributions will not be payable in respect of the First MII Earnings Period. An EP MID may become payable, however, with respect to a subsequent period, which we refer to as the Later MII Earnings Period, if the 12-Quarter Test and the 4-Quarter Test are met in respect of such Later MII Earnings Period. If both tests are met with respect to a Later MII Earnings Period, then for each calendar quarter after the Later MII Earnings Period, the holders of the Class A units, common units and management incentive interests will receive 2%, 83% and 15%, respectively, of cash distributions from available cash from operating surplus that we pay for such quarter in excess of the Target Distribution.

However, if (a) the 12-Quarter Test has been met in respect of the First MII Earnings Period or any Later MII Earnings Period, but not the 4-Quarter Test; (b) the 4-Quarter Test has been met in any period of four full, consecutive and non-overlapping quarters occurring after the end of the First MII Earnings Period or Later MII Earnings Period, as the case may be, up to three of which quarters can fall within the First MII Earnings Period or Later MII Earnings Period, as the case may be, (we refer to such four-quarter period as the MII 4-Quarter Earnings Period); and (c) we have paid at least the IQD in each calendar quarter occurring between the end of the First MII Earnings Period or Later MII Earnings Period, as the case may be, and the beginning of the MII 4-Quarter Earnings Period:

- the holders of our Class A units, common units and management incentive interests will receive 2%, 83% and 15%, respectively, of cash distributions from available cash from operating surplus that we pay in excess of the Target Distribution for each calendar quarter after the MII 4-Quarter Earnings Period; and

- the holder of our management incentive interests will receive an EP MID with respect to the First MII Earnings Period or Later MII Earnings Period, as the case may be.

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, how much they will be. For a further discussion of the management incentive interests, please read the information set forth under the caption How We Make Cash Distributions Management Incentive Interests.

Special Class D interests distribution

In order to address the risks of 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 and the potential reduction in our revenues resulting therefrom, at the closing of this offering CHI will contribute $8.0 million to us for all of our Class D interests. For each full calendar quarter during the period commencing January 1, 2007 and ending on December 31, 2012 that the sharing arrangement remains in effect, we will distribute to the holder of the Class D interests $333,333, 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 unitholders for that quarter. 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, unless the special distribution right has been terminated earlier. 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 and the remaining portion of the $8.0 million contribution not so returned in special cash distributions will be retained by us to partially offset the reduction in our revenues resulting from termination of the sharing arrangement in respect of the Trust. In the case of such termination of the special distribution right, CHI will have the right only 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 distribution right is terminated during a quarter, the special distribution to the holder of the Class D interests will be pro rated 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.

Based upon our estimated production for the twelve months ending September 30, 2007 and the weighted average net realized sales price for our production used in calculating our Estimated Adjusted EBITDA for that twelve-month period under the caption Cash Distribution Policy and Restrictions on Distributions, we estimate that, if the sharing arrangement in respect of the Trust was terminated as of October 1, 2006, our revenues would be reduced by approximately $5.6 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 1.4 years, if the production and prices set forth under Cash Distribution Policy and Restrictions on Distributions Our Estimated Cash Available to Pay Distributions were to remain constant throughout such period.

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Pro forma and expected ability to pay the IQD	We believe, based on the assumptions and considerations included under the caption Cash Distribution Policy and Restrictions on Distributions of this prospectus, that we will have sufficient cash flow from operations to enable us to pay the IQD of $0.425 on all Class A and common units for each quarter in the twelve-month period ending September 30, 2007. For a calculation of our ability to make distributions to you based on our pro forma results for the year ended December 31, 2005 and the twelve months ended June 30, 2006, please read the information included under the caption Cash Distribution Policy and Restrictions on Distributions Unaudited Pro Forma Available Cash to Pay Distributions.
Issuance of additional units	We can issue an unlimited number of additional limited liability company interests without the consent of our unitholders. Please read Risk Factors Risks Related to Our Structure We may issue an unlimited number of additional units without your approval, which would dilute your existing ownership interests, Units Eligible for Future Sale and The Limited Liability Company Agreement Issuance of Additional Securities.
Agreement to be bound by limited liability agreement; common unit voting rights	By purchasing a common unit, you will be admitted as a member of our limited liability company and be deemed to have agreed to be bound by all of the terms of our limited liability company agreement. Our board of managers will manage us and will rely on personnel from CEPM and its affiliates to oversee our operations. Pursuant to our limited liability company agreement, as a common unitholder you will be entitled to vote on the following matters: annual election of three members of our five-member board of managers; specified amendments to our limited liability company agreement; merger of our company or the sale of all or substantially all of our assets; and dissolution of our company. Please read The Limited Liability Company Agreement Voting Rights.
Board of Managers	Our board of managers will initially be comprised of five members, two of whom will be elected by the holders of the Class A units and the remainder of whom will be elected by the holders of the common units. Because Constellation will own more than a majority of our outstanding common units immediately after the closing of this offering, Constellation, in combination with CEPM as owner of the

	Class A units, will be able to elect a majority of the members of our board of managers. In addition, as the removal of a manager elected by our common unitholders requires the approval of the holders of not less than 66 2/3% of our outstanding common units, our public common unitholders will not be able to remove a member of our board of managers unless Constellation votes its common units in favor of such a removal.
Limitations on common unitholder actions	Our limited liability company agreement (i) prohibits common unitholders from taking unitholder action by written consent and (ii) nullifies the common unitholder voting rights of any person other than Constellation or its affiliates that holds 20% or more of our outstanding common units.
Limited call right	If at any time any person and its affiliates own more than 80% of the outstanding common units, such person will have the right, but not the obligation, to purchase all of the remaining common units at a price not less than the then current market price of the common units.
Fiduciary duties	Our limited liability company agreement provides that the fiduciary duties of our managers and officers are generally to act in good faith in acting on our behalf in such capacity.
	As a result of our relationship with Constellation and its affiliates, as well as the fact that our executive officers and Class A managers also serve as managers, directors, officers or employees of Constellation or its other affiliates, conflicts of interest exist and will arise in the future. The ultimate resolution of these conflicts of interest may result in the interests of Constellation or its affiliates being favored over your interests, may be to our detriment and could adversely affect the market price of the common units. If in resolving these conflicts of interest 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, you will not be able to assert that such resolution constituted a breach of fiduciary duty owed to us or to you by our board of managers and officers. For example, our limited liability company agreement establishes a conflicts committee of our board of managers, consisting solely of independent managers, which will be responsible for reviewing transactions involving potential conflicts of interest. If the conflicts committee approves such a transaction, you will not be able to assert that such approval or the consummation of such transaction constituted a breach of fiduciary duties owed to you by our managers and officers. Please read Management Our Board of Managers Conflicts Committee.
Estimated ratio of taxable income to distributions	We estimate that, if you own the common units that you purchase in this offering through the record date for distributions for the period

	ending December 31, 2009, you will be allocated, on a cumulative basis, an amount of federal taxable income for that period that will be approximately 20% of the cash distributed to you with respect to that period. Please read Material Tax Consequences Tax Consequences of Unit Ownership for the basis of this estimate.
Material tax consequences	For a discussion of other material federal income tax consequences that may be relevant to prospective unitholders who are individual citizens or residents of the United States, please read Material Tax Consequences.
Exchange listing and trading symbol	We have applied to list our common units on NYSE Arca under the trading symbol CEP.

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Summary Historical and Pro Forma

Consolidated Financial Data

Set forth below is our summary historical and unaudited pro forma consolidated financial data for the periods indicated. We were formed in February 2005 and had no operations prior to the completion of a $161.1 million acquisition of natural gas reserves and equipment in the Robinson s Bend Field from Everlast Energy LLC, or Everlast, on June 13, 2005. We applied the purchase method of accounting to the separable assets and liabilities of the natural gas properties and equipment acquired from Everlast. The summary historical consolidated financial data of Everlast for the period from January 1, 2005 through June 12, 2005 and as of and for the years ended December 31, 2004 and 2003 have been derived from Everlast s audited historical financial statements. The summary historical financial data of Constellation Energy Partners LLC as of December 31, 2005 and for the period from February 7, 2005 (inception) through December 31, 2005, have been derived from our audited historical consolidated financial statements. The summary historical consolidated financial data of Constellation Energy Partners LLC as of and for the six months ended June 30, 2006 and for the period from February 7, 2005 (inception) to June 30, 2005 have been derived from our unaudited historical consolidated financial statements. The summary unaudited pro forma consolidated financial data as of and for the six months ended June 30, 2006 and for the year ended December 31, 2005 have been derived from our unaudited pro forma consolidated financial statements. For a description of the adjustments made in the unaudited pro forma consolidated financial statements, please read the notes to those financial statements.

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 GAAP. We explain this measure below and reconcile it to net income and net cash flow provided by operating activities, the most directly comparable financial measures calculated and presented in accordance with GAAP in Non-GAAP Financial Measure Adjusted EBITDA below.

You should read the following summary financial data in conjunction with 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 prospectus. You should also read the pro forma information, together with the unaudited pro forma consolidated financial statements and related notes included in this prospectus.

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 in 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 represent 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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	Predecessor			Successor				
	Everlast Energy LLC			Constellation Energy Partners LLC				
							Pro Forma	
	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 period from February 7, 2005 (inception) to June 30, 2005[(b)]	For the six months ended June 30, 2006	For the year ended December 31, 2005	For the six months ended June 30, 2006
	As Restated[(a)]	As Restated[(a)]			Unaudited	Unaudited	Unaudited	Unaudited
		(In 000 s)				(In 000 s)		
Statement of Operations Data:								
Revenues:								
Gas sales	$ 22,320	$ 27,494	$ 12,882	$ 25,957	$ 1,377	$ 17,605	$ 38,839	$ 17,605
Loss from mark-to-market activities	(3,664)	(9,107)	(15,313)				(15,313)	
Total revenues	18,656	18,387	(2,431)	25,957	1,377	17,605	23,526	17,605
Operating expenses:								
Lease operating expenses	4,428	5,270	2,769	4,175	357	3,495	6,944	3,495
Production taxes	1,279	1,479	676	1,400	72	909	2,076	909
General and administrative	1,945	2,706	594	4,184	3,275	2,731	4,778	2,731
Depreciation, depletion and amortization	3,684	3,719	1,683	4,176	350	3,811	7,281	3,811
Accretion expense	73	86	46	78	7	71	141	71
Total operating expenses	11,409	13,260	5,768	14,013	4,061	11,017	21,220	11,017
Other expenses/(income):								
Interest expense/(income), net	1,961	3,028	2,437	3		(197)	1,546	573
Organization costs	299							
Total other expenses/(income)	2,260	3,028	2,437	3		(197)	1,546	573
Total expenses/(income)	13,669	16,288	8,205	14,016	4,061	10,820	22,766	11,590
Net income (loss)	$ 4,987	$ 2,099	$ (10,636)	$ 11,941	$ (2,684)	$ 6,785	$ 760	$ 6,015
Other Financial Information (unaudited)								
Adjusted EBITDA	$ 10,193	$ 14,738	$ 8,795	$ 16,198	$ (2,327)	$ 10,470	$ 24,993	$ 10,470

(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 prospectus.

(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			
	Everlast Energy LLC			Constellation Energy Partners LLC			
							Pro Forma
	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 period from February 7, 2005 (inception) to June 30, 2005[(b)]	For the six months ended June 30, 2006	For the six months ended June 30, 2006
	As Restated[(a)]	As Restated[(a)]			Unaudited	Unaudited	Unaudited
		(In 000 s)				(In 000 s)	
Balance Sheet Data (at period end):							
Cash and cash equivalents	$ 2,563	$ 2,012		$ 14,831		$ 3,880	$ 7,827
Other current assets	1,812	4,562		6,097		17,912	5,713
Natural gas properties, net of accumulated depreciation, depletion and amortization	49,252	52,531		165,211		169,282	169,282
Other assets	590	1,579				311	311
Total assets	$ 54,217	$ 60,684		$ 186,139		$ 191,385	$ 183,133
Current liabilities	$ 4,403	$ 4,482		$ 13,895		$ 10,797	$ 10,797
Debt	26,000	67,500		63		52	22,052
Preferred units subject to mandatory redemption	16,752						
Other long-term liabilities	2,671	3,314		3,014		3,099	3,099
Class D interests							8,000
Members equity							
Common members equity (deficit)	4,391	(14,612)		169,167		176,523	138,271
Accumulated other comprehensive income						914	914
Total members equity (deficit)	4,391	(14,612)		169,167		177,437	139,185
Total liabilities and members equity (deficit)	$ 54,217	$ 60,684		$ 186,139		$ 191,385	$ 183,133
Cash Flow Data:							
Net cash provided by operating activities	$ 9,773	$ 4,906	$ 6,639	$ 23,313	$ 2,931	$ 8,805	
Net cash used in investing activities	(47,832)	(6,997)	(4,203)	(147,237)	(139,357)	(19,745)	
Net cash provided by (used in) financing activities	40,622	1,540	(2,500)	138,755	138,770	(11)	
Development of natural gas properties	(2,040)	(5,680)	(4,000)	(8,286)	(406)	(7,285)	

(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 prospectus.

(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) plus:

- 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 reserves by our board of managers) the cash distributions we can 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 an alternative to net income, operating income, cash flow 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 Adjusted EBITDA to net income and net cash flow provided by operating activities, our most directly comparable GAAP performance and liquidity measures, for each of the periods presented:

	Predecessor			Successor				
	Everlast Energy LLC			Constellation Energy Partners LLC				
							Pro Forma	
	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 period from February 7, 2005 (inception) to June 30, 2005	For the six months ended June 30, 2006	For the year ended December 31, 2005	For the six months ended June 30, 2006
					Unaudited	Unaudited	Unaudited	Unaudited
		(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	$ (2,684)	$ 6,785	$ 760	$ 6,015
Add:								
Interest expense/(income), net	1,961	3,028	2,437	3		(197)	1,546	573
Depreciation, depletion and amortization	3,684	3,719	1,683	4,176	350	3,811	7,281	3,811
Accretion of asset retirement obligation	73	86	46	78	7	71	141	71
Unrealized loss/(gain) on natural gas derivatives	(512)	(2,156)	15,265				15,265	
Realized loss/(gain) on cancelled natural gas derivatives		7,962						
Adjusted EBITDA	$ 10,193	$ 14,738	$ 8,795	$ 16,198	$ (2,327)	$ 10,470	$ 24,993	$ 10,470
Reconciliation of Net Cash Provided by Operating Activities to Adjusted EBITDA:								
Net cash provided by operating activities	$ 9,773	$ 4,906	$ 6,639	$ 23,313	$ 2,931	$ 8,805		
Add:								
Interest expense/(income), net[(a)]	1,305	2,596	2,437	3		(197)		
Expenses paid by CCG on behalf of CEP				(64)		(571)		
Realized loss on cancelled natural gas derivatives		7,962						
Changes in working capital:								
Accounts receivable	1,547	2,278	707	1,289	(1,535)	(1,869)		
Prepaid expenses	265	(246)	131	62	21	75		
Other assets			10	211		807		
Loan amortization cost	(288)	(685)	(237)					
Accounts payable	(908)	(993)	(807)	(1,703)	863	2,187		
Royalty payable	(1,321)	(708)	(110)	(1,859)	(364)	1,240		
Accrued liabilities	(180)	(372)	25	(5,054)	(4,243)	(7)		
Adjusted EBITDA	$ 10,193	$ 14,738	$ 8,795	$ 16,198	$ (2,327)	$ 10,470		

(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.

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Summary Reserve and Operating Data

The following is a summary of our estimated net proved reserves attributable to our properties in the Robinson s Bend Field and summary unaudited information with respect to our production and sales of natural gas, all as of the dates indicated. We have prepared the estimates of proved natural gas reserves described in this prospectus. You should refer to Risk Factors, Management s Discussion and Analysis of Financial Condition and Results of Operations, Business Oil and Natural Gas Data Proved Reserves and our historical consolidated financial statements in evaluating the material presented below.

The following table reflects our internal estimates of proved natural gas reserves based on SEC definitions that were used to prepare our financial statements for the following periods:

	Predecessor		Successor
	Everlast Energy LLC		Constellation Energy Partners LLC
	As of December 31,		
Reserve data:	**2003**	**2004**	**2005**
Estimated net proved reserves:			
Natural gas (Bcf)	163.7	162.2	112.0
Proved developed reserves (Bcf)	100.7	101.4	89.3
Proved undeveloped reserves (Bcf)	63.0	60.8	22.7
Proved developed reserves as a percent of total reserves	62%	62%	80%
Standardized Measure (in millions) (a)	$ 194.2	$ 206.8	$ 295.4
Natural gas price SONAT Gas Daily (price per Mmbtu) (b)	$ 5.92	$ 6.05	$ 10.06

(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. For a description of our derivative transactions, please read Management s Discussion and Analysis of Financial Condition and Results of Operations Cash Flow from Operations.

(b) Natural gas prices as of each period end were based on the Southern Natural Gas Louisiana mid-point price, as published in Platts Gas Daily, which we refer to as the SONAT Gas Daily Price, on the last business day of the relevant period.

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 prospectus. Our 2005 estimates of proved reserves are lower than the 2004 and 2003 estimates for Everlast, the predecessor company, because of the decision of our current 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 provides 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, 2004 estimate of reserves because no amounts were due or paid in respect of the NPI at that time.

Our 2005 proved reserve estimate is 112.0 Bcf. At December 31, 2005, NSAI, an independent petroleum engineering firm, prepared an estimate of 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 estimate of our 2005 proved reserves is materially consistent with our internal estimate.

Our 2004 and 2003 proved reserve estimates are 162.2 Bcf and 163.7 Bcf, respectively. These are our internal estimates of proved reserves that were used in the 2004 and 2003 Everlast financial statements included elsewhere in this prospectus. We prepared the estimates of 2004 and 2003 proved reserves for financial statement purposes by starting with NSAI s December 31, 2005 net proved reserve estimate, which was prepared based upon a continuation of the assumptions used by Everlast, including the prior accelerated drilling program and reserve assumptions, and rolling back the estimate to December 31, 2004 and 2003 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 December 31, 2004 was not based on the SEC definition of proved reserves, while the reserve report prepared by NSAI for Everlast as of December 31, 2003, which was based on the SEC definition of proved reserves, included different assumptions than those used by NSAI in preparing the December 31, 2005 proved reserves estimate. To prepare reserve estimates for these periods in compliance with the SEC definitions, we adopted the roll back approach described above and in Note 2 and Note 17 to the historical financial statements. Everlast s previous non-SEC compliant reserve estimates were 173.4 Bcf at December 31, 2004 and 166.2 Bcf at December 31, 2003.

RISK FACTORS

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

The following risks could materially and adversely affect our business, financial condition or results of operations. If any of the events described below were to occur, we may not be able to pay quarterly distributions on our common units, the trading price of our common units could decline and you could lose part or all of your investment in our company.

Risks Related to Our Business

We may not have sufficient cash from operations to pay the IQD following establishment of cash reserves and payment of fees and expenses, including payments to CEPM.

We may not have sufficient cash flow from operations each quarter to pay the IQD of $0.425 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; 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. For a description of additional restrictions and factors that may affect our ability to make cash distributions, please read Cash Distribution Policy and Restrictions on Distributions.

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.

If we are unable to achieve the Estimated Adjusted EBITDA set forth in Cash Distribution Policy and Restrictions on Distributions and cannot borrow the required amounts, we may be unable to pay the full, or any, amount of the IQD on the common units, in which event the market price of our common units may decline substantially.

The calculation of Estimated Adjusted EBITDA for the twelve months ending September 30, 2007 set forth in Cash Distribution Policy and Restrictions on Distributions has been prepared by our management and we

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have not received an opinion or report on it from any independent accountants. The assumptions underlying this calculation are inherently uncertain and are subject to significant business, economic, regulatory and competitive risks and uncertainties that could cause actual results to differ materially from those expected. If we do not achieve the expected results or cannot borrow the amounts needed, we may not be able to pay the full, or any, amount of the IQD, in which event the market price of our common units may decline substantially.

We would not have generated sufficient available cash on a pro forma basis to have paid the IQD on all of our outstanding common units and Class A units for the year ended December 31, 2005 or the six months ended June 30, 2006.

The amount of available cash we will need to pay the IQD for four quarters on the common units and the Class A units to be outstanding immediately after this offering is approximately $25.1 million. If we had completed the transactions contemplated in this prospectus on January 1, 2005, pro forma available cash generated during the year ended December 31, 2005 would have been approximately $8.6 million. If we had completed the transactions contemplated in this prospectus on July 1, 2005, pro forma available cash generated during the twelve months ended June 30, 2006 would have been approximately $8.3 million. These amounts of pro forma cash available for distribution would have been sufficient to allow us to pay approximately 34% and 33%, respectively, of the $0.425 per quarter IQD on our common units and Class A units during these periods. For a calculation of our ability to make distributions to you based on our pro forma results for the year ended December 31, 2005 and the twelve months ended June 30, 2006, please read Cash Distribution Policy and Restrictions on Distributions.

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 the 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. For example, during the year ended December 31, 2005, the SONAT Gas Daily Price ranged from a high of $19.79 per MMBtu to a low of $5.55 per MMBtu. 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 you.

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

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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, 2005, our average annual decline rate for proved developed producing reserves is approximately 5% during the next fifteen years. Because total estimated proved reserves include our proved undeveloped reserves at December 31, 2005, we expect that 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, 2005, 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 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 prospectus, 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 estimates are less reliable than those 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 decline by $1.00 per Mcf, then the Standardized Measure of our proved reserves as of December 31, 2005 would decrease from approximately $295.4 million to approximately $262.0 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:

- supply of and demand for natural gas;
- actual prices we receive for natural gas;

our actual operating costs in providing natural gas;

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- 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 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 to you.

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 to you.

We rely on third parties for our management. While our board of managers will have the right and responsibility to manage our affairs, we expect to rely on third parties to manage the day-to-day aspects of our business. We will enter into a management services agreement with CEPM, a wholly owned subsidiary of Constellation. Pursuant to that agreement, we will be 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. We also expect that CEPM will 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 to you.

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 to you.

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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;
- 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 will restrict 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 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 you.

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 a buyer 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.

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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 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 our future indebtedness to pay these 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 will have 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 will restrict our ability to obtain additional financing, make investments, lease equipment, sell assets and engage in business combinations. We will also be 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 the reserve-based credit facility could result in a default under our reserve-based credit facility, which could cause all of our existing indebtedness to be immediately due and payable. Each of the following is expected to be 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, including a covenant requiring that Constellation and its affiliates shall maintain the right to elect our Class A managers, in the credit facility or other loan documents, subject, in certain instances, to certain grace periods;
- 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 voting power of our outstanding voting securities to less than 10%, and (ii) the ownership by any person (other than a wholly-owned subsidiary of Constellation) of our outstanding voting securities with a combined voting power of more than 35%.

The reserve-based credit facility will limit 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. Upon the closing of our reserve-based credit facility, we will not 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 will be 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. Giving effect to the use of the net proceeds from this offering, we estimate our borrowings under the credit facility will be $22.0 million, or approximately 22% of our estimated initial borrowing base of $100.0 million upon the closing of the offering.

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

We estimate that we will have $22.0 million of indebtedness outstanding immediately after the closing of this offering. Following this offering, we estimate that will have the ability to incur additional debt, including the capacity to borrow up to an additional $78.0 million under our new reserve-based credit facility, subject to borrowing base limitations in the credit agreement. 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.

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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 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 31, 2005 and September 1, 2006 was $10.08 per MMBtu and $5.815 per MMBtu, respectively. Upon termination of the Trust, the gas purchase contract with Torch Energy Marketing, Inc., an affiliate of the original sponsor of the Trust, or TEMI, including the portion assigned to us, will terminate. Based upon our estimated production for the twelve months ending September 30, 2007 and the weighted average net realized sales price for our production used in calculating our Estimated Adjusted EBITDA for that twelve-month period under the caption Cash Distribution Policy and Restrictions on Distributions, we estimate that, if the sharing arrangement in respect of the Trust was terminated as of October 1, 2006, our revenues would be reduced by approximately $5.6 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 1.4 years, if the production and prices set forth under Cash Distribution Policy and Restrictions on Distributions Our Estimated Cash Available to Pay Distributions 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 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, 2005 and 2004, the monthly index price varied between a low of $6.12 and a high of $14.01, and a low of $5.05 and a high of $7.74, respectively. For the eight months ended August 31, 2006, the monthly index price varied between a low of $5.87 and a high of $11.67.

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) 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 the seven months ended July 31, 2006, the amount payable under the gas purchase contract was, on average, approximately $3.37 per MMBtu and $2.82 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 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 six months ended June 30, 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 31%, 27%, 18%, 13% and 11%, 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 intend to utilize are generally based on posted market prices, which may differ significantly from the actual natural gas prices we realize in our operations. If we had implemented this hedging strategy on June 30, 2005 for the twelve months ended June 30, 2006, we estimate that we would have realized approximately $5.9 million less revenue for that period. On June 20, 2006, we entered into derivative transactions that hedge the future prices of approximately 78% of the expected production from our currently producing wells from October 2006 to December 2009. Please read Management s Discussion and Analysis of Financial Condition and Results of Operations Quantitative and Qualitative Disclosure about Market Risk.

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

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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.

We hold natural gas leases on approximately 17,100 net acres 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 September 2006 and October 2010. Leases covering approximately 7,614 net acres are scheduled to expire before September 30, 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 natural gas 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, 2005, we had identified 120 gross proved undeveloped drilling locations and approximately 244 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.

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In addition, no proved reserves are assigned to any of the approximately 244 potential drilling locations we have identified and therefore, there may exist 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 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.

Drilling for and producing 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 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 you.

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;

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- 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;

- the federal Resource Conservation and Recovery Act, or RCRA, related federal regulations, and comparable state laws and regulations that impose requirements for the handling and disposal of waste from our facilities; and

- the Comprehensive Environmental Response, Compensation and Liability Act of 1980, or CERCLA, also known as Superfund, 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. Please read Business Environmental Matters and Regulation.

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, 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 naturally occurring radioactive material, or 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 the Alabama Department of Environmental Management, 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

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substances that we handle. For instance, we must maintain permits and adhere to certain controls related to the storage and proper disposal of naturally occurring radioactive material, or 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. Please read Business Environmental Matters and Regulation for more information.

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 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 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 to you.

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 who can spread these additional costs over a greater number of wells and larger operating staff. Please read Business Environmental Matters and Regulation for more information on the laws and regulations that affect us.

We will incur increased costs as a result of being a public company.

We have no history operating as a public company. As a public company, we will incur significant legal, accounting and other expenses that we did not incur as a private company. In addition, the Sarbanes-Oxley Act of 2002, as well as new rules subsequently implemented by the SEC and the NYSE Arca, have required changes in corporate governance practices of public companies. We expect these new rules and regulations to increase our legal and financial compliance costs and to make activities more time-consuming and costly. For example, as a result of becoming a public company, we are required to have three independent managers, create board committees and adopt polices regarding internal controls and disclosure controls and procedures, including the preparation of reports on internal control over financial reporting. In addition, we will incur additional costs associated with our public company reporting requirements. We also expect these new rules and regulations to make it more difficult and more expensive for us to obtain director and officer liability insurance and we may be required to accept reduced policy limits and coverage or incur substantially higher costs to obtain the same or similar coverage. As a result, it may be more difficult for us to attract and retain qualified persons to serve on our board of managers or as executive officers. The costs we incur as a result of being a public company will decrease the amount of cash available to pay distributions to you.

Risks Related to Our Structure

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

Upon completion of this offering, Constellation will indirectly own approximately 57% of the outstanding common units, or approximately 50% if the underwriters option to purchase additional common units is exercised in full, and 100% of the outstanding Class A units. The percentages do not reflect any common units that may be issued under the long-term incentive plan that we expect to adopt prior to the closing of this offering. Accordingly, Constellation and its affiliates will be able to assert great influence in any vote 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.

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 you in the event you have a claim relating to conflicts of interest or the resolution of such a conflict of interest.

Following the offering, two of the members of our board of managers who will be appointed by CEPM, the holder of our Class A units, and are officers of, and will be 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 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;

- 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;

- each of our executive officers and our Class A managers also serve as a manager, director, officer or employee of Constellation or its affiliates (other than us) and (i) while acting in such person s capacity as such a manager, director, officer or employee of Constellation or such affiliates, as opposed to such person s capacity as our executive officer or Class A manager, such person will not owe any fiduciary duty to us or our security holders and (ii) in making decisions in such person s capacity as such a manager, director, officer or employee of Constellation or such affiliates may favor the interests of Constellation or such affiliate over your interests and may be to our detriment;

- following the closing of this offering, 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, you will not be able to assert that such resolution constituted a breach of fiduciary duty owed to us or to you 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 Laws, or the DGCL. Section 203 of the DGCL as it applies to us prevents an interested unitholder,

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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 will not have the right to vote for two of our managers, and the common units that will be indirectly owned by Constellation immediately after this offering will give Constellation the ability to elect a majority of our managers.

CEPM, as the sole holder of our Class A units, will have 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 will be subject to annual election at a meeting of our common unitholders.

Since Constellation will own more than a majority of our outstanding common units immediately after the closing of this offering, Constellation, in combination with CEPM as owner of the Class A units, will be able to elect a majority of the members of our board of managers. In addition, since the removal of a manager elected by our common unitholders requires the approval of the holders of not less than a majority of our outstanding common units, our public common unitholders will not be able 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 you.

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 you.

You will experience immediate and substantial dilution of $10.59 per common unit.

The assumed initial public offering price of $20.00 per common unit exceeds our pro forma net tangible book value of $9.41 per common unit. Based on the assumed initial public offering price, you will incur immediate and substantial dilution of $10.59 per common unit. Please read Dilution.

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We may issue additional units without your approval, which would dilute your existing 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:

- your 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 you to sell your 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, you may be required to sell your common units at an undesirable time or price and therefore may receive a lower or no return on your investment. You may also incur tax liability upon a sale of your common units. For additional information about the call right, please read The Limited Liability Company Agreement Limited Call Right.

Unitholders may have limited liquidity for their common units, a trading market may not develop for the common units and you may not be able to resell your common units at the initial public offering price.

Prior to the offering, there has been no public market for the common units. After the offering, there will be 6,275,000 publicly traded common units, which number does not include any common units that may be issued under the long-term incentive plan that we expect to adopt prior to the closing of this offering. We do not know the extent to which investor interest will lead to the development of a trading market or how liquid that market might be. You may not be able to resell your common units at or above the initial public offering price. Additionally, the lack of liquidity may result in wide bid-ask spreads, contribute to significant fluctuations in the market price of the common units and limit the number of investors who are able to buy the common units.

If our common unit price declines after the initial public offering, you could lose a significant part of your investment.

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 Securities and Exchange Commission;
- 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;

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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 you if the distribution would cause our liabilities to exceed the fair value of our assets. Delaware law provides that for a period of three years from the date of 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.

Following the completion of this offering, CEPH will control an aggregate of 8,214,010 common units. In addition, we have agreed to register for 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. Please also read Units Eligible for Future Resale and Material Tax Consequences Disposition of Units Constructive Termination.

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

You should read Material Tax Consequences for a more complete discussion of the expected material federal income tax consequences of owning and disposing of common units.

Our tax treatment depends on our status as a partnership for federal income tax purposes, as well as our not being subject to 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 you would generally be taxed as corporate distributions, and no income, gain, loss, deduction or credit would flow through to you. 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 you 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 amounts will be adjusted to reflect the impact of that law on us.

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

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

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 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. Please read Material Tax Consequences Uniformity of Units for a further discussion of the effect of the depreciation and amortization positions we will adopt.

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 your tax basis in your common units.

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

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.

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

In addition to federal income taxes, you 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

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jurisdictions in which we do business or own property now or in the future, even if you do not reside in any of those jurisdictions. You 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, you may be subject to penalties for failure to comply with those requirements. We will initially do business and own assets in Alabama and Maryland. 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. Our counsel has not rendered an opinion on the state or local tax consequences of an investment in the common units. In addition, if you sell your units, you may incur a tax liability in excess of the amount of cash you receive from the sale.

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CAUTIONARY NOTE REGARDING FORWARD LOOKING STATEMENTS

This prospectus 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 our:

- the volatility of realized natural gas prices;
- discovery, estimation, development and replacement of oil and natural gas reserves;
- business and financial strategy;
- drilling locations;
- technology;
- cash flow, liquidity and financial position;
- the impact on us of termination of the sharing arrangement before December 31, 2012;
- production volumes;
- lease operating expenses, general and administrative costs and finding and development costs;
- availability of drilling and production equipment, labor and other services;
- future operating results;
- prospect development and property acquisitions;
- 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 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

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

All of these types of statements, other than statements of historical fact included in this prospectus, are forward looking statements. These forward looking statements may be found in the Summary, Risk Factors, Management s Discussion and Analysis of Financial Condition and Results of Operations, Cash Distribution Policy and Restrictions on Distributions, Business and other sections of this prospectus. In some cases, you can identify forward looking statements 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 prospectus 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 prospectus 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 prospectus. All forward looking statements speak only as of the date of this prospectus. 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.

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USE OF PROCEEDS

The following table sets forth the estimated sources and uses of the funds we expect to receive from the sale of common units in this offering and related transactions. The actual sources and uses of these funds may differ from those set forth below.

Sources of Funds		Uses of Funds	
Sale of 6,275,000 common units[a]	$113.8 million	Distribution to CEPH[c][d]	$136.0 million
Contribution by CHI for the Class D interests[b]	$ 8.0 million	Retained for working capital[d][e]	$ 7.8 million
Borrowings under our new reserve-based credit facility[b]	$ 30.0 million	Reduction of borrowings under our new reserve-based credit facility	$ 8.0 million
Total	$151.8 million	Total	$151.8 million

(a) We estimate that we will receive net proceeds of approximately $113.8 million from the sale of the 6,275,000 common units offered by this prospectus, assuming an initial public offering price of $20.00 per common unit (the mid-point of the price range set forth on the cover of this prospectus) and after deducting underwriting discounts and commissions of $8.5 million and estimated offering expenses of $3.2 million.

(b) Will be consummated immediately prior to the closing of this offering.

(c) Reimbursement for capital expenditures incurred by CCG prior to this offering.

(d) If the initial public offering price exceeds the mid-point of the price range, we will distribute the excess net proceeds to CEPH. If the initial public offering price is less than the mid-point of the price range, we will reduce the size of the special distribution to CEPH in an amount equal to the reduction in net proceeds.

(e) Includes cash to be retained by us, of which at least $5.0 million will exceed the amounts we expect to be necessary for our working capital purposes. As a result, at least $5.0 million of the net proceeds from our initial public offering will be available for future distributions to our unitholders.

If the underwriters option to purchase additional common units is exercised, we will use the additional net proceeds to purchase a number of common units from CEPH equal to the number of common units issued upon exercise of that option. If the underwriters option is exercised in full, CEPH s ownership of common units will be reduced from 8,214,010 common units to 7,272,760 common units, reducing CEPH s and CEPM s combined limited liability company interest in us from approximately 58% to approximately 51%, which percentages do not reflect any common units that may be issued under the long-term incentive plan that we expect to adopt prior to the closing of this offering.

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CAPITALIZATION

The following table sets forth our cash and cash equivalents and our capitalization as of June 30, 2006:

on a historical basis; and

on a pro forma basis to reflect the offering of the common units (assuming we price this offering at $20.00 per common unit, the mid-point of the price range reflected on the cover page of this prospectus), the $8.0 million cash contribution to be made to us in respect of the Class D interests, our borrowing of $30.0 million under our reserve-based credit facility and the application of the net proceeds from these transactions and this offering as described under Use of Proceeds.

We derived this table from, and it should be read together with and is qualified in its entirety by reference to, our historical and unaudited pro forma consolidated financial statements and the accompanying notes included elsewhere in this prospectus. You should also read this table in conjunction with Summary Constellation Energy Partners LLC The Transactions and Limited Liability Company Structure, Use of Proceeds and Management s Discussion and Analysis of Financial Condition and Results of Operations .

	As of June 30, 2006	
	Historical	Pro Forma
	(In 000 s)	
Cash and cash equivalents	$ 3,880	$ 7,827
Debt		
Note payable	$ 52	$ 52
Reserve-based credit facility[(a)]		22,000
Total debt	52	22,052
Class D Interests[(a)(b)]		8,000
Equity		
Members equity[(c)]	177,437	
Common units held by public[(c)]:		58,457
Common units held by CEPH:[(c)]		77,944
Class A units held by CEPM:		2,784
Total equity[(d)]	177,437	139,185
Total capitalization	$ 177,489	$ 169,237

(a) Prior to the closing of this offering, we will borrow $30.0 million under our reserve-based credit facility. The proceeds are included in the distribution to CEPH described in Use of Proceeds. The proceeds of $8.0 million contributed to us by CHI for the Class D interests will be used to reduce the borrowing under our reserve-based credit facility from $30.0 million to $22.0 million immediately following the offering.

(b) Due to their contingently redeemable feature, the Class D interests will be 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*.

(c) Does not reflect any common units that may be issued under the long-term incentive plan that we expect to adopt prior the the closing of this offering.

(d) Includes $0.9 million of unrealized gains on our cash flow hedges.

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DILUTION

Dilution is the amount by which the offering price paid by the purchasers of common units sold in this offering will exceed the net tangible book value per common unit after the offering. Net tangible book value is our total tangible assets less total liabilities. Assuming an initial public offering price of $20.00 per common unit, on a pro forma basis as of June 30, 2006, after giving effect to the offering of common units and the application of the related net proceeds, and assuming the underwriters option to purchase additional common units is not exercised, our net tangible book value would be $139.2 million, or $9.41 per common unit. Thus, purchasers of common units in this offering will experience substantial and immediate dilution in net tangible book value per common unit for financial accounting purposes, as illustrated in the following table:

Assumed initial public offering price per common unit		$ 20.00
Net tangible book value per common unit before the offering[(a)]	$ 20.85	
Decrease in net tangible book value per common unit attributable to purchasers in the offering	(11.44)	
Less: Pro forma net tangible book value per common unit after the offering[(b)]		9.41
Immediate dilution in net tangible book value per common unit to new investors		$ 10.59

(a) Determined by dividing the total number of common units and Class A units to be issued to CEPM and its affiliates (8,214,010 common units and 295,690 Class A units) into our net tangible book value of the contributed assets and liabilities of $177.4 million as of June 30, 2006.

(b) Determined by dividing the total number of common units and Class A units to be outstanding after this offering (14,489,010 common units and 295,690 Class A units) into our pro forma net tangible book value, after giving effect to the application of the expected net proceeds we receive from this offering, of $139.2 million as of June 30, 2006.

The following table sets forth the number of units that we will issue and the total consideration contributed to us by CEPM and its affiliates in respect of their Class A units and common units and by the purchasers of common units in this offering upon consummation of the transactions contemplated by this prospectus:

	Class A and Common Units Acquired			Total Consideration	
	Class	Number	Percent	Amount (In 000 s)	Percent
CEPM and its affiliates[(1)(2)]	Class A units	295,690	2%[(3)]	$ 862	0.6%
CEPM and its affiliates[(1)(2)]	Common units	8,214,010	56%[(3)]	23,938	15.9%
New investors	Common units	6,275,000	42%[(3)]	125,500	83.5%
Total		14,784,700	100%	$ 150,300	100%

(1) Upon the consummation of the transactions contemplated by this prospectus, CEPM and its affiliates will own 8,214,010 common units and 295,690 Class A units, the management incentive interests and the Class D interests.

(2) Book value of the consideration provided by CEPM and its affiliates, as of June 30, 2006, after giving effect to the application of the net proceeds of this offering and distribution of the excess cash in the cash pool and related transactions is as follows:

	(In millions)
Net tangible book value	$ 177.4
Less: Distribution to CEPH	(136.0)
Distribution of excess cash and cash pool	(16.6)
	$ 24.8

(3) These percentages do not reflect any common units that may be issued pursuant to the long-term incentive plan we expect to adopt prior to the closing of this offering.

HOW WE MAKE CASH DISTRIBUTIONS

Initial Quarterly Distributions

The amount of distributions paid under our cash distribution policy and the decision to make any distribution will be determined by our board of managers, taking into consideration the terms of our limited liability company agreement. We intend to distribute to the holders of common units and Class A units on a quarterly basis at least the IQD of $0.425 per unit, or $1.70 per unit per year to the extent we have sufficient available cash after we establish appropriate reserves and pay fees and expenses, including payments to CEPM in reimbursement of costs and expenses it incurs on our behalf. Our IQD is intended to reflect the level of cash that we expect to be available for distribution per common unit and Class A unit each quarter from our productive assets. There is no guarantee we will pay the IQD in any quarter and we will be prohibited from making any distributions to unitholders if it would cause an event of default or an event of default is existing under our credit agreement. Please read Management s Discussion and Analysis of Financial Condition and Results of Operations. Our board of managers has adopted a policy that it will raise our quarterly cash distribution only when it believes that (i) we have sufficient reserves and liquidity for the proper conduct of our business, including the maintenance of our asset base, and (ii) we can maintain such an increased distribution level for a sustained period. While this is our current policy, our board of managers may alter such policy in the future when and if it determines such alteration to be appropriate.

Distributions of Available Cash

Overview

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

Definition of Available Cash

We define available cash in the glossary, and it generally means, for each fiscal quarter, all cash on hand at the end of the quarter:

- less the amount of cash reserves established by our board of managers to:
  - provide for the proper conduct of our business (including reserves for future capital expenditures and credit needs);
  - comply with applicable law, any of our debt instruments, or other agreements; or
  - provide funds for distributions (1) to our unitholders for any one or more of the next four quarters or (2) in respect of our Class D interests or management incentive interests;

plus all cash on hand on the date of determination of available cash for the quarter resulting from working capital borrowings made after the end of the quarter. Working capital borrowings are generally borrowings that are made under our reserve-based credit facility or another arrangement and in all cases are used solely for working capital purposes or to pay distributions to unitholders.

Operating Surplus and Capital Surplus

General

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

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Definition of Operating Surplus

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

- $20.0 million (as described below); plus

- all of our cash receipts after the closing of this offering, excluding cash from (1) borrowings that are not working capital borrowings, (2) sales of equity and debt securities and (3) sales or other dispositions of assets outside the ordinary course of business; plus

- working capital borrowings made after the end of a quarter but before the date of determination of operating surplus for the quarter; plus

- cash distributions paid on equity issued to finance all or a portion of the construction, replacement or improvement of a capital asset (such as equipment or reserves) during the period beginning on the date that we enter into a binding obligation to commence the construction, acquisition or improvement of a capital improvement or replacement of a capital asset and ending on the earlier to occur of the date the capital improvement or capital asset is placed into service or the date that it is abandoned or disposed of; plus

- if the right to receive distributions (other than distributions in liquidation) on the Class D interests terminates before December 31, 2012, the excess of the amount of the $8.0 million contribution by CHI for the Class D interests over the cumulative cash distributions paid on the Class D interests before such termination shall be included in operating surplus, such inclusion to occur over a series of quarters with the amount included in each quarter to be equal to the amount of the payment we make to the Trust in respect of the NPI for such quarter that would not have been paid but for termination of the sharing arrangement; less

- our operating expenditures (as defined below) after the closing of this offering; less

- the amount of cash reserves established by our board of managers to provide funds for future operating expenditures; less

- all working capital borrowings not repaid within twelve months after having been incurred.

As described above, operating surplus does not reflect actual cash on hand that is available for distribution to our unitholders. For example, it includes a provision that will enable us, if we choose, to distribute as operating surplus up to $20.0 million of cash we receive in the future from non-operating sources such as asset sales, issuances of securities and long-term borrowings that would otherwise be distributed as capital surplus. In addition, the effect of including, as described above, certain cash distributions on equity securities in operating surplus would be to increase operating surplus by the amount of any such cash distributions. As a result, we may also distribute as operating surplus up to the amount of any such cash distributions we receive from non-operating sources.

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

We define operating expenditures in the glossary, and it generally means all of our cash expenditures, including, but not limited to, taxes, reimbursement of expenses to CEPM for services under the management services agreement, payments made in the ordinary course of business under commodity hedge contracts, manager and officer compensation, repayment of working capital borrowings, debt service payments and estimated maintenance capital expenditures, provided that operating expenditures will not include:

- repayment of working capital borrowings deducted from operating surplus pursuant to the last bullet point of the definition of operating surplus when such repayment actually occurs;

- payments (including prepayments and prepayment penalties) of principal of and premium on indebtedness, other than working capital borrowings;

- expansion capital expenditures;

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- actual maintenance capital expenditures;
- investment capital expenditures;
- payment of transaction expenses relating to interim capital transactions; or
- distributions to our members (including distributions in respect of our Class D interests and management incentive interests).

Capital Expenditures

For purposes of determining operating surplus, maintenance capital expenditures are those capital expenditures required to maintain, including over the long term, our asset base, and expansion capital expenditures are those capital expenditures that we expect will increase our asset base over the long term. Examples of maintenance capital expenditures include capital expenditures associated with the replacement of equipment and oil and natural gas reserves (including non-proved reserves attributable to undeveloped leasehold acreage), whether through the development, exploitation and production of an existing leasehold or the acquisition or development of a new oil or natural gas property. Maintenance capital expenditures will also include interest (and related fees) on debt incurred and distributions on equity issued to finance all or any portion of a replacement asset during the period from such financing until the earlier to occur of the date any such replacement asset is placed into service or the date that it is abandoned or disposed of. Plugging and abandonment costs will also constitute maintenance capital expenditures. Capital expenditures made solely for investment purposes will not be considered maintenance capital expenditures.

Because our maintenance capital expenditures can be very large and irregular, the amount of our actual maintenance capital expenditures may differ substantially from period to period, which could cause similar fluctuations in the amounts of operating surplus, adjusted operating surplus and cash available for distribution to our unitholders if we subtracted actual maintenance capital expenditures from operating surplus. As a result, to eliminate the effect on operating surplus of these fluctuations, our limited liability company agreement will require that an estimate of the average quarterly maintenance capital expenditures (including estimated plugging and abandonment costs) necessary to maintain our asset base over the long term be subtracted from operating surplus each quarter as opposed to the actual amounts spent. The amount of estimated maintenance capital expenditures deducted from operating surplus is subject to review and change by our board of managers at least once a year, provided that any change is approved by our conflicts committee. The estimate will be made at least annually and whenever an event occurs that is likely to result in a material adjustment to the amount of our maintenance capital expenditures, such as a major acquisition or the introduction of new governmental regulations that will impact our business. For purposes of calculating operating surplus, any adjustment to this estimate will be prospective only. For a discussion of the amounts we have allocated toward estimated maintenance capital expenditures, please read Cash Distribution Policy and Restrictions on Distributions.

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

- it will reduce the risk that maintenance capital expenditures in any one quarter will be large enough to render operating surplus less than the initial quarterly distribution to be paid on all the units for that quarter and subsequent quarters;
- it will increase our ability to distribute as operating surplus cash we receive from non-operating sources;

it will be more difficult for us to raise our distribution above the IQD and pay management incentive distributions on our management incentive interests; and

it will reduce the likelihood that a large maintenance capital expenditure during the First MII Earnings Period or Later MII Earnings Period will prevent the payment of a management incentive distribution in respect of the First MII Earnings Period or Later MII Earnings Period since the effect of an estimate is to spread the expected expense over several periods, thereby mitigating the effect of the actual payment of the expenditure on any single period.

Expansion capital expenditures are those capital expenditures that we expect will increase our asset base. Examples of expansion capital expenditures include the acquisition of reserves or equipment, the acquisition of new leasehold interest, or the development, exploitation and production of an existing leasehold interest, to the extent such expenditures are incurred to increase our asset base. Expansion capital expenditures will also include interest (and related fees) on debt incurred and distributions on equity issued to finance all or any portion of such capital improvement during the period from such financing until the earlier to occur of the date any such capital improvement is placed into service or the date that it is abandoned or disposed of. Capital expenditures made solely for investment purposes will not be considered expansion capital expenditures.

As described above, none of actual maintenance capital expenditures, investment capital expenditures or expansion capital expenditures are subtracted from operating surplus. Because actual maintenance capital expenditures, investment capital expenditures and expansion capital expenditures include interest payments (and related fees) on debt incurred and distributions on equity issued to finance all of the portion of the construction, replacement or improvement of a capital asset (such as equipment or reserves) during the period from such financing until the earlier to occur of the date any such capital asset is placed into service or the date that it is abandoned or disposed of, such interest payments and equity distributions are also not subtracted from operating surplus (except, in the case of maintenance capital expenditures, to the extent such interest payments and distributions are included in estimated maintenance capital expenditures).

Investment capital expenditures are those capital expenditures that are neither maintenance capital expenditures nor expansion capital expenditures. Investment capital expenditures largely will consist of capital expenditures made for investment purposes. Examples of investment capital expenditures include traditional capital expenditures for investment purposes, such as purchases of securities, as well as other capital expenditures that might be made in lieu of such traditional investment capital expenditures, such as the acquisition of a capital asset for investment purposes or development of our undeveloped properties in excess of maintenance capital expenditures, but which are not expected to expand for more than the short term our asset base.

Capital expenditures that are made in part for maintenance capital purposes and in part for investment capital or expansion capital purposes will be allocated as maintenance capital expenditures, investment capital expenditures or expansion capital expenditure by our board of managers, based upon its good faith determination, subject to approval by our conflicts committee.

Definition of Capital Surplus

We also define capital surplus in the glossary, and it will generally be generated only by:

- borrowings other than working capital borrowings;
- sales of debt and equity securities; and
- sales or other disposition of assets for cash, other than inventory, accounts receivable and other current assets sold in the ordinary course of business or as part of normal retirements or replacements of assets.

Characterization of Cash Distributions

We will treat all available cash distributed as coming from operating surplus until the sum of all available cash distributed since we began operations equals the operating surplus as of the most recent date of determination of available cash. We will treat any amount distributed in excess of operating surplus, regardless of its source, as capital surplus. We do not anticipate that we will make any distributions from capital surplus.

Distributions of Available Cash from Operating Surplus

We will make distributions of available cash from operating surplus for any quarter in the following manner:

- *first,* 98% to the common unitholders, pro rata, and 2% to the holder(s) of our Class A units, pro rata, until we distribute for each outstanding unit an amount equal to the Target Distribution for that quarter; and *thereafter,* any amount distributed in respect of such quarter in excess of the Target Distribution per unit will be distributed 98% to the holders of the common units, pro rata, and 2% to the holder(s) of our Class A units until distributions become payable in respect of our management incentive interests as described in Management Incentive Interests below.

The Class A units will be entitled to 2% of all cash distributions from operating surplus, without any requirement for future capital contributions by the holders of such Class A units, even if we issue additional common units or other senior or subordinated equity securities in the future. The percentage interests shown above for the Class A units assume they have not been converted into common units. If the Class A units have been converted, the common units will receive the 2% of distributions originally allocated to the Class A units.

Management Incentive Interests

Management incentive interests represent the right to receive 15% of quarterly distributions of available cash from operating surplus after the Target Distribution has been achieved and certain other tests have been met. CEPM currently holds the management incentive interests, which are evidenced by the Class C limited liability company interests, but may transfer these rights separately from its Class A units, subject to restrictions in our limited liability company agreement. The earliest that we could be required to make distributions in respect of the management incentive interests is after a period of 12 consecutive quarters after this 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.

Prior to the end of the First MII Earnings Period or Later MII Earnings Period, which are defined below, we will not pay any management incentive distributions. To the extent, however, that during the First MII Earnings Period or Later MII Earnings Period we distribute available cash from operating surplus in excess of the Target Distribution, our board of managers intends to cause us to reserve an amount for payment of the EP MID, which is defined below, earned during the First MII Earnings Period or Later MII Earnings Period, as the case may be, after such period ends. If during the First MII Earnings Period or Later MII Earnings Period we fail to satisfy a condition specified in the next paragraph, our board of managers will cause any such reserved amount to be released from that reserve and restored to available cash.

Payments to the holder of our management incentive interests will be subject to the satisfaction of certain requirements. The first requirement is the 12-Quarter Test, which requires that for the 12 full, consecutive, non-overlapping calendar quarters that begin with the first calendar quarter in respect of which we pay per unit cash distributions from operating surplus to holders of Class A and common units in an amount equal to or greater than the Target Distribution (that is, our $0.425 IQD plus $0.06375) (we refer to such 12-quarter period as the First MII Earnings Period):

- we pay cash distributions from operating surplus to holders of our outstanding Class A and common units in an amount that on average exceeds the Target Distribution on all of the outstanding Class A units and common units over the First MII Earnings Period;
- we generate adjusted operating surplus (which is summarized below and is defined in the glossary included as Appendix B) during the First MII Earnings Period that on average is in an amount at least equal to 100% of all distributions on the outstanding Class A and common units up to the Target Distribution plus 117.65% of all such distributions in excess of the Target Distribution; and
- we do not reduce the amount distributed per unit in respect of any such 12 quarters.

The second requirement is the 4-Quarter Test, which requires that for each of the last four full, consecutive, non-overlapping calendar quarters in the First MII Earnings Period:

- we pay cash distributions from operating surplus to the holders of our outstanding Class A and common units that exceed the Target Distribution on all of the outstanding Class A and common units;

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We generate adjusted operating surplus in an amount at least equal to 100% of all distributions on the outstanding Class A and common units up to the Target Distribution plus 117.65% of all such distributions in excess of the Target Distribution; and

we do not reduce the amount distributed per unit in respect of any such four quarters.

If both the 12-Quarter Test and the 4-Quarter Test have been met, then: (i) we will make a one-time management incentive distribution (contemporaneously with the distribution paid in respect of the Class A and common units for the twelfth calendar quarter in the First MII Earnings Period) to the holder of our management incentive interests equal to 17.65% of the sum of the cumulative amounts, if any, by which quarterly cash distributions per unit part on the outstanding Class A and common units during the First MII Earnings Period exceeded the Target Distribution on all of the outstanding Class A and common units (we refer to this one-time management incentive distribution as an EP MID); and (ii) for each calendar quarter after the First MII Earnings Period, the holders of our Class A units, common units and management incentive interests will receive 2%, 83% and 15%, respectively, of cash distributions from available cash from operating surplus that we pay for such quarter in excess of the Target Distribution.

If the 12-Quarter Test is not met and except as described below, management incentive distributions will not be payable in respect of the First MII Earnings Period and the holder of the management incentive interests will forfeit any and all rights to any management incentive distributions in respect of the First MII Earnings Period. An EP MID may become payable, however, with respect to a Later MII Earnings Period, if the 12-Quarter Test and the 4-Quarter Test are met in respect of such Later MII Earnings Period. A Later MII Earnings Period may begin with the first quarter following the quarter in which the 12-Quarter Test is not met, or, where we do not meet the 12-Quarter Test because we reduced our cash distribution in a particular quarter, the Later MII Earnings Period may begin with the quarter in which such reduction is made. If both tests are met with respect to a Later MII Earnings Period, then for each calendar quarter after the Later MII Earnings Period, the holders of the Class A units, common units and management incentive interests will receive 2%, 83% and 15%, respectively, of cash distributions from available cash from operating surplus that we pay for such quarter in excess of the Target Distribution.

However, if (a) the 12-Quarter Test has been met in respect of the First MII Earnings Period or any Later MII Earnings Period, but not the 4-Quarter Test; (b) the 4-Quarter Test has been met in any period of four full, consecutive and non-overlapping quarters occurring after the end of the First MII Earnings Period or Later MII Earnings Period, as the case may be, up to three of which quarters can fall within the First MII Earnings Period or Later MII Earnings Period, as the case may be (we refer to such four-quarter period as the MII 4-Quarter Earnings Period); and (c) we have paid at least the IQD in each calendar quarter occurring between the end of the First MII Earnings Period or Later MII Earnings Period, as the case may be, and the beginning of the MII 4-Quarter Earnings Period:

the holders of our Class A units, common units and management incentive interests will receive 2%, 83% and 15%, respectively, of cash distributions from available cash from operating surplus that we pay in excess of the Target Distribution for each calendar quarter after the MII 4-Quarter Earnings Period; and

the holder of our management incentive interests will receive an EP MID with respect to the First MII Earnings Period or Later MII Earnings Period, as the case may be.

Our board of managers has adopted a policy that it will raise our quarterly cash distribution only when it believes that (i) we have sufficient reserves and liquidity for the proper conduct of our business, including the maintenance of our asset base, and (ii) we can maintain such increased distribution level for a sustained period. While this is our current policy, our board of managers may alter such policy in the future when and if it determines such alteration to be appropriate.

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Definition of Adjusted Operating Surplus

We define adjusted operating surplus in the glossary and for any period it generally means:

- operating surplus generated with respect to that period less any amounts described in the fifth bullet point under Definition of Operating Surplus above; less

- any net increase in working capital borrowings with respect to that period (excluding any such borrowings to the extent the proceeds are distributed to the record holder of our Class D interests); less

- any net reduction in cash reserves for operating expenditures with respect to that period not relating to an operating expenditure made with respect to that period; plus

- any net decrease in working capital borrowings with respect to that period; plus

- any net increase in cash reserves for operating expenditures made with respect to that period required by any debt instrument for the repayment of principal, interest or premium.

Adjusted operating surplus is intended to reflect the cash generated from our operations during a particular period and therefore excludes net increases in working capital borrowings and net drawdowns of reserves of cash generated in prior periods.

Percentage Allocations of Available Cash from Operating Surplus

The following table illustrates the percentage allocations of the additional available cash from operating surplus between the unitholders and CEPM as the owner of our management incentive interests up to various distribution levels. The amounts set forth under Marginal Percentage Interest in Distributions are the percentage interests of our Class A unitholders and common unitholders and the holders of our management incentive interests in any available cash from operating surplus we distribute up to and including the corresponding amount in the column Quarterly Distribution Level, until available cash from operating surplus we distribute reaches the next distribution level, if any. The percentage interests shown for the IQD are also applicable to quarterly distribution amounts that are less than the IQD. The percentage interests shown in the table below assume that the Class A units have not been converted into common units as described herein.

		Marginal Percentage Interest in Distributions		
	Quarterly Distribution Level	**Class A Unitholders**	**Common Unitholders**	**Management Incentive Interests**
IQD	$0.425	2%	98%	0%
Target Distribution	above $0.425 up to $0.48875	2%	98%	0%

Thereafter*	above $0.48875	2%	83%	15%

* Assumes the management incentive interests have met the 12-Quarter Test and the 4-Quarter Test. Until the 12-Quarter Test and the 4-Quarter Test are met and distributions in respect of the management incentive interests become payable, quarterly distributions in excess of the $0.48875 Target Distribution will be made 2% to the holder of the Class A units and 98% to the holders of common units, pro rata.

Distributions from Capital Surplus

How Distributions from Capital Surplus Will Be Made

We will make distributions of available cash from capital surplus, if any, in the following manner:

First, 2% to the holder of our Class A units and 98% to all common unitholders, pro rata, until we distribute for each common unit that was issued in this offering an amount of available cash from capital surplus equal to the initial public offering price; and

Thereafter, we will make all distributions of available cash from capital surplus as if they were from operating surplus.

Effect of a Distribution from Capital Surplus

Our limited liability company agreement treats a distribution of capital surplus as the repayment of the initial common unit price from this initial public offering, which is a return of capital. The initial public offering price less any distributions of capital surplus per common unit is referred to as the unrecovered initial common unit price. Each time a distribution of capital surplus is made, the IQD and the Target Distribution will be reduced in the same proportion as the corresponding reduction in the unrecovered initial common unit price. Because distributions of capital surplus will reduce the IQD, after any of these distributions are made, it may be easier for CEPM to receive management incentive distributions. However, any distribution of capital surplus before the unrecovered initial common unit price is reduced to zero cannot be applied to the payment of the IQD.

Once we distribute capital surplus on a common unit issued in this offering in an amount equal to the initial common unit price, we will reduce the IQD and the Target Distribution to zero. We will then make all future distributions from operating surplus, with 2% being distributed to the holder of our Class A units, 83% being distributed to our common unitholders, pro rata, and 15% being distributed to the holder of our management incentive interests. The percentage interests shown above for the Class A units assume they have not been converted into common units. If the Class A units have been converted, the common units will receive the 2% of distributions originally allocated to the Class A units.

Adjustment to the IQD and Target Distribution

In addition to adjusting the IQD and Target Distribution to reflect a distribution of capital surplus, if we combine our common units into fewer common units or subdivide our common units into a greater number of common units, we will proportionately adjust:

- the IQD;
- the Target Distribution; and
- the unrecovered initial common unit price.

For example, if a two-for-one split of the common units should occur, the Target Distribution and the unrecovered initial common unit price would each be reduced to 50% of its initial level. We will not make any adjustment by reason of the issuance of additional units for cash or property.

In addition, if legislation is enacted or if existing law is modified or interpreted by a court of competent jurisdiction, so that we become taxable as a corporation or otherwise subject to taxation as an entity for federal, state or local income tax purposes, we will reduce the IQD and the Target Distribution for each quarter by multiplying each by a fraction, the numerator of which is available cash for that quarter (after deducting our board of manager s estimate of our aggregate liability for the quarter for such income taxes payable by reason of such legislation or interpretation) and the denominator of which is the sum of available cash for that quarter plus our board of managers estimate of our aggregate liability for the quarter for such income taxes payable by reason of such legislation or interpretation. To the extent that the actual tax liability differs from the estimated tax liability for any quarter, the difference will be accounted for in subsequent quarters.

Quarterly Cash Distributions on our Class D Interests

In order to address the risk of early termination, without the prior consent of board of managers, prior to December 31, 2012, of the sharing arrangement under the gas purchase contract pertaining to the calculation of amounts payable to the Trust for the NPI, and the potential reduction in our revenues resulting therefrom, at the closing of this offering CHI will contribute $8.0 million to us for all of our Class D interests. For each full calendar quarter during the period commencing January 1, 2007 and ending on December 31, 2012 that the sharing arrangement remains in effect, we will distribute to the holder of the Class D interests $333,333, 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 unitholders for that quarter. 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, unless the special distribution right has been terminated earlier. Such special quarterly cash distributions will be made 45 days after the end of each calendar quarter, commencing with the quarter ending March 31, 2007.

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 and the remaining portion of the $8.0 million original contribution not so returned in special cash distributions will be retained by us to partially offset the reduction in our revenues resulting from termination of the sharing arrangement. In the case of such termination of the special distribution right, CHI will have the right only 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. See Distributions of Cash Upon Liquidation below. If the gas purchase contract in respect of the Trust Wells is terminated during a quarter, the special distribution to CHI as the holder of our Class D interests will be prorated for that quarter based on the ratio of the number of days in such quarter prior to the effective date of such termination to 90. If we and any of the Trust, the trustee of the Trust or any subsequent holder of the NPI become involved in a dispute or proceeding in which such person asserts that prior to December 31, 2012 the sharing arrangement ceased to be applicable in calculating amounts payable in respect of production from the Trust Wells, special cash distributions in respect of the Class D interests for periods commencing at the inception of such dispute will be suspended, and such suspended amounts will only be paid to the holder of the Class D interests to the extent it is finally determined that the sharing arrangement remained applicable during some or all of the suspension period.

Distributions of Cash Upon Liquidation

General

If we dissolve in accordance with our limited liability company agreement, we will sell or otherwise dispose of our assets in a process called liquidation. We will first apply the proceeds of liquidation to the payment of our creditors. We will distribute any remaining proceeds to the unitholders, to CHI, the entity that will contribute $8.0 million to us in exchange for the Class D interests, CEPH and CEPM in accordance with their capital account balances, as adjusted to reflect any gain or loss upon the sale or other disposition of our assets in liquidation.

Manner of Adjustments for Gain

The manner of the adjustment for gain is set forth in our limited liability company agreement, and requires that we will allocate any gain to the unitholders and holders of the Class A units in the following manner:

First, to the holders of common units who have negative balances in their capital accounts to the extent of and in proportion to those negative balances;

Second, 2% to the holder of our Class A units and 98% to the common unitholders, pro rata, until the capital account for each common unit is equal to the sum of:

(1) the unrecovered initial common unit price; and

(2) the amount of the IQD for the quarter during which our liquidation occurs; and

Third, 100% to the holder of our Class D interests, until the capital account of the Class D interests equals, in the aggregate, the excess, if any, of (i) the $8.0 million capital contribution made to us by CHI at the closing of this offering for all of our Class D interests over (ii) the cumulative amount distributed as a special distribution to the holder of the Class D interests in accordance with the description under Quarterly Cash Distributions On Our Class D interests above;

Fourth, 2% to the holder of our Class A units and 98% to the common unitholders, pro rata, until the capital account for each common unit is equal to the sum of:

(1) the amount described above under the second bullet point of this paragraph; and

(2) the excess of (I) over (II), where

(I) equals the sum of the excess of the Target Distribution per common unit over the IQD for each quarter of our existence; and

(II) equals the cumulative amount per common unit of any distributions of available cash from operating surplus in excess of the IQD per common unit that we distributed 98% to our common unitholders, pro rata, for each quarter of our existence; and

Thereafter, 2% to the holder of our Class A units, 83% to all common unitholders, pro rata, and 15% to the holder of our management incentive interests.

Manner of Adjustments for Losses

Upon our liquidation, we will generally allocate any loss 2% to the holder of the Class A units and 98% to the holders of the outstanding common units, pro rata.

Adjustments to Capital Accounts

We will make adjustments to capital accounts upon the issuance of additional common units. In doing so, we will allocate any unrealized and, for tax purposes, unrecognized gain or loss resulting from the adjustments to the holder of the Class A units, the common unitholders, the holders of Class D interests and the holders of the management incentive interests in the same manner as we allocate gain or loss upon liquidation. In the event that we make positive adjustments to the capital accounts upon the issuance of additional common units, we will allocate any later negative adjustments to the capital accounts resulting from the issuance of additional common units or upon our liquidation in a manner which results, to the extent possible, in the capital account balances of the holders of the management incentive interests equaling the amount which they would have been if no earlier positive adjustments to the capital accounts had been made.

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CASH DISTRIBUTION POLICY AND

RESTRICTIONS ON DISTRIBUTIONS

You should read the following discussion of our cash distribution policy in conjunction with specific assumptions included in this section. For more detailed information regarding the factors and assumptions upon which our cash distribution policy is based, please read Our Estimated Cash Available to Pay Distributions Our Estimated Adjusted EBITDA below. In addition, you should read Cautionary Note Regarding Forward-Looking Statements and Risk Factors for information regarding statements that do not relate strictly to historical or current facts and certain risks inherent in our business.

For additional information regarding our historical and pro forma results of operations, you should refer to our historical and pro forma consolidated financial statements for the six months ended June 30, 2006 and the year ended December 31, 2005, included elsewhere in this prospectus as well as Management s Discussion and Analysis of Financial Condition and Results of Operations.

General

Rationale for our Cash Distribution Policy

Our cash distribution policy reflects a basic judgment that our unitholders will be better served by our distributing our available cash (after deducting expenses, estimated maintenance capital expenditures and reserves) rather than our retaining it. Moreover, it is the current policy of our board of managers that we should increase our level of quarterly cash distributions per unit only when, in its judgment, it believes that (i) we have sufficient reserves and liquidity for the conduct of our business, including the maintenance of our asset base, and (ii) we can maintain such an increased distribution level for a sustained period. The amount of available cash will be determined by our board of managers for each calendar quarter after the closing of the offering and will be based upon recommendations from our management. Because we believe we will generally finance any expansion capital expenditures and investment capital expenditures from external financing sources, we also believe that our investors are best served by our distributing all of our available cash. In addition, since we are not subject to an entity-level federal income tax, we have more cash to distribute to you than would be the case were we subject to federal income tax. Our cash distribution policy is consistent with the terms of our limited liability company agreement, which requires that we distribute all of our available cash quarterly (and our available cash is determined after deducting expenses, estimated maintenance capital expenditures and reserves). Under that policy, we will pay an initial quarterly distribution, or IQD, of $0.425 per Class A unit and common unit for each complete quarter. These distributions will not be cumulative. Consequently, if distributions on our common units and Class A units are not paid with respect to any fiscal quarter at the anticipated IQD rate, our unitholders will not be entitled to receive such payments in the future. We are a recently formed limited liability company and have not historically made any cash distributions. For a more detailed discussion, please read How We Make Cash Distributions elsewhere in this prospectus.

Restrictions and Limitations on Our Ability to Make Quarterly Distributions

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

Other than the obligation under our limited liability company agreement to distribute available cash on a quarterly basis, which is subject to our board of managers authority to establish reserves and other limitations, our unitholders have no contractual or other legal right to receive distributions.

Our board of managers will have broad discretion to establish reserves for the prudent conduct of our business and for the payments to the holders of our Class D interests and for future cash distributions, including, during the First MII Earnings Period or any Later MII Earnings Period, payment of the EP

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MID, and the establishment of those reserves could result in a reduction in cash distributions to you from the levels we currently anticipate pursuant to our stated distribution policy.

Our ability to make distributions of available cash will depend primarily on our cash flow from operations, which primarily depends on our level of production and our realized natural gas prices. Although our limited liability company agreement provides for quarterly distributions of available cash, we have no prior history of making distributions to our members.

Our distribution policy will be subject to restrictions on distributions under our new reserve-based credit agreement. Specifically, our credit agreement requires us to maintain a ratio of total borrowings outstanding under our reserve-based credit facility to our Borrowing Base (as defined in our credit agreement) measured at the time of the distribution of not more than 0.90 to 1.0. In addition, the credit facility contains covenants requiring us to maintain, as of the last day of each fiscal quarter, a ratio of our Adjusted EBITDA (as defined in our credit agreement) to our 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 that results in or could result in acceleration of any of our indebtedness in excess of $1.0 million will constitute an event of default under our credit agreement that would prohibit us from making distributions. Should we be unable to satisfy these restrictions or another default or event of default occurs and is continuing under our credit agreements, we would be prohibited from making a distribution to you notwithstanding our stated distribution policy. Please read Management s Discussion and Analysis of Financial Condition and Results of Operations Capital Resources and Liquidity Reserve-Based Credit Facility.

Even if our cash distribution policy is not modified or revoked, the amount of distributions we pay and the decision to make any distribution is determined by our board of managers, taking into consideration the terms of our limited liability company agreement.

We have a limited operating history and therefore we have a limited historical basis upon which to rely in our determination as to whether we will have sufficient available cash to pay the initial quarterly distribution.

Under Section 18-607 of the Delaware Limited Liability Company Act, or Delaware Act, we may not make a distribution to you if the distribution would cause our liabilities to exceed the fair value of our assets.

We may lack sufficient cash to pay distributions to our unitholders due to a number of factors, including reduced production from our wells, lower prices for the natural gas we sell, increases in our operating or selling, general and administrative expense, principal and interest payments on our outstanding debt, tax expenses, capital expenditures, working capital requirements or other anticipated cash needs. See Risk Factors for information regarding the factors.

Although our limited liability company agreement requires us to distribute our available cash, our limited liability company agreement may be amended with the approval of our board of managers and both a common unit majority and a Class A unit majority. At the closing of this offering, CEPH will own approximately 57% of the outstanding common units (approximately 50% if the underwriters exercise their option to purchase additional common units in full) and CEPM will own 100% of the outstanding Class A units. These common unit percentages do not reflect any common units that may be issued under the long-term incentive plan that we expect to adopt prior to the closing of this offering.

Our ability to make distributions to our unitholders depends on the performance of our subsidiaries and their ability to distribute funds to us. The ability of our subsidiaries to make distributions to us may be restricted by, among other things, the provisions of existing and future indebtedness, applicable state limited liability company laws and other laws and regulations, including state laws and policies affecting our oil and natural gas production, gathering and marketing operations.

Our Cash Distribution Policy Limits Our Ability to Grow

Because we distribute all of our available cash, our growth may not be as significant as businesses that reinvest their available cash to expand ongoing operations. If we issue additional common units or incur debt to fund acquisitions and expansion capital expenditures, the payment of distributions on those additional units or interest on that debt could increase the risk that we will be unable to maintain or increase our per unit distribution level.

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

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

Our Initial Quarterly Distribution Rate

Our Cash Distribution Policy

Upon completion of this offering, our board of managers will adopt a policy pursuant to which we will pay an initial quarterly distribution, or IQD, of $0.425 per Class A unit and common unit for each complete quarter. Beginning with the quarter ending December 31, 2006, we will pay our distributions within 45 days after the end of each quarter ending March, June, September and December to holders of record on the record date established for such distribution. If the distribution date does not fall on a business day, we will make the distribution on the business day immediately preceding the indicated distribution date. We will adjust our first distribution for the period from the closing of the offering through December 31, 2006 based on the actual length of the period. These distributions will not be cumulative. Consequently, if distributions on our common units and Class A units are not paid with respect to any fiscal quarter at the anticipated IQD rate, our unitholders will not be entitled to receive such payments in the future.

If the underwriters exercise their option to purchase additional common units from us, we will use the additional net proceeds from such exercise to redeem from CEPM an equivalent number of common units. Accordingly, the exercise of the underwriters option will not affect the total amount of units outstanding or the amount of cash needed to pay the initial quarterly distribution rate on all units. Our ability to make cash distributions at the initial distribution rate pursuant to this policy will be subject to the factors described above under the caption Restrictions and Limitations on Our Ability to Make Quarterly Distributions.

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The following table sets forth the estimated aggregate amount of available cash from operating surplus, which we also refer to as cash available for distributions, needed to pay the IQD on all of the common units and the Class A units to be outstanding immediately after this offering for one full quarter (at the initial rate of $0.425 per unit per quarter) and for four full quarters (at the initial rate of $1.70 per unit for four quarters):

		Initial Quarterly Distribution	
	Number of Units	One Quarter	Four Quarters
		(In 000 s)	
Common units	14,489,010(a)	$ 6,158	$ 24,631
Class A units	295,690(a)	126	503
Total	14,784,700	$ 6,284	$ 25,134

(a) Does not include any common units that may be issued under the long-term incentive plan that we expect to adopt prior to the closing of this offering.

The Class A units will be entitled to 2% of all distributions that we make prior to our liquidation. The 2% sharing ratio of the Class A units will not be reduced if we issue additional equity securities in the future.

We do not have a legal obligation to pay distributions at our initial distribution rate or at any other rate except as provided in our limited liability company agreement. Our distribution policy is consistent with the terms of our limited liability company agreement, which requires that we distribute all of our available cash quarterly. Under our limited liability company agreement, available cash is defined to generally mean, for each fiscal quarter, cash generated from our business in excess of the amount our board of managers determines is necessary or appropriate to provide for the conduct of our business, to comply with applicable law, any of our debt instruments or other agreements or to provide for payment of the EP MID to the holder of our management incentive interests or for future distributions to the holder of our Class D interests or to our unitholders for any one or more of the upcoming four quarters. Holders of our common units may pursue judicial action to enforce provisions of our limited liability company agreement, including those related to requirements to make cash distributions as described above; however, our limited liability company agreement provides that any determination made by our board of managers must be made in good faith and that any such determination will not be subject to any other standard imposed by our limited liability company agreement, the Delaware Act or any other law, rule or regulation or at equity. Our limited liability company agreement also provides that, in order for a determination by our board of managers to be made in good faith, our board of managers must believe that the determination is in our best interests.

The requirement in our limited liability company agreement to distribute all of our available cash quarterly may not be modified or repealed without amending our limited liability company agreement; however, the actual amount of our cash distributions for any quarter is subject to fluctuation based on the amount of cash we generate from our business and the amount of reserves our board of managers establishes in accordance with our limited liability company agreement as described above. Our limited liability company agreement may be amended with the approval of our board of managers and holders of a majority of our outstanding common units.

In the sections that follow, we present in detail the basis for our belief that we will have sufficient available cash from operating surplus to pay the IQD on all outstanding Class A units and common units for each full calendar quarter through September 30, 2007. In those sections, we present the following two tables:

Our Estimated Cash Available to Pay Distributions, in which we present our Estimated Adjusted EBITDA for the twelve months ending September 30, 2007. In the footnotes to this first table, we present the significant assumptions and considerations underlying our belief that we will generate sufficient Estimated Adjusted EBITDA to pay the IQD on all outstanding Class A units and common units for each quarter through September 30, 2007; and

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Unaudited Pro Forma Cash Available to Pay Distributions, in which we present our estimate of the amount of available cash we would have had on a pro forma basis in 2005 and for the twelve months ended June 30, 2006, based on our pro forma financial statements that are included elsewhere in this prospectus.

Financial Forecast

For the purpose of this offering, our management has prepared the prospective financial information set forth in Our Estimated Cash Available to Pay Distributions below, and such information is the responsibility of our management. Our forecast information presents, to our best knowledge and belief, our expected results of operations and cash flows for the twelve-month period ending September 30, 2007. Our forecast financial information reflects our judgment as of the date of this prospectus of conditions we expect to exist and the course of action we expect to take during the twelve months ending September 30, 2007. The assumptions disclosed in the footnotes to the table under the caption Our Estimated Cash Available to Pay Distributions Our Estimated Adjusted EBITDA below are those that we believe are significant to our forecasted information, but we can give you no assurance that our forecast results will be achieved. There will likely be differences between our forecast and actual results, and those differences could be material. If the forecast is not achieved, we may not be able to pay the full IQD or any amount on our outstanding common units.

Our forecast financial information is a forward-looking statement and should be read together with the historical and pro forma financial statements and the accompanying notes included elsewhere in this prospectus and together with Management s Discussion and Analysis of Financial Condition and Results of Operations. In the view of our management, however, such information was prepared on a reasonable basis, reflects the best currently available estimates and judgments, and presents, to the best of management s knowledge and belief, the assumptions and considerations on which we base our belief that we can generate the Estimated Adjusted EBITDA necessary for us to have sufficient available cash for distribution to pay a distribution on the common units and Class A units at the initial quarterly distribution rate. However, this information is not fact and should not be relied upon as being necessarily indicative of future results, and readers of this prospectus are cautioned not to place undue reliance on the prospective financial information.

Neither our independent registered public accounting firm, nor any other independent accountants, have compiled, examined or performed any procedures with respect to the prospective financial information contained in this section, nor have they expressed any opinion or any other form of assurance on such information or its achievability, and they assume no responsibility for the prospective financial information. Such independent registered public accounting firms reports included elsewhere in this prospectus relate to the appropriately described historical financial information contained in this section. Such reports do not extend to the tables and related information contained in this section and should not be read to do so. In addition, such tables and information were not prepared:

- with a view toward compliance with the guidelines established by the American Institute of Certified Public Accountants for preparation and presentation of prospective financial information; or

- in accordance with GAAP.

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

As a result of the factors described in Our Estimated Cash Available to Pay Distributions and in the footnotes to the table in that section, we believe we will be able to pay distributions at the initial quarterly distribution rate of $0.425 per unit on all outstanding common units and

Class A units for each full calendar quarter in the twelve-month period ending September 30, 2007. The number of outstanding common units on which we have based such belief does not include any common units that may be issued under the long-term incentive plan that we expect to adopt prior to the closing of this offering.

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Our Estimated Cash Available to Pay Distributions

In order to pay the IQD to our unitholders of $0.425 per unit per quarter over the four full calendar quarters ending September 30, 2007, our cumulative available cash to pay distributions must be at least approximately $25.1 million over that period. We have calculated that the minimum amount of our Estimated Adjusted EBITDA for the twelve-month period ending September 30, 2007 that we estimate will be necessary to generate cash available to pay aggregate distributions of approximately $25.1 million over that period is approximately $31.6 million. Adjusted EBITDA should not be considered an alternative to net income, income before income taxes, cash flows from operating activities or any other measure of financial performance calculated in accordance with GAAP as those items are used to measure operating performance or liquidity.

Adjusted EBITDA is a significant liquidity metric to be used by our management to indicate (prior to the establishment of any 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 operating cash flow at a level that can sustain or support an increase in our quarterly distribution rates. As used in this prospectus, the term Adjusted EBITDA means the sum of net income (loss) plus:

- 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.

In the table below entitled Our Estimated Adjusted EBITDA, we calculate that our Estimated Adjusted EBITDA will be approximately $31.6 million for the four full calendar quarters ending September 30, 2007, which is sufficient for us to be able to generate cash available to pay aggregate distributions of approximately $25.1 million to the holders of our common units and Class A units, assuming borrowings of $5.3 million to fund our investment capital expenditures and distributions on our Class D interests. If we do not borrow funds to finance such expenditures, we would experience a shortfall in the amount of cash generated from our operations to both pay the aggregate cash distributions on our common units and Class A units and make the investment capital expenditures we expect to make and pay cash distributions on our Class

D interests.

In calculating the Estimated Adjusted EBITDA that we will need to pay cash distributions, we have included estimates of estimated maintenance capital expenditures, investment capital expenditures and expansion capital expenditures for the twelve-month period ending September 30, 2007. Maintenance capital expenditures are capital expenditures that we expect to make on an ongoing basis to maintain our asset base (including our undeveloped leasehold acreage) at a steady level over the long term. These expenditures include the drilling and completion of additional development wells to offset the expected production decline during such period from our producing properties, as well as additions to our inventory of unproved properties or proved reserves required to maintain our asset base.

Investment capital expenditures are capital expenditures that are neither maintenance capital expenditures nor expansion capital expenditures. Our estimated investment capital expenditures for the twelve months ending September 30, 2007 consist of capital expenditures we expect to make to drill and complete additional development wells and to refracture the formations of specified existing wells in excess of the level of such operations that are necessary to offset our expected depletion rate of our producing properties and replace reserves.

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Expansion capital expenditures consist of capital expenditures we expect to make to expand the size of our asset base for longer than the short term. These expenditures would include amounts expended to increase the rate of development and production of our existing properties at a rate in excess of that necessary to offset our expected depletion rate decline of existing producing properties and which excess production or operating capacity we expect to extend for longer than the short term. Expansion capital expenditures also consist of capital expenditures that increase our inventory of unproved properties or our proved reserves to the extent such increases exceed those necessary to maintain our asset base. Expansion capital expenditures may include expenditures for additional producing properties, undeveloped leasehold acreage, gathering, treating or processing facilities, new drilling, workovers, recompletions, completion and other production enhancement technologies that we expect will increase our asset base over the long term. For the twelve months ending September 30, 2007, we have not estimated any expansion capital expenditures since we do not have any acquisitions pending or planned and the capital expenditures we expect to incur on our existing properties do not include any that would constitute expansion capital expenditures.

You should read the footnotes to the table under the caption Our Estimated Adjusted EBITDA below for a discussion of the material assumptions underlying our belief that we will be able to generate the Estimated Adjusted EBITDA of approximately $31.6 million. Our belief is based on those assumptions and reflects our judgment, as of the date of this prospectus, regarding the conditions we expect to exist and the course of action we expect to take over the twelve-month period ending September 30, 2007. The assumptions we disclose below are those that we believe are significant to our ability to generate the necessary Estimated Adjusted EBITDA. If our estimates prove to be materially incorrect, we may not be able to pay the IQD or any amount on our outstanding units during the four calendar quarters ending September 30, 2007.

When considering our Estimated Adjusted EBITDA, you should keep in mind the risk factors and other cautionary statements under the heading Risk Factors and elsewhere in this prospectus. Any of these risk factors or the other risks discussed in this prospectus could cause our financial condition and results of operations to vary significantly from those set forth in the table below.

Our Estimated Adjusted EBITDA

The following table illustrates (i) our Estimated Adjusted EBITDA that we expect to generate for the twelve months ending September 30, 2007 based on the assumptions and considerations described in the footnotes to the table and (ii) the estimated cash available to pay distributions for the twelve-month period ending September 30, 2007, assuming that the offering was consummated on October 1, 2006. We explain each of the adjustments presented below in the footnotes to the table. All of the amounts for the twelve-month period ending September 30, 2007 in the table and footnotes below are estimates.

		Twelve-Month Period Ending September 30, 2007
		(In 000 s, except per unit data and ratios)
Estimated Adjusted EBITDA[(a)]	$	31,624
Less:		
Estimated maintenance capital expenditures[(b)]		(4,950)
Estimated interest expense[(c)]		(1,540)
Estimated investment capital expenditures[(d)]		(4,272)
Cash required to pay Class D special cash distributions[(e)]		(1,029)
Add:		
Borrowings to finance investment capital expenditures and Class D distributions[(c)(d)(e)]		5,301

Excess proceeds from initial public offering available for distribution[(f)]		5,027
Estimated cash available to pay distributions	$	30,161
Less:		
Estimated total cash distributions to common unitholders and Class A unitholder	$	(25,134)
Excess cash available	$	5,027

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		Twelve-Month Period Ending September 30, 2007 (In 000 s, except per unit data and ratios)
Estimated cash distributions		
Annualized initial quarterly distribution per unit	$	1.70
Estimated total cash distributions to common unitholders and Class A unitholder[(g)]	$	25,134
Borrowing base ratio[(h)]		0.2x
Interest coverage ratio[(h)]		18.6x
Total debt/Adjusted EBITDA ratio[(h)]		0.7x

(a) As reflected in the table below, to generate our Estimated Adjusted EBITDA for the twelve months ending September 30, 2007, we have assumed the following regarding our operations, revenues and expenses:

Net sales volumes[(1)]	5.0 Bcf
Average Henry Hub Price (NYMEX) (hedged volumes)[(2)]	$9.22 per MMBtu
Average SONAT Inside FERC Price (unhedged volumes)[(2)]	$8.82 per MMBtu
Percentage of net production hedged	78%
Weighted average net realized natural gas sales price[(2)]	$9.11 per MMBtu
Estimated adjusted EBITDA (in thousands):	
Total revenues[(3)]	$43,980
Field operating expenses[(4)]	(8,717)
Torch NPI Payment[(5)]	(291)
General and administrative expenses[(6)]	(4,803)
Hedge gains[(3)]	1,455
Estimated Adjusted EBITDA	$31,624

(1) Our forecasted net sales volumes for the twelve months ending September 30, 2007 are based on our estimated proved reserves as of December 31, 2005, which were prepared using a price of $10.06 per MMBtu, based on the SONAT Gas Daily Price on December 30, 2005. The price used in preparing our proved reserve estimates, which price is consistent with SEC rules and regulations, differs from the price of $9.11 per MMBtu used to compile our net forecasted revenues, which reflects pricing as of September 1, 2006. For the twelve months ended June 30, 2006, our sales volumes were approximately 4.5 Bcf. We are forecasting our sales volumes to be approximately 5.0 Bcf for the period from October 1, 2006 through September 30, 2007, which is consistent with the forecasted production in our internal reserve estimates. We expect to be able to add the additional 0.5 Bcf from our drilling and refracture program in combination with compression and other production enhancing techniques.

Our estimates of approximately 5.0 Bcf net to our interest include production attributable to the 20 gross (20 net) development wells on proved undeveloped drilling locations that we intend to drill and complete and are assumed to be placed on production during the twelve months ending September 30, 2007. We have assumed that each of the 20 gross (20 net) new wells is completed as a commercial well at an initial production rate of 50-75 Mcf/d, which is consistent with the average initial production rate for the gross development wells drilled by Everlast in the first half of 2005 and the 9 gross (9 net) development wells that we drilled and completed in the second half of 2005. It is also consistent with the 25 wells drilled and completed in the first nine months of 2006. During the nine months ended September 30, 2006, we drilled and completed 25 gross (25 net) wells and spudded an additional 6 gross (6 net) wells that are in the process of completion. We commenced drilling on 10 of the 25 wells in 2005 and brought them onto production in 2006. Based on our experience and that of Everlast with drilling and completing development wells in the Black Warrior Basin, we have assumed that these development wells are drilled at an average rate of 1.7 gross wells per month and are placed on production approximately 40 days after the first wells are spudded.

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During the nine months ended September 30, 2006, we refractured the formations of 2 gross (2 net) well locations. We also assumed that we will refracture 7 gross (7 net) additional wells during the twelve months ending September 30, 2007.

(2) Our weighted average net natural gas sales price of $9.11 per MMBtu is calculated taking into account our executed hedges of 3.7 Bcf (or approximately 78% of our forecasted proved developed production volume from currently producing wells) at a weighted average NYMEX natural gas sales price of approximately $9.22 per MMBtu, and unhedged production volumes at an assumed price based on the SONAT Inside FERC Price, of $8.82 per MMBtu (based on forward curves as of September 1, 2006).

Our weighted average NYMEX hedge price of $9.22 per MMBtu was derived from our contractual fixed price contracts that were executed on June 20, 2006. Under these contracts, we have hedged approximately 0.9 Bcf of fourth quarter 2006 production at $8.83 per MMBtu and approximately 3.7 Bcf of 2007 production at $9.345 per MMBtu (2.8 Bcf of which is attributable to the nine months ending September 30, 2007). This results in our weighted average hedge price of $9.22 per MMBtu for the twelve months ending September 30, 2007.

The unhedged price for SONAT Inside FERC was derived from the weighted average forward market for NYMEX less our internal basis differential from NYMEX for SONAT as of September 1, 2006. The basis differential to NYMEX was approximately zero on September 1, 2006. On September 1, 2006, the NYMEX weighted average forward price was approximately $8.824 per MMBtu and SONAT was approximately $8.826 per MMBtu.

The weighted average sales price has been calculated as the sum of the forecasted sales revenues from all production plus any gains or losses from executed hedges divided by the sales volumes forecasted for the period.

We initiated our hedging policy on June 20, 2006 and we intend to actively monitor and manage any further commodity price risk based upon our hedging policy.

On a pro forma basis, for the twelve months ended June 30, 2006, our average net realized sales price was approximately $8.00 per MMBtu as compared to approximately $9.11 per MMBtu forecast for the twelve-month period ending September 30, 2007.

(3) In calculating our Estimated Adjusted EBITDA, we have netted from our total revenues estimated gains that we expect to incur of approximately $1.5 million due to hedges of the forecasted production.

(4) Our forecasted field operating expenses consist of lease operating expenses, production expenses, minor maintenance, tools and supplies, production taxes (including severance and ad valorem taxes) and other customary charges. We believe that the amount reflected in the forecast for field operating expenses is sufficient to cover the expenses we will incur during the twelve months ending September 30, 2007 assuming production at the forecast level. If our actual field operating expenses are higher than we estimate, we believe that we will have sufficient capacity under our reserve-based credit facility to fund such incremental expenditures.

Our production taxes are calculated as a percentage of our revenues. As prices or volumes increase, our production taxes increase and as prices and volumes decrease, our production taxes decrease. Our forecasted production tax rate of approximately 5.3% is consistent with our historical production taxes of 5.4% and 5.2% for the year ended December 31, 2005 and the six months ended June 30, 2006, respectively.

Our forecasted lease operating expenses of approximately $6.4 million are $0.5 million lower than 2005 lease operating expenses, which were approximately $6.9 million. The $0.5 million difference is due to specific non-recurring costs such as costs incurred for transition services in connection with the purchase of our properties in the Robinson s Bend Field, that, in many cases, were duplicative. In addition, we have adjusted for charges that were non-recurring or discretionary in nature.

(5) We have assumed that the gas purchase contract in respect of production from the Trust Wells attributable to the NPI remains in effect. We do not directly hedge the NPI related production volumes. Based upon the assumptions set forth in notes (1) and (2) above, we have assumed that the forecasted net payment to the Trust would be approximately $0.3 million during such twelve-month period after consideration of all deductible estimated NPI related expenses. If the gas purchase contract or the sharing arrangement provided thereunder were terminated as of October 1, 2006, we estimate that our revenues would decline by $5.6 million during the twelve-month period ending September 30, 2007 based on forecast production from the Trust Wells for such twelve-month period and assuming the weighted average net realized sales price of $9.11 per MMBtu.

We made no payments to the Trust in respect of the NPI in 2005. For the eight months ended August 31, 2006, we paid the Trust approximately $0.2 million, which is comprised of actual calculations through June 30, 2006 and estimates for July and August 2006. We have not made a payment for production since February 2006 and, based upon our forward prices as of the forecast date, do not expect any further payments to the Trust in respect of the NPI until at least January 2007. However, changes in forward prices from our forecast date may change when our next payment with respect to the NPI will occur.

(6) Our forecasted general and administrative expenses include the following:

- approximately $1.0 million in estimated expenses attributable to operations on the Robinson s Bend Field properties, accounting and other similar administrative costs;

- approximately $2.0 million in estimated expenses associated with being a publicly traded entity, including, among other things, incremental accounting and audit fees, director and officer liability insurance, tax return preparation, investor relations, registrar and transfer agent fees and reports to our unitholders; and

- approximately $1.8 million of estimated expenses associated with financial, portfolio management and hedging services performed on our behalf by CEPM under the management services agreement, as well as officer compensation and other third-party consulting fees.

We have further assumed that we do not make any acquisitions during the twelve-month period ending September 30, 2007, and that we do not reimburse CEPM under the management services agreement for any acquisition services during such period. Our total forecasted general and administrative expenses of $4.8 million for the twelve months ending September 30, 2007, compares to approximately $1.7 million of pro forma general and administrative expenses, excluding $3.1 million attributable to the consulting fee payable to The Investment Company, for the year ended December 31, 2005. The pro forma general and administrative expenses do not include some costs associated with being a public entity, which we estimate will be approximately $3.1 million per year. These costs are $2.0 million of expenses associated with being a public entity and $1.1 million of costs not already reflected in the pro forma period such as officer and other employee compensation and other fees that will be required.

(b) Our limited liability company agreement requires that we deduct from operating surplus each quarter estimated maintenance capital expenditures as opposed to actual maintenance capital expenditures in order to reduce disparities in operating surplus caused by fluctuations in our actual maintenance capital expenditures. Because of the substantial capital expenditures we are required to make to maintain our production and asset base, we estimate that our initial annual estimated maintenance capital expenditures for purposes of calculating operating surplus will be approximately $5.0 million per year as described in the next paragraph. Our board of managers, with the approval of our conflicts committee, may determine to increase the annual amount of our estimated maintenance capital expenditures. In years when 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.

We expect to invest approximately $30.0 million in capital over the next six years (an average of approximately $5.0 million per year) related to maintenance capital expenditure projects. As a result, we expect that our estimated maintenance capital expenditures for the twelve-month period ending September 30, 2007, will be approximately $5.0 million. Our drilling program assumes that we will drill a total of 20 gross (20 net) development wells during the twelve months ending September 30, 2007. Of these wells, 12 gross (12 net) wells will constitute maintenance capital projects required to maintain our production volumes and on which we assume we will spend $4.8 million of the $5.0 million. We currently plan to continue that drilling program to develop our proved undeveloped drilling locations over the next six years. We also have included in estimated maintenance capital expenditures approximately $150,000 per year for potential costs that we may incur for lease renewals and acquisitions that will enable us to maintain our asset base.

Our forecasted average costs for drilling and refracturing wells are consistent with our actual results for the six months ended June 30, 2006. Of the 17 wells that were drilled and completed, our average costs were approximately $410,000 per well. We are forecasting approximately $400,000 per well to drill and complete during October 1, 2006 through September 30, 2007. Of the two wells that we refractured during the six months ended June 30, 2006, our average cost per refracture was approximately $110,000 as compared to our forecast of $137,500 per refracture for our forecast period October 1, 2006 through September 30, 2007.

(c) We have assumed that our interest expense (excluding fees) for the twelve-month period ending September 30, 2007 will be approximately $1.5 million. We intend to borrow under our reserved-based credit facility amounts sufficient to pay interest during acquisition and development of any investment capital expenditures or any expansion capital expenditures before production, transportation or gathering, as the case may be, begins. For this reason, interest expense associated with our expected investment capital expenditures is capitalized and included in estimated investment capital expenditures, rather than estimated interest expense. Prior to the offering, we intend to borrow $30.0 million under our reserve-based credit facility. We also intend to use the $8.0 million in funds from the Class D interests to reduce the $30.0 million balance of the reserve-based credit facility to $22.0 million. For the twelve-month period ending September 30, 2007, we have assumed that our estimated investment capital expenditures consist of approximately $4.1 million (before interest expense), all of which we expect to fund with borrowings under our reserve-based credit facility. We have assumed that we pay 7% annualized interest on the end of month balance of the credit facility, which includes the $22.0 million initial net debt and cumulative borrowings of $4.1 million for investment capital. Our actual interest expense from February 7, 2005 (inception) through December 31, 2005 was approximately $3,000. If we do not borrow funds to pay our investment capital expenditures and distributions on our Class D interests, we would experience a shortfall in the cash available to allow us, together with cash generated from operations to pay our investment capital expenditures and distributions on our Class D interests and to pay our annualized initial quarterly distribution on our outstanding common units and Class A units. We do not expect that any of our expected development drilling or formation refracture operations to be conducted during the twelve months ending September 30, 2007 will constitute expansion capital expenditures. Our limited liability company agreement does not restrict us from borrowing to pay distributions on our Class A units, common units and other limited liability company interests, such as the management incentive interests and Class D interests. However, we may borrow funds under our reserve based credit facility (i) as long as there has not been a default or event of default under our credit agreement and if the amount of borrowings outstanding under our credit facility is less than 90% of our borrowing base, and (ii) under our limited liability company agreement working capital borrowings constitute operating surplus only if we repay such borrowings within one year. Please read Management s Discussion and Analysis Capital Resources and Liquidity Reserve-Based Credit Facility. Furthermore, we assume that all of our debt incurred for other than working capital purposes will be refinanced as it comes due, although we have the right to establish cash reserves, including reserves for debt repayments, before determining the amount of cash available for distribution.

(d) We have assumed that our estimated drilling and other production enhancement expenditures that are in excess of those necessary to replace our asset base during the twelve-month period ending September 30, 2007, including our unproven properties, and to offset over the long-term the expected production decline

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from our properties will constitute investment capital expenditures. If we do make any such investment capital or expansion capital expenditures, we expect to fund those expenditures with borrowings under our reserve-based credit facility, the issuance of debt or equity securities or a combination thereof until production or other operations commence, after which we intend to refinance any short-term indebtedness incurred to fund such expenditures with the issuance of long-term debt, equity securities or a combination thereof. As a result, we do not expect any such investment capital expenditures or expansion capital expenditures and related borrowings to have an immediate impact on available cash. Our investment capital expenditures projected for the twelve-month period ending September 30, 2007 of approximately $4.3 million, including interest expense related to expansion capital borrowings, is expected to be incurred to drill, develop and place on production 8 gross (8 net) wells during such period. These 8 newly drilled gross wells would be in excess of the 12 gross wells that we project need to be drilled, completed and placed on production in the twelve months ending September 30, 2007 to offset the expected production decline rate from our existing producing wells. The estimated $4.3 million also includes capital required for the refracturing of the formations of approximately 7 gross (7 net) of our existing proved developed non-producing wells that we plan to complete during the twelve months ending September 30, 2007. Approximately $0.2 million of the $4.3 million is interest expense related to borrowings of investment capital, which we have assumed we will fund with borrowings and not pay out of available cash.

(e) We will be required to pay special cash distributions in respect of the Class D interests totaling $1.0 million for the twelve months ending September 30, 2007 unless the gas purchase contract or, without the prior consent of our board of managers, the sharing arrangement provided thereunder is terminated before September 30, 2007. For purposes of this estimate, we have assumed that we deploy in our business the $8.0 million contributed to us for the Class D interests and that we borrow the amounts necessary to fund such special cash distributions under our reserve-based credit facility (payment of such special cash distributions would be made on or about May 15, 2007, August 14, 2007 and November 14, 2007, each in the amount of $333,333). We will generally be required to make four quarterly payments in any given year, assuming the sharing arrangement has not been terminated without the prior consent of our board of managers, but the first payment is not required to be made until May 15, 2007 for the first quarter of 2007.

(f) $7.8 million of the proceeds from this offering will be retained in working capital. Of the $7.8 million, $5.0 million will be retained for the purposes of providing cash available for coverage of the initial quarterly distribution amounts and is thus included in the estimated cash available to pay distributions. While this $5.0 million will be available to pay distributions, we do not currently expect to use such cash to pay distributions for the forecast period. The remaining $2.8 million of the $7.8 million retained in working capital will be used for working capital purposes and is not expected to be used for distribution to the unitholders and is therefore not included in estimated cash available to pay distributions.

(g) The table below sets forth the assumed number of outstanding common units and Class A units upon the closing of this offering and the full IQD payable on the outstanding common units and Class A units for the twelve-month period ending September 30, 2007.

	Number of Units	Distributions Per Unit	Aggregate Distributions
			(in 000 s)
Estimated distributions on common units	14,489,010(1)	$ 1.70	$ 24,631
Estimated distributions on Class A units	295,690	1.70	503
Total	14,784,700(1)	$ 1.70	$ 25,134

(1) Does not include any common units that may be issued under the long-term incentive plan that we expect to adopt prior to the closing of this offering. We have assumed that no common units are issued under that plan for the twelve-month period ending September 30, 2007.

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(h) Our new reserve-based credit facility contains a covenant requiring us to have, as of the date of any distribution, a ratio of total borrowings outstanding under our reserve-based credit facility to our Borrowing Base (as defined in our credit agreement), of not more than 0.90 to 1.0. In addition, it contains a covenant requiring us to maintain, as of the last day of each fiscal quarter, a ratio of our Adjusted EBITDA (as defined in our credit agreement) to our 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. We believe that we will be in compliance with these covenants for the twelve-month period ending September 30, 2007. A default by us that results in or could result in acceleration of any of our indebtedness in excess of $1.0 million constitutes an event of default under our credit agreement that would prohibit us from making distributions.

In preparing the estimates above, we have assumed that there will be no material change in the following matters, and thus they will have no impact on our Estimated Adjusted EBITDA:

- There will not be any material expenditures related to new federal, state or local regulations or interpretations.
- There will not be any material change in the natural gas industry or in market, regulatory and general economic conditions that would affect our cash flow.
- We will not undertake any extraordinary transactions that would materially affect our cash flow.
- There will be no material nonperformance or credit-related defaults by suppliers, customers or vendors.
- The gas purchase contract (including the sharing arrangement provided thereunder) remains in effect.

While we believe that the assumptions we used in preparing the estimates set forth above are reasonable based upon management s current expectations concerning future events, they are inherently uncertain and are subject to significant business, economic regulatory and competitive risks and uncertainties, including those described in Risk Factors, that could cause actual results to differ materially from those we anticipate. If our assumptions are not realized, the actual available cash that we generate could be substantially less than the amount we currently estimate and could, therefore, be insufficient to permit us to pay the full IQD or any amount on all our outstanding common units in respect of the four calendar quarters ending September 30, 2007 or thereafter, in which event the market price of the common units may decline materially.

Sensitivity Analysis

Our ability to generate sufficient cash from our operations to pay distributions to our unitholders of not less than the IQD per unit for the twelve months ending September 30, 2007 is a function of two primary variables: production volumes and natural gas prices. In the paragraphs below, we discuss the impact that changes in either of these variables, while holding all other variables constant, would have on our ability to generate sufficient cash from our operations to pay the IQD on our outstanding units.

Production volume changes

For purposes of our estimates set forth above, we have assumed that our net production attributable to the Robinson s Bend Field totals 5.0 Bcf during the twelve months ending September 30, 2007. If our actual net production realized during such twelve-month period is 5% more (or 5% less) than such estimate (that is, if actual net realized production is 5.25 Bcf or 4.75 Bcf), we estimate that our estimated cash available to pay distributions would increase (decrease) by approximately $2.1 million, assuming no other changes in any other variables.

Natural gas price changes

For purposes of our estimates set forth above, we have assumed that our weighted average net realized natural gas sales price for our net production volumes is $9.11 per MMBtu. If the average realized natural gas sales price for our net production volumes were to increase (decrease) by $1.00 per MMBtu, we estimate that our estimated cash available to pay distributions would increase (decrease) by approximately $1.2 million, assuming we maintain hedges of approximately 78% of our expected production from currently producing wells from October 1, 2006 through September 30, 2007 and no other changes in any other variables.

In order to address, in part, volatility in natural gas prices, we have implemented a commodity price risk management program that is intended to reduce the volatility in our revenues due to short-term changes in natural gas prices. Under that program, we have adopted a policy that contemplates hedging the prices for approximately 80% of our expected production for a period of up to five years as appropriate. Implementation of such policy will mitigate, but will not eliminate, our sensitivity to short-term changes in prevailing natural gas prices.

Unaudited Pro Forma Available Cash to Pay Distributions

If we had completed the transactions contemplated in this prospectus on January 1, 2005, our pro forma available cash to pay distributions generated during 2005 would have been approximately $8.6 million. This amount would have been sufficient to pay approximately 34% of our $0.425 per quarter IQD ($1.70 on an annualized basis) on our outstanding common units and Class A units. These common unit percentages do not reflect any common units that may be issued under the long-term incentive plan that we expect to adopt prior to the closing of this offering. If we had completed the transactions contemplated in this prospectus on July 1, 2005, our pro forma available cash to pay distributions generated during the twelve months ended June 30, 2006 would have been approximately $8.3 million. This amount would have been sufficient to pay approximately 33% of our $0.425 per quarter IQD ($1.70 on an annualized basis) on our outstanding common units and Class A units. These common unit percentages do not reflect any common units that may be issued under the long-term incentive plan that we expect to adopt prior to the closing of this offering. Pro forma cash available to pay distributions also excludes any cash from working capital or other borrowings. As described in How We Make Cash Distributions Operating Surplus and Capital Surplus, cash from these sources may also be used to pay distributions. Pursuant to the terms of our limited liability company agreement, our board of managers would have had the discretionary authority to cause us to borrow funds under our reserve-based credit facility to make up some or all of this estimated shortfall. For purposes of the calculation in the table below, however, we have assumed that we did not borrow any amounts to fund such estimated shortfall and that we paid out 100% of our pro forma available cash for distributions, which represented $8.6 million for 2005 and $8.3 million for the twelve months ended June 30, 2006.

In the future, it is management s intent to borrow to the extent prudent and feasible to fund any short-term shortfall in cash available for distribution. Under the reserve-based credit facility that we plan to enter into prior to or at the closing of this offering, we expect to be able to incur debt to pursue our business plan and to pay distributions to our unitholders. However, 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, which is estimated to be $100 million upon the closing of the offering, or if we are then in default under such facility. Giving effect to the use of the proceeds from this offering, we estimate our borrowing under the credit facility immediately after this offering will be $22.0 million.

The following table illustrates, on a pro forma basis for 2005 and the twelve months ended June 30, 2006, cash available to pay distributions, assuming, in each case, that the following transactions had occurred on January 1, 2005 and July 1, 2005, respectively:

- the acquisition of our properties in the Robinson s Bend Field from Everlast;
- the indebtedness associated with our reserve-based credit facility;

aggregate payments (payable quarterly) to CHI of approximately $1.0 million in respect of the Class D interests, which we assume to be funded with borrowings under our reserve-based credit facility; and this offering and the application of the net proceeds thereof, together with the $30.0 million assumed to be drawn under our reserve-based credit facility and $8.0 million from issuance of the Class D interests, as described under the caption Use of Proceeds.

Each of the pro forma adjustments presented below is explained in the footnotes to such adjustments.

The pro forma financial statements, from which pro forma available cash is derived, do not purport to present our results of operations had the transactions contemplated above actually been completed as of the dates indicated. Furthermore, available cash is a cash accounting concept, while our pro forma financial statements have been prepared on an accrual basis. We derived the amounts of pro forma available cash stated above in the manner described in the table below. As a result, the amount of pro forma available cash should only be viewed as a general indication of the amount of available cash that we might have generated had we been formed and completed the transactions contemplated below in earlier periods.

	Pro Forma Year Ended December 31, 2005	**Pro Forma 12 Months Ended June 30, 2006**
	(In 000 s, except ratios)	
	(unaudited)	
Net income[(a)]	$ 760	$ 16,986
Plus:		
Interest expense[(b)]	1,546	1,546
Depreciation, depletion and amortization	7,281	7,987
Accretion of asset retirement obligation	141	149
Unrealized loss on natural gas derivatives	15,265	
Adjusted EBITDA	$ 24,993	$ 26,668
Less:		
Estimated incremental general and administrative expenses[(c)]	3,100	3,100
Pro forma cash flow from operations	21,893	23,568
Less:		
Cash necessary to pay initial quarterly distributions on Class A units and common units[(d)]	25,134	25,134
Pro forma cash flow from operations after distributions	(3,241)	(1,566)
Less:		
Pro forma capital expenditures[(e)]	(12,286)	(14,233)
Cash required to pay Class D special cash distributions[(f)]	(1,000)	(1,000)
Shortfall	$ (16,524)	$ (16,799)
Borrowing base ratio[(g)]	0.2x	0.2x
Interest coverage ratio[(g)]	16.2x	17.2x
Total debt/Adjusted EBITDA ratio[(g)]	0.9x	0.8x

(a) Excludes any adjustment for estimated incremental ongoing expenses we expect to incur as a result of being a publicly traded entity, including, among other things, incremental accounting and audit fees, director and officer liability insurance, tax return preparation, investor relations, registrar and transfer agent fees and reports to unitholders. We estimate that these incremental general and administrative expenses will be approximately $3.1 million annually.

(b) Gives effect to interest on net borrowings of $22.0 million under our reserve-based credit facility as of the beginning of each period presented. The interest rate on these amounts is 7%.

(c) Gives effect to $3.1 million in incremental general and administrative expenses we estimate that we would incur as a result of being a public company.

(d) Does not include any common units that may be issued under the long-term incentive plan that we expect to adopt prior to the closing of this offering.

(e) Gives effect to the capital expenditures for the drilling and completion of new wells and wells that were in the process of being drilled. It also gives effect to other capital expenditures such as facilities, pipelines, and other support equipment. During the year ended December 31, 2005, CEP and Everlast drilled and completed a total of 18 gross (18 net) development wells and commenced drilling on an additional 9 gross (9 net) wells. During the twelve months ended June 30, 2006, we drilled and completed 29 gross (29 net) wells and commenced drilling on an additional 7 gross (7 net) wells. During such periods, neither we nor Everlast characterized capital expenditures as maintenance, investment or expansion and, during such periods, neither we nor Everlast planned capital expenditures in a manner intended to maintain or expand the production or asset base of the Robinson s Bend Field. As a result, we have not attempted to characterize the pro forma capital expenditures reflected herein as maintenance, investment or expansion. The capital expenditures that we and Everlast incurred during 2005 and for the twelve months ended June 30, 2006 were all funded from cash generated by our and Everlast s operations, respectively.

(f) Gives effect to the assumed payment of approximately $1.0 million in special distributions in respect of the Class D interests, assuming that payment of such special distributions was required to be made commencing with the quarter ended June 30, 2005 (for the year ended December 31, 2005) and December 31, 2005 (for the twelve months ended June 30, 2006). We will generally be required to make four quarterly payments in any given year, assuming the sharing arrangement has not been terminated without the prior consent of our board of managers.

(g) Our reserve-based credit facility contains covenants requiring us to have, as of the date of any distribution, a ratio of total borrowings outstanding under our reserve-based credit facility to our Borrowing Base (as defined in our credit agreement) of not more than 0.90 to 1.0. In addition, the credit facility contains covenants requiring us to maintain, as of the last day of each fiscal quarter, a ratio of our Adjusted EBITDA (as defined in our credit agreement) to our 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. We would have been in compliance on a pro forma basis with these covenants for the year ended December 31, 2005 and the twelve months ended June 30, 2006. In addition, a default by us that results in or could result in an acceleration of any of our indebtedness in excess of $1.0 million will constitute an event of default under our credit agreement that would prohibit us from making distributions.

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SELECTED HISTORICAL AND PRO FORMA

CONSOLIDATED FINANCIAL DATA

Set forth below is our selected historical and unaudited pro forma consolidated financial data for the periods indicated. 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 Energy LLC, or Everlast, on June 13, 2005. We applied the purchase method of accounting to the separable assets and liabilities of the natural gas properties and equipment acquired from Everlast. The selected historical consolidated financial data of Everlast for the period from January 1, 2005 through June 12, 2005 and as of and for the years ended December 31, 2004 and 2003 have been derived from Everlast s audited historical financial statements. The historical financial data as of and for the years ended December 31, 2002 and December 31, 2001 have been derived from unaudited financial data of Torch Energy, the predecessor to Everlast. The historical financial data of Constellation Energy Partners LLC as of December 31, 2005 and for the period from February 7, 2005 (inception) to December 31, 2005, have been derived from our audited historical consolidated financial statements. The historical consolidated financial data of Constellation Energy Partners, LLC as of and for the six months ended June 30, 2006 and for the period from February 7, 2005 (inception) to June 30, 2005 have been derived from our unaudited historical consolidated financial statements. The selected unaudited pro forma consolidated financial data as of and for the six months ended June 30, 2006 and for the year ended December 31, 2005 have been derived from our unaudited pro forma consolidated financial statements. For a description of the adjustments made in the unaudited pro forma consolidated financial statements, please read the notes to those financial statements.

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 GAAP. We explain this measure below and reconcile it to net income and net cash flow provided by operating activities, the most directly comparable financial measures calculated and presented in accordance with GAAP in Non-GAAP Financial Measure Adjusted EBITDA below.

You should read the following selected financial data in conjunction with 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 prospectus. You should also read the pro forma information together with the unaudited pro forma consolidated financial statements and related notes included in this prospectus.

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 represent 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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	Predecessor					Successor				
	Torch Energy		Everlast Energy LLC			Constellation Energy Partners LLC				
									Pro Forma	
	For the year ended December 31, 2001	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 period from February 7, 2005 (inception) to June 30, 2005[(b)]	For the six months ended June 30, 2006	For the year ended December 31, 2005	For the six months ended June 30, 2006
	Unaudited	Unaudited	As Restated[(a)]	As Restated[(a)]			Unaudited	Unaudited	Unaudited	Unaudited
	(In 000 s)		(In 000 s)					(In 000 s)		
Statement of Operations Data:										
Revenues:										
Gas sales	$ 9,216	$ 8,710	$ 22,320	$ 27,494	$ 12,882	$ 25,957	$ 1,377	$ 17,605	$ 38,839	$ 17,605
Loss from mark-to-market activities			(3,664)	(9,107)	(15,313)				(15,313)	
Total revenues	9,216	8,710	18,656	18,387	(2,431)	25,957	1,377	17,605	23,526	17,605
Operating Expenses:										
Lease operating expenses	9,254	7,763	4,428	5,270	2,769	4,175	357	3,495	6,944	3,495
Production taxes	592	368	1,279	1,479	676	1,400	72	909	2,076	909
General and administrative	162	92	1,945	2,706	594	4,184	3,275	2,731	4,778	2,731
Depreciation, depletion and amortization	199	77	3,684	3,719	1,683	4,176	350	3,811	7,281	3,811
Accretion expense			73	86	46	78	7	71	141	71
(Gain) loss on asset sale	(193)	(4)								
Total operating expenses	10,014	8,296	11,409	13,260	5,768	14,013	4,061	11,017	21,220	11,017
Other expenses/(income):										
Interest expense/(income), net			1,961	3,028	2,437	3		(197)	1,546	573
Organization costs			299							
Total other expenses (income)			2,260	3,028	2,437	3		(197)	1,546	573
Total expenses			13,669	16,288	8,205	14,016	4,061	10,820	22,766	11,590
Net income (loss)	$ (798)	$ 414	$ 4,987	$ 2,099	$ (10,636)	$ 11,941	$ (2,684)	$ 6,785	$ 760	$ 6,015
Other Financial Information (unaudited)										
Adjusted EBITDA			$ 10,193	$ 14,738	$ 8,795	$ 16,198	$ (2,327)	$ 10,470	$ 24,993	$ 10,470

(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 prospectus.

(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			
									Pro Forma
	For the year ended December 31, 2001	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 period from February 7, 2005 (inception) to June 30, 2005(b)	For the six months ended June 30, 2006	For the six months ended June 30, 2006
	Unaudited	Unaudited	As Restated[(a)]	As Restated[(a)]			Unaudited	Unaudited	Unaudited
	(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		$ 3,880	$ 7,827
Other current assets	32,762	39,014	1,812	4,562		6,097		17,912	5,713
Natural gas properties, net of accumulated depreciation, depletion and amortization	1,555	1,587	49,252	52,531		165,211		169,282	169,282
Other assets			590	1,579				311	311
Total assets	$ 34,317	$ 40,601	$ 54,217	$ 60,684		$ 186,139		$ 191,385	$ 183,133
Current liabilities	$ 37,941	$ 43,812	$ 4,403	$ 4,482		$ 13,895		$ 10,797	$ 10,797
Debt			26,000	67,500		63		52	22,052
Preferred units subject to mandatory redemption			16,752						
Other long-term liabilities			2,671	3,314		3,014		3,099	3,099
Class D Interests									8,000
Members Equity									
Common members equity (deficit)	(3,624)	(3,211)	4,391	(14,612)		169,167		176,523	138,271
Accumulated other comprehensive income								914	914
Total members equity (deficit)	(3,624)	(3,211)	4,391	(14,612)		169,167		177,437	139,185
Total liabilities and members equity (deficit)	$ 34,317	$ 40,601	$ 54,217	$ 60,684		$ 186,139		$ 191,385	$ 183,133
Cash Flow Data:									
Net cash provided by operating activities	$ (219)	$ 109	$ 9,773	$ 4,906	$ 6,639	$ 23,313	$ 2,931	$ 8,805	
Net cash provided by (used in) investing activities	219	(109)	(47,832)	(6,997)	(4,203)	(147,237)	(139,357)	(19,745)	
Net cash provided by (used in) financing activities			40,622	1,540	(2,500)	138,755	138,770	(11)	
Development of natural gas properties	(61)	(109)	(2,040)	(5,680)	(4,000)	(8,286)	(406)	(7,285)	

(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 prospectus.

(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) plus:

- 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 to be used by our management to indicate (prior to the establishment of any 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 an alternative to 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) and net cash flow provided by operating activities to Adjusted EBITDA, our most directly comparable GAAP performance and liquidity measures, for each of the periods presented:

	Predecessor			Successor				
	Everlast Energy LLC			Constellation Energy Partners LLC				
							Pro Forma	
	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 period from February 7, 2005 (inception) to June 30, 2005	For the six months ended June 30, 2006	For the year ended December 31, 2005	For the six months ended June 30, 2006
		(In 000 s)			(Unaudited)	(Unaudited) (In 000 s)	(Unaudited)	(Unaudited)
Reconciliation of Net Income (Loss) to Adjusted EBITDA:								
Net income/(loss)	$ 4,987	$ 2,099	$ (10,636)	$ 11,941	$ (2,684)	$ 6,785	$ 760	$ 6,015
Add:								
Interest expense/(income), net[(a)]	1,961	3,028	2,437	3		(197)	1,546	573
Depreciation, depletion and amortization	3,684	3,719	1,683	4,176	350	3,811	7,281	3,811
Accretion of asset retirement obligation	73	86	46	78	7	71	141	71
Unrealized loss/(gain) on natural gas derivatives	(512)	(2,156)	15,265				15,265	
Realized loss on cancelled natural gas derivatives		7,962						
Adjusted EBITDA	$ 10,193	$ 14,738	$ 8,795	$ 16,198	$ (2,327)	$ 10,470	$ 24,993	$ 10,470
Reconciliation of Net Cash Provided by Operating Activities to Adjusted EBITDA:								
Net cash provided by operating activities	$ 9,773	$ 4,906	$ 6,639	$ 23,313	$ 2,931	$ 8,805		
Add:								
Interest expense/(income), net[(a)]	1,305	2,596	2,437	3		(197)		
Expenses paid by CCG on behalf of CEP				(64)		(571)		
Realized loss on cancelled natural gas derivatives		7,962						
Changes in working capital:								
Accounts receivable	1,547	2,278	707	1,289	(1,535)	(1,869)		
Prepaid expenses	265	(246)	131	62	21	75		
Other assets			10	211		807		
Loan amortization cost	(288)	(685)	(237)					
Accounts payable	(908)	(993)	(807)	(1,703)	863	2,187		
Royalty payable	(1,321)	(708)	(110)	(1,859)	(364)	1,240		
Accrued liabilities	(180)	(372)	25	(5,054)	(4,243)	(7)		
Adjusted EBITDA	$ 10,193	$ 14,738	$ 8,795	$ 16,198	$ (2,327)	$ 10,470		

(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.

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MANAGEMENT S DISCUSSION AND ANALYSIS OF

FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following discussion and analysis should be read in conjunction with the Selected Historical and Pro Forma Consolidated Financial Data and the accompanying financial statements and related notes included elsewhere in this prospectus. The following discussion contains forward-looking statements that reflect our future plans, estimates, 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 prospectus, particularly in Risk Factors and Cautionary Note Regarding 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 coalbed methane reserves and production in the Robinson s Bend Field in June 2005. These reserves were acquired from Everlast and included working interests in 424 coalbed methane producing wells at the time of the acquisition. 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 producing reserves with long-lived, stable production and step-out development opportunities. Such properties may include associated midstream assets such as gathering systems, compression, dehydrating and treating facilities and other similar facilities;
- identify and work with third-party operators who have experience in regions in which we seek to acquire an ownership interest and who will hold an ownership interest in our properties;
- increase reserves and production through what we believe to be low-risk development and exploitation drilling; and
- reduce the volatility in our revenues resulting from changes in oil and natural gas commodity prices through hedging.

Our future natural gas reserves and 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 and our ability to pay quarterly cash distributions to our unitholders.

Our estimated proved reserves at December 31, 2005 were approximately 112.0 Bcf, approximately 80% of which were classified as proved developed producing. Our estimated proved reserves at December 31, 2005 had a Standardized Measure of approximately $295.4 million, which excluded the impact of taxes because we are not a taxable entity. Our average proved reserve-to-production ratio is approximately 25 years, based on our estimated proved reserves at December 31, 2005 and annualized production for the six months ended December 31, 2005. We currently own a 100% working interest (an approximate 75% average net revenue interest, calculated before the Torch Royalty NPI) in our Robinson s Bend Field producing properties, which had 436 producing natural gas wells as of December 31, 2005.

As of December 31, 2005, 404 of our wells in the Robinson s Bend Field were subject to a non-operating net profits interest, or 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 certain wells in the Robinson s Bend Field, or 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 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 will increase and our revenues will decrease in each case compared to the amounts if the sharing arrangement remained in effect. For a further description of the NPI and the related contractual arrangement, as well as the circumstances under which the sharing arrangement may be terminated, please read Business Natural Gas Data Torch Royalty NPI.

Daily field operations are performed by employees of our wholly owned subsidiary, Robinson s Bend Operating II, LLC, whose employees operate under the direct supervision of Ironhorse Energy, LP, or Ironhorse. We entered into a professional services agreement with Ironhorse to provide us with these project management services for the Robinson s Bend Field. Other support services, including geology, engineering, land administration and revenue accounting, will be provided to us by CEPM and its affiliates.

We will enter into a management services agreement with CEPM, an indirect wholly owned subsidiary of Constellation. Pursuant to that agreement, CEPM will provide us with legal, accounting, finance and tax services. We also expect that CEPM will provide us with property management, engineering and other services and with assistance in hedging our production as well as acquisition services in respect of opportunities for us to acquire long-lived, stable and proved oil and natural gas reserves. 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, finance, tax and risk management services. While neither Constellation nor CEPM has any obligation to provide us with acquisition services under the management services agreement, 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.

Following this offering we will be dependent on CEPM for management of our operations and, pursuant to the management services agreement, we will reimburse CEPM for the reasonable costs of the services it provides to us. Our board of managers has the right and the duty to review the services provided, and the costs charged, by CEPM under that agreement. Our board of managers may in the future cause us to hire additional personnel to supplement or replace some or all of the services provided by CEPM, as well as employ third-party service providers. If we were to take such actions, they could increase the overall costs of our operations. For a description of the services that CEPM will provide to us under the management services agreement and our obligation to reimburse CEPM for the costs it incurs in providing those services, please read Certain Relationships and Related Party Transactions Agreements Governing the Transactions Management Services Agreement.

Our revenue, cash flow from operations and future growth depend substantially on factors beyond our control, such as economic, political and regulatory developments and competition from other sources of energy. Historically, natural gas and oil prices have been volatile and may fluctuate widely in the future. Sustained periods of low prices for natural gas or oil could materially adversely affect our financial position, our results of operations, the quantities of natural gas and oil reserves that we can economically produce and our access to capital.

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 higher realized sales prices for natural gas have more than offset the higher drilling and operating costs we have incurred since our acquisition. 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.

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 maintain our focus on 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 plan, we intend to invest the capital necessary to maintain our production or 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, 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 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 our acquisition from Everlast. Though the financial statements represent 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 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 is 112.0 Bcf which is lower than our 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 believe it provides relevant information for the purposes of estimating reserves and we have 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

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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. The reserve estimates of 162.2 Bcf at December 31, 2004 and 163.7 Bcf at December 31, 2003 used to prepare the 2004 and 2003 financial statements of our predecessor, Everlast, were also prepared by us using internal estimates.

We prepared the estimates of the 2004 and 2003 proved reserves for financial statement purposes by starting with NSAI s December 31, 2005 proved reserve estimate, which was based upon Everlast s drilling program and reserve assumptions, and rolling that estimate back to December 31, 2004 and 2003 by making appropriate adjustments for actual production, prices and development activity. The roll-back process 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. The reserve report prepared by NSAI for Everlast for December 31, 2003, while based on the SEC definition of proved reserves, included different assumptions than those used by NSAI in preparing the December 31, 2005 estimate.

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 and 2003 in preparing the financial statements of our predecessor for the years ended December 31, 2004 and 2003. In preparing the roll-back to December 31, 2004 and 2003, 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 and 2003 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 and 2003. The previous reserve estimates were 173.4 Bcf at December 31, 2004 and 166.2 Bcf at December 31, 2003.

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 prospectus. These gains and losses are reported in the financial statements of CCG. On June 20, 2006, we executed hedges for approximately 78% of our expected production from currently producing wells for October 2006 through December 2009.

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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 are 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.

Outlook

We expect that, during the remainder of 2006 and for our forecast period, our business will continue to be affected by the risks described in 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 and Drilling

Our net production for September 2006 was approximately 0.41 Bcf, or about 4.9 Bcf on an annualized basis. We have determined, based upon internal reserve and production analysis, that drilling approximately 12 new wells per year on our properties in the Robinson s Bend Field would maintain those production levels for approximately five years. For the twelve months ending September 30, 2007, we expect net production of approximately 5.0 Bcf. This is based upon our current drilling and refracture plan, which includes a total of 20 newly drilled wells and 7 refractures during that twelve-month period.

Natural Gas Prices

Natural gas prices have been extremely volatile over the past three years and even more so in the past nine to twelve months. We believe that this trend has been significantly 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 (given the correlation between natural gas and oil) and growth in domestic natural gas demand. The currently high levels of natural gas in storage, resulting at least in part from a relatively mild winter of 2005 in the United States, have caused natural gas prices to decline substantially from the higher levels prevailing during the later part of 2005.

Hedging Activities

As of June 30, 2006, we had hedges for approximately 78% of our expected production from currently producing wells from October 2006 through December 2009. Previously, hedges for natural gas production by CCG and its subsidiaries were generally held by CCG and maintained on CCG s books on a portfolio basis. However, we expect our hedging policy will be to hedge approximately 80% of our total forecasted proved developed production from currently producing wells for a five-year period. These hedges are required by our lender under the terms of our reserve-based credit facility. However, our management may modify the hedging percentages and strategies as it deems appropriate for market conditions and our business strategy. For accounting purposes, these hedges are being treated as cash flow hedges.

Field Operating Expenses

Our field operating expenses include, without limitation, 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 the twelve months ending September 30, 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 the six months ended June 30, 2006. We expect our future field operating costs will be correlated to the price of natural gas, although the cost changes generally lag and are less volatile than natural gas price changes. When natural gas prices are higher, demand for these services is higher, resulting in increased costs for such services. 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 calculated as a percentage of sales revenue. We will consider the effect of production taxes on hedged revenues and quantities when we execute and manage our hedges.

General and Administrative Expenses

We expect that our general and administrative expenses will be approximately $4.8 million for the twelve months ending September 30, 2007. There are three main components of these estimated costs:

- operational general and administrative expenses will comprise approximately $1.0 million of our forecasted general and administrative costs. These costs include third-party well-level accounting charges, Ironhorse and other consultant fees, accounting, annual reserve reports and other similar administrative expenses;

- costs associated with annual and quarterly reports to unitholders, our annual meeting of unitholders, tax return and Schedule K-1 preparation and distribution, investor relations, registrar and transfer agent fees, incremental insurance costs, fees of independent managers, accounting fees and legal fees will comprise approximately $2.0 million of our estimated total general and administrative expenses;

- other overhead charges, including financial, portfolio management and hedging services performed on our behalf by CEPM under the management services agreement, other third-party consulting fees and reimbursement of affiliate employee expense will comprise approximately $1.8 million of our estimated total general and administrative expenses.

These estimated general and administrative costs assume that we do not make any acquisitions during the twelve-month period ending September 30, 2007, and that we do not reimburse CEPM under the management services agreement for any acquisition services during such period.

Results of Operations

We acquired 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.

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

	Predecessor			Successor		
	Everlast Energy LLC			Constellation Energy Partners LLC		
	For the year ended December 31, 2003[(a)]	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 period from February 7, 2005 (inception) to June 30, 2005[(b)]	For the six months ended June 30, 2006
					Unaudited	Unaudited
	(In 000 s, except production, cost and price data)			(In 000 s, except production, cost and price data)		
Statement of Operations Data:						
Revenues:						
Gas sales	$ 22,320	$ 27,494	$ 12,882	$ 25,957	$ 1,377	$ 17,605
Loss from mark-to-market activities	(3,664)	(9,107)	(15,313)			
Total revenues	18,656	18,387	(2,431)	25,957	1,377	17,605
Operating expenses:						
Lease operating expenses	4,428	5,270	2,769	4,175	357	3,495
Production taxes	1,279	1,479	676	1,400	72	909
General and administrative expenses	1,945	2,706	594	4,184	3,275	2,731
Depreciation, depletion and amortization	3,684	3,719	1,683	4,176	350	3,811
Accretion expense	73	86	46	78	7	71
Total operating expenses	11,409	13,260	5,768	14,013	4,061	11,017
Other expenses/(income):						
Interest expense/(income)	1,961	3,028	2,437	3		(197)
Organizational costs	299					
Total other expenses/(income)	2,260	3,028	2,437	3		(197)
Net income (loss)	$ 4,987	$ 2,099	$ (10,636)	$ 11,941	$ (2,684)	$ 6,785
Net production:						
Total production (MMcf)	4,566	4,527	1,970	2,525	217	2,200
Average daily production (Mcf/d)	12,500	12,400	12,100	12,500	12,053	12,156
Average sales prices:						
Price per Mcf including economic hedges	$ 4.09	$ 4.06	$ (1.23)[(c)]	$ 10.28[(d)]	$ 6.35[(d)]	$ 8.00[(d)]
Price per Mcf excluding economic hedges	$ 4.89	$ 6.07	$ 6.54	$ 10.28	$ 6.35	$ 8.00
Average unit costs per Mcf:						

Field operating expenses	$ 1.25	$ 1.49	$ 1.75	$ 2.21	$ 1.98	$ 2.00
General and administrative expenses	$ 0.43	$ 0.60	$ 0.30	$ 1.66	$ 15.10	$ 1.24
Depreciation, depletion and amortization	$ 0.81	$ 0.82	$ 0.85	$ 1.65	$ 1.61	$ 1.73

(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 prospectus.

(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 economic 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 June 30, 2005 and December 31, 2005. On June 20, 2006, we entered into derivative transactions that hedge the future prices of approximately 78% of our expected production from October 2006 through December 2009 from currently producing wells.

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Revenue

Gas Sales

Our natural gas sales for the six months ended June 30, 2006 were $17.6 million, which were driven by average prices of $8.00 per Mcf. Production for that period was 2.2 Bcf.

Our natural gas sales for the period from February 7, 2005 (inception) to June 30, 2005 were $1.4 million. For the period from February 7, 2005 (inception) to June 30, 2005, our total production was 0.2 Bcf, with an average sales price of $6.35 per Mcf.

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 Mcf/d, 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 the period from January 1, 2005 to June 12, 2005, Everlast s production was 2.0 Bcf, with an average realized sales price of $6.54 per Mcf. Everlast s natural gas sales increased by $4.9 million, or 22%, to $27.5 million for the year ended December 31, 2004 compared to gas sales of $22.3 million for 2003. This was due to a 24% increase in the average natural gas price, which was $6.07 per Mcf for the year ended December 31, 2004, compared to $4.89 per Mcf for the year ended December 31, 2003, as total production remained relatively stable at approximately 4.5 Bcf.

Mark-to-Market Activities

We did not have any mark-to-market derivatives for the six months ended June 30, 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. 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 and $3.7 million for the years ended December 31, 2004 and 2003, respectively. 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 reserves. All of our current reserves are located in Tuscaloosa County in the State of Alabama. We assess our field operating expenses by monitoring the expenses in relation to the volume of production and the number of wells under operation.

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For the six months ended June 30, 2006, field operating expenses were $4.4 million, or $2.00 per Mcf. Significant field operating expenses during this period included:

- Production taxes of $0.9 million, or $0.41 per Mcf (the current production tax rate is approximately 5% of gas sales);
- Field salaries and operating supervision costs of $0.9 million, or $0.43 per Mcf;
- Well servicing and work-over costs $1.0 million, or $0.45 per Mcf;
- Power and fuel costs of $0.4 million, or $0.19 per Mcf;
- Maintenance and repair costs of $0.3 million, or $0.16 per Mcf;
- Gas marketing costs of $0.2 million, or $0.08 per Mcf;
- Insurance and bond costs of $0.1 million, or $0.07 per Mcf; and
- Miscellaneous operating costs of $0.5 million, or $0.24 per Mcf.

Our field operating expenses were $0.4 million for the period from February 7, 2005 (inception) to June 30, 2005, or an average of approximately $1.98 per Mcf of production during that period.

For the period from February 7, 2005 (inception) to June 30, 2005, significant field operating expenses included:

- Production taxes of $0.1 million, or $0.33 per Mcf; and
- Miscellaneous operating costs of $0.3 million, or $1.65 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 during such period 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, and $5.7 million, or $1.25 per Mcf, for the years ended December 31, 2004 and 2003, respectively.

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

Production taxes of $0.7 million, or $0.30 per Mcf;

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

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- 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.

Field operating expenses for the year ended December 31, 2004 were $6.7 million, an increase of $1.0 million, or 18%, over field operating expenses of $5.7 for the year ended December 31, 2003. Production taxes increased by $0.2 million from 2003 to 2004. The production tax rate was consistent for both years, and the increase was due to an increase in gas prices. In 2004, three recompletions were performed that refractured seven more productive zones than in 2003. Power and fuel costs for the year ended December 31, 2004 were $0.8 million, an increase of $0.2 million, or 24%, over power and fuel costs for the year ended December 31, 2003, due to higher energy prices.

General and Administrative Expenses

General and administrative expenses include the costs of our employees, related benefits, field office lease, professional fees and other costs not directly associated with field operations. We monitor general and administrative expenses in relation to the volume of production and the number of wells under operation.

Our general and administrative expenses were $2.7 million, or $1.24 per Mcf, for the six months ended June 30, 2006. Significant general and administrative costs during this period were:

- Audit fees of $1.0 million, or $0.45 per Mcf;
- Professional services and consulting fees of $0.7 million, or $0.31 per Mcf;
- Consulting fees of $0.7 million, or $0.32 per Mcf; and
- Landman consulting fees of $0.2 million, or $0.09 per Mcf, related to lease acquisition efforts.

Our general and administrative expenses were $3.3 million, or $15.08 per Mcf, for the period of February 7, 2005 (inception) to June 30, 2005. For the period from February 7, 2005 (inception) to June 30, 2005, significant general and administrative costs were:

- Consulting fees of $3.1 million, or $14.40 per Mcf, to be paid by CCG pursuant to an agreement with The Investment Company for consulting services associated with the acquisition of our properties in the Robinson s Bend Field; and

- Professional services of $0.1 million, or $0.07 per Mcf.

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. 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 described above; 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.

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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, an increase of $0.8 million, or 50%, over general and administrative expenses of $1.9 million for the year ended December 31, 2003. The increase resulted primarily from an increase in corporate salaries of $1.0 million.

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 six months ended June 30, 2006 was $3.8 million, or $1.73 per Mcf. This reflects our basis in the assets as of June 2006 of $177.3 million, gross of accumulated depletion. As described above, we calculate depletion using units-of-production under the successful efforts method of accounting.

Our depreciation, depletion and amortization for the period from February 7, 2005 (inception) to June 30, 2005 was $0.3 million, or $1.61 per Mcf.

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 each of the years ended December 31, 2004 and December 31, 2003. 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, $59.7 million and $52.7 million as of June 12, 2005, December 31, 2004 and 2003, respectively. Production was constant for 2003, 2004 and the period from January 1, 2005 to June 12, 2005, which is why Everlast s depletion was relatively consistent for such periods.

Other Income (Expenses)

Our other income (expenses) for the six months ended June 30, 2006 was $0.2 million, or $0.09 per Mcf. Interest income was earned on the cash pool agreement with CCG. As of June 2006, we had a receivable from CCG of $12.2 million. The interest rate as of June 30, 2006 was 5.25%.

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, $3.0 million for the year ended December 31, 2004 and $1.9 million for the year ended December 31, 2003. For 2003, $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. At December 31, 2003, the weighted average interest rate on Everlast s floating rate debt was 3.8% and debt outstanding was $26.0 million. For 2003, the remaining $0.7 million of 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. 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.

Capital Resources and Liquidity

Our primary source of capital for the six months ended June 30, 2006 was our cash flow from operations. Net cash provided by operating activities for the six months was $8.8 million. We expect to continue to generate cash flow sufficient to support our projected maintenance capital expenditures for the remainder of 2006.

Our primary source of capital since February 7, 2005 (inception) has been our cash flow from operations. Net cash provided by operating activities was $23.3 million for the period from February 7, 2005 (inception) to December 31, 2005. Net cash provided by operating activities was $2.9 million for the period from February 7, 2005 (inception) to June 30, 2005. We expect to continue to generate cash flow sufficient to support our projected maintenance capital expenditures. In addition, immediately prior to the closing of this offering, we expect to establish a reserve-based credit facility to allow us to help finance future expansion capital expenses, such as incremental drilling and recompletions, as well acquisitions. Upon completion of the offering and application of the net proceeds therefrom, we expect to have $22.0 million of debt outstanding under the reserve-based credit facility and $88.0 million in unused borrowing capacity.

We expect to fund our 2006 and 2007 maintenance capital expenditures with cash flow from operations, while funding our 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 September 30, 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 September 30, 2007. 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 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 this 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. See Cash Distribution Policy and Restrictions on Distributions.

In the event that we acquire additional gas or oil properties that exceed our existing capital resources, we expect that we will finance those acquisitions with a combination of expanded or new debt facilities and, if necessary, 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

Prior to or at the closing of this offering, we plan to enter 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. We expect that the credit facility will mature four years from the closing of the credit facility. The amount available for borrowing at any one time is expected to be limited to the borrowing base, which will be set at $100.0 million at the closing of the credit facility. The borrowing base is expected to be re-determined semi-annually 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. We expect that 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 expected to be secured by mortgages on our natural gas properties, as well as a pledge of all ownership interests in our subsidiaries. We expect to be required to maintain the mortgages on properties representing at least 85% of our natural gas properties. Additionally, the obligations under the credit facility are expected to be guaranteed by all of our operating subsidiaries and any future subsidiaries.

Borrowings under the credit facility are expected to be 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 is expected to apply for letters of credit.

At our election, interest is expected to be determined by reference to:

- the London interbank offered rate, or 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.

We expect that interest will generally be payable quarterly for domestic bank rate loans and at the applicable maturity date for LIBOR loans.

The new credit facility is expected to contain various covenants that will 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.

We also expect the credit facility to contain 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).

Upon completion of this offering, we expect that we will 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.

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If an event of default exists under the credit facility, we expect that 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 expected to be 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, including a covenant requiring that Constellation and its affiliates shall maintain the right to elect our Class A managers, in the credit facility or other loan documents, subject, in certain instances, to certain grace periods;
- 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 voting power of our outstanding voting securities to less than 10%, and (ii) the ownership by any person (other than a wholly-owned subsidiary of Constellation) of our outstanding voting securities with a combined voting power of more than 35%.

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.

Cash Flow from Operations

Our net cash flow provided by operating activities was $8.8 million for the six months ended June 30, 2006. The major component of our cash flow for that period was net income of $6.8 million.

Net cash provided by operating activities was $23.3 million for the period from February 7, 2005 (inception) to December 31, 2005 and $2.9 million for the period from February 7, 2005 (inception) to June 30, 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 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 depletion, depreciation and amortization of $4.2 million, which was driven by our capitalized costs of $169.4 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

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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 depletion, depreciation and amortization of $1.7 million, which was driven by Everlast s capitalized costs of $63.8 million.

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. Currently, we use fixed-price swaps to hedge the prices of approximately 78% of our expected production from currently producing wells for October 2006 through December 2009.

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 June 30, 2006 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
2006							930,000	$ 8.83	930,000	$ 8.83
2007	924,999	$ 9.35	924,999	$ 9.35	924,999	$ 9.35	924,999	$ 9.35	3,699,996	$ 9.35
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
									11,430,000	

Investing Activities Acquisitions and Capital Expenditures

Our capital expenditures were $7.5 million for the six months ended June 30, 2006, which primarily relate to drilling, development and exploitation of natural gas properties during that quarter. We paid Everlast $2.4 million, which was the remaining balance of the purchase price for the Robinson s Bend properties. We drilled 15 gross wells (15 net wells) and completed 17 gross wells (17 net wells) during the six months. In addition, we had $12.2 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 administer and manage this cash pool arrangement. CCG may borrow from the pool at market interest rates. If we require cash, and CCG has an outstanding balance, CCG is required to immediately remit payment to us for the required cash amount. We expect that the cash pool arrangement will be terminated prior to the closing of this offering. At the termination of the arrangement, our net receivable balance under the cash pool will be canceled and CCG will retain the funds in respect of that receivable. The cash pool is recorded as an investment due from affiliate. This investment is due on demand.

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 and exploitation of natural gas properties since we acquired the Robinson s Bend Field and $139.0 million for the acquisition of the Robinson s Bend Field from Everlast. The total acquisition price for the Robinson s Bend 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.

Our capital expenditures were $139.4 million for the period from February 7, 2005 (inception) to June 30, 2005. This includes $0.4 million for drilling, development and exploitation of natural gas properties since we acquired our properties in the Robinson s Bend Field and $139.0 million for the acquisition of our properties in the Robinson s Bend Field 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 no wells and completed 2 gross (2 net) wells.

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 and exploitation 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 $9.2 million for the twelve months ending September 30, 2007, including interest expense of approximately $0.2 million. The capital budget, which predominantly 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 September 30, 2007, we anticipate that the proceeds of this offering, 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 September 30, 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 used in financing activities was $11,000 for the six months ended June 30, 2006. This represents a payment of our debt for the quarter.

Net cash provided by financing activities was $138.8 million for the period from February 7, 2005 (inception) to December 31, 2005 and from February 7, 2005 (inception) to June 30, 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 and 2003.

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Impact of Inflation

Inflation in the United States has been relatively low in recent years and did not have a material impact on our results of operations for the period from February 7, 2005 (inception) through June 30, 2006, or Everlast s results of operations for the period from January 1, 2005 through June 12, 2005 and the years ended December 31, 2003 and 2004.

Higher natural gas prices have led to industry-wide increases in drilling and oilfield service costs. These increases in drilling and service costs are also driven by shortages of drilling rigs, pipe, equipment and qualified support personnel. Continued increases in costs or shortages of equipment and personnel could negatively impact our drilling programs and increase our operating costs.

Contingencies and Contractual Obligations

As of December 31, 2005, 404 of our wells in the Robinson s Bend Field were subject to a non-operating net profits interest, or 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 certain wells in the Robinson s Bend Field, or 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. 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 will increase and our revenues will decrease in each case compared to the amounts if the sharing arrangement remained in effect. For a further description of the NPI and the related contractual arrangement, as well as the circumstances under which the sharing arrangement may be terminated, please read Business Natural Gas Data Torch Royalty NPI.

Our contractual obligations as of December 31, 2005 are provided in the following table. These payments are for debt and interest related to a note for support equipment.

	Payments due by period (in thousands)				
	Total	2006	2007-2008	2009-2010	Thereafter
Contractual Obligations					
Notes payable including interest	$ 68	$ 30	$ 38	$	$
Total	$ 68	$ 30	$ 38	$	$

Quantitative and Qualitative Disclosure 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-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.

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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 transactions were 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.

At the date of our 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.

However, a $1.00 per MMBtu price increase (decrease) in the natural gas prices of our unhedged natural gas production of 2,525 MMcf from June 13, 2005 (the date of the acquisition) through December 31, 2005 would have increased or decreased our cash available for distribution by approximately $2.4 million.

Interest Rate Risk

At December 31, 2005, we had debt outstanding of $63,000, which incurred interest at a fixed rate of 6.12%. We had no variable interest rate debt at that date. At June 30, 2006, we had debt outstanding of $52,000, which incurred interest at a fixed rate of 6.12%. We had no variable interest rate debt at that date.

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 units-of-production. 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 (wells and related equipment and facilities) be amortized on the basis of proved developed reserves. As more fully described in Note 17 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 Note 13 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, 2005, 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 gas properties were 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 gas properties. Upon the sale or disposition of oil and 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 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 years ended December 31, 2004 and 2003.

Depletion, depreciation 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.

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Reserves and their relation to estimated future net cash flows impacts our depletion calculations. As a result, adjustments to depletion 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 was 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 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.

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 (see Note 14 of the notes to the consolidated financial statements included elsewhere in this prospectus). 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 as of December 31, 2005, June 12, 2005, December 31, 2004 or December 31, 2003.

Hedging Activities

We implemented a hedging policy to hedge approximately 80% of our expected proved developed 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 will account for these hedging activities as cash flow hedges pursuant to SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities*, as amended.

We will 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 will record the ineffective portion of changes in the fair value of derivatives used as hedges immediately in earnings. We will summarize hedging activities under SFAS No. 133 and the income statement classification of amounts reclassified from Accumulated other comprehensive income (loss) generally as gas sales.

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Accounting Standards Adopted

In May 2005, the Financial Accounting Standards Board (FASB) issued SFAS No. 154, *Accounting Changes and Error Corrections A Replacement of APB Opinion No. 20 and FASB Statement No. 3.* This Statement requires retrospective application to prior periods financial statements of changes in accounting principle, unless it is impracticable to determine either the period-specific effects or the cumulative effect of the change. This Statement does not change the guidance for reporting the correction of an error in previously issued financial statements or a change in accounting estimate. The provisions of this Statement are effective for accounting changes and correction of errors made in fiscal years beginning after December 15, 2005. The adoption of this standard did not have a material impact on our financial results. We discuss 2004 and 2003 restatements in Note 2 to the historical financial statements included elsewhere in this prospectus.

On April 4, 2005, the FASB issued FASB Staff Position (FSP) No. 19-1 *Accounting for Suspended Well Costs*. This staff position amends SFAS No. 19, *Financial Accounting and Reporting by Oil and Gas Producing Companies* and provides guidance about exploratory well costs to companies which use the successful efforts method of accounting. The FSP states that exploratory well costs should continue to be capitalized if: 1) a sufficient quantity of reserves are discovered in the well to justify its completion as a producing well and 2) sufficient progress is made in assessing the reserves and the well s economic and operating feasibility. If the exploratory well costs do not meet both of these criteria, these costs should be expensed, net of any salvage value. Additional annual disclosures are required to provide information about management s evaluation of capitalized exploratory well costs. In addition, the FSP requires annual disclosure of: 1) net changes from period to period of capitalized exploratory well costs for wells that are pending the determination of proved reserves, 2) the amount of exploratory well costs that have been capitalized for a period greater than one year after the completion of drilling and 3) an aging of exploratory well costs suspended for greater than one year with the number of wells it related to. Further, the disclosures should describe the activities undertaken to evaluate the reserves and the projects, the information still required to classify the associated reserves as proved and the estimated timing for completing the evaluation. The guidance in the FSP is required to be applied to the first reporting period beginning after April 4, 2005 on a prospective basis to existing and newly capitalized exploratory well costs. The adoption of this standard did not have a material impact on our financial results.

On March 30, 2005, the FASB issued FASB Interpretation (FIN) No. 47, *Accounting for Conditional Asset Retirement Obligations*. This interpretation clarifies that the term conditional asset retirement obligation as used in SFAS No. 143 refers to a legal obligation to perform an asset retirement activity in which the timing and/or method of settlement are conditional on a future event that may or may not be within the control of the entity incurring the obligation. The obligation to perform the asset retirement activity is unconditional even though uncertainty exists about the timing and/or method of settlement. Thus, the timing and/or method of settlement may be conditional on a future event. Accordingly, an entity is required to recognize a liability for the fair value of a conditional asset retirement obligation if the fair value of the liability can be reasonably estimated. Uncertainty about the timing and/or method of settlement of a conditional asset retirement obligation should be factored into the measurement of the liability, rather than the timing of recognition of the liability, when sufficient information exists. FIN No. 47 was effective for us at the end of the fiscal year ended December 31, 2005. The adoption of this standard did not have a material impact on our financial results.

Accounting Standards Issued But Not Effective

In April 2006, the FASB issued Staff Position 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 FASB Interpretation 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.*

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BUSINESS

Overview

We are a limited liability company that was formed by Constellation to acquire coalbed methane reserves and production in June 2005. We are focused on the acquisition, development and exploitation of 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, 2005 were approximately 112.0 Bcf, approximately 80% of which were classified as proved developed producing. Our estimated proved reserves at December 31, 2005 had an estimated Standardized Measure of approximately $295.4 million. Our average proved reserve-to-production ratio is approximately 25 years based on our estimated proved reserves at December 31, 2005 and annualized production for the six months ended December 31, 2005. We currently own a 100% working interest (an approximate 75% average net revenue interest, calculated before the Torch Royalty NPI described below) in our Robinson s Bend Field producing properties, which had 436 producing natural gas wells as of December 31, 2005.

The Black Warrior Basin is one of the oldest and most prolific coalbed methane basins in the country, with over 2,750 producing coalbed methane wells as of 2002 (the most recent date for which information is available), based on a report by the Department of Energy, Energy Information Administration. These multi-seam vertical wells 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 5% to 6% per year. A typical well produces over a period of 20 to over 50 years and on average have less favorable economic characteristics than conventional gas wells. For a further description of the characteristics of coalbed methane production, please read Description of Our Properties and Projects Characteristics of Coalbed Methane.

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 producing reserves with long-lived, stable production and step-out development opportunities, which may include associated midstream assets such as gathering systems, compression, dehydrating and treating facilities and other similar facilities. We seek to acquire from third parties and Constellation long lived properties with a high percentage of proved producing reserves, moderate production decline rates and with reserve development and exploitation potential, such as is found in coalbed methane, shale and tight sands properties, and associated midstream assets, like gathering systems, compression, dehydrating and treating facilities and other similar facilities. Proved producing reserves tend to be the lowest risk category for oil and natural gas production, providing immediate cash flow and more predictable future production. The long lived, stable production profile of our target properties is well suited to our primary business objective. While we are currently focused on the Black Warrior Basin, we will continue to assess opportunities in other areas in the United States that provide long lived reserves and may expand into those areas if attractive opportunities become available. Our property base in the Robinson s Bend Field provides us with opportunities to increase our ownership in the Robinson s Bend Field.

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Identify and work with third-party operators who have experience in regions in which we seek to acquire an ownership interest and who will hold an ownership interest in our properties. We plan to target acquisitions of significant working interests in areas in which we can work with third-party operators on our E&P properties that have technical development expertise and experience in the particular oil or natural gas field in which we are acquiring an interest and who will hold a working interest in such properties. By working with experienced operators that also own a working interest in such properties, we expect to have significant influence over the development and operations of our future acquisitions.

Increase reserves and production through what we believe to be low-risk development and exploitation drilling. We plan to balance our acquisition efforts with growth of our proved reserves through development and exploitation activities. As of December 31, 2005, we had identified 364 total potential drilling locations on our acreage in the Robinson s Bend Field, of which 120 locations were proved undeveloped drilling locations. As of December 31, 2005, we also had identified 133 gross (133 net) existing wells that were candidates for refracture stimulation activities, or refractures, designed to enhance production from those wells. Pursuant to the development and exploitation plan we intend to implement upon completion of this offering, we plan to drill, complete and place on production approximately 20 gross (20 net) development wells and refracture formations on an average of 27 gross (27 net) wells over each of the next six years. We expect to refracture the formation on 7 gross (7 net) wells during the twelve months ending September 30, 2007. Based upon current drilling and completion costs and expected increases in the same, we have budgeted approximately $7.9 million per year for our 20-well annualized drilling program for each of the next six years. In addition, the cost to refracture a formation is approximately $137,500, or an average of about $3.7 million per year over the six-year period.

Reduce the volatility in our revenues resulting from changes in oil and natural gas commodity prices through hedging. On June 20, 2006, we entered into hedging arrangements to reduce the impact of natural gas price volatility on our cash flow from operations. We have hedged the future prices of approximately 78% of our expected production from currently producing wells from October 2006 through December 2009. We currently intend to hedge approximately 80% of our total expected production from our proved developed properties for the next five years. By removing the price volatility from a significant portion of our proved developed natural gas production, we will mitigate, but not eliminate, the potential effects of changing natural gas prices on our cash flow from operations. Please read Management s Discussion and Analysis and Financial Condition and Results of Operations Critical Accounting Policies and Estimates Hedging Activities.

Competitive Strengths

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

Our relationship with Constellation. We believe our ability to grow through acquisitions is enhanced by our relationship with Constellation, an integrated energy company that has developed a portfolio of oil and natural gas investments in North America.

Operational and Technical Support from Constellation. We believe our relationship with Constellation will provide us with a wide range of operational, commercial, technical, risk management, asset management and other expertise including:

- a technical evaluation team whose professionals have many years of experience in engineering, geology, recovery methods and production of oil and natural gas;

- a portfolio management team whose professionals have many years of land, title, marketing and sales, operations and development experience; and a team of professionals with substantial risk management expertise, including commodity price hedging.

Low-Risk Development Drilling Operations. During the twelve months ended December 31, 2005, we (and our predecessor, Everlast) drilled and completed 18 gross (18 net) development wells, 100% of which are producing natural gas in commercial quantities. For additional detail, please read Natural Gas Data Development Costs. Our average well currently takes four days to drill and complete, and we budget an average cost of $400,000 to drill, complete and place on production each well. Most of our wells are producing and are typically connected to a pipeline within approximately 40 days after drilling has commenced. In order to sustain or grow our production in the long term, we will have to acquire or develop other producing E&P properties, which may not have the same production characteristics and will likely increase our costs.

Predictable, Long-Lived Reserves. Our properties are located in the Black Warrior Basin in Alabama, a coal seam natural gas basin with a long history of relatively stable production characterized by low to moderate rates of production decline compared to rates generally experienced in conventional production. Our current reserves have an average reserve life of approximately 25 years.

Control of Operations. We own at least a 75% working interest in all of our currently undeveloped leasehold acreage, and a 100% working interest in all of our leasehold acreage that is held by production, in the Robinson s Bend Field. In addition, we own and operate all of the compression, gas gathering, water handling and related facilities for the Robinson s Bend Field. As a result, we are able to control decisions with respect to the development and operations of our properties in the Robinson s Bend Field.

Large Undeveloped Acreage Base. As of December 31, 2005, we had identified 364 total potential drilling locations on our acreage in the Robinson s Bend Field, of which 120 locations were proved undeveloped drilling locations. We also had identified 133 gross (133 net) well formation refracture candidates as of December 31, 2005. We drilled, completed and placed on production 25 gross (25 net) development wells and refractured the formation of 2 gross (2 net) well locations during the nine months ended September 30, 2006. During the twelve months ending September 30, 2007, we currently plan to drill, complete and place on production approximately 20 gross (20 net) development wells and to refracture the formations of approximately 7 gross (7 net) existing wells.

Our Relationship With Constellation

We believe that one of our principal strengths is our relationship with Constellation, an integrated energy company with 2005 revenues of approximately $17.1 billion and total assets of approximately $19.2 billion as of June 30, 2006. Constellation s common stock trades on The New York Stock Exchange under the symbol CEG. Constellation is engaged in numerous aspects of the energy industry, including, through CCG, oil and natural gas E&P, natural gas transportation, natural gas storage and physical and financial natural gas trading.

A principal component of our business strategy is to grow our asset base and production through the acquisition of E&P properties characterized by long-lived, stable production. Constellation, through CCG, has a track record of successfully acquiring developed and undeveloped E&P properties. CCG is currently developing several other E&P projects in various locations with unconventional production, including coalbed methane, tight sands and shale. As CCG continues to develop the E&P properties that comprise these projects, and potentially other undeveloped E&P properties that it may acquire in the future, it is possible these projects will have characteristics suitable for us and our business strategies. These characteristics may include a combination of the following:

- a high percentage of proved developed producing reserves;
- long-lived, stable production;
- a significant number of step-out development opportunities; that is, properties where, as development progresses, reserves from newly completed wells are reclassified from the proved undeveloped to the proved developed category and additional adjacent locations are added to proved undeveloped reserves;

a significant working interest in the wells;

properties where we can work with third-party operators with experience in the applicable regions and who hold an interest in such properties; and

low operating costs.

Constellation views us as an integral component of the growth strategy for its upstream oil and natural gas business and intends to use us as its primary vehicle to develop a portfolio of long-lived, proved producing E&P properties. However, Constellation has no obligation or commitment to do so, and may act in a manner that is beneficial to its interests and detrimental to ours.

We will enter into a management services agreement with CEPM, an indirect wholly owned subsidiary of Constellation. Pursuant to that agreement, CEPM will provide us with legal, accounting, finance and tax services. We also expect that CEPM will provide us with property management, engineering and other services and with assistance in hedging our production, as well as acquisition services in respect of opportunities for us to acquire long-lived, stable and proved oil and natural gas reserves. 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, finance, tax and risk management services. While neither Constellation nor CEPM has any obligation to provide us with acquisition services under the management services agreement 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.

Following this offering we will be dependent on CEPM for management of our operations and, pursuant to the management services agreement, we will reimburse CEPM for the reasonable costs of the services it provides to us. Our board of managers has the right and the duty to review the services provided, and the costs charged, by CEPM under that agreement. Our board of managers may in the future cause us to hire additional personnel to supplement or replace some or all of the services provided by CEPM, as well as employ third-party service providers. If we were to take such actions, they could increase the overall costs of our operations. For a description of the services that CEPM will provide to us under the management services agreement and our obligation to reimburse CEPM for the costs it incurs in providing those services, please read Certain Relationships and Related Party Transactions Agreements Governing the Transactions Management Services Agreement.

While our relationship with Constellation and its subsidiaries is a significant strength, it is also a source of potential conflicts. For example, none of Constellation or any of its affiliates (other than us) is restricted from competing with us and each of our executive officers and our Class A managers also serves as a manager, director, officer or employee of Constellation or its other affiliates. Constellation or its affiliates (other than us) may acquire, invest in or dispose of E&P or other assets in the future without any obligation to offer us the opportunity to purchase or own interests in those assets. The ultimate resolution of the conflicts of interest that exist or arise as a result of either our relationship with Constellation and its other affiliates or the status of our executive officers and our Class A managers as a manager, director, officer or employee of Constellation or its other affiliates may result in the interests of Constellation or its affiliates being favored over your interests and may be to our detriment. Please read Conflicts of Interest and Fiduciary Duties.

In December 2005, Constellation entered into an Agreement and Plan of Merger with FPL Group, Inc., a Florida corporation whose common stock trades on The New York Stock Exchange under the symbol FPL. FPL Group, Inc. is also an integrated energy company with 2005 revenues of $11.8 billion and total assets of $33.8 billion as of June 30, 2006. The merger agreement contains numerous conditions that must be satisfied or waived before the merger is consummated, and there can be no assurance that it will be consummated.

Description of Our Properties and Projects

We produce gas out of our Robinson s Bend Field properties in the Black Warrior Basin in Alabama. At December 31, 2005, we operated 436 gross productive wells, which constituted all producing wells in the Robinson s Bend Field.

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Black Warrior Basin

The Black Warrior Basin is one of the oldest and most prolific coalbed methane basins in the country, with over 2,750 producing coalbed methane wells as of 2002 (the most recent date for which information is available) based on a report by the Department of Energy, Energy Information Administration. These multi-seam vertical coal wells range from 500 to 3,700 feet deep, with coal seams averaging a total of 25 to 30 feet of net pay per well.

Characteristics of Coalbed Methane

The rock containing natural gas, referred to as source rock, is usually different from reservoir rock, which is the rock through which the natural gas is produced, while, in coalbed methane, the coal seam serves as both the source rock and the reservoir rock. The storage mechanism is also different. Gas is stored in the pore or void space of the rock in conventional natural gas, but in coalbed methane, most, and frequently all, of the gas is stored by adsorption. This adsorption allows large quantities of gas to be stored at relatively low pressures. A unique characteristic of coalbed methane is that the gas flow can be increased by reducing the reservoir pressure. Frequently, the coalbed pore space, which is in the form of cleats or fractures, is filled with water. The reservoir pressure is reduced by pumping out the water, releasing the methane from the molecular structure, which allows the methane to flow through the cleat structure to the well bore. While a conventional natural gas well typically decreases in flow as the reservoir pressure is drawn down, a coalbed methane well will typically increase in production for up to five years depending on well spacing and then start on a decline to a final decline rate of as low as 5% to 6% per year. A typical well produces over a period of 20 to over 50 years. Production rates from newly drilled and completed wells in the Robinson s Bend Field do not always increase as the formation dewaters.

Coalbed methane and conventional natural gas both have methane as their major component. While conventional natural gas often has more complex hydrocarbon gases, coalbed methane rarely has more than 2% of the more complex hydrocarbons. In the eastern coal fields of the United States, coalbed methane is generally 98% to 99% pure methane and requires only dehydration of the gas to remove moisture to achieve pipeline quality. In the western coal fields of the United States, it is also sometimes necessary to strip out either carbon dioxide or nitrogen. Once coalbed methane has been produced, it is gathered, transported, marketed and priced in the same manner as conventional natural gas.

The content of gas within a coal seam is measured through gas desorption testing. The ability to flow gas and water to the well bore in a coalbed methane well is determined by the fracture or cleat network in the coal. While, at shallow depths of less than 500 feet, these fractures are sometimes open enough to produce the fluids naturally, at greater depths the networks are progressively squeezed shut, reducing the ability to flow. It is necessary to provide other avenues of flow such as hydraulically fracturing the coal seam. By pumping fluids at high pressure, fractures are opened in the coal and a slurry of fluid and sand proppant is pumped into the fractures so that the fractures remain open after the release of pressure, thereby enhancing the flow of both water and gas to allow the economic production of gas.

Robinson s Bend Field

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

The Robinson s Bend Field is located in rural western Tuscaloosa County and Pickens County, Alabama and encompasses a gross surface area of approximately 109 square miles. As of December 31, 2005, the Robinson s Bend Field operated with approximately 436 natural gas wells. The field has been primarily developed on 80-acre spacing. The State of Alabama has approved field-wide 40-acre spacing. We are currently developing our properties in the field on both 40- and 80-acre spacing.

The field has nine 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 180 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 and produced water are discharged 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, or SONAT. A small portion of the natural gas (approximately 15%) 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, or ADEM, and our National Pollutant Discharge Elimination System, or NPDES, permits. In addition, there are three saltwater disposal wells that are not currently in use.

Our subsidiary, Robinson s Bend Operating II, LLC, has a staff of 24 full-time employees that perform field level operations, maintenance and drilling. These employees are supervised by Ironhorse, our third-party operations supervisor. See Operations General. Engineering and project management services will continue to be provided by CEPM, pursuant to a management services agreement, with the assistance of third-party contractors and consultants. Drilling is conducted using third-party rigs under the supervision of our field staff. Well completion services and logging services are also conducted using third-party contractors. There is an ongoing drilling program in place with the objective of drilling and completing an average of 20 gross (20 net) development wells per year over the six-year period ending September 30, 2012. Three third-party rig contractors operate nine rigs and drill wells in the Black Warrior Basin. We have not experienced unanticipated delays in scheduling drilling rigs and completion and stimulation services with our contractors since purchasing the Robinson s Bend Field in June 2005. In the Black Warrior Basin, it typically takes 3 to 4 days to drill the well to the targeted depth using a land-based rig and an additional 3 to 5 days to complete and stimulate the well.

The following development and exploitation techniques are used by us in an effort to increase reserves and production from our existing wells and drill sites: (1) assessing additional production formations in existing wellbores, (2) formation stimulation, (3) artificial lift equipment enhancement, (4) infill drilling on closer well spacing and (5) drilling for deeper formations. During 2005, a total of 18 gross (18 net) wells were drilled and completed. From June 13, 2005 through December 31, 2005, we drilled and completed 9 gross (9 net) of those 18 wells. Those 18 wells developed 6.0 Bcf of natural gas previously categorized as proved undeveloped reserves and added 1.6 Bcf of estimated proved undeveloped reserves and 0.15 Bcf of estimated proved developed reserves. A total of approximately $8.2 million was invested in these and other activities on the properties. From June 13, 2005 through December 31, 2005, the field s reserve replacement rate, or the ratio of added proved reserves to production, was approximately 69%.

We plan to maximize our production through our development and exploitation activities in the Robinson s Bend Field and to grow our proved reserve base and production through selective acquisitions of long-lived producing properties. As of December 31, 2005, we had identified 364 total potential gross drilling locations in the Robinson s Bend Field, of which 120 gross (120 net) were proved undeveloped drilling locations. We had also identified 133 gross (133 net) formation refracture wells. During the nine months ended September 30, 2006 we drilled and completed 25 gross (25 net) development wells and spudded an additional 6 gross (6 net) wells that are in the process of completion. We currently intend to drill and complete an average of 20 gross (20 net) wells during each of the six years ending September 30, 2012 and to refracture the formation on an average of 27 gross (27 net) wells during each year of such six-year period. We expect to refracture the formation on 7 gross (7 net) wells during the twelve months ending September 30, 2007.

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Natural Gas Data

Proved Reserves

The following table reflects our internal estimates of net proved natural gas reserves based on SEC definitions that were used to prepare our financial statements for the periods presented. The estimates of net proved reserves have not been filed with or included in reports to any federal authority or agency other than the SEC in connection with this offering. The Standardized Measures shown in the table are not intended to represent the current market values of our estimated natural gas reserves.

	Predecessor		Successor
	Everlast Energy LLC		Constellation Energy Partners LLC
	As of December 31,		
Reserve data:	**2003**	**2004**	**2005**
Estimated net proved reserves:			
Natural gas (Bcf)	163.7	162.2	112.0
Proved developed reserves (Bcf)	100.7	101.4	89.3
Proved undeveloped reserves (Bcf)	63.0	60.8	22.7
Proved developed reserves as a percent of total reserves	62%	62%	80%
Standardized Measure (in millions) (a)	$ 194.2	$ 206.8	$ 295.4
Natural gas price SONAT Gas Daily (price per Mmbtu) (b)	$ 5.92	$ 6.05	$ 10.06

(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. For a description of our derivative transactions, please read Management s Discussion and Analysis of Financial Condition and Results of Operations Cash Flow from Operations.

(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.

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 prospectus. Our 2005 estimates of proved reserves are lower than the 2004 and 2003 estimates for Everlast, the predecessor company, because of the decision of our current 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 provides relevant current 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, 2004 estimate of reserves because no amounts were due or paid in respect of the NPI at that time.

Our 2005 proved reserve estimate is 112.0 Bcf. At December 31, 2005, NSAI, an independent petroleum engineering firm, prepared an estimate of 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 2005 proved reserves is materially consistent with our internal estimate.

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Our 2004 and 2003 proved reserve estimates are 162.2 Bcf and 163.7 Bcf, respectively. These are our internal estimates of proved reserves that were used in the 2004 and 2003 Everlast financial statements included elsewhere in this prospectus. We prepared the estimates of 2004 and 2003 proved reserves for financial statement purposes by starting with NSAI s December 31, 2005 net proved reserve estimate, which was prepared based upon a continuation of the assumptions used by Everlast, including the prior accelerated drilling program and reserve assumptions, and rolling back the estimate to December 31, 2004 and 2003 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 December 31, 2004 was not based on the SEC definition of proved reserves, while the reserve report prepared by NSAI for Everlast as of December 31, 2003, which was based on the SEC definition of proved reserves, included different assumptions than those used in NSAI in preparing, December 31, 2005 proved reserves estimate. To prepare reserve estimates for these periods in compliance with the SEC definitions, we adopted the roll back approach described above and in Note 2 and Note 17 to the historical financial statements. Everlast s previous non-SEC compliant reserve estimates were 173.4 Bcf at December 31, 2004 and 166.2 Bcf at December 31, 2003.

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 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 recovered. Please read Risk Factors Risks Related to Our Business 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.

Future prices received for production and costs may vary, perhaps significantly, from the prices and costs assumed for purposes of these estimates. The Standardized Measure values shown should not be construed as the current market value of the reserves. The 10% discount factor used to calculate present value, which is required by Financial Accounting Standard Board 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.

Market Price Sensitivity

We are exposed to market price changes of natural gas and oil commodities, specifically to NYMEX Henry Hub gas and SONAT Inside FERC Price gas for our existing properties. On June 20, 2006, we executed derivative transactions that hedge the future prices of approximately 78% of our expected production from currently producing wells from October 2006 through December 2009. Prior to this offering, we expect to adopt a hedging policy under which we expect to hedge approximately 80% of our expected production from proved developed reserves for the next five-year period. We believe that we will significantly reduce, but not eliminate, our risk relative to natural gas market price moves by implementing such hedges. For instance, if on a pro forma basis we had hedged 80% of our pro forma 2005 production, we estimate that a $1.00 per MMBtu increase (decrease) in natural gas prices would have increased (decreased) our natural gas sales by approximately $0.9 million.

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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,		For the period from January 1, 2005 to June 12,	For the period from February 7, 2005 (inception) to December 31,	For the six months ended June 30,
	2003	2004	2005	2005[a]	2006
Net Production:					
Total production (MMcf)	4,566	4,527	1,970	2,525	2,200
Average daily production (Mcf/d)	12,500	12,400	12,100	12,500	12,156
Average Sales Prices:					
Price per Mcf including economic hedges	$ 4.09	$ 4.06	$ (1.23)[c]	$ 10.28[b]	$ 8.00[b]
Price per Mcf excluding economic hedges	$ 4.89	$ 6.07	$ 6.54	$ 10.28	$ 8.00
Average Unit Costs Per Mcf:					
Field operating expenses[d]	$ 1.25	$ 1.49	$ 1.75	$ 2.21	$ 2.00
General and administrative expense	$ 0.43	$ 0.60	$ 0.30	$ 1.66	$ 1.24
Depreciation, depletion and amortization	$ 0.81	$ 0.82	$ 0.85	$ 1.65	$ 1.73

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

(b) We had no derivatives as of December 31, 2005. On June 20, 2006, we entered into derivative transactions that hedge the future prices of approximately 78% of our expected production from currently producing wells from October 2006 to December 2009.

(c) Price per Mcf including economic hedges includes mark-to-market losses of approximately $15 million on derivative transactions that did not qualify for hedge accounting treatment.

(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 the NPI held by the Trust. The NPI is a non-operating net revenue interest upon specified natural gas sales revenues from the Trust Wells reduced by specified associated expenditures. The units of the Trust are listed for trading on The NYSE. An affiliate of Torch Energy Corporation conveyed the NPI to the Trust in November 1993, together with net profits interests on three other properties. The Trust terminates on a specified date, unless terminated earlier in accordance with its terms. In connection with the termination of the Trust, the trustee is required to sell the NPI and distribute the net proceeds from that sale to its unitholders. We acquired our initial 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.

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, 2005, we owned a working interest in 436 producing wells in the Robinson s Bend Field, of which 404 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

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with respect to the remaining 11 wells that are subject to the NPI as of December 31, 2005, 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 Net Overriding Royalty Conveyance. After January 1, 2003, 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. Since July 1, 2003, deductible expenses have exceeded gross proceeds attributable to the Trust Wells, and as of December 31, 2005, the cumulative deficit was 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 August 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. 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 $2.18 and $2.13 per MMBtu in 2005 and 2004, respectively, and is estimated to be approximately $2.22 per MMBtu in 2006. 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 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.

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.

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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. The Trust has previously advised its investors 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 September 1, 2006, the Henry Hub spot prices for natural gas were $10.08 and $5.815 per MMBtu, respectively. However, on September 1, 2006 the December 2006 futures contract price for natural gas was approximately $9.901 per MMbtu.

If the Trust is terminated, the gas purchase contract will be terminated, and we will no longer be obligated to sell gas produced from 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, and 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 an extent, the risks of the potential adverse impact on our operating results from the 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, CHI will contribute to us at the closing of this 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 likely not eliminate, the adverse impact of our reduced revenues from the termination of the sharing arrangement. For a further description of this special distribution right, please read Cash Distribution Policy and Restrictions on Distributions and Certain Relationships and Related Party Transactions Agreements Governing the Transactions Class D Contribution by CHI.

Productive Wells

The following table sets forth information at December 31, 2005 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, 2005	
	Gross	**Net**
Operated	436	436
Non-operated		
Total	436	436

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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, 2003, 2004 and 2005 and the nine months ended September 30, 2006, and wells commenced by us during the nine months ended September 30, 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, 2003, 2004 or 2005 or the nine months ended September 30, 2006.

	Year Ended December 31,			Nine Months Ended September 30, 2006	Wells in Progress as of September 30, 2006
	2003	2004	2005		
Gross:					
Development					
Productive	1	9	18	25	6
Dry					
Total	1	9	18	25	6
Net:					
Development					
Productive	1	9	18	25	6
Dry					
Total	1	9	18	25	6

Development Costs

From June 13, 2005 through December 31, 2005, we drilled and completed 9 gross (9 net) of the 18 wells completed during the year ended December 31, 2005. Those 18 wells developed 6.0 Bcf of natural gas previously categorized as proved undeveloped reserves and added 1.6 Bcf of estimated proved undeveloped and 0.15 Bcf of estimated proved developed reserves. We invested a total of $7.9 million in these and other activities on our properties in the Robinson s Bend Field. Our historical development costs may not be indicative of our future development costs, as developing properties involves a variety of risks, and we are unable to predict the amount or timing of future proved reserve additions or the costs that we may incur in connection with any such reserve additions.

Developed and Undeveloped Acreage

The following table sets forth information as of December 31, 2005 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)]	
	Gross[(c)]	Net[(d)]	Gross[(c)]	Net[(d)]
Total	38,000	38,000	18,500	17,100

(a) Developed acres are acres spaced 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 with a productive well.
(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.

Leases

We have over 850 leases in the Robinson s Bend Field. The typical 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 on the lease in the form of overriding royalty interests and net profits interests, including the NPI. 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. In some instances, our lease net revenue interest may be as high as 83%.

Under our lease agreements, our leases of E&P properties on which there is a productive well extends 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 rental payments beyond the royalty amount stipulated by each lease. The area held by production from a particular well is typically the applicable spacing unit for such well as specified under state law. Our leases cover approximately 55,000 total project acres with 38,000 (69%) considered to be held by production. The remaining 17,100 (31%) acres related to undeveloped leases that are still within their original lease term and still have the potential for development, if warranted by drilling success in nearby locations. Barring establishment of commercial production, most of these leases will expire between September 2006 and October 2010. Leases covering approximately 7,614 net acres are scheduled to expire before September 30, 2007. Recently, higher potential locations were identified on the project and we petitioned the state to approve an enlargement of the existing field area to include those lands. The State of Alabama approved the request and we have acquired new leases on approximately 700 net acres and expect to acquire an additional 300 acres in this area.

Operations

General

We have entered into a professional services agreement with Ironhorse Energy LP, or 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 will continue to be provided by CEPM through our management services agreement.

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

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drilled by Pense Brothers Drilling Company, an established Black Warrior Basin drilling contractor. Cementing and completion is currently conducted by Superior Well Services, Schlumberger 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 will continue to be 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 who is a landman with over 20 years of experience in various Texas and Gulf Coast producing areas.

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 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 entries that are 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 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 Natural Gas Data Torch Royalty NPI.

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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.

For the six months ended June 30, 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 31%, 27%, 18%, 13% and 11% 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 six months ended June 30, 2006.

Hedging Activity

We expect to enter and have entered into hedging transactions with unaffiliated third parties with respect to natural gas prices to achieve more predictable cash flows and to reduce our exposure to short term fluctuations in natural gas prices. For a more detailed discussion of our hedging transactions and our expected hedging policy, please read Management s Discussion and Analysis of Financial Condition and Results of Operations Critical Accounting Policies and Estimates Hedging Activities and Management s Discussion and Analysis of Financial Condition and Results of Operations Quantitative and Qualitative Disclosures About Market Risk.

Competition

We operate in a highly competitive environment for acquiring properties, marketing oil and natural gas and securing 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. Also, there is substantial competition for capital available for investment in the oil and natural gas industry. None of Constellation or any of its affiliates is restricted from competing with us. Constellation or its affiliates may acquire, invest in or dispose of E&P 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 any 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.

Title to Properties

At the time we acquired 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. Prior to the commencement of drilling operations on those properties, however, we conduct a thorough title examination and perform curative work with respect to significant defects. To the extent title opinions or other investigations reflect title defects on those properties, we are typically responsible for curing any title defects at our expense. We generally will not commence drilling operations on a property until we have cured any material title defects 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 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 prospectus.

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, or RCRA, and comparable state statutes, regulate the generation, transportation, treatment, storage, disposal and cleanup of hazardous wastes and non-hazardous wastes. Under the auspices of the federal Environmental Protection Agency, or 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, or 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, or 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, or 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 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 the Alabama Department of Environmental Management, also known as 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 sometime 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 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.

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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. As of the date of this prospectus, we are not aware of any environmental issues or claims that will require material capital expenditures during 2006 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 August 31, 2006, our subsidiary, Robinson s Bend Operations II, LLC, has 24 full-time field employees. The field employees average over nine years of experience operating and working on the Robinson s Bend Field with six of the employees averaging over 15 years of experience operating this specific field. None of these employees is subject to a collective bargaining agreement or an employment contract.

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

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Management Reimbursement of Expenses of CEPM. We believe that we and our subsidiaries have favorable relationships with our employees.

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 Tuscaloosa, Alabama that houses the field supervisor and the rest of our field employees. Our subsidiary, Robinson s Bend Production, LLC, owns both the land and office space in Tuscaloosa.

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 the various environmental protection statutes to which we are subject.

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MANAGEMENT

Management of Constellation Energy Partners LLC

Our Board of Managers

Upon completion of this offering, our board of managers will consist of five members, three of whom will satisfy the independence requirements of NYSE Arca and SEC rules. Our current board of managers consists of two members, Felix J. Dawson and John R. Collins, who are senior officers of Constellation and not independent. Our current board is expected to appoint immediately following the pricing of this offering Richard H. Bachmann and John N. Seitz as independent managers and to serve as the initial members of the audit committee, the compensation committee, the conflicts committee and the nominating and governance committee. Our current board is expected to appoint the remaining independent manager within 90 days of the pricing of this offering. The current members and the remaining members of the board expected to be appointed following the pricing of this offering will serve until the first annual meeting of the holders of our Class A and common units following this offering and will be subject to re-election annually as described below. The board intends to appoint four functioning committees immediately following the pricing of this offering: an audit committee, a compensation committee, a conflicts committee and a nominating and governance committee.

Audit Committee

We currently contemplate that the audit committee will initially consist of two managers, with one additional manager to be appointed within 90 days of the pricing of this offering. All members of the audit committee will be independent under the independence standards established by NYSE Arca and SEC rules, and we expect that the committee will have an audit committee financial expert, as defined under the SEC rules. 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.

Compensation Committee

We currently contemplate that the compensation committee will initially consist of two managers, with one additional manager to be appointed within 90 days of the pricing of this offering. All members of the compensation committee will be 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 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 contemplate that we will 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.

Conflicts Committee

We currently contemplate that the conflicts committee will initially consist of two managers, with one additional manager to be appointed within 90 days of the pricing of this offering. The conflicts committee will review specific matters that the board believes may involve conflicts of interest. The conflicts committee will determine if the resolution of the conflict of interest is fair and reasonable to our company. Our limited liability company agreement will provide 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.

Nominating and Governance Committee

We currently contemplate that the nominating and governance committee will initially consist of two managers with one additional manager to be appointed within 90 days of the pricing of this offering. All members of the nominating and governance committee will be independent under the independence standards established by NYSE Arca and SEC rules. This 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 assess manager, board and committee effectiveness, developing and implementing our corporate governance guidelines, setting the remuneration for non-employee managers, committee members and committee chairpersons and otherwise taking a leadership role in shaping the corporate governance of our company.

Election of Our Board of Managers

At our first annual meeting of the holders of our Class A and common units following this offering:

- CEPM, as the holder of all of our Class A units, will have the right to elect two members of our board of managers; and
- our common unitholders will have the right to elect the remaining three members of our board of managers.

The board of managers will be subject to re-election on an annual basis in this manner at each annual meeting of the holders of our Class A and common units.

Removal of Members of Our Board of Managers

Any manager elected by the holder of our Class A units may be removed, with or without cause, by 66 $^{2}/3$% of the outstanding Class A units then entitled to vote at an election of managers. Any manager elected by the holders of our common units may be removed, with or without cause, by at least a majority of the outstanding common units then entitled to vote at an election of managers.

Governance Matters

Independence of Board Members

We are committed to having a board of managers that consists of at least a majority of independent managers. Pursuant to NYSE Arca listing standards, a manager will be considered independent if the board determines that he or she does not have a material relationship with us (either directly or as a member, unitholder or officer of an organization that has a material relationship with us).

Heightened Independence for Audit Committee Members

As required by the Sarbanes-Oxley Act of 2002, the SEC has adopted rules that direct national securities exchanges and associations to prohibit the listing of securities of a public company if members of its audit committee do not satisfy a heightened independence standard. In order to meet this standard, a member of an audit committee may not receive any consulting fee, advisory fee or other compensation from the public company other than fees for service as a director or committee member and may not be considered an affiliate of the public company. Our board of managers expects that all members of its audit committee will satisfy this heightened independence requirement.

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Audit Committee Financial Expert

An audit committee plays an important role in promoting effective corporate governance, and it is imperative that members of an audit committee have requisite financial literacy and expertise. As required by the SEC rules, a public company must disclose whether its audit committee has a member that is an audit committee financial expert. An audit committee financial expert is defined as a person who, based on his or her experience, possesses all of the following attributes:

- An understanding of generally accepted accounting principles and financial statements;
- An ability to assess the general application of such principles in connection with the accounting for estimates, accruals and reserves;
- Experience preparing, auditing, analyzing or evaluating financial statements that present a breadth and level of complexity of accounting issues that are generally comparable to the breadth and level of complexity of issues that can reasonably be expected to be raised by a company s financial statements, or experience actively supervising one or more persons engaged in such activities;
- An understanding of internal controls and procedures for financial reporting; and
- An understanding of audit committee functions.

Our board of managers expects that our audit committee will have an audit committee financial expert.

Executive Sessions of Board

Our board of managers will hold regular executive sessions in which non-management board members meet without any members of management present. The purpose of these executive sessions is to promote open and candid discussion among the non-management managers. During such executive sessions, one manager is designated as the presiding manager and is responsible for leading and facilitating such executive sessions.

Compensation Committee Interlocks and Insider Participation

During the year ended December 31, 2005, we had no compensation committee. 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.

Meetings of Board of Managers

Our board will hold regular and special meetings at any time as may be necessary. Regular meetings may be held without notice on dates set by the board from time to time. Special meetings of the board may be called with reasonable notice to each member upon request of the chairman of the board or upon the written request of a majority of the board members. A quorum for a regular or special meeting will exist when a majority of the members are participating in the meeting either in person or by telephone conference. Any action required or permitted to be taken at a board meeting may be taken without a meeting, without prior notice and without a vote, if all of the members sign a written consent authorizing the action.

Our Board of Managers and Executive Officers

The following table shows information for members of our board of managers, manager nominees 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	38	Chief Executive Officer, President and Manager
John R. Collins	49	Manager
Richard H. Bachmann	53	Independent manager nominee
John N. Seitz	54	Independent manager nominee
Angela A. Minas	42	Chief Financial Officer, Chief Accounting Officer and Treasurer

Felix J. Dawson is our Chief Executive Officer, President and a member of our board of managers. We expect Mr. Dawson to be appointed chairman of our board of managers immediately following the pricing of this offering. He also serves as Co-President and CEO of CCG, a position to which he was appointed in August 2005. 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, a position that he has held since December 2001. Mr. Collins 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 expected to be appointed, immediately following the pricing of this offering, as a member of our board of managers and our audit, compensation and nominating and governance committees and is expected to chair 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. Mr. Bachmann also serves as a director of Texas Eastern Products Pipeline Company LLC, also an affiliate of EPCO Inc. and the general partner of TEPPCO Partners L.P., a publicly traded midstream energy company.

John N. Seitz is expected to be appointed, immediately following the pricing of this offering, as a member of our board of managers and our audit, compensation and conflicts committees and is expected to chair our nominating and governance committee. Mr. Seitz is also currently the Co-Chief Executive Officer and a director and 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 is our Chief Financial Officer, Chief Accounting Officer and Treasurer, a position to which she was appointed in September 2006. Ms. Minas also serves as Managing Director Portfolio Management of CCG, a position to which she was appointed in 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.

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Executive Compensation

We were formed in February 2005 and did not begin operations until our acquisition of 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 currently contemplate that we will not reimburse CEPM for the compensation of our executive officers to be paid by CCG for 2006, as set forth in the table below. Please read Reimbursement of Expenses of CEPM.

The following table sets forth the annual compensation that we expect CCG to pay to our chief executive officer and our chief financial officer and chief accounting officer in 2007 for services related to our business and affairs to be performed upon consummation of this offering. No compensation will be paid in 2006. We have no other officers.

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 amount that we have agreed to pay for these two 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.

Employment Agreements

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

Compensation of Managers

Following the completion of this offering, 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 expect to pay such independent managers an annual retainer of $40,000 and $2,500 per meeting for attending meetings of our board of managers, as well as committee meetings. We may in the future grant independent managers awards under the long-term incentive plan that we expect to adopt prior to the closing of this offering. 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.

Reimbursement of Expenses of CEPM

We will reimburse CEPM on a quarterly basis for its costs in providing services to us including all supervisory and management direct and indirect costs 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 will be 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

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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 will approve the expenses that are allocable to us. There is no limit on the amount of expenses for which CEPM may be reimbursed. Please read Certain Relationships and Related Party Transactions Agreements Governing the Transactions Management Services Agreement.

Long-Term Incentive Plan

General. We intend to adopt 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 will consist of common unit grants, restricted common units, phantom common units, common unit options and common unit appreciation rights. The long-term incentive plan will permit the grant of awards covering an aggregate of 575,000 common units. The plan will be administered by the compensation committee of our board of managers.

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. However, no change in any outstanding grant 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 will permit the grant of common units. A common unit grant is a grant of common units that vests 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 grantee 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 will determine 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. In addition, the restricted common units and phantom common units will vest upon a change of control of our company, as defined in the plan, unless provided otherwise by the compensation committee in the applicable award agreement.

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 will permit 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 will be 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. In addition, the common unit options and common unit appreciation rights will become exercisable upon a change in control of our company, as defined in the plan, unless provided otherwise by the committee in the applicable award agreement. 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. 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 or 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.

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SECURITY OWNERSHIP OF CERTAIN

BENEFICIAL OWNERS AND MANAGEMENT

The following table sets forth the beneficial ownership of our units immediately following the consummation of this offering and the formation transactions, assuming no exercise of the underwriters option to purchase additional common units, and held by:

- each unitholder who then will be 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.

Name of Beneficial Owner	Common Units to be Beneficially Owned		Class A Units to be Beneficially Owned		Percentage of Total Units to be Beneficially Owned
	Number	Percentage	Number	Percentage	Percentage
Constellation Energy Group, Inc.[(1)]	8,214,010	57%	295,690	100%	58%
Constellation Energy Partners Holdings, LLC[(2)]	8,214,010	57%	295,690	100%	58%
Constellation Energy Partners Management, LLC[(3)]			295,690	100%	2%
Felix J. Dawson					
John R. Collins					
Richard H. Bachmann[(4)]					
John N. Seitz[(4)]					
Angela A. Minas					
All managers and executive officers as a group (5 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.

(4) Messrs. Bachmann and Seitz are independent manager nominees expected to be appointed to our board of managers immediately following the pricing of this offering.

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CERTAIN RELATIONSHIPS AND RELATED PARTY TRANSACTIONS

After this offering, assuming no exercise of the underwriters option to purchase additional common units:

- CEPM will own 295,690 Class A units, representing a 2% limited liability company interest in us, and all of the management incentive interests;
- CEPH will own 8,214,010 common units, representing an approximate 56% limited liability company interest in us; and
- CHI will own all of our Class D interests.

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

The following table summarizes the distributions and payments to be made by us to CCG, CEPH, CEP Equity II LLC, CHI and CEPM in connection with the formation, ongoing operation and any liquidation of Constellation Energy Partners LLC. These distributions and payments were determined by and among affiliated entities and, consequently, are not the result of arm s-length negotiations.

Formation Stage

Consideration received by CEPM and CEPH in our restructuring	295,690 Class A units; 8,214,010 common units; and the management incentive interests.
Consideration received by CEP Equity II LLC in exchange for $475,000	the Floyd Shale Rights.
Consideration received by CHI for the $8.0 million contribution to us	all of our Class D interests.
Consideration received by CCG for cash in excess of $7.8 million	Distribution of all cash in excess of $7.8 million, including the cash pool balance, which was $12.2 million as of June 30, 2006.

Operational Stage

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 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. For a discussion of the management incentive interests, please read How We Make Cash Distributions Management Incentive Interests. Assuming we have sufficient available cash to pay the IQD on all of our outstanding units for four quarters, but no distributions in excess of the full IQD, CEPM would receive an annual distribution of approximately $0.5 million on its Class A units and CEPH would receive an annual distribution of approximately $14.0 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, 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 pro rated 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 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.
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.
	Please read The Limited Liability Company Agreement Election of Members of Our Board of Managers Elimination of Special Voting Rights of Class A Units. 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 Stage

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. Please read How We Make Cash Distributions Distributions of Cash Upon Liquidation.

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Agreements Governing the Transactions

We and other Constellation affiliates have entered into or will enter into the various documents and agreements that will effect the offering transactions, including the contribution of $8.0 million to us by CHI and the conveyance by us to CEP Equity II, LLC of the Floyd Shale Rights. These agreements, including the management services agreement described below, will not be the result of arm s length negotiations, and they, or any of the transactions that they provide for, may not be effected on terms at least as favorable to the parties to these agreements as they could have been obtained from unaffiliated third parties. All of the transaction expenses incurred in connection with these transactions will be paid from the proceeds of this offering.

Class D Contribution by CHI

In order to address the risks of 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, and the potential reduction in our revenues resulting therefrom, at the closing of this offering CHI will contribute $8.0 million to us for all of our Class D interests. For each full calendar quarter during the period commencing January 1, 2007 and ending on December 31, 2012 that the sharing arrangement remains in effect, we will distribute to the holder of the Class D interests $333,333, 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 unitholders for that quarter. 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, unless the special distribution right has been terminated earlier. 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 and the remaining portion of the $8.0 million original contribution not so returned in special cash distributions will be retained by us to partially offset the reduction in our revenues resulting from termination of the sharing arrangement in respect of the Trust. In the case of such termination of the special distribution right, CHI will have the right only 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 distribution right is terminated during a quarter, the special distribution to the holder of the Class D interests will be pro rated 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.

Based upon our estimated production for the twelve months ending September 30, 2007 and the weighted average net realized sales price for our production used in calculating our Estimated Adjusted EBITDA for that twelve-month period under the caption Cash Distribution Policy and Restrictions on Distributions, we estimate that, if the sharing arrangement in respect of the Trust was terminated as of October 1, 2006, our revenue would be reduced by approximately $5.6 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 1.4 years, if the production and prices set forth under Cash Distribution Policy and Restrictions on Distributions Our Estimated Cash Available to Pay Distributions were to remain constant throughout such period.

Sale of Floyd Shale Rights

In connection with this offering, we will sell 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. We refer to this mineral interest as the Floyd Shale Rights. The Floyd Shale Rights are not material to our business and no value has been assigned to them in our historical financial statements included elsewhere in this prospectus. The Floyd Shale Rights do not fit our investment strategy, given the uncertainty of encountering commercial quantities of oil and natural gas. We will receive $475,000 in return for this sale of the Floyd Shale Rights.

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Omnibus Agreement

Upon the closing of this offering, we will enter into the omnibus agreement with CCG. Under the omnibus agreement, CCG will indemnify us after the closing of this offering against certain liabilities relating to:

- for a period of six years and 30 days after the closing of this 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 this offering;
- legal actions pending against Constellation or us at the time of the closing of this offering;
- events and conditions associated with the ownership by Constellation or its affiliates of the Floyd Shale Rights after the closing of this offering; and
- for a period of one year after the closing, any miscalculation in the amount payable to the Trust in respect of the NPI for any period prior to the closing of this offering, provided (i) that such miscalculation relates to amount(s) payable no more than four years prior to the closing of this offering and (ii) the aggregate amount payable by CCG pursuant to this bullet point does not exceed $500,000.

Management Services Agreement

Upon the closing of this offering, we will enter into a management services agreement with CEPM that will govern 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. Please read Conflicts of Interest and Fiduciary Duties.

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.

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 will be 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 will be 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 will grant 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 Business Natural Gas Data Torch Royalty NPI.

Cash Pool Arrangement

In February 2006, we entered into a cash pool arrangement with CCG. This cash pool arrangement is administered and managed by us. CCG may borrow from the pool at market interest rates. If we require cash, and CCG has an outstanding balance, CCG is required to immediately remit payment to us for the required cash amount. We expect that our participation in the cash pool arrangement will be terminated prior to the closing of this offering. Upon the termination of the arrangement, our net receivable balance under the cash pool arrangement will be canceled and CCG will retain the funds in respect of that receivable.

Transactions with Executive Officers, Managers and Principal Unitholders

Please read Summary Constellation Energy Partners LLC The Transactions and Limited Liability Company Structure for a description of transactions between us and our principal unitholders.

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CONFLICTS OF INTEREST AND FIDUCIARY DUTIES

Conflicts of Interests

Affiliates of Constellation own all of our Class A units, 8,214,010 common units, our management incentive interests and our Class D interests. In addition, upon the consummation of this offering, we will enter into a management services agreement with CEPM, a subsidiary of Constellation, and following this offering we will be dependent on CEPM for the management of our operations. Please read Certain Relationships and Related Party Transactions Agreements Governing the Transactions Management Services Agreement. Conflicts of interest exist and may arise in the future as a result of the relationships between us and our unaffiliated unitholders and our board of managers and executive officers and Constellation and its affiliates, including CEPM and CEPH. These potential conflicts may relate to the divergent interests of these parties.

Whenever a conflict arises between Constellation and its affiliates, on the one hand, and us or any other unitholder, on the other hand, our board of managers will resolve that conflict. Our limited liability company agreement limits the remedies available to unitholders in the event a unitholder has a claim relating to conflicts of interest.

No breach of obligation will occur under our limited liability company agreement in respect of any conflict of interest if the resolution of the conflict is:

- approved by the conflicts committee of our board of managers, although our board of managers is not obligated to seek such approval;
- approved by the vote of a majority of the outstanding units, excluding any common or Class A units owned by CEPM, CEPH or any of their affiliates although our board of managers is not obligated to seek such approval;
- on terms no less favorable to us than those generally provided to or available from unaffiliated third parties; or
- fair and reasonable to us, taking into account the totality of the relationships between the parties involved, including other transactions that may be particularly favorable or advantageous to us.

We anticipate that our board of managers will submit for review and approval by our conflicts committee any acquisitions of properties or other assets that we propose to acquire from Constellation or any of its affiliates.

If our board of managers does not seek approval from the conflicts committee of our board of managers and our board determines that the resolution or course of action taken with respect to the conflict of interest satisfies either of the standards set forth in the third and fourth bullet points above, then it will be presumed that, in making its decision, the board of managers, including board members affected by the conflict of interest, acted in good faith, and in any proceeding brought by or on behalf of any member or the company, the person bringing or prosecuting such proceeding will have the burden of overcoming such presumption. Unless the resolution of a conflict is specifically provided for in our limited liability company agreement, our board of managers or its conflicts committee may consider any factors in good faith when resolving a conflict. When our limited liability company agreement requires someone to act in good faith, it requires that person to reasonably believe that he is acting in our best interests, unless the context otherwise requires.

Conflicts of interest could arise in the situations described below, among others.

Constellation and its affiliates may compete with us.

None of Constellation or any of its affiliates is restricted from competing with us. Constellation and its affiliates may acquire, invest in or dispose of E&P or other assets, including those that might be in direct competition with us.

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Neither Constellation nor its affiliates have any obligation to offer us the opportunity to purchase or own interests in any assets.

We intend to rely on CEPM to provide us with opportunities for the acquisition of oil and natural gas reserves, however, neither Constellation nor its affiliates has any obligation to offer us the opportunity to purchase or own interests in any assets.

Affiliates of Constellation not only have the exclusive right to elect two members of our board of managers but also can assert great influence in the election of the other three members of our board of managers.

CEPM, as the holder of our Class A units will have the exclusive right to elect two members of our board of managers, and CEPH, as the holder of a majority of our common units, will be able to assert great influence in any vote of common unitholders, including the election of the three members of our board of managers that are elected by the common unitholders. In turn, our board of managers shall have the power to appoint our officers. Situations in which the interests of our management and Constellation and its affiliates may differ from interests of our unaffiliated unitholders include 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 management will use its reasonable discretion to establish and maintain cash reserves sufficient to fund our drilling program;

- our management team determines the timing and extend of our drilling program and related capital expenditures, asset purchases and sales, borrowings, issuances of additional membership interests and reserve adjustments, all of which will affect the amount of cash that we distribute to our unitholders;

- 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; and

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

Our executive officers and our Class A managers also serve as managers, directors, officers or employees of Constellation or its other affiliates as a result of which conflicts of interest exist and will arise in the future.

Our executive officers and our Class A managers are also managers, directors, officers or employees of Constellation or its affiliates (other than us). While acting in such person s capacity as a manager, director, officer or employee of Constellation or such affiliates, as opposed to such person s capacity as our executive officer or Class A manager, such person will not owe any fiduciary duty to us or our security holders. In addition, in making decisions in such person s capacity as a manager, director, officer or employee of Constellation or such affiliate, such person may make a decision that favors the interests of Constellation or such affiliate over your interests and may be to our detriment, notwithstanding that in making decisions in such person s capacity as our officer or manager such person is required to act in good faith and in accordance with the standards set forth in our limited liability company agreement. If in resolving a conflict of interest any of our executive officers and our Class A managers satisfies the applicable standards set forth in our limited liability company agreement for resolving a conflict of interest, you will not be able to assert that such resolution constituted a breach of fiduciary duty owed to us or to you by such executive officer or Class A manager.

We may compete for the time and effort of our managers and officers who are also managers, directors and officers of Constellation and its affiliates.

Constellation and its affiliates conduct business and activities of their own in which we have no economic interest. Certain of our managers and officers are employees of Constellation and serve as managers, directors and officers of Constellation and its affiliates. Our managers and officers are not required to work full time on our business and affairs and may devote significant time to the affairs of Constellation and its affiliates. There could be material competition for the time and effort of our managers and officers who provide services to Constellation and its affiliates.

Unitholders will have no right to enforce obligations of Constellation and its affiliates under agreements with us.

Any agreements, including the management services agreement, between us, on the one hand, and Constellation and its affiliates, on the other hand, will not grant to our unitholders any right to enforce the obligations of Constellation and its affiliates in our favor.

Contracts between us, on the one hand, and Constellation and its affiliates, on the other, will not be the result of arm s-length negotiations.

Neither our limited liability company agreement nor any of the other contracts or arrangements, including our management services agreement, between us and Constellation and its affiliates are or will be the result of arm s-length negotiations.

Fiduciary Duties

Our limited liability company agreement provides that our business and affairs shall be managed under the direction of our board of managers, which shall have the power to appoint our officers. Our limited liability company agreement further provides that the authority and function of our board of managers and officers shall be identical to the authority and functions of a board of directors and officers of a corporation organized under the Delaware General Corporation Law, or DGCL. Finally, our limited liability company agreement provides that the fiduciary duties and obligations owed to us and to our members by our board of managers and officers is generally to act in good faith in the performance of their duties on our behalf. Our limited liability company agreement permits affiliates of our managers to invest or engage in other businesses or activities that compete with us. In addition, if our conflicts committee approves a transaction involving potential conflicts, or if a transaction is on terms generally available from unaffiliated third parties or an action is taken that is fair and reasonable to the company, unitholders will not be able to assert that such approval constituted a breach of fiduciary duties owed to them by our managers and officers.

We are unlike publicly traded partnerships whose business and affairs are managed by a general partner with fiduciary duties to the partnership. While CEPM will provide legal, accounting, finance, tax, property management, engineering and other services to us, pursuant to the management services agreement, subject to the oversight of our board of managers, we have no general partner with fiduciary duties to us. CEPM s duties to us are contractual in nature and arise solely under the management services agreement. As a consequence, none of Constellation, CEPM, CEPH, CCG or their affiliates will owe to us a fiduciary duty similar to that owed by a general partner to its limited partners.

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DESCRIPTION OF THE COMMON UNITS

The Common Units

The common units represent limited liability company interests in us. The holders of common units are entitled to participate in distributions and exercise the rights or privileges provided under our limited liability company agreement. For a description of the relative rights and preferences of holders of common units in and to distributions, please read this section and How We Make Cash Distributions. For a description of the rights and privileges of holders of common units under our limited liability company agreement, including voting rights, please read The Limited Liability Company Agreement.

Transfer Agent and Registrar

Computershare will serve as registrar and transfer agent for the common units. We pay all fees charged by the transfer agent for transfers of common units, except the following fees that will be paid by holders of common units:

- surety bond premiums to replace lost or stolen certificates, taxes and other governmental charges;
- special charges for services requested by a holder of a common unit; and
- other similar fees or charges.

There will be no charge to unitholders for disbursements of our cash distributions. We will indemnify the transfer agent, its agents and each of their shareholders, managers, officers and employees against all claims and losses that may arise out of acts performed or omitted in that capacity, except for any liability due to any gross negligence or intentional misconduct of the indemnified person or entity.

The transfer agent may at any time resign, by notice to us, or be removed by us. The resignation or removal of the transfer agent will become effective upon our appointment of a successor transfer agent and registrar and its acceptance of the appointment. If no successor has been appointed and has accepted the appointment within 30 days after notice of the resignation or removal, we are authorized to act as the transfer agent and registrar until a successor is appointed.

Transfer of Common Units

By transfer of common units in accordance with our limited liability company agreement, each transferee of common units shall be admitted as a unitholder of our company with respect to the common units transferred when such transfer and admission is reflected on our books and records. Additionally, each transferee of common units:

- becomes the record holder of the common units;
- automatically agrees to be bound by the terms and conditions of, and is deemed to have executed our limited liability company agreement;
- represents that the transferee has the capacity, power and authority to enter into the limited liability company agreement;
- grants powers of attorney to our officers and any liquidator of our company as specified in the limited liability company agreement; and
- makes the consents and waivers contained in our limited liability company agreement.

A transferee will become a unitholder of our company for the transferred common units upon the recording of the name of the transferee on our books and records.

Until a common unit has been transferred on our books, we and the transfer agent, notwithstanding any notice to the contrary, may treat the record holder of the common unit as the absolute owner for all purposes, except as otherwise required by law or stock exchange regulations.

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THE LIMITED LIABILITY COMPANY AGREEMENT

The following is a summary of the material provisions of our limited liability company agreement. The form of the limited liability company agreement is included in this prospectus as Appendix A. We will provide prospective investors with a copy of the form of this agreement upon request at no charge.

We summarize the following provisions of our limited liability company agreement elsewhere in this prospectus:

- with regard to distributions of available cash on our Class A units, common units, management incentive interests and Class D interests, please read How We Make Cash Distributions.
- with regard to the transfer of common units, please read Description of the Common Units Transfer of Common Units;
- with regard to the election of members of our board of managers, please read Management Management of Constellation Energy Partners LLC Our Board of Managers; and
- with regard to allocations of taxable income and taxable loss, please read Material Tax Consequences.

Organization

Our company was formed in February 2005 and will remain in existence until dissolved in accordance with our limited liability company agreement.

Purpose

Under our limited liability company agreement, we are permitted to engage, directly or indirectly, in any activity that our board of managers approves and that a limited liability company organized under Delaware law lawfully may conduct; provided, that our board of managers shall not cause us to engage, directly or indirectly, in any business activities that it determines would cause us to be treated as an association taxable as a corporation or otherwise taxable as an entity for federal income tax purposes.

Although our board of managers has the ability to cause us and our operating subsidiaries to engage in activities other than the acquisition, development and exploitation, of oil and natural gas properties and related midstream assets, our board of managers has no current plans to do so. Our board of managers is authorized in general to perform all acts it deems to be necessary or appropriate to carry out our purposes and to conduct our business.

Fiduciary Duties

For a description of fiduciary duties, please read Conflicts of Interest and Fiduciary Duties.

Agreement to be Bound by Limited Liability Company Agreement; Power of Attorney

By purchasing a common unit in us, you will be admitted as a member of our company and will be deemed to have agreed to be bound by the terms of our limited liability company agreement. Pursuant to this agreement, each holder of common units and each person who acquires a common unit from a holder of common units grants to our board of managers (and, if appointed, a liquidator) a power of attorney to, among other things, execute and file documents required for our qualification, continuance or dissolution. The power of attorney also grants our board of managers the authority to make certain amendments to, and to make consents and waivers under and in accordance with, our limited liability company agreement.

Capital Contributions

Unitholders (including holders of common units) are not obligated to make additional capital contributions, except as described below under Limited Liability.

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Limited Liability

Unlawful Distributions

The Delaware Limited Liability Company Act (the Delaware Act) provides that any unitholder who receives a distribution and knew at the time of the distribution that the distribution was in violation of the Delaware Act shall be liable to the company for the amount of the distribution for three years. Under the Delaware Act, a limited liability company may not make a distribution to any unitholder if, after the distribution, all liabilities of the company, other than liabilities to unitholders on account of their limited liability company interests and liabilities for which the recourse of creditors is limited to specific property of the company, would exceed the fair value of the assets of the company. For the purpose of determining the fair value of the assets of a company, the Delaware Act provides that the fair value of property subject to liability for which recourse of creditors is limited shall be included in the assets of the company only to the extent that the fair value of that property exceeds the nonrecourse liability. Under the Delaware Act, an assignee who becomes a substituted unitholder of a company is liable for the obligations of his assignor to make contributions to the company, except the assignee is not obligated for liabilities unknown to him at the time he became a unitholder and that could not be ascertained from the limited liability company agreement.

Failure to Comply with the Limited Liability Provisions of Jurisdictions in Which We Do Business

Our subsidiaries will initially conduct business only in the State of Alabama. We may decide to conduct business in other states, and maintenance of limited liability for us, as a member of our operating subsidiaries, may require compliance with legal requirements in the jurisdictions in which the operating subsidiaries conduct business, including qualifying our subsidiaries to do business there. Limitations on the liability of unitholders for the obligations of a limited liability company have not been clearly established in many jurisdictions. We will operate in a manner that our board of managers considers reasonable and necessary or appropriate to preserve the limited liability of our unitholders.

Voting Rights

Holders of our common units and our Class A units, have voting rights on most matters. Upon the consummation of this offering, CEPM will own all of our Class A units and CEPH will own 8,214,010 of our common units. The following matters require the unitholder vote specified below:

Election of members of the board of managers	Following our initial public offering, our board of managers will consist of five members, as required by our limited liability company agreement. Except as set forth below, at the first annual meeting of our unitholders following this offering, Class A unitholders, voting as a single class, will elect two managers and their successors, and the holders of our common units, voting together as a single class, will elect the remaining three managers and their successors. Please read Election of Members of Our Board of Managers, Removal of Members of Our Board of Managers and Elimination of Special Voting Rights of Class A Units.
Issuance of additional securities including common units	No approval right.

Amendment of the limited liability company agreement	Certain amendments may be made by our board of managers without unitholder approval. Other amendments generally require the

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	approval of both a common unit majority and Class A unit majority. Please read Amendment of Our Limited Liability Company Agreement.
Merger of our company or the sale of all or substantially all of our assets	Common unit majority and Class A unit majority. Please read Merger, Sale or Other Disposition of Assets.
Dissolution of our company	Common unit majority and Class A unit majority. Please read Termination and Dissolution.

Matters requiring the approval of a common unit majority require the approval of at least a majority of the outstanding common units voting together as a single class. In addition, matters requiring the approval of a Class A unit majority require the approval of at least a majority of the outstanding Class A units voting together as a single class.

Issuance of Additional Securities

Our limited liability company agreement authorizes us to issue an unlimited number of additional securities and authorizes us to buy securities for the consideration and on the terms and conditions determined by our board of managers without the approval of our unitholders.

It is possible that we will fund acquisitions through the issuance of additional common units or other equity securities. Holders of any additional common units we issue will be entitled to share equally with the then-existing holders of common units, Class A units and management incentive interests in our distributions of available cash. Also, the issuance of additional common units or other equity securities may dilute the value of the interests of the then-existing holders of common units in our net assets.

In accordance with Delaware law and the provisions of our limited liability company agreement, we may also issue additional securities that, as determined by our board of managers, may have special voting or other rights to which the units are not entitled.

The holders of units will not have preemptive or preferential rights to acquire additional units or other securities.

Election of Members of Our Board of Managers

At our first annual meeting of the holders of our Class A units and our common unitholders following this offering:

- two members of our board of managers will be elected by CEPM, as the holder of all of our Class A units; and
- three members of our board of managers will be elected by our common unitholders.

The board of managers will be subject to re-election on an annual basis in this manner at our annual meeting of the holders of our Class A units and our common unitholders.

Removal of Members of Our Board of Managers

Any manager elected by the holder of our Class A units may be removed, with or without cause, by the holders of 66 $^{2}/_{3}$% of the outstanding Class A units then entitled to vote at an election of managers. Any manager

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elected by the holders of our common units may be removed, with or without cause, by the holders of at least a majority of the outstanding common units then entitled to vote at an election of managers.

Increase in the Size of Our Board of Managers

The size of our board of managers may increase only with the approval of the holders of 66 $^{2}/_{3}$% outstanding Class A units. If the size of our board of managers is so increased, the vacancy created thereby shall be filled by a person appointed by our board of managers or a nominee approved by a majority vote of our common unitholders, unless such vacancy is specified by an amendment to our limited liability company agreement as a vacancy to be filled by our Class A unitholders, in which case such vacancy shall be filled by a person approved by our Class A unitholders.

Elimination of Special Voting Rights of Class A Units

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, subject to the matters described under Election of Members of Our Board of Managers Increase in the Size of Our Board of Managers above. This right can be eliminated only upon a proposal submitted by or with the consent of our board of managers and the vote of the holders of not less than 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.

Amendment of Our Limited Liability Company Agreement

General

Amendments to our limited liability company agreement may be proposed only by or with the consent of our board of managers. To adopt a proposed amendment, other than the amendments discussed below, our board of managers is required to seek written approval of the holders of the number of units required to approve the amendment or call a meeting of our unitholders to consider and vote upon the proposed amendment. Except as described below, an amendment must be approved by a common unit majority and a Class A unit majority.

Prohibited Amendments

No amendment may be made that would:

enlarge the obligations of any unitholder without its consent, unless approved by at least a majority of the type or class of member interests so affected;

provide that we are not dissolved upon an election to dissolve our company by our board of managers that is approved by a common unit majority and a Class A unit majority;

entitle members holding common units and/or Class A units to more or less than one vote per unit;

prohibit the holders of Class A units from acting without a meeting;

change the procedures for notice to members of business to be brought before a meeting and nominations to board of managers;

require some percentage other than a majority of votes cast affirmatively or negatively by members holding units for approval of matters submitted for a member vote;

allow the calling of a special meeting by other than a majority of the board of managers;

change the term of existence of our company;

give any person the right to dissolve our company other than our board of managers right to dissolve our company with the approval of a common unit majority and a Class A unit majority; or

enlarge the size of our board of managers without the approval of the holders of $66\,^2/3\%$ of our Class A units.

The provision of our limited liability company agreement preventing the amendments having the effects described in any of the clauses above can be amended upon the approval of the holders of at least 75% of the outstanding common units, voting together as a single class, and 75% of the outstanding Class A units, voting together as a single class.

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No Unitholder Approval

Our board of managers may generally make amendments to our limited liability company agreement without unitholder approval to reflect:

- a change in our name, the location of our principal place of our business, our registered agent or our registered office;
- the admission, substitution, withdrawal or removal of members in accordance with our limited liability company agreement;
- a change that our board of managers determines to be necessary or appropriate for us to qualify or continue our qualification as a company in which our members have limited liability under the laws of any state or to ensure that neither we, our operating subsidiaries nor any of its subsidiaries will be treated as an association taxable as a corporation or otherwise taxed as an entity for federal income tax purposes;
- the merger of our company or any of its subsidiaries into, or the conveyance of all of our assets to, a newly formed entity if the sole purpose of that merger or conveyance is to effect a mere change in our legal form into another limited liability entity;
- an amendment that is necessary, in the opinion of our counsel, to prevent us, members of our board, or our officers, agents or trustees from in any manner being subjected to the provisions of the Investment Company Act of 1940, the Investment Advisors Act of 1940, or plan asset regulations adopted under the Employee Retirement Income Security Act of 1974, or ERISA, whether or not substantially similar to plan asset regulations currently applied or proposed;
- an amendment that our board of managers determines to be necessary or appropriate for the authorization of additional securities or rights to acquire securities;
- any amendment expressly permitted in our limited liability company agreement to be made by our board of managers acting alone;
- an amendment effected, necessitated or contemplated by a merger agreement that has been approved under the terms of our limited liability company agreement;
- any amendment that our board of managers determines to be necessary or appropriate for the formation by us of, or our investment in, any corporation, partnership or other entity, as otherwise permitted by our limited liability company agreement;
- a change in our fiscal year or taxable year and related changes;
- a merger, conversion or conveyance effected in accordance with the limited liability company agreement; and
- any other amendments substantially similar to any of the matters described in the clauses above.

In addition, our board of managers may make amendments to our limited liability company agreement without unitholder approval if our board of managers determines that those amendments:

- do not adversely affect the unitholders (including any particular class of unitholders as compared to other classes of unitholders) in any material respect;

- are necessary or appropriate to satisfy any requirements, conditions or guidelines contained in any opinion, directive, order, ruling or regulation of any federal or state agency or judicial authority or contained in any federal or state statute;

- are necessary or appropriate to facilitate the trading of common units or to comply with any rule, regulation, guideline or requirement of any securities exchange on which the common units are or will

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be listed for trading, compliance with any of which our board of managers deems to be in the best interests of us and our common unitholders;

are necessary or appropriate for any action taken by our board of managers relating to splits or combinations of units under the provisions of our limited liability company agreement; or

are required to effect the intent expressed in this prospectus or the intent of the provisions of our limited liability company agreement or are otherwise contemplated by our limited liability company agreement.

Opinion of Counsel and Unitholder Approval

Our board of managers will not be required to obtain an opinion of counsel that an amendment will not result in a loss of limited liability to our unitholders or result in our being treated as an entity for federal income tax purposes if one of the amendments described above under No Unitholder Approval should occur. No other amendments to our limited liability company agreement will become effective without the approval of holders of at least 90% of the common units and Class A units unless we obtain an opinion of counsel to the effect that the amendment will not affect the limited liability under applicable law of any unitholder of our company.

Any amendment that would have a material adverse effect on the rights or preferences of any type or class of outstanding units in relation to other classes of units will require the approval of at least a majority of the type or class of units so affected. Any amendment that reduces the voting percentage required to take any action is required to be approved by the affirmative vote of unitholders whose aggregate outstanding units constitute not less than the voting requirement sought to be reduced.

Merger, Sale or Other Disposition of Assets; Conversion

Our board of managers is generally prohibited, without the prior approval of a common unit majority and a Class A unit majority from causing us to, among other things, sell, exchange or otherwise dispose of all or substantially all of our assets in a single transaction or a series of related transactions, including by way of merger, consolidation or other combination, or approving on our behalf the sale, exchange or other disposition of all or substantially all of the assets of our subsidiaries, provided that our board of managers may mortgage, pledge, hypothecate or grant a security interest in all or substantially all of our assets without that approval. Our board of managers may also sell all or substantially all of our assets under a foreclosure or other realization upon the encumbrances above without that approval.

If the conditions specified in the limited liability company agreement are satisfied, our board of managers may merge our company or any of its subsidiaries into, or convey all of our assets to, a newly formed entity if the sole purpose of that merger or conveyance is to effect a mere change in our legal form into another limited liability entity. Additionally, the Company may convert into any other entity as defined in the Delaware Limited Liability Company Act, whether such entity is formed under the laws of the State of Delaware or any other state in the United States of America. Our unitholders are not entitled to dissenters rights of appraisal under the limited liability company agreement or applicable Delaware law in the event of a merger or consolidation, a sale of all or substantially all of our assets or any other transaction or event.

Termination and Dissolution

We will continue as a company until terminated under our limited liability company agreement. We will dissolve upon: (1) the election of our board of managers to dissolve us, if approved by a common unit majority and a Class A unit majority; (2) the sale, exchange or other disposition of all or substantially all of the assets and properties of our company and our subsidiaries; or (3) the entry of a decree of judicial dissolution of our company.

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Liquidation and Distribution of Proceeds

Upon our dissolution, the liquidator authorized to wind up our affairs will, acting with all of the powers of our board of managers that the liquidator deems necessary or desirable in its judgment, liquidate our assets and apply the proceeds of the liquidation as provided in How We Make Cash Distributions Distributions of Cash Upon Liquidation. The liquidator may defer liquidation or distribution of our assets for a reasonable period of time or distribute assets to unitholders in kind if it determines that a sale would be impractical or would cause undue loss to our unitholders.

Anti-Takeover Provisions

Our limited liability company agreement contains specific provisions that are intended to discourage a person or group from attempting to take control of our company without the approval of our board of managers. Specifically, our limited liability company agreement provides that we will elect to have Section 203 of the DGCL apply to transactions in which an interested common unitholder (as described below) seeks to enter into a merger or business combination with us. Under this provision, such a holder will not be permitted to enter into a merger or business combination with us unless:

- prior to such time, our board of managers approved either the business combination or the transaction that resulted in the common unitholder s becoming an interested common unitholder;
- upon consummation of the transaction that resulted in the common unitholder becoming an interested common unitholder, the interested common unitholder owned at least 85% of our outstanding common units at the time the transaction commenced, excluding for purposes of determining the number of common units outstanding those common units owned:
  - by persons who are managers and also officers; and
  - by employee common unit plans in which employee participants do not have the right to determine confidentially whether common units held subject to the plan will be tendered in a tender or exchange offer; or
- at or subsequent to such time the business combination is approved by our board of managers and authorized at an annual or special meeting of our common unitholders, and not by written consent, by the affirmative vote of the holders of at least 66 $^{2}/3$% of our outstanding voting common units that are not owned by the interested common unitholder.

Section 203 defines business combination to include:

- any merger or consolidation involving the company and the interested common unitholder;
- any sale, transfer, pledge or other disposition of 10% or more of the assets of the company involving the interested common unitholder;

subject to certain exceptions, any transaction that results in the issuance or transfer by the company of any common units of the company to the interested common unitholder;

any transaction involving the company that has the effect of increasing the proportionate share of the units of any class or series of the company beneficially owned by the interested common unitholder; or

the receipt by the interested common unitholder of the benefit of any loans, advances, guarantees, pledges or other financial benefits provided by or through the company.

In general, by reference to Section 203, an interested common unitholder is any person or entity, other than Constellation, CEPM, their affiliates or transferees, that beneficially owns (or within three years did own) 15% or more of the outstanding common units of the company and any entity or person affiliated with or controlling or controlled by such entity or person.

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The existence of this provision would be expected to have an anti-takeover effect with respect to transactions not approved in advance by our board of managers, including discouraging attempts that might result in a premium over the market price for common units held by common unitholders.

Our limited liability agreement also 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.

Limited Call Right

If at any time any person owns more than 80% of the then-issued and outstanding common units, it will have the right, which it may assign in whole or in part to any of its affiliates or to us, to acquire all, but not less than all, of the remaining common units held by unaffiliated persons as of a record date to be selected by our board of managers, on at least 10 days but not more than 60 days notice. The common unitholders are not entitled to dissenters rights of appraisal under the limited liability company agreement or applicable Delaware law if this limited call right is exercised. The purchase price in the event of this purchase is the greater of:

- the highest cash price paid by such person for any common units purchased within the 90 days preceding the date on which such person first mails notice of its election to purchase the remaining common units; and

- the closing market price of the common units as of the date three days before the date the notice is mailed.

As a result of this limited call right, a holder of common units may have his limited liability company interests purchased at an undesirable time or price. Please read Risk Factors Risks Related to Our Structure. The tax consequences to a common unitholder of the exercise of this call right are the same as a sale by that common unitholder of his common units in the market. Please read Material Tax Consequences Disposition of Units.

Meetings; Voting

All notices of meetings of unitholders shall be sent or otherwise given in accordance with Sections 11.4 and 14.1 of our limited liability company agreement not less than 10 days nor more than 60 days before the date of the meeting. The notice shall specify the place, date and hour of the meeting and (i) in the case of a special meeting, the general nature of the business to be transacted (no business other than that specified in the notice may be transacted) or (ii) in the case of the annual meeting, those matters which the board of managers, at the time of giving the notice, intends to present for action by the unitholders (but any proper matter may be presented at the meeting for such action). The notice of any meeting at which managers are to be elected shall include the name of any nominee or nominees who, at the time of the notice, the board of managers intends to present for election. Any previously scheduled meeting of the unitholders may be postponed, and any special meeting of the unitholders may be cancelled, by resolution of the board of managers upon public notice given prior to the date previously scheduled for such meeting of unitholders.

Units that are owned by an assignee who is a record holder, but who has not yet been admitted as a member, shall be voted at the written direction of the record holder by a proxy designated by our board of managers. Absent direction of this kind, the units will not be voted, except that units held by us on behalf of non-citizen assignees shall be voted in the same ratios as the votes of unitholders on other units are cast.

Any action required or permitted to be taken by our common unitholders must be effected at a duly called annual or special meeting of unitholders and may not be effected by any consent in writing by such common unitholders.

Special meetings of the unitholders may only be called by a majority of our board of managers. Unitholders may vote either in person or by proxy at meetings. The holders of a majority of the outstanding units for which a meeting has been called represented in person or by proxy shall constitute a quorum unless any action by the unitholders requires approval by holders of a greater percentage of the units, in which case the quorum shall be the greater percentage.

Each record holder of a unit has a vote according to his percentage interest in us, although additional units having special voting rights could be issued. Please read Issuance of Additional Securities. Units held in nominee or street name accounts will be voted by the broker or other nominee in accordance with the instruction of the beneficial owner unless the arrangement between the beneficial owner and its nominee provides otherwise.

Any notice, demand, request, report or proxy material required or permitted to be given or made to record holders of units under our limited liability company agreement will be delivered to the record holder by us or by the transfer agent.

Our limited liability agreement also 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.

Non-Citizen Assignees; Redemption

If we or any of our subsidiaries are or become subject to federal, state or local laws or regulations that, in the reasonable determination of our board of managers, create a substantial risk of cancellation or forfeiture of any property that we have an interest in because of the nationality, citizenship or other related status of any unitholder or assignee, we may redeem, upon 30 days advance notice, the units held by the unitholder or assignee at their current market price. To avoid any cancellation or forfeiture, our board of managers may require each unitholder or assignee to furnish information about his nationality, citizenship or related status. If a unitholder or assignee fails to furnish information about his nationality, citizenship or other related status within 30 days after a request for the information or our board of managers determines after receipt of the information that the unitholder or assignee is not an eligible citizen, the unitholder or assignee may be treated as a non-citizen assignee. In addition to other limitations on the rights of an assignee who is not a substituted unitholder, a non-citizen assignee does not have the right to direct the voting of his units and may not receive distributions in kind upon our liquidation.

Indemnification

Under our limited liability company agreement and subject to specified limitations, we will indemnify to the fullest extent permitted by law from and against all losses, claims, damages or similar events any person who is or was our manager or officer, or while serving as our manager or officer, is or was serving as a tax matters member or, at our request, as a manager, officer, tax matters member, employee, partner, fiduciary or trustee of us or any of our subsidiaries. Additionally, we shall indemnify to the fullest extent permitted by law and authorized by our board of managers, from and against all losses, claims, damages or similar events any person is or was an employee or agent (other than an officer) of our company.

Any indemnification under our limited liability company agreement will only be out of our assets. We are authorized to purchase insurance against liabilities asserted against and expenses incurred by persons for our activities, regardless of whether we would have the power to indemnify the person against liabilities under our limited liability company agreement.

Books and Reports

We are required to keep appropriate books of our business at our principal offices. The books will be maintained for both tax and financial reporting purposes on an accrual basis. For tax and fiscal reporting purposes, our fiscal year is the calendar year.

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We will furnish or make available to record holders of units, within 120 days after the close of each fiscal year, an annual report containing audited financial statements and a report on those financial statements by our independent public accountants. Except for our fourth quarter, we will also furnish or make available summary financial information within 90 days after the close of each quarter.

We will furnish each record holder of a unit with information reasonably required for tax reporting purposes within 90 days after the close of each calendar year. This information is expected to be furnished in summary form so that some complex calculations normally required of unitholders can be avoided. Our ability to furnish this summary information to unitholders will depend on the cooperation of unitholders in supplying us with specific information. Every unitholder will receive information to assist him in determining his federal and state tax liability and filing his federal and state income tax returns, regardless of whether he supplies us with information.

Right To Inspect Our Books and Records

Our limited liability company agreement provides that a unitholder can, for a purpose reasonably related to his interest as a unitholder, upon reasonable demand and at his own expense, have furnished to him:

- a current list of the name and last known address of each unitholder;
- a copy of our tax returns;
- information as to the amount of cash, and a description and statement of the agreed value of any other property or services, contributed or to be contributed by each unitholder and the date on which each became a unitholder;
- copies of our limited liability company agreement, the certificate of formation of the company, related amendments and powers of attorney under which they have been executed;
- information regarding the status of our business and financial condition; and
- any other information regarding our affairs as is just and reasonable.

Our board of managers may, and intends to, keep confidential from our unitholders information that it believes to be in the nature of trade secrets or other information, the disclosure of which our board of managers believes in good faith is not in our best interests, information that could damage our company or our business, or information that we are required by law or by agreements with a third-party to keep confidential.

Registration Rights

We have agreed to register for sale under the Securities Act and applicable state securities laws any common units or other of our securities held by CEPM, CEPH or any of their affiliates if an exemption from the registration requirements is not otherwise available. These registration rights continue for two years following any termination of the special voting rights of the holders of our Class A units. We have also agreed to include any of our securities held by CEPM, CEPH or their affiliates in any registration statement that we file to offer our securities for cash, except an offering relating solely to an employee benefit plan, for the same period. We are obligated to pay all expenses incidental to the registration, excluding underwriting discounts and commissions. Please read Units Eligible for Future Sale.

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UNITS ELIGIBLE FOR FUTURE SALE

After the sale of the common units offered by this prospectus, and assuming that the underwriters option to purchase additional common units is not exercised, CEPH will hold an aggregate of 8,214,010 common units and CEPM will hold all of our 295,690 Class A units and management incentive interests that upon certain circumstances may convert into common units. Please read The Limited Liability Company Agreement Election of Members of Our Board of Managers Elimination of Special Voting Rights of Class A Units. The sale of these common units could have an adverse impact on the price of the common units or on any trading market that may develop.

The common units sold in this offering will generally be freely transferable without restriction or further registration under the Securities Act, except that any common units held by an affiliate of ours may not be resold publicly except in compliance with the registration requirements of the Securities Act or under an exemption under Rule 144 or otherwise. Rule 144 permits securities acquired by an affiliate of the issuer to be sold into the market in an amount that does not exceed, during any three month period, the greater of:

- 1% of the total number of the securities outstanding; and
- the average weekly reported trading volume of the common units for the four calendar weeks prior to the sale.

Sales under Rule 144 are also subject to specific manner of sale provisions, holding period requirements, notice requirements and the availability of current public information about us. A person who is not deemed to have been an affiliate of ours at any time during the three months preceding a sale, and who has beneficially owned his units for at least two years, would be entitled to sell common units under Rule 144 without regard to the public information requirements, volume limitations, manner of sale provisions and notice requirements of Rule 144.

Our limited liability company agreement does not restrict our ability to issue equity securities without unitholder approval at any time. Any issuance of additional units or other equity securities would result in a corresponding decrease in the proportionate ownership interest in us represented by, and could adversely affect the cash distributions to and market price of, units then outstanding. Please read The Limited Liability Company Agreement Issuance of Additional Securities.

Under our limited liability company agreement, CEPM, CEPH and their affiliates have the right to cause us to register under the Securities Act and applicable state securities laws the offer and sale of any units that they hold. Subject to the terms and conditions of our limited liability company agreement, these registration rights allows CEPM, CEPH or their assignees holding any units to require registration of any of these units and to include any of these units in a registration by us of other units, including units offered by us or by any unitholder. CEPM will continue to have these registration rights for two years following any termination of the special voting rights of the Class A units. In connection with any registration of this kind, we will indemnify each unitholder participating in the registration and its officers, managers and controlling persons from and against any liabilities under the Securities Act or any applicable state securities laws arising from the registration statement or prospectus. We will bear all costs and expenses incidental to any registration, excluding any underwriting discounts and commissions. Except as described below, CEPM or CEPH may sell their units in private transactions at any time, subject to compliance with applicable laws.

We, our officers and managers, and CEPH and CEPM and their affiliates, have agreed not to sell any units for a period of 180 days after the date of this prospectus, subject to certain exceptions. Please read Underwriting for a description of these lock up provisions.

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MATERIAL TAX CONSEQUENCES

This section is a discussion of the material tax consequences that may be relevant to prospective common unitholders who are individual citizens or residents of the United States and, unless otherwise noted in the following discussion, is the opinion of Andrews Kurth LLP, counsel to us, insofar as it relates to matters of United States federal income tax law and legal conclusions with respect to those matters. This section is based on current provisions of the Internal Revenue Code, existing and proposed regulations and current administrative rulings and court decisions, all of which are subject to change. Later changes in these authorities may cause the tax consequences to vary substantially from the consequences described below. Unless the context otherwise requires, references in this section to us or we are references to Constellation Energy Partners LLC and our limited liability company operating subsidiaries.

This section does not address all federal income tax matters that affect us or common unitholders. Furthermore, this section focuses on common unitholders who are individual citizens or residents of the United States and has only limited application to corporations, estates, trusts, non-resident aliens or other common unitholders subject to specialized tax treatment, such as tax-exempt institutions, foreign persons, individual retirement accounts (IRAs), employee benefit plans, real estate investment trusts (REITs) or mutual funds. Accordingly, we urge each prospective holder of common units to consult, and depend on, his own tax advisor in analyzing the federal, state, local and foreign tax consequences particular to him of the ownership or disposition of our units.

No ruling has been or will be requested from the IRS regarding any matter that affects us or prospective common unitholders. Instead, we will rely on opinions and advice of Andrews Kurth LLP. Unlike a ruling, an opinion of counsel represents only that counsel s best legal judgment and does not bind the IRS or the courts. Accordingly, the opinions and statements made in this discussion may not be sustained by a court if contested by the IRS. Any contest of this sort with the IRS may materially and adversely impact the market for our units and the prices at which our units trade. In addition, the costs of any contest with the IRS, principally legal, accounting and related fees, will result in a reduction in cash available for distribution to our common unitholders and thus will be borne directly by our common unitholders. Furthermore, the tax treatment of us, or of an investment in us, may be significantly modified by future legislative or administrative changes or court decisions. Any modifications may or may not be retroactively applied.

All statements regarding matters of law and legal conclusions set forth below, unless otherwise noted, are the opinion of Andrews Kurth LLP and are based on the accuracy of the representations made by us. Statements of fact do not represent opinions of Andrews Kurth LLP.

For the reasons described below, Andrews Kurth LLP has not rendered an opinion with respect to the following specific federal income tax issues:

- the treatment of a common unitholder whose units are loaned to a short seller to cover a short sale of units (please read Tax Consequences of Unit Ownership Treatment of Short Sales);
- whether our monthly convention for allocating taxable income and losses is permitted by existing Treasury regulations (please read Disposition of Units Allocations Between Transferors and Transferees);
- whether percentage depletion will be available to a common unitholder or the extent of the percentage depletion deduction available to any common unitholder (please read Tax Treatment of Operations Depletion Deductions);

whether the deduction related to United States production activities will be available to a common unitholder or the extent of such deduction to any holder of common units (please read Tax Treatment of Operations Deduction for United States Production Activities); and

whether our method for depreciating Section 743 adjustments is sustainable in certain cases (please read Tax Consequences of Unit Ownership Section 754 Election and Uniformity of Units).

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Partnership Status

Except as discussed in the following paragraph, a limited liability company that has more than one member and that has not elected to be treated as a corporation is treated as a partnership for federal income tax purposes and, therefore, is not a taxable entity and incurs no federal income tax liability. Instead, each partner is required to take into account his share of items of income, gain, loss and deduction of the partnership in computing his federal income tax liability, even if no cash distributions are made to him. Distributions by a partnership to a partner are generally not taxable to the partner unless the amount of cash distributed to him is in excess of his adjusted basis in his partnership interest.

Section 7704 of the Internal Revenue Code provides that publicly traded partnerships will, as a general rule, be taxed as corporations. However, an exception, referred to in this discussion as the Qualifying Income Exception, exists with respect to publicly traded partnerships 90% or more of the gross income of which for every taxable year consists of qualifying income. Qualifying income includes income and gains derived from the exploration, development, mining or production, processing, transportation and marketing of natural resources, including oil, natural gas, and products thereof. Other types of qualifying income include interest (other than from a financial business), dividends, gains from the sale of real property and gains from the sale or other disposition of capital assets held for the production of income that otherwise constitutes qualifying income. We estimate that less than 3% of our current gross income does not constitute qualifying income; however, this estimate could change from time to time. Based on and subject to this estimate, the factual representations made by us, and a review of the applicable legal authorities, Andrews Kurth LLP is of the opinion that more than 90% of our current gross income constitutes qualifying income. The portion of our income that is qualifying income can change from time to time.

No ruling has been or will be sought from the IRS, and the IRS has made no determination as to our status or the status of our operating subsidiaries for federal income tax purposes or whether our operations generate qualifying income under Section 7704 of the Internal Revenue Code. Instead, we will rely on the opinion of Andrews Kurth LLP. Andrews Kurth LLP is of the opinion, based upon the Internal Revenue Code, its regulations, published revenue rulings, court decisions and the representations described below, that we will be classified as a partnership, and each of our operating subsidiaries will be disregarded as an entity separate from us, for federal income tax purposes.

In rendering its opinion, Andrews Kurth LLP has relied on factual representations made by us. The representations made by us upon which Andrews Kurth LLP has relied include:

- Neither we, nor any of our limited liability company subsidiaries, have elected nor will we elect to be treated as a corporation; and

- For each taxable year, more than 90% of our gross income will be income that Andrews Kurth LLP has opined or will opine is qualifying income within the meaning of Section 7704(d) of the Internal Revenue Code.

If we fail to meet the Qualifying Income Exception, other than a failure that is determined by the IRS to be inadvertent and that is cured within a reasonable time after discovery, we will be treated as if we had transferred all of our assets, subject to liabilities, to a newly formed corporation, on the first day of the year in which we fail to meet the Qualifying Income Exception, in return for stock in that corporation and then distributed that stock to common unitholders in liquidation of their interests in us. This deemed contribution and liquidation would be tax-free to common unitholders and us so long as we, at that time, do not have liabilities in excess of the tax basis of our assets. Thereafter, we would be treated as a corporation for federal income tax purposes.

If we were taxable as a corporation in any taxable year, either as a result of a failure to meet the Qualifying Income Exception or otherwise, our items of income, gain, loss and deduction would be reflected only on our tax return rather than being passed through to common unitholders, and our net income would be taxed to us

at corporate rates. In addition, any distribution made to a common unitholder would be treated as taxable dividend income to the extent of our current or accumulated earnings and profits, or, in the absence of earnings and profits, a nontaxable return of capital to the extent of the common unitholder s tax basis in his units, or taxable capital gain, after the common unitholder s tax basis in his units is reduced to zero. Accordingly, taxation as a corporation would result in a material reduction in a common unitholder s cash flow and after-tax return and thus would likely result in a substantial reduction of the value of the units.

The remainder of this section is based on Andrews Kurth LLP s opinion that we will be classified as a partnership for federal income tax purposes.

Common Unitholder Status

Common unitholders who become members of Constellation Energy Partners LLC will be treated as partners of Constellation Energy Partners LLC for federal income tax purposes. Also, common unitholders whose units are held in street name or by a nominee and who have the right to direct the nominee in the exercise of all substantive rights attendant to the ownership of their units will be treated as partners of Constellation Energy Partners LLC for federal income tax purposes.

A beneficial owner of units whose units have been transferred to a short seller to complete a short sale would appear to lose his status as a partner with respect to those units for federal income tax purposes. Please read Tax Consequences of Unit Ownership Treatment of Short Sales.

Items of our income, gain, loss, or deduction are not reportable by a common unitholder who is not a partner for federal income tax purposes, and any cash distributions received by a common unitholder who is not a partner for federal income tax purposes would therefore be fully taxable as ordinary income. These common unitholders are urged to consult their own tax advisors with respect to their status as partners in us for federal income tax purposes.

The references to common unitholders in the discussion that follows are to persons who are treated as partners in Constellation Energy Partners LLC for federal income tax purposes.

Tax Consequences of Unit Ownership

Flow-Through of Taxable Income

We will not pay any federal income tax. Instead, each common unitholder will be required to report on his income tax return his share of our income, gains, losses and deductions without regard to whether corresponding cash distributions are received by him. Consequently, we may allocate income to a common unitholder even if he has not received a cash distribution. Each common unitholder will be required to include in income his share of our income, gain, loss and deduction for our taxable year or years ending with or within his taxable year. Our taxable year ends on December 31.

Treatment of Distributions

Distributions made by us to a common unitholder generally will not be taxable to him for federal income tax purposes to the extent of his tax basis in his units immediately before the distribution. Cash distributions made by us to a common unitholder in an amount in excess of his tax basis in his units generally will be considered to be gain from the sale or exchange of those units, taxable in accordance with the rules described under Disposition of Units below. To the extent that cash distributions made by us cause a common unitholder s at risk amount to be less than zero at the end of any taxable year, he must recapture any losses deducted in previous years. Please read Limitations on Deductibility of Losses.

Any reduction in a common unitholder s share of our liabilities for which no partner bears the economic risk of loss, known as non-recourse liabilities, will be treated as a distribution of cash to that common unitholder. A decrease in a common unitholder s percentage interest in us because of our issuance of additional units will decrease his share of our nonrecourse liabilities and thus will result in a corresponding deemed distribution of cash, which may constitute a non-pro rata distribution. A non-pro rata distribution of money or property may result in ordinary income to a common unitholder, regardless of his tax basis in his units, if the distribution reduces the common unitholder s share of our unrealized receivables, including recapture of intangible drilling costs, depletion and depreciation recapture, and/or substantially appreciated inventory items, both as defined in Section 751 of the Internal Revenue Code, and collectively, Section 751 Assets. To that extent, he will be treated as having received his proportionate share of the Section 751 Assets and having exchanged those assets with us in return for the non-pro rata portion of the actual distribution made to him. This latter deemed exchange will generally result in the common unitholder s realization of ordinary income. That income will equal the excess of (1) the non-pro rata portion of that distribution over (2) the common unitholder s tax basis for the share of Section 751 Assets deemed relinquished in the exchange.

Ratio of Taxable Income to Distributions

We estimate that a purchaser of our common units in this offering who holds those common units from the date of closing of this offering through the record date for distributions for the period ending December 31, 2009, will be allocated on a cumulative basis an amount of federal taxable income for that period that will be approximately 20% of the cash distributed to the common unitholder with respect to that period. We anticipate that thereafter, the ratio of taxable income allocable to cash distributions to the common unitholders will increase. These estimates are based upon assumptions with respect to gross income, capital expenditures, cash flow and anticipated cash distributions. These estimates and assumptions are subject to, among other things, numerous business, economic, regulatory, competitive and political uncertainties beyond our control. Further, the estimates are based on current tax law and tax reporting positions that we intend to adopt and with which the IRS could disagree. Accordingly, these estimates may not prove to be correct. The actual percentage of distributions that will constitute taxable income could be higher or lower, and any differences could be material and could materially affect the value of the units.

Basis of Units

A common unitholder s initial tax basis for his units will be the amount he paid for the units plus his share of our nonrecourse liabilities. That basis will be increased by his share of our income and by any increases in his share of our nonrecourse liabilities. That basis generally will be decreased, but not below zero, by distributions to him from us, by his share of our losses, by depletion deductions taken by him to the extent such deductions do not exceed his proportionate share of the adjusted tax basis of the underlying producing properties, by any decreases in his share of our nonrecourse liabilities and by his share of our expenditures that are not deductible in computing taxable income and are not required to be capitalized. A common unitholder s share of our nonrecourse liabilities will generally be based on his share of our profits. Please read Disposition of Units Recognition of Gain or Loss.

Limitations on Deductibility of Losses

The deduction by a common unitholder of his share of our losses will be limited to his tax basis in his units and, in the case of an individual common unitholder or a corporate common unitholder, if more than 50% of the value of its stock is owned directly or indirectly by or for five or fewer individuals or some tax-exempt

organizations, to the amount for which the common unitholder is considered to be at risk with respect to our activities, if that amount is less than his tax basis. A common unitholder must recapture losses deducted in previous years to the extent that distributions cause his at-risk amount to be less than zero at the end of any taxable year. Losses disallowed to a common unitholder or recaptured as a result of these limitations will carry forward and will be allowable as a deduction in a later year to the extent that his tax basis or at-risk amount, whichever is the limiting factor, is subsequently increased. Upon the taxable disposition of a unit, any gain recognized by a common unitholder can be offset by losses that were previously suspended by the at-risk limitation but may not be offset by losses suspended by the basis limitation. Any excess loss above that gain previously suspended by the at risk or basis limitations is no longer utilizable.

In general, a common unitholder will be at risk to the extent of his tax basis in his units, excluding any portion of that basis attributable to his share of our nonrecourse liabilities, reduced by any amount of money he borrows to acquire or hold his units, if the lender of those borrowed funds owns an interest in us, is related to the common unitholder or can look only to the units for repayment. A common unitholder s at-risk amount will increase or decrease as the tax basis of the common unitholder s common units increases or decreases, other than tax basis increases or decreases attributable to increases or decreases in his share of our nonrecourse liabilities. Moreover, a common unitholder s at risk amount will decrease by the amount of the common unitholder s depletion deductions and will increase to the extent of the amount by which the common unitholder s percentage depletion deductions with respect to our property exceed the common unitholder s share of the basis of that property.

The at risk limitation applies on an activity-by-activity basis, and in the case of oil and natural gas properties, each property is treated as a separate activity. Thus, a taxpayer s interest in each oil or gas property is generally required to be treated separately so that a loss from any one property would be limited to the at risk amount for that property and not the at risk amount for all the taxpayer s oil and natural gas properties. It is uncertain how this rule is implemented in the case of multiple oil and natural gas properties owned by a single entity treated as a partnership for federal income tax purposes. However, for taxable years ending on or before the date on which further guidance is published, the IRS will permit aggregation of oil or gas properties we own in computing a common unitholder s at risk limitation with respect to us. If a common unitholder must compute his at risk amount separately with respect to each oil or gas property we own, he may not be allowed to utilize his share of losses or deductions attributable to a particular property even though he has a positive at risk amount with respect to his units as a whole.

The passive loss limitation generally provides that individuals, estates, trusts and some closely held corporations and personal service corporations are permitted to deduct losses from passive activities, which are generally defined as trade or business activities in which the taxpayer does not materially participate, only to the extent of the taxpayer s income from those passive activities. The passive loss limitation is applied separately with respect to each publicly traded partnership. Consequently, any losses we generate will be available to offset only our passive income generated in the future and will not be available to offset income from other passive activities or investments, including our investments, a common unitholder s investments in other publicly traded partnerships, or a common unitholder s salary or active business income. If we dispose of all or only a part of our interest in an oil and gas property, common unitholders will be able to offset their suspended passive activity losses from our activities against the gain, if any, on the disposition. Any previously suspended losses in excess of the amount of gain recognized will remain suspended. Notwithstanding whether a natural gas and oil property is a separate activity, passive losses that are not deductible because they exceed a common unitholder s share of income we generate may only be deducted by the common unitholder in full when he disposes of his entire investment in us in a fully taxable transaction with an unrelated party. The passive activity loss rules are applied after certain other applicable limitations on deductions, including the at-risk rules and the tax basis limitation.

A common unitholder s share of our net income may be offset by any of our suspended passive losses, but it may not be offset by any other current or carryover losses from other passive activities, including those attributable to other publicly traded partnerships.

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Limitation on Interest Deductions

The deductibility of a non-corporate taxpayer s investment interest expense is generally limited to the amount of that taxpayer s net investment income. Investment interest expense includes:

interest on indebtedness properly allocable to property held for investment;

our interest expense attributable to portfolio income; and

the portion of interest expense incurred to purchase or carry an interest in a passive activity to the extent attributable to portfolio income.

The computation of a common unitholder s investment interest expense will take into account interest on any margin account borrowing or other loan incurred to purchase or carry a unit.

Net investment income includes gross income from property held for investment and amounts treated as portfolio income under the passive loss rules, less deductible expenses, other than interest, directly connected with the production of investment income, but generally does not include gains attributable to the disposition of property held for investment. The IRS has indicated that net passive income earned by a publicly traded partnership will be treated as investment income to its common unitholders. In addition, the common unitholder s share of our portfolio income will be treated as investment income.

Entity-Level Collections

If we are required or elect under applicable law to pay any federal, state or local income tax on behalf of any common unitholder or any former common unitholder, we are authorized to pay those taxes from our funds. That payment, if made, will be treated as a distribution of cash to the common unitholder on whose behalf the payment was made. If the payment is made on behalf of a common unitholder whose identity cannot be determined, we are authorized to treat the payment as a distribution to all current common unitholders. We are authorized to amend our limited liability company agreement in the manner necessary to maintain uniformity of intrinsic tax characteristics of units and to adjust later distributions, so that after giving effect to these distributions, the priority and characterization of distributions otherwise applicable under our limited liability company agreement is maintained as nearly as is practicable. Payments by us as described above could give rise to an overpayment of tax on behalf of a common unitholder in which event the common unitholder would be required to file a claim in order to obtain a credit or refund.

Allocation of Income, Gain, Loss and Deduction

In general, if we have a net profit, our items of income, gain, loss and deduction will be allocated among the common unitholders in accordance with their percentage interests in us. If we have a net loss for an entire year, the loss will be allocated to our common unitholders according to their percentage interests in us to the extent of their positive capital account balances.

Specified items of our income, gain, loss and deduction will be allocated under Section 704(c) of the Internal Revenue Code to account for the difference between the tax basis and fair market value of our assets at the time of this offering, which assets are referred to in this discussion as Contributed Property. These allocations are required to eliminate the difference between a partner s book capital account, credited with the fair market value of Contributed Property, and the tax capital account, credited with the tax basis of Contributed Property, referred to in this discussion as the book-tax disparity. The effect of these allocations to a common unitholder who purchases units in this offering will be essentially the same as if the tax basis of our assets were equal to their fair market value at the time of the offering. In the event we issue additional units or engage in certain other transactions in the future, Section 704(c) allocations will be made to all holders of partnership interests, including purchasers of units in this offering, to account for the difference between the book basis for purposes of maintaining capital accounts and the fair market value of all property held by us at the time of the future transaction. In addition, items of recapture income will be allocated to the extent possible to

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the common unitholder who was allocated the deduction giving rise to the treatment of that gain as recapture income in order to minimize the recognition of ordinary income by other common unitholders. Finally, although we do not expect that our operations will result in the creation of negative capital accounts, if negative capital accounts nevertheless result, items of our income and gain will be allocated in an amount and manner sufficient to eliminate the negative balance as quickly as possible.

An allocation of items of our income, gain, loss or deduction, other than an allocation required by Section 704(c), will generally be given effect for federal income tax purposes in determining a common unitholder s share of an item of income, gain, loss or deduction only if the allocation has substantial economic effect. In any other case, a common unitholder s share of an item will be determined on the basis of his interest in us, which will be determined by taking into account all the facts and circumstances, including:

- his relative contributions to us;
- the interests of all the common unitholders in profits and losses;
- the interest of all the common unitholders in cash flow; and
- the rights of all the common unitholders to distributions of capital upon liquidation.

Andrews Kurth LLP is of the opinion that, with the exception of the issues described in Tax Consequences of Unit Ownership Section 754 Election, Uniformity of Units and Disposition of Units Allocations Between Transferors and Transferees, allocations under our limited liability company agreement will be given effect for federal income tax purposes in determining a common unitholder s share of an item of income, gain, loss or deduction.

Treatment of Short Sales

A common unitholder whose units are loaned to a short seller to cover a short sale of units may be considered as having disposed of those units. If so, he would no longer be a partner for tax purposes with respect to those units during the period of the loan and may recognize gain or loss from the disposition. As a result, during this period:

- none of our income, gain, loss or deduction with respect to those units would be reportable by the common unitholder;
- any cash distributions received by the common unitholder with respect to those units would be fully taxable; and
- all of these distributions would appear to be ordinary income.

Andrews Kurth LLP has not rendered an opinion regarding the treatment of a common unitholder whose units are loaned to a short seller. Therefore, common unitholders desiring to assure their status as partners and avoid the risk of gain recognition are urged to modify any applicable brokerage account agreements to prohibit their brokers from loaning their units. The IRS has announced that it is studying issues relating to the tax treatment of short sales of partnership interests. Please also read Disposition of Units Recognition of Gain or Loss.

Alternative Minimum Tax

Each common unitholder will be required to take into account his distributive share of any items of our income, gain, loss or deduction for purposes of the alternative minimum tax. The current minimum tax rate for non-corporate taxpayers is 26% on the first $175,000 of alternative minimum taxable income in excess of the exemption amount and 28% on any additional alternative minimum taxable income. Prospective common unitholders are urged to consult their tax advisors with respect to the impact of an investment in our units on their liability for the alternative minimum tax.

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Tax Rates

In general, the highest effective federal income tax rate for individuals currently is 35% and the maximum federal income tax rate for net capital gains of an individual currently is 15% if the asset disposed of was held for more than 12 months at the time of disposition.

Section 754 Election

We will make the election permitted by Section 754 of the Internal Revenue Code. That election is irrevocable without the consent of the IRS. That election will generally permit us to adjust a unit purchaser s tax basis in our assets (inside basis) under Section 743(b) of the Internal Revenue Code to reflect his purchase price. The Section 743(b) adjustment does not apply to a person who purchases units directly from us, and it belongs only to the purchaser and not to other common unitholders. Please also read, however, Allocation of Income, Gain, Loss and Deduction above. For purposes of this discussion, a common unitholder s inside basis in our assets has two components: (1) his share of our tax basis in our assets (common basis) and (2) his Section 743(b) adjustment to that basis.

Treasury regulations under Section 743 of the Internal Revenue Code require, if the remedial allocation method is adopted (which we will adopt), a portion of the Section 743(b) adjustment attributable to recovery property to be depreciated over the remaining cost recovery period for the Section 704(c) built-in gain. Under Treasury Regulation Section 1.167(c)-l(a)(6), a Section 743(b) adjustment attributable to property subject to depreciation under Section 167 of the Internal Revenue Code rather than cost recovery deductions under Section 168 is generally required to be depreciated using either the straight-line method or the 150% declining balance method. Under our limited liability company agreement, we are authorized to take a position to preserve the uniformity of units even if that position is not consistent with these Treasury regulations. Please read Uniformity of Units.

Although Andrews Kurth LLP is unable to opine on the validity of this approach because there is no clear authority on this issue, we intend to depreciate the portion of a Section 743(b) adjustment attributable to unrealized appreciation in the value of Contributed Property, to the extent of any unamortized book-tax disparity, using a rate of depreciation or amortization derived from the depreciation or amortization method and useful life applied to the common basis of the property, or treat that portion as non-amortizable to the extent attributable to property the common basis of which is not amortizable. This method is consistent with the regulations under Section 743 but is arguably inconsistent with Treasury regulation Section 1.167(c)-1(a)(6), which is not expected to directly apply to a material portion of our assets. To the extent a Section 743(b) adjustment is attributable to appreciation in value in excess of the unamortized book-tax disparity, we will apply the rules described in the Treasury regulations and legislative history. If we determine that this position cannot reasonably be taken, we may take a depreciation or amortization position under which all purchasers acquiring units in the same month would receive depreciation or amortization, whether attributable to common basis or a Section 743(b) adjustment, based upon the same applicable rate as if they had purchased a direct interest in our assets. This kind of aggregate approach may result in lower annual depreciation or amortization deductions than would otherwise be allowable to some common unitholders. Please read Uniformity of Units.

A Section 754 election is advantageous if the transferee s tax basis in his units is higher than the units share of the aggregate tax basis of our assets immediately prior to the transfer. In that case, as a result of the election, the transferee would have, among other items, a greater amount of depletion and depreciation deductions and his share of any gain on a sale of our assets would be less. Conversely, a Section 754 election is disadvantageous if the transferee s tax basis in his units is lower than those units share of the aggregate tax basis of our assets immediately prior to the transfer. Thus, the fair market value of the units may be affected either favorably or unfavorably by the election. A basis adjustment is required regardless of whether a Section 754 election is made in the case of a transfer of an interest in us if we have a substantial built-in loss immediately after the transfer, or

if we distribute property and have a substantial basis reduction. Generally a built-in loss or a basis reduction is substantial if it exceeds $250,000.

The calculations involved in the Section 754 election are complex and will be made on the basis of assumptions as to the value of our assets and other matters. For example, the allocation of the Section 743(b) adjustment among our assets must be made in accordance with the Internal Revenue Code. The IRS could seek to reallocate some or all of any Section 743(b) adjustment we allocated to our tangible assets to goodwill instead. Goodwill, an intangible asset, is generally either nonamortizable or amortizable over a longer period of time or under a less accelerated method than our tangible assets. We cannot assure you that the determinations we make will not be successfully challenged by the IRS or that the resulting deductions will not be reduced or disallowed altogether. Should the IRS require a different basis adjustment to be made, and should, in our opinion, the expense of compliance exceed the benefit of the election, we may seek permission from the IRS to revoke our Section 754 election. If permission is granted, a subsequent purchaser of units may be allocated more income than he would have been allocated had the election not been revoked.

Tax Treatment of Operations

Accounting Method and Taxable Year

We will use the year ending December 31 as our taxable year and the accrual method of accounting for federal income tax purposes. Each common unitholder will be required to include in income his share of our income, gain, loss and deduction for our taxable year ending within or with his taxable year. In addition, a common unitholder who has a taxable year ending on a date other than December 31 and who disposes of all of his units following the close of our taxable year but before the close of his taxable year must include his share of our income, gain, loss and deduction in income for his taxable year, with the result that he will be required to include in income for his taxable year his share of more than twelve months of our income, gain, loss and deduction. Please read Disposition of Units Allocations Between Transferors and Transferees.

Depletion Deductions

Subject to the limitations on deductibility of losses discussed above, common unitholders will be entitled to deductions for the greater of either cost depletion or (if otherwise allowable) percentage depletion with respect to our oil and natural gas interests. Although the Internal Revenue Code requires each common unitholder to compute his own depletion allowance and maintain records of his share of the adjusted tax basis of the underlying property for depletion and other purposes, we intend to furnish each of our common unitholders with information relating to this computation for federal income tax purposes.

Percentage depletion is generally available with respect to common unitholders who qualify under the independent producer exemption contained in Section 613A(c) of the Internal Revenue Code. For this purpose, an independent producer is a person not directly or indirectly involved in the retail sale of oil, natural gas, or derivative products or the operation of a major refinery. Percentage depletion is calculated as an amount generally equal to 15% (and, in the case of marginal production, potentially a higher percentage) of the common unitholder s gross income from the depletable property for the taxable year. The percentage depletion deduction with respect to any property is limited to 100% of the taxable income of the common unitholder from the property for each taxable year, computed without the depletion allowance. A common unitholder that qualifies as an independent producer may deduct percentage depletion only to the extent the common unitholder s daily production of domestic crude oil, or the natural gas equivalent, does not exceed 1,000 barrels. This depletable amount may be allocated between oil and natural gas production, with 6,000 cubic feet of domestic natural gas production regarded as equivalent to one barrel of crude oil. The 1,000 barrel limitation must be allocated among the independent producer and controlled or related persons and family members in proportion to the respective production by such persons during the period in question.

In addition to the foregoing limitations, the percentage depletion deduction otherwise available is limited to 65% of a common unitholder s total taxable income from all sources for the year, computed without the depletion allowance, net operating loss carrybacks, or capital loss carrybacks. Any percentage depletion deduction disallowed because of the 65% limitation may be deducted in the following taxable year if the percentage depletion deduction for such year plus the deduction carryover does not exceed 65% of the common unitholder s total taxable income for that year. The carryover period resulting from the 65% net income limitation is indefinite.

Common unitholders that do not qualify under the independent producer exemption are generally restricted to depletion deductions based on cost depletion. Cost depletion deductions are calculated by (i) dividing the common unitholder s share of the adjusted tax basis in the underlying mineral property by the number of mineral units (barrels of oil and thousand cubic feet, or Mcf, of natural gas) remaining as of the beginning of the taxable year and (ii) multiplying the result by the number of mineral units sold within the taxable year. The total amount of deductions based on cost depletion cannot exceed the common unitholder s share of the total adjusted tax basis in the property.

All or a portion of any gain recognized by a common unitholder as a result of either the disposition by us of some or all of our oil and natural gas interests or the disposition by the common unitholder of some or all of his units may be taxed as ordinary income to the extent of recapture of depletion deductions, except for percentage depletion deductions in excess of the basis of the property. The amount of the recapture is generally limited to the amount of gain recognized on the disposition.

The foregoing discussion of depletion deductions does not purport to be a complete analysis of the complex legislation and Treasury regulations relating to the availability and calculation of depletion deductions by the common unitholders. Further, because depletion is required to be computed separately by each common unitholder and not by our partnership, no assurance can be given, and counsel is unable to express any opinion, with respect to the availability or extent of percentage depletion deductions to the common unitholders for any taxable year. We encourage each prospective common unitholder to consult his tax advisor to determine whether percentage depletion would be available to him.

Deductions for Intangible Drilling and Development Costs

We will elect to currently deduct intangible drilling and development costs (IDCs). IDCs generally include our expenses for wages, fuel, repairs, hauling, supplies and other items that are incidental to, and necessary for, the drilling and preparation of wells for the production of oil, natural gas, or geothermal energy. The option to currently deduct IDCs applies only to those items that do not have a salvage value.

Although we will elect to currently deduct IDCs, each common unitholder will have the option of either currently deducting IDCs or capitalizing all or part of the IDCs and amortizing them on a straight-line basis over a 60-month period, beginning with the taxable month in which the expenditure is made. If a common unitholder makes the election to amortize the IDCs over a 60-month period, no IDC preference amount will result for alternative minimum tax purposes.

Integrated oil companies must capitalize 30% of all their IDCs (other than IDCs paid or incurred with respect to oil and natural gas wells located outside of the United States) and amortize these IDCs over 60 months beginning in the month in which those costs are paid or incurred. If the taxpayer ceases to be an integrated oil company, it must continue to amortize those costs as long as it continues to own the property to which the IDCs relate. An integrated oil company is a taxpayer that has economic interests in crude oil deposits and also carries on substantial retailing or refining operations. An oil or gas producer is deemed to be a substantial retailer or refiner if it is subject to the rules disqualifying retailers and refiners from taking percentage depletion. In order to qualify as an independent producer that is not subject to these IDC deduction limits, a common unitholder, either directly or indirectly through certain related parties, may not be involved in the refining of more than 75,000 barrels of oil (or the equivalent amount of natural gas) on average for any day during the taxable year or in the retail marketing of oil and natural gas products exceeding $5 million per year in the aggregate.

IDCs previously deducted that are allocable to property (directly or through ownership of an interest in a partnership) and that would have been included in the adjusted basis of the property had the IDC deduction not been taken are recaptured to the extent of any gain realized upon the disposition of the property or upon the disposition by a common unitholder of interests in us. Recapture is generally determined at the common unitholder level. Where only a portion of the recapture property is sold, any IDCs related to the entire property are recaptured to the extent of the gain realized on the portion of the property sold. In the case of a disposition of an undivided interest in a property, a proportionate amount of the IDCs with respect to the property is treated as allocable to the transferred undivided interest to the extent of any gain recognized. See Disposition of Units Recognition of Gain or Loss.

Deduction for United States Production Activities

Subject to the limitations on the deductibility of losses discussed above and the limitation discussed below, common unitholders will be entitled to a deduction, herein referred to as the Section 199 deduction, equal to a specified percentage of our qualified production activities income that is allocated to such common unitholder. The percentages are 3% for qualified production activities income generated in the year 2006; 6% for the years 2007, 2008, and 2009; and 9% thereafter.

Qualified production activities income is generally equal to gross receipts from domestic production activities reduced by cost of goods sold allocable to those receipts, other expenses directly associated with those receipts, and a share of other deductions, expenses and losses that are not directly allocable to those receipts or another class of income. The products produced must be manufactured, produced, grown or extracted in whole or in significant part by the taxpayer in the United States.

For a partnership, the Section 199 deduction is determined at the partner level. To determine his Section 199 deduction, each common unitholder will aggregate his share of the qualified production activities income allocated to him from us with the common unitholder s qualified production activities income from other sources. Each common unitholder must take into account his distributive share of the expenses allocated to him from our qualified production activities regardless of whether we otherwise have taxable income. However, our expenses that otherwise would be taken into account for purposes of computing the Section 199 deduction are only taken into account if and to the extent the common unitholder s share of losses and deductions from all of our activities is not disallowed by the basis rules, the at-risk rules or the passive activity loss rules. Please read Tax Consequences of Unit Ownership Limitations on Deductibility of Losses.

The amount of a common unitholder s Section 199 deduction for each year is limited to 50% of the IRS Form W-2 wages paid by the common unitholder during the calendar year that are deducted in arriving at qualified production activities income. Each common unitholder is treated as having been allocated IRS Form W-2 wages from us equal to the common unitholder s allocable share of our wages that are deducted in arriving at our qualified production activities income for that taxable year. It is not anticipated that we or our subsidiaries will pay material wages that will be allocated to our common unitholders.

This discussion of the Section 199 deduction does not purport to be a complete analysis of the complex legislation and Treasury authority relating to the calculation of domestic production gross receipts, qualified production activities income, or IRS Form W-2 Wages, or how such items are allocated by us to common unitholders. Further, because the Section 199 deduction is required to be computed separately by each common unitholder, no assurance can be given, and counsel is unable to express any opinion, as to the availability or extent of the Section 199 deduction to the common unitholders. Each prospective common unitholder is encouraged to consult his tax advisor to determine whether the Section 199 deduction would be available to him.

Lease Acquisition Costs

The cost of acquiring oil and natural gas leaseholder or similar property interests is a capital expenditure that must be recovered through depletion deductions if the lease is productive. If a lease is proved worthless and abandoned, the cost of acquisition less any depletion claimed may be deducted as an ordinary loss in the year the lease becomes worthless. Please read Tax Treatment of Operations Depletion Deductions.

Geophysical Costs

Geophysical costs paid or incurred in connection with the exploration for, or development of, oil or gas within the U.S. are allowed as a deduction ratably over the 24-month period beginning on the date that such expense was paid or incurred.

Operating and Administrative Costs

Amounts paid for operating a producing well are deductible as ordinary business expenses, as are administrative costs to the extent they constitute ordinary and necessary business expenses which are reasonable in amount.

Tax Basis, Depreciation and Amortization

The tax basis of our assets, such as casing, tubing, tanks, pumping units and other similar property, will be used for purposes of computing depreciation and cost recovery deductions and, ultimately, gain or loss on the disposition of these assets. The federal income tax burden associated with the difference between the fair market value of our assets and their tax basis immediately prior to (i) this offering will be borne by our existing common unitholders, and (ii) any other offering will be borne by our common unitholders as of that time. Please read Tax Consequences of Unit Ownership Allocation of Income, Gain, Loss and Deduction.

To the extent allowable, we may elect to use the depreciation and cost recovery methods that will result in the largest deductions being taken in the early years after assets are placed in service. Property we subsequently acquire or construct may be depreciated using accelerated methods permitted by the Internal Revenue Code.

If we dispose of depreciable property by sale, foreclosure, or otherwise, all or a portion of any gain, determined by reference to the amount of depreciation previously deducted and the nature of the property, may be subject to the recapture rules and taxed as ordinary income rather than capital gain. Similarly, a common unitholder who has taken cost recovery or depreciation deductions with respect to property we own will likely be required to recapture some or all of those deductions as ordinary income upon a sale of his interest in us. Please read Tax Consequences of Unit Ownership Allocation of Income, Gain, Loss and Deduction and Disposition of Units Recognition of Gain or Loss.

The costs incurred in selling our units (called syndication expenses) must be capitalized and cannot be deducted currently, ratably or upon our termination. There are uncertainties regarding the classification of costs as organization expenses, which we may be able to amortize, and as syndication expenses, which we may not amortize. The underwriting discounts and commissions we incur will be treated as syndication expenses.

Valuation and Tax Basis of Our Properties

The federal income tax consequences of the ownership and disposition of units will depend in part on our estimates of the relative fair market values and the tax bases of our assets. Although we may from time to time consult with professional appraisers regarding valuation matters, we will make many of the relative fair market value estimates ourselves. These estimates and determinations of basis are subject to challenge and will not be binding on the IRS or the courts. If the estimates of fair market value or basis are later found to be incorrect, the character and amount of items of income, gain, loss or deduction previously reported by common unitholders might change, and common unitholders might be required to adjust their tax liability for prior years and incur interest and penalties with respect to those adjustments.

Disposition of Units

Recognition of Gain or Loss

Gain or loss will be recognized on a sale of units equal to the difference between the common unitholder s amount realized and the common unitholder s tax basis for the units sold. A common unitholder s amount realized will equal the sum of the cash or the fair market value of other property he receives plus his share of our nonrecourse liabilities. Because the amount realized includes a common unitholder s share of our nonrecourse liabilities, the gain recognized on the sale of units could result in a tax liability in excess of any cash received from the sale.

Prior distributions from us in excess of cumulative net taxable income for a unit that decreased a common unitholder s tax basis in that unit will, in effect, become taxable income if the unit is sold at a price greater than the common unitholder s tax basis in that unit, even if the price received is less than his original cost.

Except as noted below, gain or loss recognized by a common unitholder, other than a dealer in units, on the sale or exchange of a unit held for more than one year will generally be taxable as capital gain or loss. A portion of this gain or loss, which may be substantial, however, will be separately computed and taxed as ordinary income or loss under Section 751 of the Internal Revenue Code to the extent attributable to assets giving rise to unrealized receivables or inventory items that we own. The term unrealized receivables includes potential recapture items, including depreciation, depletion, and IDC recapture. Ordinary income attributable to unrealized receivables and inventory items may exceed net taxable gain realized on the sale of a unit and may be recognized even if there is a net taxable loss realized on the sale of a unit. Thus, a common unitholder may recognize both ordinary income and a capital loss upon a sale of units. Net capital loss may offset capital gains and no more than $3,000 of ordinary income, in the case of individuals, and may only be used to offset capital gain in the case of corporations.

The IRS has ruled that a partner who acquires interests in a partnership in separate transactions must combine those interests and maintain a single adjusted tax basis for all those interests. Upon a sale or other disposition of less than all of those interests, a portion of that tax basis must be allocated to the interests sold using an equitable apportionment method. Treasury regulations under Section 1223 of the Internal Revenue Code allow a selling common unitholder who can identify units transferred with an ascertainable holding period to elect to use the actual holding period of the units transferred. Thus, according to the ruling, a common unitholder will be unable to select high or low basis units to sell as would be the case with corporate stock, but, according to the regulations, may designate specific units sold for purposes of determining the holding period of units transferred. A common unitholder electing to use the actual holding period of units transferred must consistently use that identification method for all subsequent sales or exchanges of units. A common unitholder considering the purchase of additional units or a sale of units purchased in separate transactions is urged to consult his tax advisor as to the possible consequences of this ruling and those Treasury regulations.

Specific provisions of the Internal Revenue Code affect the taxation of some financial products and securities, including partnership interests, by treating a taxpayer as having sold an appreciated partnership interest, one in which gain would be recognized if it were sold, assigned or terminated at its fair market value, if the taxpayer or related persons enter(s) into:

- a short sale;
- an offsetting notional principal contract; or
- a futures or forward contract with respect to the partnership interest or substantially identical property.

Moreover, if a taxpayer has previously entered into a short sale, an offsetting notional principal contract or a futures or forward contract with respect to the partnership interest, the taxpayer will be treated as having sold that position if the taxpayer or a related person then acquires the partnership interest or substantially identical property. The Secretary of the Treasury is also authorized to issue regulations that treat a taxpayer who enters into transactions or positions that have substantially the same effect as the preceding transactions as having constructively sold the financial position.

Allocations Between Transferors and Transferees

In general, our taxable income or loss will be determined annually, will be prorated on a monthly basis and will be subsequently apportioned among the common unitholders in proportion to the number of units owned by

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each of them as of the opening of the applicable exchange on the first business day of the month (the Allocation Date). However, gain or loss realized on a sale or other disposition of our assets other than in the ordinary course of business will be allocated among the common unitholders on the Allocation Date in the month in which that gain or loss is recognized. As a result, a common unitholder transferring units may be allocated income, gain, loss and deduction realized after the date of transfer.

Although simplifying conventions are contemplated by the Code and most publicly traded partnerships use similar simplifying conventions, the use of this method may not be permitted under existing Treasury regulations. Accordingly, Andrews Kurth LLP is unable to opine on the validity of this method of allocating income and deductions between common unitholders. If this method is not allowed under the Treasury regulations, or only applies to transfers of less than all of the common unitholder s interest, our taxable income or losses might be reallocated among the common unitholders. We are authorized to revise our method of allocation between common unitholders, as well as among common unitholders whose interests vary during a taxable year, to conform to a method permitted under future Treasury regulations.

A common unitholder who owns units at any time during a quarter and who disposes of them prior to the record date set for a cash distribution for that quarter will be allocated items of our income, gain, loss and deductions attributable to that quarter but will not be entitled to receive that cash distribution.

Notification Requirements

A common unitholder who sells any of his units, other than through a broker, generally is required to notify us in writing of that sale within 30 days after the sale (or, if earlier, January 15 of the year following the sale). A person who purchases units is required to notify us in writing of that purchase within 30 days after the purchase, unless a broker or nominee will satisfy such requirement. We are required to notify the IRS of any such transfers of units and to furnish specified information to the transferor and transferee. Failure to notify us of a transfer of units may lead to the imposition of substantial penalties.

Constructive Termination

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 common unitholders. In the case of a common unitholder reporting on a taxable year other than a fiscal year ending December 31, the closing of our taxable year may result in more than 12 months of our taxable income or loss being 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 common unitholders receiving two Schedule K-1s) for one calendar year and the cost of the preparation of these returns will be borne by all common unitholders. We would be required to make new tax elections after a termination, including a new election under Section 754 of the Internal Revenue Code, and a termination would result in a deferral of our deductions for depreciation. A termination could also result in penalties if we were unable to determine that the termination had occurred. Moreover, a termination might either accelerate the application of, or subject us to, any tax legislation enacted before the termination.

Uniformity of Units

Because we cannot match transferors and transferees of units, we must maintain uniformity of the economic and tax characteristics of the units to a purchaser of these units. In the absence of uniformity, we may be unable to completely comply with a number of federal income tax requirements, both statutory and regulatory. A lack of uniformity can result from a literal application of Treasury Regulation Section 1.167(c)-1(a)(6). Any non-uniformity could have a negative impact on the value of the units. Please read Tax Consequences of Unit Ownership Section 754 Election.

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We intend to depreciate the portion of a Section 743(b) adjustment attributable to unrealized appreciation in the value of Contributed Property, to the extent of any unamortized book-tax disparity, using a rate of depreciation or amortization derived from the depreciation or amortization method and useful life applied to the common basis of that property, or treat that portion as nonamortizable, to the extent attributable to property the common basis of which is not amortizable, consistent with the regulations under Section 743 of the Internal Revenue Code. This method is consistent with the Treasury regulations applicable to property depreciable under the accelerated cost recovery system or the modified accelerated cost recovery system, which we expect will apply to substantially all, if not all, of our depreciable property. We also intend to use this method with respect to property that we own, if any, depreciable under Section 167 of the Internal Revenue Code, even though that position may be inconsistent with Treasury regulation Section 1.167(c)-1(a)(6). We do not expect Section 167 to apply to a material portion, if any, of our assets. Please read Tax Consequences of Unit Ownership Section 754 Election. To the extent that the Section 743(b) adjustment is attributable to appreciation in value in excess of the unamortized book-tax disparity, we will apply the rules described in the Treasury regulations and legislative history. If we determine that this position cannot reasonably be taken, we may adopt a depreciation and amortization position under which all purchasers acquiring units in the same month would receive depreciation and amortization deductions, whether attributable to a common basis or Section 743(b) adjustment, based upon the same applicable rate as if they had purchased a direct interest in our property. If we adopt this position, it may result in lower annual deductions than would otherwise be allowable to some common unitholders and risk the loss of depreciation and amortization deductions not taken in the year that these deductions are otherwise allowable. We will not adopt this position if we determine that the loss of depreciation and amortization deductions will have a material adverse effect on the common unitholders. If we choose not to utilize this aggregate method, we may use any other reasonable depreciation and amortization method to preserve the uniformity of the intrinsic tax characteristics of any units that would not have a material adverse effect on the common unitholders. Our counsel, Andrews Kurth LLP, is unable to opine on the validity of any of these positions. The IRS may challenge any method of depreciating the Section 743(b) adjustment described in this paragraph. If this challenge were sustained, the uniformity of units might be affected, and the gain from the sale of units might be increased without the benefit of additional deductions. Please read Disposition of Units Recognition of Gain or Loss.

Tax-Exempt Organizations and Other Investors

Ownership of units by employee benefit plans, other tax-exempt organizations, non-resident aliens, foreign corporations and other foreign persons raises issues unique to those investors and, as described below, may have substantially adverse tax consequences to them.

Employee benefit plans and most other organizations exempt from federal income tax, including individual retirement accounts and other retirement plans, are subject to federal income tax on unrelated business taxable income. Virtually all of our income allocated to a common unitholder that is a tax-exempt organization will be unrelated business taxable income and will be taxable to them.

A regulated investment company, or mutual fund, is required to derive at least 90% of its gross income from certain permitted sources. Income from the ownership of units in a qualified publicly traded partnership is generally treated as income from a permitted source. We expect that we will meet the definition of a qualified publicly traded partnership.

Non-resident aliens and foreign corporations, trusts or estates that own units will be considered to be engaged in business in the United States because of the ownership of units. As a consequence they will be required to file federal tax returns to report their share of our income, gain, loss or deduction and pay federal income tax at regular rates on their share of our net income or gain. Under rules applicable to publicly traded partnerships, we will withhold tax, at the highest effective applicable rate, from cash distributions made quarterly to foreign common unitholders. Each foreign common unitholder must obtain a taxpayer identification number from the IRS and submit that number to our transfer agent on a Form W-8 BEN or applicable substitute form in order to obtain credit for these withholding taxes. A change in applicable law may require us to change these procedures.

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In addition, because a foreign corporation that owns units will be treated as engaged in a United States trade or business, that corporation may be subject to the United States branch profits tax at a rate of 30%, in addition to regular federal income tax, on its share of our income and gain, as adjusted for changes in the foreign corporation s U.S. net equity, that is effectively connected with the conduct of a United States trade or business. That tax may be reduced or eliminated by an income tax treaty between the United States and the country in which the foreign corporate common unitholder is a qualified resident. In addition, this type of common unitholder is subject to special information reporting requirements under Section 6038C of the Internal Revenue Code.

Under a ruling issued by the IRS, a foreign common unitholder who sells or otherwise disposes of a unit will be subject to federal income tax on gain realized on the sale or disposition of that unit to the extent the gain is effectively connected with a United States trade or business of the foreign common unitholder. Apart from the ruling, a foreign common unitholder will not be taxed or subject to withholding upon the sale or disposition of a unit if he has owned less than 5% in value of the units during the five-year period ending on the date of the disposition and if the units are regularly traded on an established securities market at the time of the sale or disposition.

Administrative Matters

Information Returns and Audit Procedures

We intend to furnish to each common unitholder, within 90 days after the close of each calendar year, specific tax information, including a Schedule K-1, which describes his share of our income, gain, loss and deduction for our preceding taxable year. In preparing this information, which will not be reviewed by counsel, we will take various accounting and reporting positions, some of which have been mentioned earlier, to determine each common unitholder s share of income, gain, loss and deduction.

We cannot assure you that those positions will yield a result that conforms to the requirements of the Internal Revenue Code, Treasury regulations or administrative interpretations of the IRS. Neither we nor counsel can assure prospective common unitholders that the IRS will not successfully contend in court that those positions are impermissible. Any challenge by the IRS could negatively affect the value of the units.

The IRS may audit our federal income tax information returns. Adjustments resulting from an IRS audit may require each common unitholder to adjust a prior year s tax liability and possibly may result in an audit of his own return. Any audit of a common unitholder s return could result in adjustments not related to our returns as well as those related to our returns.

Partnerships generally are treated as separate entities for purposes of federal tax audits, judicial review of administrative adjustments by the IRS and tax settlement proceedings. The tax treatment of partnership items of income, gain, loss and deduction are determined in a partnership proceeding rather than in separate proceedings with the partners. The Internal Revenue Code requires that one partner be designated as the Tax Matters Partner for these purposes. The limited liability company agreement appoints CEPM as our Tax Matters Partner, subject to redetermination by our board of managers from time to time.

The Tax Matters Partner will make some elections on our behalf and on behalf of common unitholders. In addition, the Tax Matters Partner can extend the statute of limitations for assessment of tax deficiencies against common unitholders for items in our returns. The Tax Matters Partner may bind a common unitholder with less than a 1% profits interest in us to a settlement with the IRS unless that common unitholder elects, by filing a statement with the IRS, not to give that authority to the Tax Matters Partner. The Tax Matters Partner may seek judicial review, by which all the common unitholders are bound, of a final partnership administrative adjustment and, if the Tax Matters Partner fails to seek judicial review, judicial review may be sought by any common unitholder having at least a 1% interest in profits or by any group of common unitholders having in the aggregate at least a 5% interest in profits. However, only one action for judicial review will go forward, and each common unitholder with an interest in the outcome may participate.

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A common unitholder must file a statement with the IRS identifying the treatment of any item on his federal income tax return that is not consistent with the treatment of the item on our return. Intentional or negligent disregard of this consistency requirement may subject a holder of common units to substantial penalties.

Nominee Reporting

Persons who hold an interest in us as a nominee for another person are required to furnish to us:

- the name, address and taxpayer identification number of the beneficial owner and the nominee;
- a statement regarding whether the beneficial owner is:
  - a person that is not a United States person,
  - a foreign government, an international organization or any wholly owned agency or instrumentality of either of the foregoing, or
  - a tax-exempt entity;
- the amount and description of units held, acquired or transferred for the beneficial owner; and
- specific information including the dates of acquisitions and transfers, means of acquisitions and transfers, and acquisition cost for purchases, as well as the amount of net proceeds from sales.

Brokers and financial institutions are required to furnish additional information, including whether they are United States persons and specific information on units they acquire, hold or transfer for their own account. A penalty of $50 per failure, up to a maximum of $100,000 per calendar year, is imposed by the Internal Revenue Code for failure to report that information to us. The nominee is required to supply the beneficial owner of the units with the information furnished to us.

Accuracy-related Penalties

An additional tax equal to 20% of the amount of any portion of an underpayment of tax that is attributable to one or more specified causes, including negligence or disregard of rules or regulations, substantial understatements of income tax and substantial valuation misstatements, is imposed by the Internal Revenue Code. No penalty will be imposed, however, for any portion of an underpayment if it is shown that there was a reasonable cause for that portion and that the taxpayer acted in good faith regarding that portion.

A substantial understatement of income tax in any taxable year exists if the amount of the understatement exceeds the greater of 10% of the tax required to be shown on the return for the taxable year or $5,000. The amount of any understatement subject to penalty generally is reduced if any portion is attributable to a position adopted on the return:

- for which there is, or was, substantial authority, or
- as to which there is a reasonable basis and the relevant facts of that position are disclosed on the return.

We believe we will not be classified as a tax shelter. If any item of income, gain, loss or deduction included in the distributive shares of common unitholders could result in that kind of an understatement of income for which no substantial authority exists, we would be required to disclose the pertinent facts on our return. In addition, we will make a reasonable effort to furnish sufficient information for common unitholders to make adequate disclosure on their returns to avoid liability for this penalty. More stringent rules would apply to an understatement of tax resulting from ownership of units if we were classified as a tax shelter.

A substantial valuation misstatement exists if the value of any property, or the adjusted basis of any property, claimed on a tax return is 200% or more of the amount determined to be the correct amount of the

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valuation or adjusted basis. No penalty is imposed unless the portion of the underpayment attributable to a substantial valuation misstatement exceeds $5,000 ($10,000 for a corporation other than an S Corporation or a personal holding company). If the valuation claimed on a return is 400% or more than the correct valuation, the penalty imposed increases to 40%.

Reportable Transactions

If we were to engage in a reportable transaction, we (and possibly you and others) would be required to make a detailed disclosure of the transaction to the IRS. A transaction may be a reportable transaction based upon any of several factors, including the fact that it is a type of transaction publicly identified by the IRS as a listed transaction or that it produces certain kinds of losses in excess of $2 million. Our participation in a reportable transaction could increase the likelihood that our federal income tax information return (and possibly your tax return) is audited by the IRS. Please read Information Returns and Audit Procedures above.

Moreover, if we were to participate in a listed transaction or a reportable transaction (other than a listed transaction) with a significant purpose to avoid or evade tax, you could be subject to the following provisions of the American Jobs Creation Act of 2004:

- accuracy-related penalties with a broader scope, significantly narrower exceptions, and potentially greater amounts than described above at Accuracy-related Penalties,

- for those persons otherwise entitled to deduct interest on federal tax deficiencies, nondeductibility of interest on any resulting tax liability, and

- in the case of a listed transaction, an extended statute of limitations.

We do not expect to engage in any reportable transactions.

State, Local and Other Tax Considerations

In addition to federal income taxes, you will be subject to other taxes, including state and local income taxes, unincorporated business taxes, and estate, inheritance or intangible taxes that may be imposed by the various jurisdictions in which we do business or own property or in which you are a resident. We currently do business and own property in Maryland and Alabama. We may also own property or do business in other states in the future. Although an analysis of those various taxes is not presented here, each prospective common unitholder should consider their potential impact on his investment in us. You may not be required to file a return and pay taxes in some states because your income from that state falls below the filing and payment requirement. You will be required, however, to file state income tax returns and to pay state income taxes in many of the states in which we may do business or own property, and you may be subject to penalties for failure to comply with those requirements. In some states, tax losses may not produce a tax benefit in the year incurred and also may not be available to offset income in subsequent taxable years. Some of the states may require us, or we may elect, to withhold a percentage of income from amounts to be distributed to a common unitholder who is not a resident of the state. Withholding, the amount of which may be greater or less than a particular common unitholder s income tax liability to the state, generally does not relieve a nonresident common unitholder from the obligation to file an income tax return. Amounts withheld may be treated as if distributed to common unitholders for purposes of determining the amounts distributed by us. Please read Tax Consequences of Unit Ownership Entity-Level Collections. Based on current law and our estimate of our future operations, we anticipate that any amounts required to be withheld will not be material.

It is the responsibility of each common unitholder to investigate the legal and tax consequences, under the laws of pertinent states and localities, of his investment in us. Andrews Kurth LLP has not rendered an opinion on the state local, or foreign tax consequences of an investment in us. We strongly recommend that each prospective common unitholder consult, and depend on, his own tax counsel or other advisor with regard to those matters. It is the responsibility of each common unitholder to file all tax returns, that may be required of him.

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INVESTMENT IN OUR COMPANY BY EMPLOYEE BENEFIT PLANS

An investment in us by an employee benefit plan is subject to additional considerations because the investments of these plans are subject to the fiduciary responsibility and prohibited transaction provisions of ERISA and restrictions imposed by Section 4975 of the Internal Revenue Code. For these purposes, the term employee benefit plan includes, but is not limited to, qualified pension, profit sharing and stock bonus plans, Keogh plans, simplified employee pension plans and tax deferred annuities or IRAs established or maintained by an employer or employee organization. Among other things, the person with investment discretion with respect to the assets of an employee benefit plan, often called a fiduciary, should consider:

- whether the investment is prudent under Section 404(a)(1)(B) of ERISA;
- whether in making the investment, that plan will satisfy the diversification requirements of Section 404(a)(l)(C) of ERISA; and
- whether the investment will result in recognition of unrelated business taxable income by the plan and, if so, the potential after tax investment return.

A plan fiduciary should determine whether an investment in us is authorized by the appropriate governing instrument and is a proper investment for the plan.

Section 406 of ERISA and Section 4975 of the Internal Revenue Code prohibits employee benefit plans, and IRAs that are not considered part of an employee benefit plan, from engaging in specified transactions involving plan assets with parties that are parties in interest under ERISA or disqualified persons under the Internal Revenue Code with respect to the plan.

In addition to considering whether the purchase of common units is a prohibited transaction, a fiduciary of an employee benefit plan should consider whether the plan will, by investing in us, be deemed to own an undivided interest in our assets, with the result that CEPM also would be a fiduciary of the plan and our operations would be subject to the regulatory restrictions of ERISA, including its prohibited transaction rules, as well as the prohibited transaction rules of the Internal Revenue Code.

The Department of Labor regulations provide guidance with respect to whether the assets of an entity in which employee benefit plans acquire equity interests would be deemed plan assets under some circumstances. Under these regulations, an entity s assets would not be considered to be plan assets if, among other things:

- the equity interests acquired by employee benefit plans are publicly offered securities i.e., the equity interests are widely held by 100 or more investors independent of the issuer and each other, freely transferable and registered under some provisions of the federal securities laws;
- the entity is an operating company, i.e., it is primarily engaged in the production or sale of a product or service other than the investment of capital either directly or through a majority owned subsidiary or subsidiaries; or

there is no significant investment by benefit plan investors, which is defined to mean that less than 25% of the value of each class of equity interest, disregarding some interests held by CEPM, its affiliates, and some other persons, is held by the employee benefit plans referred to above, IRAs and other employee benefit plans not subject to ERISA, including governmental plans.

Our assets should not be considered plan assets under these regulations because it is expected that the investment will satisfy the requirements in the first bullet above.

Plan fiduciaries contemplating a purchase of our common units should consult with their own counsel regarding the consequences under ERISA and the Internal Revenue Code in light of the serious penalties imposed on persons who engage in prohibited transactions or other violations.

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UNDERWRITING

Citigroup Global Markets Inc. and Lehman Brothers Inc. are acting as joint bookrunning managers of this offering, and are acting as representatives of the underwriters named below. Subject to the terms and conditions stated in the underwriting agreement dated the date of this prospectus, each of the underwriters named below has severally agreed to purchase, and we have agreed to sell to that underwriter, the number of common units set forth opposite the underwriter s name.

Underwriters	Number of Common Units
Citigroup Global Markets Inc.	
Lehman Brothers Inc.	
UBS Securities LLC	
Wachovia Capital Markets, LLC	
Scotia Capital (USA) Inc.	
Total	6,275,000

The underwriting agreement provides that the obligations of the underwriters to purchase the common units included in this offering are subject to approval of legal matters by counsel and to other conditions. The underwriters are obligated to purchase all the common units (other than those covered by the option to purchase additional common units described below) if they purchase any of the common units.

The underwriters propose to offer some of the common units directly to the public at the public offering price set forth on the cover page of the prospectus and some of the common units to dealers at the public offering price less a concession not to exceed $ per common unit. The underwriters may allow, and dealers may reallow, a concession not to exceed $ per common unit on our sales to other dealers. If all of the common units are not sold at the initial offering price, the representative may change the public offering price and the other selling terms. The representative has advised us that the underwriters do not intend sales to discretionary accounts to exceed 5% of the total number of our common units offered by them.

We have granted to the underwriters an option, exercisable for 30 days from the date of this prospectus, to purchase up to 941,250 additional common units at the public offering price less the underwriting discount. The underwriters may exercise the option solely for the purpose of covering over-allotments, if any, in connection with this offering. To the extent the option is exercised, each underwriter must purchase a number of additional common units approximately proportionate to that underwriter s initial purchase commitment.

We, our officers and managers and CEPH and CEPM have agreed that, for a period of 180 days from the date of this prospectus, we and they will not, without the prior written consent of Citigroup Global Markets Inc. and Lehman Brothers Inc., dispose of or hedge or make any demand for or exercise any right to file or cause to be filed a registration statement with respect to the registration of any of our common units or any securities convertible into or exchangeable for our common units.

Citigroup Global Markets Inc. and Lehman Brothers Inc., in their discretion, may release any of the securities subject to these lock-up agreements at any time without notice. Factors in deciding whether to release these units may include the length of time before the particular lock-up expires, the number of common units involved, historical trading volumes of our common units and whether the person seeking the release is our officer, manager or affiliate.

The 180-day restricted period described in the preceding paragraph will be extended if:

- during the last 17 days of the 180-day restricted period we issue an earnings release or announce material news or a material event; or

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prior to the expiration of the 180-day restricted period, we announce that we will release earnings results during the 16-day period beginning on the last day of the 180-day restricted period,

in which case the restrictions described in the preceding paragraph will continue to apply until the expiration of the 18-day period beginning on the issuance of the earnings release or the announcement of the material news or event.

Prior to this offering, there has been no public market for our common units. Consequently, the initial public offering price for the common units will be determined by negotiations between us and the representatives. Among the factors considered in determining the initial public offering price will be our record of operations, our current financial condition, our future prospects, our markets, the economic conditions in and future prospects for the industry in which we compete, our management and currently prevailing general conditions in the equity securities markets, including current market valuations of publicly traded companies considered comparable to our company. We cannot assure you, however, that the prices at which our common units will sell in the public market after this offering will not be lower than the initial public offering price or that an active trading market in our common units will develop and continue after this offering.

The following table shows the underwriting discounts and commissions that we are to pay to the underwriters in connection with this offering. These amounts are shown assuming both no exercise and full exercise of the underwriters option to purchase additional common units.

	No Exercise	Full Exercise
Per common unit		
Total		

In connection with the offering, the underwriters may purchase and sell common units in the open market. These transactions may include short sales, syndicate covering transactions and stabilizing transactions. Short sales involve syndicate sales of common units in excess of the number of common units to be purchased by the underwriters in the offering, which creates a syndicate short position. Covered short sales are sales of common units made in an amount up to the number of common units represented by the underwriters option to purchase additional common units. In determining the source of common units to close out the covered syndicate short position, the underwriters will consider, among other things, the price of common units available for purchase in the open market as compared to the price at which they may purchase common units through the option to purchase additional common units. Transactions to close out the covered syndicate short involve either purchases of the common units in the open market after the distribution has been completed or the exercise of the option to purchase additional common units. The underwriters may also make naked short sales of common units in excess of their option to purchase additional common units. The underwriters must close out any naked short position by purchasing common units in the open market. A naked short position is more likely to be created if the underwriters are concerned that there may be downward pressure on the price of the common units in the open market after pricing that could adversely affect investors who purchase in the offering. Stabilizing transactions consist of bids for or purchases of common units in the open market while the offering is in progress.

The underwriters also may impose a penalty bid. Penalty bids permit the underwriters to reclaim a selling concession from a syndicate member when an underwriter repurchases common units originally sold by that syndicate member in order to cover syndicate short positions or make stabilizing purchases.

Any of these activities may have the effect of preventing or retarding a decline in the market price of the common units. They may also cause the price of the common units to be higher than the price that would otherwise exist in the open market in the absence of these transactions. The underwriters may conduct these transactions on the NYSE Arca or in the over-the-counter market, or otherwise. If the underwriters commence any of these transactions, they may discontinue them at any time.

We have applied to list our common units on NYSE Arca under the symbol CEP.

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In addition, we will pay Citigroup Global Markets Inc. and Lehman Brothers Inc. a structuring fee equal to __% of the gross proceeds of this offering for evaluation, analysis and structuring of our company.

The expenses of the offering that are payable by us are estimated to be approximately $3.2 million (exclusive of underwriting discounts and the structuring fee). The underwriters have agreed to reimburse us for a portion of these expenses in an amount of up to approximately $.

In no event will the maximum amount of compensation to be paid to NASD members in connection with this offering exceed 10% of the gross proceeds (plus 0.5% for bona fide, accountable due diligence expenses).

The underwriters may, from time to time, engage in transactions with and perform services for us in the ordinary course of their business. Affiliates of each of Citigroup Global Markets, Inc., Lehman Brothers Inc., UBS Securities LLC, Wachovia Capital Markets, LLC and Scotia Capital (USA) Inc. are lenders under Constellation s credit facility. Additionally, affiliates of each of UBS Securities LLC, Wachovia Capital Markets, LLC and Scotia Capital (USA) Inc. are expected to be lenders under our new reserve-based credit facility.

A prospectus in electronic format may be made available on the websites maintained by one or more of the underwriters. The representatives may agree to allocate a number of common units to underwriters for sale to their online brokerage account holders. The representative will allocate common units to underwriters that may make Internet distributions on the same basis as other allocations. In addition, common units may be sold by the underwriters to securities dealers who resell common units to online brokerage account holders.

Other than the prospectus in electronic format, the information on any underwriter s web site and any information contained in any other web site maintained by an underwriter is not part of the prospectus or the registration statement of which this prospectus forms a part, has not been approved and/or endorsed by us or any underwriter in its capacity as an underwriter and should not be relied upon by investors.

We and CCG have agreed to indemnify the underwriters against certain liabilities, including liabilities under the Securities Act and to contribute to payments the underwriters may be required to make because of any of those liabilities.

Because the National Association of Securities Dealers, Inc. views the common units offered by this prospectus as interests in a direct participation program, the offering is being made in compliance with Rule 2810 of the NASD s Conduct Rules. Investor suitability with respect to the common units should be judged similarly to the suitability with respect to other securities that are listed for trading on a national securities exchange.

If you purchase any units offered in this prospectus, you may be required to pay stamp taxes and other charges under the laws and practices of the country of purchase, in addition to the offering price listed on the cover page of this prospectus.

VALIDITY OF THE UNITS

The validity of the common units will be passed upon for us by Andrews Kurth LLP, Houston, Texas. Certain legal matters in connection with the common units offered by us will be passed upon for the underwriters by Vinson & Elkins L.L.P., New York, New York.

EXPERTS

The financial statements of Constellation Energy Partners LLC as of December 31, 2005 and for the period February 7, 2005 (inception) through December 31, 2005 and of Everlast Energy LLC as of December 31, 2004 and for the period January 1, 2005 through June 12, 2005 and for each of the two years in the periods ended December 31, 2004 appearing in this Prospectus have been so included in reliance on the reports of PricewaterhouseCoopers LLP, an independent registered public accounting firm, given on the authority of such firm as experts in auditing and accounting.

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Certain information included in this prospectus regarding our estimated quantities of natural gas reserves was prepared by Netherland, Sewell & Associates, Inc.

WHERE YOU CAN FIND MORE INFORMATION

We have filed with the Securities and Exchange Commission, or the SEC, a registration statement on Form S 1 regarding the common units. This prospectus does not contain all of the information found in the registration statement. For further information regarding us and the common units offered by this prospectus, you may desire to review the full registration statement, including its exhibits and schedules, filed under the Securities Act. The registration statement of which this prospectus forms a part, including its exhibits and schedules, may be inspected and copied at the public reference room maintained by the SEC at 100 F Street, N.E., Room 1580, Washington, D.C. 20549. Copies of the materials may also be obtained from the SEC at prescribed rates by writing to the public reference room maintained by the SEC at 100 F Street, N.E., Room 1580, Washington, D.C. 20549. You may obtain information on the operation of the public reference room by calling the SEC at 1 800 SEC 0330. The SEC maintains a web site on the Internet at http://www.sec.gov. Our registration statement, of which this prospectus constitutes a part, can be downloaded from the SEC s web site.

We intend to furnish our unitholders annual reports containing our audited financial statements and furnish or make available quarterly reports containing our unaudited interim financial information for the first three fiscal quarters of each of our fiscal years.

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REPORTS OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Member 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 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, 2005 and the results of their operations and their cash flows for 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 CEP s management. Our responsibility is to express an opinion on these financial statements based on our audit. We conducted our audit 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 audit provides a reasonable basis for our opinion.

/s/ PricewaterhouseCoopers LLP

PricewaterhouseCoopers LLP

Baltimore, Maryland

June 12, 2006

To the Member 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 each of the two years 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 years ended December 31, 2004 and 2003.

As discussed in Note 6, Everlast changed its method of accounting for outstanding preferred units that were subject to mandatory redemption in 2003.

/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			Predecessor		
	CEP			Everlast		
	For the period from February 7, 2005 (inception) to December 31, 2005	For the period February 7, 2005 (inception) to June 30, 2005	Six months ended June 30, 2006	For the year ended December 31, 2003 As Restated (see Note 2)	For the year ended December 31, 2004 As Restated (see Note 2)	For the period from January 1, 2005 to June 12, 2005
		Unaudited	Unaudited			
	(In '000's except unit data)			(In '000's except unit data)		
Revenues						
Gas sales	$ 25,957	$ 1,377	$ 17,605	$ 22,320	$ 27,494	$ 12,882
Loss from mark-to-market activities (see Note 5)				(3,664)	(9,107)	(15,313)
Total revenues	25,957	1,377	17,605	18,656	18,387	(2,431)
Expenses:						
Operating expenses:						
Lease operating expenses	4,175	357	3,495	4,428	5,270	2,769
Production taxes	1,400	72	909	1,279	1,479	676
General and administrative	4,184	3,275	2,731	1,945	2,706	594
Depreciation, depletion, and amortization	4,176	350	3,811	3,684	3,719	1,683
Accretion expense	78	7	71	73	86	46
Total operating expenses	14,013	4,061	11,017	11,409	13,260	5,768
Other expense/(income)						
Interest expense/(income), net	3		(197)	1,961	3,028	2,437
Organization costs				299		
Total other expenses/(income)	3		(197)	2,260	3,028	2,437
Total expenses	14,016	4,061	10,820	13,669	16,288	8,205
Net income (loss)	$ 11,941	$ (2,684)	$ 6,785	$ 4,987	$ 2,099	$ (10,636)
Other comprehensive income			914			
Comprehensive income (loss)	$ 11,941	$ (2,684)	$ 7,699	$ 4,987	$ 2,099	$ (10,636)
Pro forma earnings per unit (unaudited)						

(See Note 1)		
Earnings per unit	$ 0.81	$ 0.45
Pro forma units outstanding	14,711,498	14,969,298

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

	Successor			Predecessor
	CEP			Everlast
	December 31, 2005	June 30, 2006	Pro Forma June 30, 2006 (see Note 3)	December 31, 2004 As Restated (see Note 2)
		Unaudited (In '000's)	Unaudited	(In '000's)
Assets				
Current assets				
Cash and cash equivalents	$ 14,831	$ 3,880	$ 3,880	$ 2,012
Accounts receivable	5,824	3,955	3,955	3,824
Investment in affiliate cash pool		12,199	12,199	
Prepaid expenses	62	137	137	19
Risk management assets		603	603	719
Other	211	1,018	1,018	
Total current assets	20,928	21,792	21,792	6,574
Natural gas properties (See Note 8)				
Natural gas properties and related equipment (successful efforts accounting method)				
Natural gas properties and equipment	143,605	150,341	150,341	
Support equipment and facilities	25,070	25,637	25,637	
Material and supplies	712	1,291	1,291	
Natural gas properties and related equipment (full cost accounting method)				
Properties being amortized				59,651
Properties not being amortized				283
Less accumulated depreciation, depletion and amortization	(4,176)	(7,987)	(7,987)	(7,403)
Net natural gas properties	165,211	169,282	169,282	52,531
Other assets				
Loan costs (net of accumulated amortization of $685 at December 31, 2004)				1,579
Risk management assets		311	311	
Total assets	$ 186,139	$ 191,385	$ 191,385	$ 60,684
Liabilities and members' equity (deficit)				
Liabilities				
Current liabilities				
Accounts payable	$ 5,179	$ 2,992	$ 2,992	$ 1,901
Accrued liabilities	5,483	5,812	5,812	552

Royalty payable	3,233	1,993	1,993	2,029
Dividends payable			135,977	
Total current liabilities	13,895	10,797	146,774	4,482
Other liabilities				
Asset retirement obligation	2,524	2,609	2,609	1,052
Mark-to-market derivatives liabilities				2,262
Environmental liabilities	490	490	490	
Debt	63	52	52	67,500
Total other liabilities	3,077	3,151	3,151	70,814
Total liabilities	16,972	13,948	149,925	75,296
Members equity (deficit)				
Common members equity (deficit)	169,167	176,523	40,546	(14,612)
Accumulated other comprehensive income		914	914	
Total members' equity (deficit)	169,167	177,437	41,460	(14,612)
Total liabilities and members' equity (deficit)	$ 186,139	$ 191,385	$ 191,385	$ 60,684

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			Predecessor		
	CEP			Everlast		
	For the period from February 7, 2005 (inception) to December 31, 2005	For the period February 7, 2005 (inception) to June 30, 2005	Six months ended June 30, 2006	For the year ended December 31, 2003 As Restated (see Note 2)	For the year ended December 31, 2004 As Restated (see Note 2)	For the period from January 1, 2005 to June 12, 2005
		Unaudited (In '000's)	Unaudited		(In '000's)	
Cash flows from operating activities:						
Net income (loss)	$ 11,941	$ (2,684)	$ 6,785	$ 4,987	$ 2,099	$ (10,636)
Adjustments to reconcile net income (loss) to cash provided by operating activities:						
Expenses paid by CCG on behalf of CEP	64		571			
Depletion, depreciation and amortization	4,176	350	3,811	3,684	3,719	1,683
Amortization of debt issuance costs				288	685	237
Accretion of return on preferred member units				656	432	
Accretion of plugging and abandonment liability	78	7	71	73	86	46
Changes in Assets and Liabilities:						
Increase (decrease) in net mark-to-market activities				(512)	(2,156)	15,265
(Increase) decrease in accounts receivable	(1,289)	1,535	1,869	(1,547)	(2,278)	(707)
(Increase) decrease in prepaid expenses	(62)	(21)	(75)	(265)	246	(131)
(Increase) in other current assets	(211)		(807)			(7,035)
Increase in deposit on sale of properties						7,025
Increase (decrease) in accounts payable	1,703	(863)	(2,187)	908	993	807
Increase (decrease) in accrued liabilities	5,054	4,243	7	180	372	(25)
Increase (decrease) in royalty payable	1,859	364	(1,240)	1,321	708	110
Net cash provided by operating activities	23,313	2,931	8,805	9,773	4,906	6,639
Cash flows from investing activities:						
Acquisition of natural gas properties	(138,951)	(138,951)	(261)	(45,851)	(1,304)	(201)
Development of natural gas properties	(8,286)	(406)	(7,285)	(2,040)	(5,680)	(4,000)
Investment in affiliate cash pool			(12,199)			
Other, net				59	(13)	(2)
Net cash used in investing activities	(147,237)	(139,357)	(19,745)	(47,832)	(6,997)	(4,203)
Cash flows from financing activities:						
Members contribution (distributions)	138,770	138,770		1	(21,102)	
Preferred members contributions (redemptions)				15,500	(17,184)	
Proceeds from issuance of debt				30,500	48,000	

Repayment of debt	(15)		(11)	(4,500)	(6,500)	(2,500)
Loan costs				(879)	(1,674)	
Net cash provided by (used in) financing activities	138,755	138,770	(11)	40,622	1,540	(2,500)
Net increase (decrease) in cash	14,831	2,344	(10,951)	2,563	(551)	(64)
Cash and cash equivalents, beginning of period			14,831		2,563	2,012
Cash and cash equivalents, end of period	$ 14,831	$ 2,344	$ 3,880	$ 2,563	$ 2,012	$ 1,948
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			893		
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					
Derivative liabilities assumed by Everlast as part of the acquisition from Torch				4,210		
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	64		571			
Accretion of distributions to preferred members				597		
Cash paid during the period for interest	$ 3	$	$ 2	$ 808	$ 1,484	$ 2,196

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

	Common Members
	(In '000's)
CEP (Successor)	
Contributions	$ 157,226
Net income	11,941
Balance, December 31, 2005	169,167
Contributions (unaudited)	571
Other comprehensive income (unaudited)	914
Net income (unaudited)	6,785
Balance, June 30, 2006 (unaudited)	$ 177,437
Everlast (Predecessor) (as restated, see Note 2)	
Initial contributions common members	$ 1
Initial contributions preferred members	15,500
Reclass to shares subject to mandatory redemption as required by SFAS No. 150 (see Note 6)	(16,097)
Net income	4,987
Balance, December 31, 2003	4,391
Distributions	(21,102)
Net income	2,099
Balance, December 31, 2004	$ (14,612)

See accompanying notes to consolidated financial statements.

CONSTELLATION ENERGY PARTNERS LLC AND SUBSIDIARIES

AND EVERLAST ENERGY LLC AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

INTERIM INFORMATION AS OF JUNE 30, 2006 AND FOR THE

PERIODS ENDED JUNE 30, 2006 AND 2005 IS UNAUDITED

(1) SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

(a) 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 wholly owned subsidiary of Constellation Energy Commodities Group, Inc. (CCG) and 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 II Production LLC (Production), Robinson s Bend II Operating LLC (Operating) and Robinson s Bend II Marketing 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.

(b) Unaudited Interim Financial Information

The accompanying unaudited consolidated balance sheet as of June 30, 2006, unaudited consolidated statements of operations and comprehensive income (loss) and cash flows for the six months ended June 30, 2006 and for the period from February 7, 2005 (inception) through June 30, 2005, and the unaudited consolidated statement of changes in members equity for the six months ended June 30, 2006 have been prepared in accordance with generally accepted accounting principles for interim financial information. Accordingly, they do not include all of the information and notes required by generally accepted accounting principles for complete

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CONSTELLATION ENERGY PARTNERS LLC AND SUBSIDIARIES

AND EVERLAST ENERGY LLC AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

financial statements. In the opinion of management, all adjustments, consisting of normal, recurring adjustments, considered necessary for a fair presentation have been included. The information disclosed in the notes to the consolidated financial statements for these periods is unaudited. Operating results for the six months ended June 30, 2006 are not necessarily indicative of the results that may be expected for the year ending December 31, 2006 or any future period.

(c) 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.

(d) 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 and Everlast placed its derivative financial instruments with financial institutions and other firms that its management believed had a high credit rating. 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 six months ended June 30, 2006, five customers accounted for approximately 31%, 27%, 18%, 13% and 11%, 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. For the year ended December 31, 2003, five customers accounted for approximately 19%, 18%, 18%, 17%, and 10%, respectively, of the gas sales revenues related to the Properties.

(e) Natural Gas Properties

(1) CEP

(a) 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 based on units-of-production. 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 17, proved reserves are estimated by CCG s internal reserve engineers, and are subject to future revisions when additional information becomes available.

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CONSTELLATION ENERGY PARTNERS LLC AND SUBSIDIARIES

AND EVERLAST ENERGY LLC AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

As described in Note 13, 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 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 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, 2005, the estimated undiscounted future cash flows for CEP s 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.

(b) 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 units-of-production method over the total proved developed reserves.

(c) 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.

(2) 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 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 natural gas properties. Upon the sale or disposition of 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 natural gas properties cannot exceed the present value of estimated future net revenues from proved 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 9) are assessed periodically to determine whether impairment has occurred. Appropriate valuation allowances

CONSTELLATION ENERGY PARTNERS LLC AND SUBSIDIARIES

AND EVERLAST ENERGY LLC AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

are established when necessary. No such allowance was required during the period from January 1, 2005 to June 12, 2005, and for the years ended December 31, 2004 and 2003.

Depletion, depreciation, and amortization of natural gas properties were computed using the units-of-production method based on estimated proved gas reserves.

(f) Natural Gas Reserve Quantities

(1) 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, 2005 is described in detail in Note 17.

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 eventually recovered.

(2) Everlast

Everlast s estimates of proved reserves were based on the quantities of natural gas and oil that engineering and geological analyses demonstrate, with reasonable certainty, to be recoverable from established reservoirs in the future under current operating and economic parameters. The proved reserve estimates of 162.2 Bcf for 2004 and 163.7 Bcf for 2003 were used to prepare the 2004 and 2003 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 and 2003 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 we use for financial statement preparation purposes. The reserve report prepared by NSAI for Everlast for year end 2003 while based on the SEC definition of proved reserves included different assumptions than those used by NSAI in preparing the 2005 estimate.

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 and 2003 in preparing the financial statements for year end 2004 and 2003.

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,

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CONSTELLATION ENERGY PARTNERS LLC AND SUBSIDIARIES

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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.

(g) 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.

(h) Derivatives and Hedging Activities

(1) CEP

As of December 31, 2005, CEP did not have any outstanding derivative positions.

On June 20, 2006, CEP entered into certain over-the-counter contracts to hedge approximately 85% of the cash flow from the sale of expected gas production from currently producing wells from October 2006 through December 2009. 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.

(2) Everlast

During 2003, 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 years ended December 31, 2004 and December 31, 2003.

In addition to the over-the-counter contracts, Everlast entered into one long-term, fixed price natural gas sales contract that expired December 31, 2003. This contract met the criteria of a derivative under SFAS No. 133.

(i) 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 14). CEP

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CONSTELLATION ENERGY PARTNERS LLC AND SUBSIDIARIES

AND EVERLAST ENERGY LLC AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

accounts for the NPI as an overriding royalty interest. This is consistent with how CEP accounts for the NPI for reserves purposes, similar to royalty payments. 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.

(j) 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.

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 as of June 30, 2006, June 30, 2005, December 31, 2005, June 12, 2005, December 31, 2004 or December 31, 2003.

(k) Income Taxes

CEP is a single-member liability company that is a disregarded entity for federal income tax purposes under Regulation 301.7701-3(b). That means, for Federal income tax purposes, CEP is accounted for as a division of CCG and does 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. If CEP were a separate taxpayer, income taxes for the period from February 7, 2005 (inception) to December 31, 2005, for the period from February 7, 2005 (inception) to June 30, 2005, and for the six months ended June 30, 2006 would have been $4.7 million, $1.1 million, and $2.7 million, respectively. As of December 31, 2005, the income tax basis of CEP s assets was $170.1 million.

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, December 31, 2004 and 2003, the income tax basis of Everlast s assets was $53.8 million, $55.9 million, and $54.7 million, respectively.

(l) 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,

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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 depletion, depreciation and amortization, and

disclosure of contingent assets and liabilities at the date of the financial statements of CEP and Everlast.

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.

(m) Earnings per Unit

CEP had one common member who held one common unit as of December 31, 2005 and June 30, 2006. Therefore, historical earnings per unit information is not meaningful. CEP intends to unitize the legal entity subsequent to the publishing of these audited financial statements but prior to the public offering. See discussion of the determination of pro forma earnings per unit below.

Historical Pro Forma Earnings per Unit (Unaudited)

In contemplation of a public offering, CEP has included an unaudited computation of pro forma earnings per unit. CEP expects to declare a distribution of approximately $136.0 million to CCG immediately prior to the proposed initial public offering. Because these distributions exceed net income for 2005 and the six months ended June 30, 2006, 6,201,798 and 6,459,598 units were added to the outstanding units to compute the unaudited pro forma basic and diluted earnings per unit for the period February 7, 2005 (inception) to December 31, 2005 and for the six months ended June 30, 2006, respectively. These units represent the incremental number of units at the expected offering price that would be required to fund the distribution to CCG in excess of each period s net income. The pro forma earnings per unit also includes the impact of the conversion of CEP s outstanding units into approximately 8,214,010 Class B units and 295,690 Class A units to be effective immediately prior to the public offering.

The following table sets forth the calculation of historical pro forma earnings per unit:

(In 000 s except earnings per unit)

	For the period February 7, 2005 (inception) to December 31, 2005	For the six months ended June 30, 2006
Net income	$ 11,941	$ 6,785
Unit conversion	8,510	8,510
Additional units issued	6,202	6,460
Total units	14,712	14,970
Pro forma earnings per unit	$ .81	$ .45

(n) Accounting Standards Adopted

In May 2005, the Financial Accounting Standards Board (FASB) issued SFAS No. 154, *Accounting Changes and Error Corrections A Replacement of APB Opinion No. 20 and FASB Statement No. 3*. This Statement requires retrospective application to prior periods financial statements of changes in accounting principle, unless it is impracticable to determine either the period-specific effects or the cumulative effect of the

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change. This Statement does not change the guidance for reporting the correction of an error in previously issued financial statements or a change in accounting estimate. The provisions of this Statement shall be effective for accounting changes and correction of errors made in fiscal years beginning after December 15, 2005. CEP is not able to assess at this time the future impact of this Statement on its financial results. CEP discusses 2004 and 2003 restatements in Note 2.

On April 4, 2005, the FASB issued FASB Staff Position (FSP) No. 19-1, *Accounting for Suspended Well Costs*. This Staff Position amends SFAS No. 19, *Financial Accounting and Reporting by Oil and Gas Producing Companies* and provides guidance about exploratory well costs to companies which use the successful efforts method of accounting. The position states that exploratory well costs should continue to be capitalized if: 1) a sufficient quantity of reserves are discovered in the well to justify its completion as a producing well and 2) sufficient progress is made in assessing the reserves and the well s economic and operating feasibility. If the exploratory well costs do not meet both of these criteria, these costs should be expensed, net of any salvage value. Additional annual disclosures are required to provide information about management s evaluation of capitalized exploratory well costs. In addition, the FSP requires annual disclosure of: 1) net changes from period to period of capitalized exploratory well costs for wells that are pending the determination of proved reserves, 2) the amount of exploratory well costs that have been capitalized for a period greater than one year after the completion of drilling and 3) an aging of exploratory well costs suspended for greater than one year with the number of wells it related to. Further, the disclosures should describe the activities undertaken to evaluate the reserves and the projects, the information still required to classify the associated reserves as proved and the estimated timing for completing the evaluation. The guidance in the FSP is required to be applied to the first reporting period beginning after April 4, 2005 on a prospective basis to existing and newly capitalized exploratory well costs. The adoption of this standard did not have a material impact on CEP s financial results.

On March 30, 2005, the FASB issued FASB Interpretation (FIN) No. 47, *Accounting for Conditional Asset Retirement Obligations*. This interpretation clarifies that the term conditional asset retirement obligation as used in SFAS No. 143 refers to a legal obligation to perform an asset retirement activity in which the timing and/or method of settlement are conditional on a future event that may or may not be within the control of the entity incurring the obligation. The obligation to perform the asset retirement activity is unconditional even though uncertainty exists about the timing and/or method of settlement. Thus, the timing and/or method of settlement may be conditional on a future event. Accordingly, an entity is required to recognize a liability for the fair value of a conditional asset retirement obligation if the fair value of the liability can be reasonably estimated. Uncertainty about the timing and/or method of settlement of a conditional asset retirement obligation should be factored into the measurement of the liability, rather than the timing of recognition of the liability, when sufficient information exists. FIN No. 47 was effective for CEP at the end of the fiscal year ended December 31, 2005. The adoption of this standard did not have a material impact on its financial results.

(o) Accounting Standards Issued but not Effective

In April 2006, the FASB issued 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 FASB Interpretation 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.

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(2) RESTATEMENT OF EVERLAST FINANCIAL STATEMENTS

The financial statements as of December 31, 2004 and for the two years 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.

In 2003 and 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 2003 and 2004 were adjusted to remove these proved undeveloped reserves. In 2003, Everlast s original accounting was based on a proved reserve estimate of 166.2 Bcf, while the revised accounting was based on a proved reserve estimate of 163.7 Bcf. Similarly, 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. These adjustments resulted in additional depletion expense and a reduction of net income of $0.7 million and $76,000 for the years ended December 31, 2003 and 2004, respectively, and an increase in accumulated depletion of $0.8 million at December 31, 2004.

In 2003 and 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 $57,000 and $70,000 for the years ended December 31, 2003 and 2004, respectively.

As part of CEP s cut-off procedures, CEP identified certain costs incurred in 2003 and 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 an increase in operating expenses and reduction of net income of $25,000 and $37,000 for the years ended December 31, 2003 and 2004, respectively.

In 2003, Everlast assumed one long term, fixed price natural gas sales contract in connection with the acquisition of the Properties from Torch. This contract met the definition of a derivative under SFAS No. 133

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and Everlast accounted for it by recording changes in the fair value of the contract to the income statement. Everlast s original accounting was to record in Gas sales the volumes sold at the current spot price and to record the difference between volumes sold at the spot price and volumes sold at the contractual price in Loss from mark-to-market activities. In addition, the change in the fair value of this contract in 2003 was originally recorded as a gain in Loss from mark-to-market activities. Since these contracts physically delivered and Everlast was paid the contractual amount, it was incorrect to recognize gas revenues at spot prices with an offset in loss from mark-to-market activities. Accordingly, the financial statements for the year-ended December 31, 2003 have been restated to record all activity related to this contract in Gas sales . This resulted in a reduction of gas sales by approximately $1.9 million, the net of these errors, and a corresponding reduction in loss from mark-to-market activities. There was no impact on total revenues or net income in 2003.

Indirect costs associated with acquiring business operations were capitalized by Everlast when it acquired the Properties in January 2003. These costs should have been included as operating costs in the accompanying financial statements and approximately $0.1 million has been expensed (with a corresponding reduction of net income) resulting in a decrease in Natural gas properties and related equipment (full cost accounting method)-properties being amortized.

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 and a reduction in operating expenses of $0.5 million has been recorded for the year ended December 31, 2003. This increased depletion expense by $13,000 in both periods presented. The impact of these corrections increased net income by $0.5 million in 2003, and decreased net income by $13,000 in 2004.

Certain of the Properties are subject to an NPI (see Notes 1 and 14). In 2003 and 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 $2.2 million and $2.1 million for the years ended December 31, 2003 and 2004, respectively. This restatement had no impact on net income for either 2003 or 2004. In addition, because reserves in those periods 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 two years ended December 31, 2004.

Statements of Operations

For the year ended December 31, 2004	As Previously Reported	Adjustments	As Restated
		(In 000 s)	
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	(206)	2,597
Total other expenses	2,803	(206)	2,597
Total expenses	13,754	2,103	15,857
Net income	$ 2,502	$ 28	$ 2,530

For the year ended December 31, 2003	As Previously Reported	Adjustments	As Restated
		(In 000 s)	
Revenues:			
Gas sales	$ 22,094	$ 226	$ 22,320
Loss from mark-to-market activities	(5,631)	1,967	(3,664)

Total revenues	16,463	2,193	18,656
Expenses:			
Operating Expenses:			
Lease operating expenses	3,205	1,223	4,428
Production taxes	781	498	1,279
General and administrative	1,806	139	1,945
Depreciation, depletion, and amortization	3,000	684	3,684
Accretion expense	16	57	73
Total operating expenses	8,808	2,601	11,409
Other expenses:			
Interest expense, net	1,306		1,306
Organization costs	299		299
Total other expenses	1,605		1,605
Total expenses	10,413	2,601	13,014
Net income	$ 6,050	$ (408)	$ 5,642

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Balance Sheet

December 31, 2004	As Previously Reported	Adjustments	As Restated
		(In 000 s)	
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)

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

For the year ended December 31, 2003	As Previously Reported	Adjustments	As Restated
		(In 000 s)	
Net cash provided by operating activities	$ 9,416	$ 357	$ 9,773
Net cash used in investing activities	(47,475)	(357)	(47,832)
Net cash provided by financing activities	40,622		40,622
Cash and cash equivalents, beginning of period			
Cash and cash equivalents, end of period	$ 2,563	$	$ 2,563

Statement of Members Equity

	As Previously Reported	Adjustments	As Restated
		(In 000 s)	
Balance, December 31, 2003	$ 21,553	$ (408)	$ 21,145
Distributions	(38,287)		(38,287)
Net income	2,502	28	2,530
Balance, December 31, 2004	$ (14,232)	$ (380)	$ (14,612)

The information in the tables above reflects the correction of errors in the 2003 and 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 6.

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(3) PRO FORMA BALANCE SHEET INFORMATION (UNAUDITED)

CEP intends to declare a dividend (currently estimated to be approximately $136.0 million) to its parent, CEPH, prior to closing of an initial public offering of CEP s common units. The net proceeds (after deducting underwriting discounts and commissions and expenses of the offering) of the initial public offering are expected to approximate $113.8 million. The net proceeds (less $7.8 million to be retained for working capital purposes) and borrowings under a reserve-based credit facility will be used to pay that dividend. The pro forma adjustments to the historical CEP balance sheet at June 30, 2006 reflects the accrual of the dividends payable (estimated to be $136.0 million) and resulting reduction in members equity to reflect the impact of the planned dividend, but not the proceeds of the initial public offering.

(4) ACQUISITIONS

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.

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

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On January 7, 2003, Everlast acquired the Properties from various affiliates of Torch Energy Corporation (the Torch Acquisition) for a gross purchase price of $43.0 million, before closing adjustments. Everlast utilized its credit facility to acquire the Properties (see Note 7). All costs were allocated to one amortization pool as Everlast used the full cost method of accounting.

On June 6, 2003, Everlast acquired additional properties in the Black Warrior Basin from Energen Resources Corporation. The gross purchase price was $0.7 million, before closing adjustments.

(5) DERIVATIVE AND FINANCIAL INSTRUMENTS

(a) Hedging Activities

CEP has hedged approximately 78% of its expected natural gas sales from currently producing wells from October 2006 to December 2009. The value of its cash flow hedges included in Accumulated other comprehensive income was a net unrealized gain of $0.9 million at June 30, 2006. CEP expects that $0.6 million will be reclassified from Accumulated other comprehensive income to the income statement in the next twelve months. There was no material ineffectiveness for the six months ended June 30, 2006.

(b) 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 7), 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.

At December 31, 2004, the carrying amount of Everlast s derivative instruments equaled their fair value.

(c) 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 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.

(6) 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

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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 and 2003, Everlast had $0 and $16.7 million, respectively, 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 and $0.7 million for the years ended December 31, 2004 and 2003, respectively.

(7) DEBT

On December 31, 2005, CEP had $63,000 in outstanding debt. This debt is an installment note securitized by a piece of equipment and was assumed as part of the acquisition of the Properties. It has an annual interest rate of 6.12% and matures on March 31, 2008.

On January 6, 2003, Everlast entered into a syndicated credit agreement (Credit Agreement) with Wells Fargo Bank of Texas, NA (Wells Fargo) and two other banks (together with Wells Fargo, the Banks), with Wells Fargo serving as administrative agent. Proceeds from the Credit Agreement were used to make the Torch Acquisition. Borrowings under the Credit Agreement were secured by mortgages covering substantially all of Everlast s producing natural gas properties. In accordance with the Credit Agreement, the Banks were paid various underwriting, administrative and advisory fees totaling $0.9 million.

In April 2003, Everlast entered into a five year note for the purchase of equipment (Equipment Note). Everlast made monthly payments with an effective interest rate of 6.12%. Upon acquisition of the Properties by CEP, the Equipment Note was assumed by CEP, who continues to make monthly payments according to the same terms. Future minimum payments remaining under the agreement are as follows:

	(In 000 s)

2006	$	30
2007		30
2008		8
Total payments	$	68
Less interest		5
Principal remaining	$	63

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 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

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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 July 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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(8) NATURAL GAS PROPERTIES

Natural gas properties consist of the following:

	Successor	Predecessor
	CEP	Everlast
	December 31, 2005	December 31, 2004
	(In 000 s)	(In 000 s)
Natural gas properties and related equipment (successful efforts method)		
Property (acreage) costs		
Proved property	$ 168,327	$
Unproved property	188	
Natural gas properties and related equipment (full cost method)		
Costs subject to amortization		59,651
Cost not subject to amortization		123
Total property costs	168,515	59,774
Materials and supplies	712	
Land	160	160
Total	169,387	59,934
Less: Accumulated depreciation, depletion and amortization	(4,176)	(7,403)
Natural gas properties and equipment, net	$ 165,211	$ 52,531

(9) NATURAL GAS PROPERTIES NOT SUBJECT TO AMORTIZATION

Everlast used the full cost method of accounting for its natural gas properties. Under full cost, if a determination can not be made about the extent of additional gas reserves and can not be attributed to certain capital costs, the costs are excluded from the depreciation base until gas reserve estimate can be made.

At December 31, 2004, acquisition costs of $0.1 million were excluded from the depreciation basis. These costs were related to potential acquisitions, and a determination could not be made about the extent of additional gas reserves that should have been classified as a result of the project. Consequently, the associated acquisition costs were excluded in computing amortization of the full cost pool. Everlast began to amortize these costs when the project was evaluated in 2005.

Everlast acquired 210 acres of land in fee simple at the gas field in Alabama. This land was the site of the compressors and the field office. The cost of this land was $0.2 million, and was excluded from the depreciation basis as land is not depreciated.

(10) BENEFIT PLANS

Eligible employees of CEP participate in pension, postretirement, other post employment, and savings plans sponsored and administered by Constellation Energy. Contributions by Constellation Energy were approximately $1,000 and $16,000 for the period from February 7, 2005 (inception) to December 31, 2005 and for the six

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months ended June 30, 2006, respectively. There were no costs allocated to CEP for the period February 7, 2005 (inception) to June 30, 2005.

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 and $18,000 for the years ended December 31, 2004 and 2003, respectively.

(11) RELATED PARTY TRANSACTIONS

CEP is 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 $0.4 million and $1.4 million for the period February 7, 2005 (inception) to December 31, 2005 and for the six months ended June 30, 2006, respectively. There were no costs allocated to CEP for the period February 7, 2005 (inception) to June 30, 2005. CEP had an intercompany payable to CCG of $0.4 million and $1.9 million as of December 31, 2005 and June 30, 2006, respectively. This intercompany payable balance is included in accrued liabilities in the accompanying balance sheets.

During six months ended June 30, 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 is administered and managed by CEP. CCG may borrow from the pool at market interest rates. If CEP requires cash, and CCG has an outstanding balance, CCG is required to immediately remit payment to CEP for the required cash amount. If the initial public offering by CEP is successfully completed, CEP will cease its participation in the cash pool arrangement contemporaneously with the closing of that offering. As of June 30, 2006, the amount borrowed by CCG from the cash pool was $12.2 million.

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.

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.

(12) 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, 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 14). The royalty payment to the Trust is calculated using a sharing arrangement with a pricing formula that has

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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 operatin