SECURITIES AND EXCHANGE COMMISSION

FORM 8-K

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Bonanza Creek Energy, Inc. CIK:**1509589**| IRS No.: **611630631** | State of Incorp.:**DE** | Fiscal Year End: **1231** Type: **8-K** | Act: **34** | File No.: **001-35371** | Film No.: **13550221** SIC: **1311** Crude petroleum & natural gas	Mailing Address *410 17TH STREET, SUITE 1500* *DENVER CO 80202*	Business Address *410 17TH STREET, SUITE 1500* *DENVER CO 80202* *720-440-6100*

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 8-K

CURRENT REPORT
Pursuant to Section 13 or 15(d) of the
Securities Exchange Act of 1934

January 28, 2013
Date of Report

Bonanza Creek Energy, Inc.

(Exact name of registrant as specified in its charter)

Delaware	**001-35371**	**61-1630631**
(State or other jurisdiction of incorporation or organization)	(Commission File No.)	(I.R.S. employer identification number)

410 17th Street, Suite 1400
Denver, Colorado 80202
(Address of principal executive offices, including zip code)

(720) 440-6100
(Registrant’ s telephone number, including area code)

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligations of the registrant under any of the following provisions:

☐ Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

☐ Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)

☐ Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))

☐ Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

Item 8.01 Other Events.

On August 31, 2012, Bonanza Creek Energy, Inc. (the "Company") sold its property in the Kern River field in California for approximately $5.1 million and recorded a gain on the sale of oil and gas properties in the amount of $4.3 million related to this transaction. On October 15, 2012, the Company sold its property in the Sargent field in California for approximately $3.2 million, approximately equal to its book value. On November 9, 2012, the Company sold its property in the Greeley field for approximately $1.1 million, approximately equal to its book value. As a result of these transactions, we classified the results of operations and financial position of these properties as discontinued operations for all periods presented.

This Current Report on Form 8-K was prepared to provide revised financial information that presents these properties as discontinued operations for all periods presented in our Annual Report on Form 10-K for the year ended December 31, 2011, filed on March 22, 2012 ("2011 Form 10-K"). It should be noted that our net income (loss) was not impacted by the reclassification of our operations with respect to these properties as discontinued operations.

This filing includes updated information for the following items included in our 2011 Form 10-K:

ITEM 6. SELECTED FINANCIAL DATA

ITEM 7. MANAGEMENT' S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Unaffected items of our 2011 Form 10-K have not been repeated in this Current Report on Form 8-K.

Item 9.01 Financial Statements and Exhibits

(d) Exhibits

23.1 Consent of Independent Registered Public Accounting Firm Hein & Associates LLP.

99.1 Item 6. Selected Financial Data.

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

99.3 Item 8. Financial Statements and Supplementary Data.

SIGNATURE

Pursuant to the requirements of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned hereunto duly authorized.

Bonanza Creek Energy, Inc.

Date: January 28, 2013	By:	/s/ Wade E. Jaques
		Wade E. Jaques
		Vice President, Chief Accounting Officer, Controller, & Treasurer

INDEX TO EXHIBITS

Exhibit Number	Description
23.1	Consent of Independent Registered Public Accounting Firm Hein & Associates LLP
99.1	Item 6. Selected Financial Data
99.2	Item 7. Management' s Discussion and Analysis of Financial Condition and Results of Operations
99.3	Item 8. Financial Statements and Supplementary Data

Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in the Registration Statements on Form S-3 of Bonanza Creek Energy, Inc. and subsidiaries and in the related Prospectuses of our report dated March 22, 2012, except for the third paragraph of Note 13 which is dated January 28, 2013, relating to our audits of the consolidated financial statements of Bonanza Creek Energy, Inc. and its subsidiaries as of December 31, 2011 and 2010, and for the year ended December 31, 2011 and the period from its inception (December 23, 2010) to December 31, 2010, and the Bonanza Creek Energy Company, LLC and subsidiaries (predecessor) consolidated financial statements for the period January 1, 2010 to December 23, 2010 and the year ended December 31, 2009, which appear in the Current Report on Form 8-K of Bonanza Creek Energy, Inc. and Subsidiaries dated January 28, 2013.

/s/ Hein & Associates LLP

Denver, Colorado
January 28, 2013

Exhibit 99.1

Item 6. *Selected Financial Data.*

The following tables set forth selected historical financial data of us and our predecessor, BCEC, as of and for the periods indicated. The consolidated statements of operations data for the years ended December 31, 2007 and 2008 are derived from audited consolidated financial statements of BCEC not included in this report. The consolidated audited financial statements of BCEC for the periods not included in this report were previously filed in BCEI' s Form S-1 (File No. 333-174765). The consolidated statement of operations data for the years ended December 31, 2009 and the period ended December 23, 2010 are derived from the audited consolidated financial statements of BCEC included elsewhere in this report. The consolidated statement of operations data for the eight day period ended December 31, 2010 and year ended December 31, 2011 are derived from the audited consolidated financial statements of BCEI included elsewhere in this report. The consolidated balance sheets data as of December 31, 2007, 2008 and 2009 are derived from the audited consolidated financial statements of BCEC, which are not included in this report. The consolidated audited financial statements of BCEC for the periods not included in this report were previously filed in BCEI' s Form S-1 (File No. 333-174765). The consolidated balance sheet data as of December 31, 2010 and 2011 is derived from our audited consolidated financial statements of BCEI included elsewhere in this report. In management' s opinion, the financial statements include all adjustments necessary for the fair presentation of our financial condition as of such date and our results of operations for such periods.

The summary unaudited pro forma statement of operations of Bonanza Creek Energy, Inc. for the year ended December 31, 2010 gives effect to our Corporate Restructuring as if it had occurred on January 1, 2010.

The selected historical financial data should be read in conjunction with "*Management' s Discussion and Analysis of Financial Condition and Results of Continuing Operations*" and both our and our predecessor' s financial statements and the notes to those financial statements included elsewhere in this Current Report on Form 8-K.

	Bonanza Creek Energy Company, LLC (Predecessor)				Bonanza Creek Energy, Inc.		
	2007	2008	2009	Period Ended December 23, 2010(1)	Period from Inception (December 23, 2010) to December 31, 2010	Year Ended December 31, 2011	Bonanza Creek Energy, Inc. Pro Forma 2010(2)
							(unaudited)
	(in thousands, except per share data)						
Statement of Operations Data:							
Revenues:							
Oil sales	$ 7,462	$ 27,171	$ 22,377	$ 29,608	$ 1,200	$ 79,568	$ 40,466
Natural gas sales	1,736	5,160	3,655	6,226	207	13,442	10,253
Natural gas liquids and CO_2 sales	821	2,782	3,169	7,672	213	12,714	8,365
Total revenues	10,019	35,113	29,201	43,506	1,620	105,724	59,084
Operating expenses:							
Lease operating	2,191	8,633	10,745	11,948	419	18,253	14,377
Severance and ad valorem taxes	514	1,439	1,984	1,468	66	5,918	2,368
Depreciation, depletion and amortization	3,529	11,065	12,594	12,598	436	28,014	18,856

General and administrative	4,752	7,477	7,610	8,375	324	13,164	9,339
Employee stock compensation(3)	–	–	–	–	–	4,449	–
Exploration	–	9	–	226	–	878	246
Impairment of oil and gas properties(4)	–	1,594	–	–	–	623	–
Cancelled private placement(5)	–	–	–	2,378	–	–	2,378
Total operating expenses	10,986	30,217	32,933	36,993	1,245	71,299	47,564
Income (loss) from operations	(967)	4,896	(3,732)	6,513	375	34,425	11,520
Other income (expense):							
Interest expense	(1,609)	(12,227)	(16,582)	(18,001)	(58)	(4,017)	(1,263)
Amortization of debt discount	(1,684)	(5,987)	(7,963)	(8,862)	–	–	–
Write off of deferred financing costs	–	–	–	(1,663)	–	–	(1,663)
Gain on sale of oil and gas properties	–	8	–	–	–	–	–
Unrealized gain (loss) in fair value of warrant put option(6)	(32,302)	70,972	(80,640)	34,345	–	–	–
Unrealized gain (loss) in fair value of commodity derivatives	(925)	48,716	(34,589)	(7,605)	(514)	225	(8,119)
Realized gain (loss) on settled commodity derivatives	26	1,913	13,451	5,919	(47)	(3,024)	5,872
Other income (loss)	(43)	(229)	(180)	19	–	(110)	(46)
Total other income (expense)	(36,537)	103,166	(126,503)	4,152	(619)	(6,926)	(5,219)
Income (loss) from continuing operations before taxes	(37,504)	108,062	(130,235)	10,665	(244)	27,499	6,301
Income tax benefit (expense)(7)	–	–	–	–	90	(12,890)	(2,319)
Income (loss) from continuing operations	(37,504)	108,062	(130,235)	10,665	(154)	14,609	3,982
Discontinued operations							
(Loss) income from operations associated with oil and gas properties held for sale (including impairments in 2008, 2009, and 2011 of $24.8 million, $0.6 million, and $3.4 million respectively)(4)	(2,856)	(39,308)	149	64	(13)	(3,610)	(312)
Gain on sale of oil and gas properties	–	–	303	4,055	–	–	4,055
Income tax (expense) benefit	–	–	–	–	5	1,692	(1,377)
(Loss) income from discontinued operations	(2,856)	(39,308)	452	4,119	(8)	(1,918)	2,366
Net income (loss)	$ (40,360)	$ 68,754	$ (129,783)	$ 14,784	$ (162)	$ 12,691	$ 6,348
Basic and Diluted Income Per Share(8)							
Income from continuing operations					$ –	$ 0.49	$ 0.14
Income from discontinued operations					$ –	$ (0.6)	$ 0.08
Net income per common share					$ –	$ 0.43	$ 0.22
Weight Average Shares Outstanding, Basic and Diluted					29,123	29,576	29,123

(1) We completed our Corporate Restructuring on December 23, 2010.

(2) The pro forma information above gives effect to our Corporate Restructuring as if it had occurred on January 1, 2010. See “–Unaudited Pro Forma Financial Data.”

(3) In connection with our IPO, the Company distributed 243,945 fully vested shares of common stock previously held in trust to our employees and recorded a $4.1 million stock compensation charge. In addition, the Company distributed the remaining 3,400 shares of our former Class B common stock to our employees. In connection with our IPO, all issued and outstanding shares of our former Class B Common Stock converted into 437,787 shares of restricted common stock, vesting over a three year period and we recorded a

$0.1 million stock compensation charge. We expect to recognize employee stock compensation expense relating to these grants during the years ended December 31, 2012, 2013, and 2014 of approximately $2.5 million, $2.5 million, and $2.3 million, respectively, assuming no forfeitures.

(4) The impairment for the year ended 2008 resulted from a write-down of the carrying value of our oil and natural gas reserves due to depressed year-end prices. The impairment for 2011 was related to steam flooding results in our legacy California assets that were lower than expected and the impairment of one non-core field in Southern Arkansas was related to the loss of a lease.

(5) Expenditures in connection with a cancelled private placement of our preferred stock.

(6) In connection with its purchase of our senior subordinated notes D.E. Shaw Synoptic Portfolios 5, L.L.C. received warrants to purchase equity interests in our predecessor. These warrants contained a put right exercisable beginning on May 17, 2014. The periods presented for our predecessor reflect the changes in the fair market value of that put option. The warrants and aggregate warrant exercise price were exchanged for shares of our common stock in connection with our Corporate Restructuring.

(7) Our predecessor, BCEC, was a partnership for federal income tax purposes and, therefore, was not subject to entity-level taxation. Our pro forma results reflect our taxation as a subchapter "C" corporation at an estimated combined state and federal income tax rate of 36.8%.

(8) As a limited liability company, ownership interests in our predecessor were held as units rather than shares.

	Bonanza Creek Energy Company, LLC (Predecessor)			Bonanza Creek Energy, Inc.	
	As of December 31,			As of December 31,	
	2007	2008	2009	2010	2011
			(in thousands)		
Balance Sheet Data:					
Cash and cash equivalents	$ –	$ 4,088	$ 2,522	$ –	$ 2,090
Property and equipment, net	51,093	182,976	177,126	481,374	618,229
Oil and gas properties held for sale, less accumulated depreciation and depletion	38,553	12,304	11,241	15,208	9,896
Total assets	97,044	241,625	211,552	516,104	664,349
Long term debt, including current portion:					
Credit facility	27,274	107,000	99,000	55,400	6,600
Senior subordinated notes, net of discount	51,561	75,499	92,442	–	–
Subordinated unsecured note	–	10,000	10,799	–	–
Warrant put options(1)	42,851	828	81,468	–	–
Total members' /stockholders' equity (deficit)	(33,566)	35,988	(93,795)	356,380	527,982

	Bonanza Creek Energy Company, LLC (Predecessor)				Bonanza Creek Energy, Inc.	
	Year Ended December 31,			Period Ended December 23, 2010(2)	Period from Inception (December 23, 2010) to December 31, 2010	Year Ended December 31, 2011
	2007	2008	2009			
			(in thousands)			
Other Financial Data:						

Net cash provided by (used in) operating activities	$ (561)	$ 11,128	$ 11,134	$ 22,759	$ (1,633)	$ 57,603
Net cash provided by (used in) investing activities	(43,265)	(79,581)	(7,185)	(32,127)	(817)	(158,902)
Net cash provided by (used in) financing activities	38,787	72,541	(5,515)	9,297	–	103,389

(1) The warrants and aggregate warrant exercise price were exchanged for shares of our common stock in connection with our Corporate Restructuring.

(2) We completed our Corporate Restructuring on December 23, 2010.

Unaudited Pro Forma Financial Information

We completed our Corporate Restructuring on December 23, 2010. The following unaudited pro forma financial information shows the pro forma effect of our Corporate Restructuring. We have not included a pro forma balance sheet since the effects of our Corporate Restructuring are reflected in the December 31, 2010 balance sheet included elsewhere in this Current Report on Form 8-K. The unaudited pro forma statement of operations for the year ended December 31, 2010 was prepared as if our Corporate Restructuring had occurred at January 1, 2010.

The accompanying financial information was from the historical accounting records. We made no additional pro forma adjustment to general and administrative expense since we were the operator of these properties prior to the acquisitions.

The following unaudited pro forma financial statements do not purport to represent what our actual results of operations would have been if this acquisition had occurred on January 1, 2010. The unaudited pro forma financial statements should be read in conjunction with our historical financial statements and related notes for the periods presented included elsewhere in this Current Report on Form 8-K.

	Bonanza Creek Energy Company, LLC Period Ended December 23, 2010	**Holmes Eastern Company, LLC Period Ended December 23, 2010**	**Bonanza Creek Energy, Inc. Period from Inception (December 23, 2010) to December 31, 2010**	**Pro Forma Adjustments (unaudited)**	**Bonanza Creek Energy, Inc. Year Ended December 31, 2010 (unaudited)**
	(in thousands, except per share data)				
Revenues:					
Oil, natural gas, natural gas liquids and CO_2 sales	$ 43,506	$ 13,958	$ 1,620	$ –	$ 59,084
Operating expenses:					
Lease operating	11,948	2,010	419	–	14,377
Severance and ad valorem taxes	1,468	834	66	–	2,368
Exploration	227	19	–	–	246
Depreciation, depletion and amortization(1)	12,598	3,006	436	2,816	18,856

General and administrative	8,375	640	324	–	9,339
Cancelled private placement	2,378	–	–	–	2,378
Total operating expenses	36,994	6,509	1,245	2,816	47,564
Income from operations	6,512	7,449	375	(2,816)	11,520
Other income (expense):					
Other income (loss)	19	(65)	–	–	(46)
Write off of deferred financing costs	(1,663)	–	–	–	(1,663)
Unrealized gain on fair value of warrant put option(2)	34,345	–	–	(34,345)	–
Amortization of debt discount(3)	(8,862)	–	–	8,862	–
Realized gain on settled commodity derivatives	5,919	–	(47)	–	5,872
Unrealized loss in fair value of commodity derivatives	(7,605)	–	(514)	–	(8,119)
Interest expense(4)	(18,001)	(439)	(57)	17,234	(1,263)
Total other income (expense)	4,152	(504)	(618)	(8,249)	(5,219)
Income (loss) from continuing operations	10,664	6,945	(243)	(11,065)	6,301
Pro forma income tax expense(5)				(2,319)	(2,319)
Income (loss) from continuing operations					$ 3,982
(Loss) income from operations associated with oil and gas properties held for sale	65	–	(13)	(364)	(312)
Gain on sale of oil and gas properties	4,055	–	–	–	4,055
Pro forma income tax (expense) benefit(5)	–	–	–	(1,377)	(1,377)
Income from discontinued operations	4,120	–	(13)	(1,741)	2,366
Net Income	$ 14,784	$ 6,945	$ (256)	$ (15,125)	$ 6,348
Basic and diluted income per share					
Income from continuing operations					$ 0.14
Income from discontinued operations					$ 0.08
Net income per common share					$ 0.22

(1) Pro forma depletion expense gives effect to our Corporate Restructuring which required the application of purchase accounting. The expense was calculated using estimated proved reserves as of the beginning of the period, production for the applicable period, and the fair value of the purchase price allocated to proved oil and gas properties.

(2) BCEC issued an aggregate of 33,089 warrants to purchase Class A units during 2006, 2007, and 2008 in connection with the sale of senior subordinated notes. These warrants included a one time right and option to put the warrants back to BCEC at fair market value less the exercise price. This pro forma adjustment reverses the mark-to-market income for the warrant put right that was recorded during 2010. This presentation assumes that the warrants were exercised on January 1, 2010 in connection with a recapitalization.

(3) During 2010, BCEC recorded accretion expense for the subordinated debt discount. This pro forma adjustment reverses the accretion expense recorded during 2010. This presentation assumes that the subordinated debt was paid off on January 1, 2010 in connection with a recapitalization.

(4) This pro forma adjustment reduces interest expense by $10.9 million for BCEC interest expense that was paid in kind during 2010, a further reduction to interest expense for the amortization of debt issuance costs related to BCEC' s second lien term loan that was entered into during 2010, and a further reduction for cash interest expense paid on the revolving credit facilities of BCEC and HEC and BCEC' s related party note payable during 2010. This presentation assumes that BCEC' s subordinated debt, the second lien term loan and BCEC' s related party note payable were paid off and the balance outstanding on our revolving credit facility was reduced on January 1, 2010 in connection with a recapitalization.

(5) Pro forma income taxes related to our pre-tax income for the year ended December 31, 2010 and is based on our expected tax rate of 36.8%.

Pro Forma Reserve Quantity and Standardized Measure Information

The following table sets forth certain unaudited pro forma information concerning our proved oil and gas reserves giving effect to our Corporate Restructuring as if it had occurred on January 1, 2010. The following estimates of proved oil and gas reserves, both developed and undeveloped, represent interests we acquired in our Corporate Restructuring, and are located solely within the United States. Proved reserves represent estimated quantities of crude oil and natural gas which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Proved developed oil and gas reserves are the quantities expected to be recovered through existing wells with existing equipment and operating methods. Proved undeveloped oil and gas reserves are reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells for which relatively major expenditures are required for completion.

The estimate of proved reserves and related valuations for the period ended December 23, 2010 was based upon a report prepared by Cawley, Gillespie & Associates, Inc. Petroleum Consultants as of December 31, 2010, adjusted for eight days of operations. The estimates of proved reserves are inherently imprecise and are continually subject to revision based on production history, results of additional exploration and development, price changes and other factors. These estimates do not include probable or possible reserves. The information provided does not represent our estimate of expected future cash flows or value of proved oil and gas reserves.

Changes in estimated reserve quantities:

	Oil (MBbl)			Natural Gas (MMcf)		
	Bonanza Creek Energy Company, LLC	Holmes Eastern Company, LLC	Pro Forma Combined	Bonanza Creek Energy Company, LLC	Holmes Eastern Company, LLC	Pro Forma Combined
Balance–December 31, 2009	15,270	6,118	21,388	27,610	16,565	44,175
Extensions and discoveries	1,258	50	1,308	2,249	228	2,477
Sales of minerals in place	(559)	–	(559)	–	–	–
Production	(595)	(138)	(733)	(1,309)	(781)	(2,090)
Revisions to previous estimates	1,302	(308)	994	12,674	5,690	18,364
Balance–December 23, 2010	16,676	5,722	22,398	41,224	21,702	62,926
Proved developed reserves:						
December 31, 2009	4,710	1,292	6,002	7,021	5,346	12,367
December 23, 2010	6,465	1,734	8,199	13,703	6,413	20,116
Proved undeveloped reserves:						
December 31, 2009	10,560	4,826	15,386	20,589	11,219	31,808
December 23, 2010	10,211	3,988	14,199	27,521	15,289	42,810

The following table sets forth unaudited pro forma information concerning the discounted future net cash flows from our proved oil and gas reserves as of December 23, 2010, net of income tax expense, and giving effect to our Corporate Restructuring as if it had occurred on January 1, 2010. Future income tax expenses are calculated by applying appropriate year-end tax rates to future pretax net cash flows relating to proved oil and natural gas reserves. Future income tax expenses give effect to permanent differences, tax credits and loss carryforwards relating to the proved oil and natural gas reserves. Future net cash flows are discounted at a rate of 10% annually to derive the Standardized Measure. This calculation procedure does not necessarily result in an estimate of the fair market value or the present value of our oil and natural gas properties.

Standardized Measure from estimated production of proved oil and gas reserves as of December 23, 2010 (in thousands):

	Bonanza Creek Energy Company, LLC	Holmes Eastern Company, LLC	Pro Forma Combined
Future cash flows	$ 1,366,948	$ 528,802	$ 1,895,750
Future production costs	(434,498)	(138,515)	(573,013)
Future development costs	(222,007)	(130,202)	(352,209)
Future income tax expense	(126,005)	(57,242)	(183,247)
Future net cash flows	584,438	202,843	787,281
10% annual discount for estimated timing of cash flows	(299,329)	(113,149)	(412,478)
Standardized Measure	$ 285,109	$ 89,694	$ 374,803

Future cash flows as shown above were reported without consideration for the effects of derivative transactions outstanding at each period end.

Changes in Standardized Measure from proved oil and gas reserves (in thousands):

	Bonanza Creek Energy Company, LLC	Holmes Eastern Company, LLC	Pro Forma Combined
Beginning of period	$ 185,704	$ 58,150	$ 243,854
Sale of oil and gas produced, net of production costs	(31,916)	(11,113)	(43,029)
Net changes in prices and production costs	97,744	42,468	140,212
Extensions, discoveries and improved recoveries	17,405	590	17,995
Development costs incurred	21,615	9,342	30,957
Changes in estimated development cost	(30,350)	(14,006)	(44,356)
Sales of mineral in place	(10,799)	–	(10,799)
Revisions of previous quantity estimates	65,959	11,833	77,792
Net change in income taxes	(38,932)	(10,019)	(48,951)
Accretion of discount	20,368	7,183	27,551
Changes in production rates and other	(11,689)	(4,734)	(16,423)

End of period	$ 285,109	$ 89,694	$ 374,803

Average wellhead prices inclusive of adjustments for quality and location used in determining future net revenues related to the Standardized Measure calculation as of December 23, 2010 were calculated using the first-day-of-the-month price for each of the 12 months that made up the reporting period.

	Bonanza Creek Energy Company, LLC	Holmes Eastern Company, LLC
Oil (per Bbl)	$ 74.77	$ 75.33
Gas (per Mcf)	$ 4.72	$ 4.98

Exhibit 99.2

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

Year Ended December 31, 2011 Compared to Period Ended December 23, 2010

We completed our Corporate Restructuring on December 23, 2010. The operating results presented below for the audited period ended December 23, 2010 exclude the audited eight-day period from inception through December 31, 2010. The operating results of BCEI for the eight-day period from December 23, 2010 through December 31, 2010 were net revenues, operating expense, and income from operations of approximately $1.6 million, $1.2 million, and $0.4 million, respectively, and did not include transactions that were inconsistent or unusual when compared to the results for the audited period ended December 23, 2010. Other expense during this period was primarily comprised of a $0.5 million unrealized loss in the fair value of commodity derivatives.

Results of Operations

The following discussion is of our consolidated results of operations, financial condition and capital resources. You should read this discussion in conjunction with our Consolidated Financial Statements and the Notes thereto contained elsewhere in this Current Report on Form 8-K. Comparative results of operations for the period indicated are discussed below.

Year Ended December 31, 2011 Compared to Period Ended December 23, 2010

Revenues

	Period Ended December 23, 2010	Year Ended December 31, 2011	Change	Percent Change
	(In thousands, except percentages)			
Revenues:				
Crude oil sales	$ 29,609	$ 79,568	$ 49,959	169%
Natural gas sales	6,226	13,442	7,216	116%
Natural gas liquids sales	7,088	12,358	5,270	74%
CO_2 sales	583	356	(227)	(39)%
Product revenues	$ 43,506	$ 105,724	$ 62,218	143%

	Period Ended December 23, 2010	Year Ended December 31, 2011	Change	Percent Change
Sales volumes:				
Crude oil (MBbls)	401.4	887.4	486.0	121%
Natural gas (MMcf)	1,308.5	2,773.1	1,464.6	112%
Natural gas liquids (MBbls)	126.5	183.8	57.3	45%
Crude oil equivalent (MBoe)(1)	746.0	1,533.4	787.4	106%

(1) Determined using the ratio of 6 Mcf of natural gas to 1 Bbl of crude oil. Excludes CO_2 sales.

	Period Ended December 23, 2010	Year Ended December 31, 2011	Change	Percent Change
Average Sales Prices (before hedging)(1):				
Crude oil (per Bbl)	$ 73.75	$ 89.67	$ 15.92	22%
Natural gas (per Mcf)	4.76	4.85	0.09	2%
Natural gas liquids (per Bbl)	56.04	67.23	11.19	20%
Crude oil equivalent (per Boe)(2)	57.54	68.72	11.18	19%

	Period Ended December 23, 2010	Year Ended December 2011	Change	Percent Change
Average Sales Prices (after hedging)(1):				
Crude oil (per Bbl)	$ 75.69	$ 85.51	$ 9.82	13%
Natural gas (per Mcf)	5.01	5.09	0.08	2%
Natural gas liquids (per Bbl)	56.04	67.23	11.19	20%
Crude oil equivalent (per Boe)(2)	59.02	66.75	7.73	13%

(1) Although we do not designate our derivatives as cash flow hedges for financial statement purposes, the derivatives do economically hedge the price we receive for crude oil and natural gas.

(2) Determined using the ratio of 6 Mcf of natural gas to 1 Bbl of crude oil. Excludes CO_2 sales.

Revenues increased by 143% to $105.7 million for the year ended December 31, 2011 compared to $43.5 million for the period ended December 23, 2010. Oil production increased 121% and natural gas production increased 112% during the year ended December 31, 2011 as compared to the period ended December 23, 2010. The most significant components of the increased production was related to an increased drilling program and the acquisition of HEC, which occurred on December 23, 2010. Our product revenues and production for the period ended December 23, 2010 excluded HEC revenues and production of $14.0 million and 268.2 Mboe, respectively. The increase in net revenues was also the result of a 22% increase in oil prices with a 2% increase in natural gas prices, respectively, for an overall increase of 19% per Boe. Also contributing to the increased revenue was a 97% increase in production attributable to our drilling program. During 2011, we drilled and completed approximately 100 wells as compared to 42 wells during 2010.

Operating Expenses

	Period Ended December 23, 2010	Year Ended December 31, 2011	Change	Percent Change
		(In thousands, except percentages)		
Expenses:				
Lease operating	$ 11,948	$ 18,253	$ 6,305	53%
Severance and ad valorem taxes	1,468	5,919	4,451	303%
General and administrative	8,375	17,613	9,238	110%

Depreciation, depletion and amortization	12,598	28,014	15,416	122%
Exploration	227	877	650	286%
Impairment of oil and gas properties		623	623	100%
Cancelled private placement	2,378	–	(2,378)	(100)%
Operating expenses	$ 36,994	$ 71,299	$ 34,305	93%

	Period Ended December 23, 2010	Year Ended December 31, 2011	Change	Percent Change
Selected Costs ($ per Boe):				
Lease operating	$ 16.02	$ 11.90	$ (4.12)	(26)%
Severance and ad valorem taxes	1.97	3.86	1.89	96%
General and administrative	11.23	11.49	0.26	2%
Depreciation, depletion and amortization	16.89	18.27	1.38	8%
Exploration	0.30	0.57	0.27	90%
Impairment of oil and gas properties	–	0.41	0.41	100%
Cancelled private placement	3.19	–	(3.19)	(100)%
Operating expenses	$ 49.60	$ 46.50	$ (3.10)	(6)%

Lease operating expenses. Our lease operating expenses increased $6.3 million, or 53%, to $18.3 million for the year ended December 31, 2011 from $12.0 million for the period ended December 23, 2010 and decreased on an equivalent basis from $16.02 per Boe to $11.90 per Boe. The increase in lease operating expense was related to increased production volumes due to the acquisition of HEC on December 23, 2010 and increased production attributable to our drilling program. The period ended December 23, 2010 does not include HEC lease operating expenses, which were $2.0 million. During the year ended December 31, 2011, gauging and pumping, compressor rentals, well servicing and testing, and gas plant maintenance and repairs were $1.8 million, $1.0 million, $1.0 million and $0.8 million higher, respectively, than the period ended December 23, 2010. The decrease in lease operating expenses on an equivalent basis was primarily related to the lower operating costs of the wells acquired from HEC. On an equivalent basis, the lease operating expense for the wells acquired from HEC was $7.50 per Boe during the period ended December 23, 2010 as compared to the lease operating expense for BCEC' s wells which was $16.02 per Boe during the period ended December 23, 2010.

Severance and ad valorem taxes. Our severance and ad valorem taxes increased $4.4 million, or 303%, to $5.9 million for the year ended December 31, 2011 from $1.5 million for the period ended December 23, 2010 and increased on a Boe basis from $1.97 to $3.86. The increase was primarily related to a 106% increase in production volumes and a 19% increase in realized prices per Boe during the year ended December 31, 2011 as compared to the period ended December 23, 2010, and an increase in ad valorem tax of $2.4 million due to higher assessment values. The period ended December 23, 2010 does not include HEC severance and ad valorem tax, which were $0.8 million. The increase in severance and ad valorem taxes on a Boe basis for the year ended December 31, 2011 as compared to the period ended December 23, 2010 was primarily related to higher ad valorem taxes of $2.4 million and true-ups of estimated severance taxes based on Colorado severance tax returns for 2009 and 2010 that were filed during April of the subsequent year. The revision of estimated severance taxes based on the final Colorado severance tax returns resulted in a decrease in severance tax expense in 2010 and an increase in severance tax expense in 2011.

General and administrative. Our general and administrative expense increased $9.2 million, or 110%, to $17.6 million for the year ended December 31, 2011 from $8.4 million for the period ended December 23, 2010. The period ended December 23, 2010 does not include HEC' s general and administrative expenses, which were $0.6 million. During the year ended December 31, 2011 wages and benefits and legal and professional services fees were $2.1 million and $2.0 million, respectively, higher than the previous period. The increase in wages and benefits is related to increased head count and $1.1 million of the increase in legal and professional services fees were related to investigations and transactions not consummated. In connection with our IPO, the Company distributed 243,945 fully vested shares of common stock previously held in trust to our employees and recorded a $4.1 million stock compensation charge. In addition, the Company distributed the remaining 3,400 shares of our former Class B common stock to our employees. In connection with our IPO, all issued and outstanding shares of our former Class B Common Stock converted into 437,787 shares of restricted common stock, vesting over a three year period and we recorded a $0.1 million stock compensation charge. We expect to recognize employee stock compensation expense relating to these grants during the years ended December 31, 2012, 2013, and 2014 of approximately $2.5 million, $2.5 million, and $2.3 million, respectively, assuming no forfeitures.

Depreciation, depletion and amortization. Our depreciation, depletion and amortization expense increased $15.4 million, or 122%, to $28.0 million for the year ended December 31, 2011 from $12.6 million for the period ended December 23, 2010. This increase was the result of a 106% increase in production and the step up in basis that was recorded in oil and gas properties as a result of our Corporate Restructuring. In connection with our Corporate Restructuring, all of our oil and gas fields were adjusted to fair value based on each field' s discounted future net cash flows, which resulted in basis increases to the Mid-Continent and Rocky Mountain fields with corresponding decreases to the California fields. Our depreciation, depletion and amortization expense per Boe increased by $1.38, or 8%, to $18.27 for the year ended December 23, 2011 as compared to $16.89 for the period ended December 23, 2010.

Exploration. Our exploration expense increased $0.7 million, or 286%, to $0.9 million for the year ended December 31, 2011 from $0.2 million in the period ended December 23, 2010. The increase in exploration expense was primarily related to the acquisition of 7,700 acres of 3-D seismic data on the eastern edge of the Wattenberg field in Weld County, Colorado to help evaluate our Niobrara oil shale acreage.

Impairment of Proved Properties. The Company recorded $0.6 million of proved property impairments in one non-core field in Southern Arkansas for the year ended December 31, 2011. The impairment of the non-core field in Southern Arkansas was related to the loss of a lease. There were no impairments of proved properties for the period ended December 23, 2010.

Other Income and Expense

Interest expense. Our interest expense decreased $14.0 million, or 78%, to $4.0 million for the year ended December 31, 2011 from $18.0 million for the period ended December 23, 2010. The decrease resulted from the application of $182 million of cash proceeds from our Corporate Restructuring to repay the second lien term loan, the senior subordinated notes and a related party note

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payable, and to repay $29 million of principal under our credit facility on December 23, 2010. Average debt outstanding for the year ended December 31, 2011 was $95.3 million as compared to $215.3 million for the period ended December 23, 2010.

Realized gain (loss) on settled commodity derivatives. Realized gains on oil and gas hedging activities decreased by $8.9 million from a gain of $5.9 million for the period ended December 23, 2010 to a loss of $3.0 million for the year ended December 31, 2011. Because we assumed a derivative in a liability position in 2008, our realized gain was higher by $4.8 million upon the settlement of this portion of the assumed derivative in the period ended December 23, 2010. The decrease from a realized cash hedge gain to a loss period over period was primarily related to commodity prices that were 19% higher during the year ended December 31, 2011 as compared to the period ended December 23, 2010.

Income Tax Expense. Our predecessor, BCEC, was not subject to federal and state income taxes. As a result of our Corporate Restructuring, we were organized as a Delaware corporation subject to federal and state income taxes. During the year ended December 31, 2011, the estimated effective tax rate was revised to reflect significant capital expenditures in Arkansas and the effective tax rate increased from 36.87% to 37.98%. The increase in the effective tax rate was applied to the January 1, 2011 deferred income tax liability resulting in an increase to the net deferred tax liability and deferred income tax expense of $2.4 million with an additional $10.5 million incurred for federal and state income taxes for the year ended December 31, 2011 for a total deferred income tax expense in our consolidated statement of operations of $12.9 million. We are allowed to deduct various items for tax reporting purposes that are capitalized for purposes of financial statement presentation. All income taxes for the year ended December 31, 2011 were deferred.

Change in fair value of warrant put option. The fair value of the warrant put option decreased $34.3 million, or 100%, to $0 for the year ended December 31, 2011 from a gain of $34.3 million for the period ended December 23, 2010. The decrease resulted from the exercise of the warrants on December 23, 2010 in connection with our Corporate Restructuring.

Amortization of debt discount. Our expense for amortization of debt discount decreased $8.9 million, or 100%, to $0 for the year ended December 31, 2011 from $8.9 million for the period ended December 23, 2010. The decrease resulted from the retirement of BCEC' s senior subordinated notes on December 23, 2010 in connection with our Corporate Restructuring.

Period Ended December 23, 2010 Compared to Year Ended December 31, 2009

Revenues

	Year Ended December 31, 2009	Period Ended December 23, 2010	Change	Percent Change
	(In thousands, except percentages)			
Revenues:				
Crude oil sales	$ 22,377	$ 29,609	$ 7,232	32%
Natural gas sales	3,655	6,226	2,571	70%
Natural gas liquids sales	2,886	7,088	4,202	146%
CO_2 sales	283	583	300	106%
Product revenues	$ 29,201	$ 43,506	$ 14,305	49%

	Year Ended December 31, 2009	Period Ended December 23, 2010	Change	Percent Change
Sales Volumes:				
Crude oil (MBbls)	405.9	401.4	(4.5)	(1)%
Natural gas (MMcf)	931.5	1,308.5	377.0	40%
Natural gas liquids (MBbls)	69.1	126.5	57.4	83%
Crude oil equivalent (MBoe)(1)	630.3	746.0	115.7	18%

(1) Determined using the ratio of 6 Mcf of natural gas to 1 Bbl of crude oil. Excludes CO_2 sales.

	Year Ended December 31, 2009	Period Ended December 23, 2010	Change	Percent Change
Average Sales Prices (before hedging)(1):				

Crude oil (per Bbl)	$ 55.12	$ 73.75	$ 18.63	34%
Natural gas (per Mcf)	3.92	4.76	0.84	21%
Natural gas liquids (per Bbl)	41.77	56.04	14.27	34%
Crude oil equivalent (per Boe)(2)	45.88	57.54	11.66	25%

	Year Ended December 31, 2009	Period Ended December 23, 2010	Change	Percent Change
Average Sales Prices (after hedging)(1):				
Crude oil (per Bbl)	$ 71.37	$ 75.69	$ 4.32	6%
Natural gas (per Mcf)	5.08	5.01	(0.07)	(1)%
Natural gas liquids (per Bbl)	41.77	56.04	14.27	34%
Crude oil equivalent (per Boe)(2)	58.05	59.02	0.97	2%

(1) Although we do not designate our derivatives as cash flow hedges for financial statement purposes, the derivatives do economically hedge the price we receive for crude oil and natural gas.

(2) Determined using the ratio of 6 Mcf of natural gas to 1 Bbl of crude oil. Excludes CO_2 sales.

Product revenues increased by 49%, to $43.5 million in 2010 compared to $29.2 million in 2009. The increase in product revenues was primarily due to higher average prices for oil, natural gas and natural gas liquids in 2010 as compared to 2009 of 34%, 21% and 34%, respectively, and higher natural gas and natural gas liquids production in 2010 as compared to 2009 of 40% and 83%, respectively. Production increases for natural gas and natural gas liquids were due primarily to 2010 development activities on our properties in southern Arkansas and Colorado. During 2010, we drilled 51 net wells as compared to 2.5 net wells drilled in 2009. Furthermore, our McKamie gas plant in Arkansas processed natural gas for HEC in 2009 and 2010 and we recognized natural gas and natural gas liquids volumes and revenues earned under a processing agreement. Natural gas and natural gas liquid volumes and revenues increased as HEC drilled 12 wells in 2010 as compared to 4 wells in 2009. Oil production decreased by 1% in 2010 as compared to 2009 primarily due to low drilling in 2009 and early 2010 resulting in a continued rate of decline for oil production from existing wells, partially offset by increased drilling activity in the later part of 2010.

Operating Expenses

	Year Ended December 31, 2009	Period Ended December 23, 2010	Change	Percent Change
		(In thousands, except percentages)		
Expenses:				
Lease operating	$ 10,745	$ 11,948	$ 1,203	11%
Severance and ad valorem taxes	1,984	1,468	(516)	(26)%
General and administrative	7,610	8,375	765	10%
Depreciation, depletion and amortization	12,594	12,598	4	–%
Exploration	–	227	227	100%
Cancelled private placement	–	2,378	2,378	100%
Operating expenses	$ 32,933	$ 36,994	$ 4,061	12%

	Year Ended December 31, 2009	Period Ended December 23, 2010	Change	Percent Change
Selected Costs ($ per Boe):				
Lease operating	$ 17.05	$ 16.02	$ (1.03)	(6)%
Severance and ad valorem taxes	3.15	1.97	(1.18)	(37)%
General and administrative	12.07	11.23	(.084)	7%
Depreciation, depletion and amortization	19.98	16.89	(3.09)	(15)%
Exploration	–	0.30	0.30	100%
Cancelled private placement	–	3.19	3.19	100%
Operating expenses	$ 52.25	$ 49.60	$ (2.65)	(5)%

Lease operating expenses. Our lease operating expenses increased $1.2 million, or 11%, to $11.9 million in 2010 from $10.7 million in 2009. The increase in lease operating expenses was primarily related to higher compression rental costs in our Dorcheat Macedonia field and increased workover activity.

Severance and ad valorem taxes. Severance and ad valorem taxes per Boe decreased by $1.18, or 37%, to $1.97 for 2010 from $3.15 for 2009. The decrease in production taxes was due primarily to refunds received from Colorado for overpayment of severance taxes in 2008 and 2009.

General and administrative. Our general and administrative expenses increased $0.8 million, or 10%, to $8.4 million for 2010 from $7.6 million for 2009. The increase in general and administrative expenses was due primarily to an aggregate bonus of $0.5 million awarded to employees in connection with our Corporate Restructuring in December 2010.

Depreciation, depletion and amortization. Our depreciation, depletion and amortization expense was commensurate with 2009. However, our depreciation, depletion and amortization expense per Boe produced decreased by $0.84, or 7%, to $11.23 for 2010 as compared to $12.07 for 2009 due primarily to additional reserves resulting from higher commodity prices in 2010 and reserves adds from behind-pipe activities.

Cancelled private placement. During 2010, we incurred expenditures of $2.4 million in connection with our efforts to sell preferred stock through a private placement offering. Cost incurred is comprised primarily of legal fees, printing cost, travel and audit fees. The offering was cancelled in August 2010.

Other Income and Expense

Interest expense. Our interest expense increased $1.4 million, or 8%, to $18.0 million in 2010 from $16.6 million in 2009. As a result of $30 million in borrowings on a second lien note at a 14% rate, we paid down our first lien revolver at an annual rate of approximately 4%.

Realized gain on settled commodity derivatives. Our realized gain on settled commodity derivatives decreased $7.6 million, or 56%, to $5.9 million in 2010 from $13.5 million in 2009. The change was primarily related to higher commodity prices during 2010 that lowered our realized gain.

Change in fair value of warrant put option. The unrealized gain from the change in the fair value of the warrant put option increased $115 million to a gain of $34.3 million for 2010, as compared to a $80.6 million loss for the period ended December 31. 2009. This gain of $34.3 million resulted from a decrease in the value of the warrant put option from $81.5 million as of December 31, 2009 to $47.1 million as of December 23, 2010. The warrant was exercised for Class A units of BCEC and which were subsequently redeemed in exchange for shares of our former Class A Common Stock in connection with our Corporate Restructuring and, therefore, no exercise occurred after December 23, 2010.

Accretion of debt discount. Our expense for accretion of debt discount increased $0.9 million, or 11%, to $8.9 million for the year ended December 31, 2010. The accretion expense is related to the amortization of the debt discount for BCEC' s Series A, Series B and Series C Senior Subordinated Unsecured Notes.

Results for Discontinued Operations

The Company' s decision to begin marketing, with an intent to sell, all of its oil and gas properties in California during June of 2012 required retrospective revision to the Company' s year-end financial statements that were previously filed in our Annual Report on Form 10-K. The retrospective revision to reflect the discontinued operations had no impact on net income (loss), total assets or net assets for the years presented.

The operating results before income taxes for our California properties for the year ended December 31, 2011 were net revenues, operating expenses, and loss from discontinued operations of $6.7 million, $10.3 million, and $3.6 million, respectively, as compared to net revenues, gain on the sale of the Jasmin property, operating expenses, and gain from discontinued operations of $4.8 million, $4.1 million, $4.7 million, and $0.1 million for the period ended December 23, 2010. Operating expenses for the year ended December 31, 2011 included impairments in the amount of $3.4 million. Sales volumes for the year ended December 31, 2011 and period ended December 23, 201 were 66.1 MBbls and 67.6 MBbls, respectively.

The operating results before income taxes for our California properties for period ended December 23, 2010 were net revenues, gain on the sale of the Jasmin property, operating expenses, and gain from discontinued operations of $4.8 million, $4.1 million, $4.7 million, and $0.1 million, respectively, as compared to net revenues, operating expenses, and loss from discontinued operations of $5.2 million, $5.1 million, and $0.1 million for the year ended December 31, 2009. Operating expenses for the year ended December 31, 2009 include impairments of $0.6 million. Sales volumes for the period ended December 23, 2010 and year ended December 31, 2009 were 67.6 MBbls and 102.6 MBbls, respectively.

Liquidity and Capital Resources

We completed our Corporate Restructuring on December 23, 2010. The cash flows presented below for the audited period ended December 23, 2010 exclude the audited eight day period from inception through December 31, 2010. The operating cash flows, investing cash flows, and financing cash flows associated with the eight day period ended December 31, 2011 were $(1.6) million, $(0.8) million, and $−, respectively.

Our primary sources of liquidity to date have been proceeds from our initial public offering, Corporate Restructuring, capital contributions from investors, borrowings under our credit facility and cash flows from operations. Our primary use of capital has been for the acquisition and development of oil and natural gas properties.

On December 15, 2011 the Company sold 10,000,000 shares of our common stock in our IPO at $17.00 per share, less $1.105 per share for underwriting discounts and commissions. Other expenses related to the issuance and distribution of these shares were approximately $3 million.

On March 29, 2011, we entered into a $300 million senior secured revolving credit facility to provide us with additional liquidity and flexibility for capital expenditures. As of December 31, 2011, we had $6.6 million of indebtedness outstanding and $213.4 million of borrowing capacity available under our credit facility. On November 23, 2011, our borrowing base was increased to $220 million. The size of our borrowing base is at the discretion of the lenders under our credit facility and is dependent upon a number of factors, including commodity prices and oil and gas reserve levels. For a summary of the material provisions of our credit facility, see "−Credit facility."

We expect that in the future our commodity derivative positions will help us stabilize a portion of our expected cash flows from operations despite potential declines in the price of oil and natural gas. Please see "Item 7A.−Quantitative and Qualitative Disclosures on Market Risks."

We actively review acquisition opportunities on an ongoing basis. Our ability to make significant additional acquisitions for cash is dependent on our obtaining additional equity or debt financing, which we may not be able to obtain on terms acceptable to us or at all.

	Year Ended December 31		
	Year Ended December 31, 2009	Period Ended December 23, 2010	Year Ended December 31, 2011
		(in thousands)	
Financial Measures:			
Net cash provided by operating activities	$ 11,134	$ 22,759	$ 57,603
Net cash provided by (used in) investing activities	(7,185)	(32,127)	(158,902)
Net cash provided by (used in) financing activities	(5,515)	9,297	103,389
Cash and cash equivalents	2,522	2,450	2,090
Acquisitions of oil and gas properties	650	1,066	1,810
Exploration and development of oil and gas properties and investment in gas processing facility	6,612	34,728	156,871

Cash flows provided by operating activities

Net cash provided by operating activities was $57.6 million for the year ended December 31, 2011, compared to $22.8 million provided by operating activities for the period ended December 23, 2010. The increase in operating activities resulted primarily from an increase in revenues, increased production, and increased commodity prices offset by cash utilized in connection with changes in working capital when comparing the periods. Cash utilized by changes in working capital for the year ended December 31, 2011 was $7.0 million as compared to $5.8 million that was provided by changes in working capital for the comparable period during 2010. Decreases in working capital of $7.0 million for the year ended December 31, 2011 is comprised primarily of increases in accounts receivable of $11.7 million offset by an increase in accounts payables and accrued liabilities (exclusive of capital accruals) of $6.0 million due primarily to timing of accounts payable check distributions. Increases in working capital of $5.8 million during 2010 is due primarily to an increase in trade payables and accrued expenses (exclusive of capital accruals) of $6.5 million, partially offset by an increase in trade receivables of $0.7 million. Net cash provided by operating activities was $11.1 for the year ended December 31, 2009. Cash used by changes in working capital for the year ended December 31, 2009 was $2.8 million.

Cash flows provided by (used in) investing activities

Expenditures for development of oil and natural gas properties and natural gas plants are the primary use of our capital resources. Net cash used in investing activities for the year ended December 31, 2011 was $158.9 million, compared to $32.1 million cash used in investing activities for the period ended December 23, 2010. For the year ended December 31, 2011, net cash used for the development of oil and natural gas properties was $156.9 million including $22.7 million for a natural gas plant and other facilities. For the period ended December 23, 2010, excluding our Corporate Restructuring, net cash used in investing activities was $32.1 million, of which we spent approximately $1.1 million on acquisitions, $34.7 million for the exploration and development of oil and gas properties including $4.0 million for a natural gas plant and other facilities, advanced $3.7 million to fund HEC' s exploration and development program, offset by the receipt of proceeds in the amount of $7.5 million for the sale of the Jasmin field. In connection with our Corporate Restructuring, $59 million in cash along with common stock valued at $21.1 million was used to acquire HEC. For the year ended December 31, 2009, net cash used in investing activities was $7.2 million, of which we spent approximately $0.7 million for the acquisition of oil and gas properties and $6.6 million for the exploration and development of oil and gas properties.

Cash flows provided by (used in) financing activities

Net cash flow provided by financing activities for the year ended December 31, 2011 was $103.4 million primarily related to the sale of common stock, net of offering expenses, in the amount of $155.9 million offset by a net reduction in debt from payments on our credit facility in the amount of $48.8 million. Cash used for deferred financing costs was approximately $2.3 million and we spent $1.4 million to satisfy employee tax withholding requirements related to common stock that was granted during the period. Net cash provided by financing, excluding Corporate Restructuring, was $9.3 million for the period ended December 23, 2010, primarily related to net borrowings in the amount of $12.7 million offset by deferred financing charges in the amount of $3.4 million. Net cash used in financing activities was $5.5 million for the year ended December 31, 2009, primarily the result of making debt payments on our credit facility.

In connection with our Corporate Restructuring, we received net proceeds of approximately $265 million from the sale of shares of our common stock to West Face Capital and to certain clients of AIMCo. Proceeds from this transaction in the amount of $59 million along with common stock valued at $21.1 million was used to acquire HEC, $17.3 million of the proceeds were used for debt extinguishment penalties, and $182 million was used to retire BCEC' s second lien term loan, the senior subordinated notes and a related party note payable, and to make a $29 million principal payment on BCEC' s line of credit.

Credit facility

On March 29, 2011, we entered into a credit agreement providing for a $300 million senior secured revolving credit facility with an initial borrowing base of $130 million with a $5 million subfacility for standby letters of credit. On September 15, 2011, our borrowing base was increased to $180 million with a $15 million sub facility for standby letters of credit. On December 2, 2011, our borrowing base was increased to $220 million with a $15 million subfacility for standby letters of credit.

Our borrowing base under the credit agreement is redetermined semiannually on each April 1 and October 1 and may be redetermined up to one additional time between such scheduled determinations upon our request or upon the request of the required lenders (defined as lenders holding $66^2/_3$% of the aggregate commitments). The borrowing base is determined by the value of our oil and gas reserves. The borrowing base is redetermined (i) in the sole discretion of the administrative agent and all of the lenders, (ii) in accordance with their customary internal standards and practices for valuing and redetermining the value of oil and gas properties in connection with reserve based oil and natural gas loan transactions, (iii) in conjunction with the most recent engineering report and other information received by the administrative agent and the lenders relating to our proved reserves and (iv) based upon the estimated value of our proved reserves as determined by the administrative agent and the lenders.

As of December 31, 2011, we had approximately $6.6 million outstanding under our credit facility. As of March 15, 2012, we had approximately $21.6 million outstanding under our credit facility. The credit facility matures on September 15, 2016. Amounts borrowed and repaid under the credit facility may be reborrowed. The credit facility may be used only to finance development of oil and gas properties, for working capital and for other general corporate purposes.

Our obligations under the credit facility are secured by first priority liens on all of our property and assets (whether real, personal, or mixed, tangible or intangible), including our proved reserves and our oil and gas properties (which term is defined to include fee mineral interests, term mineral interests, leases, subleases, farm-outs, royalties, overriding royalties, net profit interests, carried interests, production payments, back in interests and reversionary interests). The facility is guaranteed by us and all of our direct and indirect subsidiaries.

Interest under the credit facility is generally determined by reference to either, at our option:

- the London interbank offered rate, or LIBOR, for an elected interest period plus an applicable margin between 1.75% to 2.75%; or

- an alternate base rate (being the highest of the administrative agent' s prime rate, the federal funds effective rate plus 0.5% or 3-month LIBOR plus 1.00%) plus an applicable margin between 0.75% and 1.75%.

The applicable margin varies on a daily basis based on the percentage outstanding under the borrowing base. We incur quarterly commitment fees based on the unused amount of the borrowing base ranging from 0.375% and 0.50% per annum. We may prepay loans under the credit facility at any time without premium or penalty (other than customary LIBOR breakage costs).

The credit facility contains various covenants limiting our ability to:

- grant or assume liens;

- incur or assume indebtedness;

- grant negative pledges or agree to restrict dividends or distributions from subsidiaries;

- sell, transfer, assign or convey assets, or engage in certain mergers or acquisitions;

- make certain distributions;

- make certain loans, advances and investments;

- engage in transactions with affiliates;

- enter into sale and leaseback, take-or-pay or hydrocarbon prepayment transactions; or

- enter into certain swap agreements.

The credit facility also contains covenants requiring us to maintain:

- a current ratio of not less than 1.0 to 1.0; and

- a debt to EBITDAX coverage ratio of not more than: 4.00 to 1.00 as of the quarter ending March 31, 2011 (using EBITDAX for the quarter then ended multiplied by four); 4.00 to 1.00 as of the quarter ending June 30, 2011 (using EBITDAX for the two quarters then ending multiplied by two); 4.00 to 1.00 as of the quarter ending September 30, 2011 (using EBITDAX for the three quarters then ending multiplied by $^4/_3$); and 4.00 to 1.00 as of the quarter ending December 31, 2011 and each quarter thereafter (using the trailing four-quarter EBITDAX).

As of December 31, 2011, we were in compliance with these ratios. If an event of default exists under the credit agreement, the lenders will be able to accelerate the maturity of the loan and exercise other rights and remedies.

The credit agreement contains customary events of default, including:

- failure to pay any principal, interest, fees, expenses or other amounts when due;
- the failure of any representation or warranty to be materially true and correct when made;
- failure to observe any agreement, obligation or covenant in the credit agreement, subject to cure periods for certain failures;
- a cross-default for the payment of any other indebtedness of at least $2 million;
- bankruptcy or insolvency;
- judgments against us or our subsidiaries, in excess of $2 million, that are not stayed;
- certain ERISA events involving us or our subsidiaries; and
- a change in control (as defined in the credit agreement), including the ownership by a “person” or “group” (as defined under the Securities and Exchange Act of 1934, as amended, but excluding certain permitted stockholders) directly or indirectly, of more than 35% of our common stock, other than certain of our current stockholders.

Contractual Obligations

We have the following contractual obligations and commitments as of December 31, 2011 (in thousands):

	Total	1 Year or Less	2-3 Years	4-5 Years	More Than 5 Years
Credit facility(1)	$ 6,600	–	–	$ 6,600	$ –
Operating leases(2)	4,425	568	1,508	1,501	848
Asset retirement obligations(3)	6,440	400	400	–	5,640
Total	$ 17,465	$ 968	$ 1,908	$ 8,101	$ 6,488

(1) Amount excludes interest on our credit facility as both the amount borrowed and the applicable interest rate is variable. On March 29, 2011, we entered into a new credit agreement, which matures on September 15, 2016.

(2) See Note 7 to our consolidated financial statements for a description of operating leases.

(3) Amount represents our estimate of future retirement obligations on a discounted basis unless otherwise noted. Because these costs typically extend many years into the future, management prepares estimates and makes judgments that are subject to future revisions based upon numerous factors. The $0.4 million included in the one year or less category is not discounted and is included in accounts payable and accrued expenses as of December 31, 2011.

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. The preparation of our 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 preparation of our consolidated financial statements. We provide expanded discussion of our more significant accounting policies, estimates and judgments below. We believe these accounting policies reflect our more significant estimates and assumptions used in preparation of our consolidated financial statements. See Note 2 to our audited consolidated financial statements for a discussion of additional accounting policies and estimates made by management.

Method of accounting for oil and natural gas properties

Oil and natural gas exploration and development activities are accounted for using the successful efforts method. Under this method, all property acquisition costs and costs of exploratory and development wells are capitalized when incurred, pending determination of whether the well has found proved reserves. If an exploratory well does not find proved reserves, the costs of drilling the well are charged to expense. The costs of development wells are capitalized whether productive or nonproductive. All capitalized well costs and leasehold costs of proved properties are amortized on a unit-of-production basis over the remaining life of proved developed reserves and proved reserves, respectively.

Costs of retired, sold or abandoned properties that constitute a part of an amortization base (partial field) are charged or credited, net of proceeds, to accumulated depreciation, depletion and amortization unless doing so significantly affects the unit-of-production amortization rate for an entire field, in which case a gain or loss is recognized currently. Gains or losses from the disposal of properties are recognized currently.

Expenditures for maintenance, repairs and minor renewals necessary to maintain properties in operating condition are expensed as incurred. Major betterments, replacements and renewals are capitalized to the appropriate property and equipment accounts. Estimated dismantlement and abandonment costs for oil and natural gas properties are capitalized, net of salvage, at their

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estimated net present value and amortized on a unit-of-production basis over the remaining life of the related proved developed reserves.

Unproved properties consist of costs incurred to acquire unproved leases, or lease acquisition costs. Unproved lease acquisition costs are capitalized until the leases expire or when we specifically identify leases that will revert to the lessor, at which time we expense the associated unproved lease acquisition costs. The expensing of the unproved lease acquisition costs is recorded as impairment expense in the statement of operations in our consolidated financial statements. Lease acquisition costs related to successful exploratory drilling are reclassified to proved properties and depleted on a unit-of-production basis.

For sales of entire working interests in unproved properties, gain or loss is recognized to the extent of the difference between the proceeds received and the net carrying value of the property. Proceeds from sales of partial interests in unproved properties are accounted for as a recovery of costs unless the proceeds exceed the entire cost of the property.

Oil and natural gas reserve quantities and Standardized Measure

Our independent engineers and technical staff prepare our estimates of oil and natural gas reserves and associated future net revenues. While the SEC has recently adopted rules which allow us to disclose proved, probable and possible reserves, we have elected to disclose only proved reserves in this Current Report on Form 8-K. The SEC' s revised rules define proved reserves as the quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible−from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations−prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time. Our independent engineers and technical staff must make a number of subjective assumptions based on their professional judgment in developing reserve estimates. Reserve estimates are updated annually and consider recent production levels and other technical information about each field. Oil and natural gas reserve engineering is a subjective process of estimating underground accumulations of oil and natural gas that cannot be precisely measured. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment.

Periodic revisions to the estimated reserves and future cash flows may be necessary as a result of a number of factors, including reservoir performance, new drilling, oil and natural gas prices, cost changes, technological advances, new geological or geophysical data, or other economic factors. Accordingly, reserve estimates are generally different from the quantities of oil and natural gas that are ultimately recovered. We cannot predict the amounts or timing of future reserve revisions. If such revisions are significant, they could significantly affect future amortization of capitalized costs and result in impairment of assets that may be material.

Revenue recognition

Revenue from our interests in producing wells is recognized when the product is delivered, at which time the customer has taken title and assumed the risks and rewards of ownership, and collectability is reasonably assured. Substantially all of our production is sold to purchasers under short-term (less than 12 month) contracts at market-based prices. The sales prices for oil and natural gas are adjusted for transportation and other related deductions. These deductions are based on contractual or historical data and do not require significant judgment.

Subsequently, these revenue deductions are adjusted to reflect actual charges based on third-party documents. Since there is a ready market for oil and natural gas, we sell the majority of production soon after it is produced at various locations. As a result, we maintain a minimum amount of product inventory in storage.

Impairment of proved properties

We review our proved oil and natural gas properties for impairment whenever events and circumstances indicate that a decline in the recoverability of their carrying value may have occurred. We estimate the expected undiscounted future cash flows of our oil and natural gas properties and compare such undiscounted future cash flows to the carrying amount of the oil and natural gas properties to determine if the carrying amount is recoverable. If the carrying amount exceeds the estimated undiscounted future cash flows, we will adjust the carrying amount of the oil and natural gas properties to fair value. The factors used to determine fair value are subject to our judgment and expertise and include, but are not limited to, recent sales prices of comparable properties, the present value of future cash flows, net of estimated operating and development costs using estimates of proved reserves, future commodity pricing, future production estimates, anticipated capital expenditures, and various discount rates commensurate with the risk and current market conditions associated with realizing the expected cash flows projected. Because of the uncertainty inherent in these factors, we cannot predict when or if future impairment charges for proved properties will be recorded.

Impairment of unproved properties

We assess our unproved properties periodically for impairment on a property-by-property basis based on remaining lease terms, drilling results or future plans to develop acreage and record impairment expense for any decline in value.

We have historically recognized impairment expense for unproved properties at the time when the lease term has expired or sooner if, in management' s judgment, the unproved properties have lost some or all of their carrying value. We consider the following factors in our assessment of the impairment of unproved properties:

- the remaining amount of unexpired term under our leases;
- our ability to actively manage and prioritize our capital expenditures to drill leases and to make payments to extend leases that may be closer to expiration;
- our ability to exchange lease positions with other companies that allow for higher concentrations of ownership and development;
- our ability to convey partial mineral ownership to other companies in exchange for their drilling of leases; and
- our evaluation of the continuing successful results from the application of completion technology in the Niobrara formation by us or by other operators in areas adjacent to or near our unproved properties.

The assessment of unproved properties to determine any possible impairment requires significant judgment.

Asset retirement obligations

We record the fair value of a liability for a legal obligation to retire an asset in the period in which the liability is incurred with the corresponding cost capitalized by increasing the carrying amount of the related long-lived asset. For oil and gas properties, this is the period in which the well is drilled or acquired. The asset retirement obligation, or ARO, represents the estimated amount we will incur to plug, abandon and remediate the properties at the end of their productive lives, in accordance with applicable state laws. The liability is accreted to its present value each period and the capitalized cost is depreciated on the unit-of-production method. The accretion expense is recorded as a component of Depreciation, depletion and amortization in our Consolidated Statement of Operations.

We determine the ARO by calculating the present value of estimated cash flows related to the liability. Estimating the future ARO requires management to make estimates and judgments regarding timing, existence of a liability, as well as what constitutes adequate restoration. Inherent in the fair value calculation are numerous assumptions and judgments including the ultimate costs, inflation factors, credit adjusted discount rates, timing of settlement and changes in the legal, regulatory, environmental and political environments. To the extent future revisions to these assumptions impact the fair value of the existing ARO liability, a corresponding adjustment is made to the related asset.

Derivatives

We record all derivative instruments on the balance sheet as either assets or liabilities measured at their estimated fair value. We have not designated any derivative instruments as hedges for accounting purposes and we do not enter into such instruments for speculative trading purposes. Realized gains and realized losses from the settlement of commodity derivative instruments and unrealized gains and unrealized losses from valuation changes in the remaining unsettled commodity derivative instruments are reported under Other Income (Expense) in our Consolidated Statement of Operations.

Stock-based compensation

Restricted Stock Awards. We recognize compensation expense for all restricted stock awards made to employees and directors. Stock-based compensation expense is measured at the grant date based on the fair value of the award and is recognized as expense on a straight-line basis over the requisite service period, which is generally the vesting period. The fair value of restricted stock grants is based on the value of our common stock on the date of grant. Assumptions regarding forfeiture rates are subject to change. Any such changes could result in different valuations and thus impact the amount of stock-based compensation expense recognized. Stock-based compensation expense recorded for restricted stock awards is included in General and administrative expenses on our Consolidated Statement of Operations.

Income taxes

Our provision for taxes includes both federal and state taxes. We record our federal income taxes in accordance with accounting for income taxes under GAAP which results in the recognition of deferred tax assets and liabilities for the expected future tax consequences of temporary differences between the book carrying amounts and the tax basis of assets and liabilities. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences and carryforwards are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in the period that includes the enactment date. A valuation allowance is established to reduce deferred tax assets if it is more likely than not that the related tax benefits will not be realized.

We apply significant judgment in evaluating our tax positions and estimating our provision for income taxes. During the ordinary course of business, there are many transactions and calculations for which the ultimate tax determination is uncertain. The actual outcome of these future tax consequences could differ significantly from our estimates, which could impact our financial position, results of operations and cash flows.

We also account for uncertainty in income taxes recognized in the financial statements in accordance with GAAP by prescribing a recognition threshold and measurement attribute for a tax position taken or expected to be taken in a tax return. Authoritative guidance for accounting for uncertainty in income taxes requires that we recognize the financial statement benefit of a tax position only after determining that the relevant tax authority would more likely than not sustain the position following an audit. For tax positions meeting the more-likely-than-not threshold, the amount recognized in the financial statements is the largest benefit that has a greater than 50% likelihood of being realized upon ultimate settlement with the relevant tax authority. We did not have any uncertain tax positions as of the year ended December 31, 2011.

Recent accounting pronouncements

Goodwill. In December 2010, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") 2010-28, "Intangibles−Goodwill and Other: When to Perform Step 2 of the Goodwill Impairment Test for Reporting Units with Zero or Negative Carrying Amounts" ("ASU 2010-28"). ASU 2010-28 requires step two of the goodwill impairment test to be performed when the carrying value of a reporting unit is zero or negative, if it is more likely than not that a goodwill impairment exists. The requirements of this update are effective for fiscal years beginning after December 15, 2010. The adoption of this new guidance did not have an impact on our financial position, cash flows or results of operations.

Business combinations. In December 2010, the FASB issued ASU 2010-29, "Business Combinations: Disclosure of Supplementary Pro Forma Information for Business Combinations" ("ASU 2010-29"). ASU 2010-29 clarifies that when presenting comparative pro forma financial statements in conjunction with business combination disclosures, revenue and earnings of the combined entity should be presented as though the business combination that occurred during the current year had occurred as of the beginning of the comparable prior annual reporting period. In addition, the update requires a description of the nature and amount of material, nonrecurring pro forma adjustments included in pro forma revenue and earnings that are directly attributable to the business combination. This update is effective prospectively for business combinations that occur on or after the beginning of the first annual reporting period after December 15, 2010. As ASU 2010-29 relates to disclosure requirements, there was no impact on our financial position, cash flows or results of operations.

Financial receivables. On July 21, 2010, the FASB issued ASU 2010-20 "Receivables (Topic 310)−Disclosures about the Credit Quality of Financial Receivables and the Allowance for Credit Losses." This new ASU requires disclosure of additional information to assist financial statement users to understand more clearly an entity' s credit risk exposures to finance receivables and the related allowance for credit losses. This ASU is effective for all public companies for interim and annual reporting periods ending on or after December 15, 2010 with specific items, such as the allowance rollforward and modification disclosures, effective for

periods beginning after December 15, 2010. The adoption of this new guidance did not have an impact on our financial position, cash flows or results of operations, but appropriate disclosures have been made in our consolidated financial statements.

Fair value. In January 2010, the FASB issued authoritative guidance to update certain disclosure requirements and added two new disclosure requirements related to fair value measurements. The guidance requires a gross presentation of activities within the Level 3 roll forward and adds a new requirement to disclose details of significant transfers in and out of Level 1 and 2 measurements and the reasons for the transfers. The new disclosures are required for all companies that are required to provide disclosures about recurring and nonrecurring fair value measurements, and is effective the first interim or annual reporting period beginning after December 15, 2009, except for the gross presentation of the Level 3 roll forward information, which is required for annual reporting periods beginning after December 15, 2010 and for interim reporting periods within those years. The adoption of this new guidance did not have an impact on our financial position, cash flows or results of operations, but appropriate disclosures have been made in our consolidated financial statements.

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 periods ended December 31, 2011, 2010 and 2009. Although the impact of inflation has been insignificant in recent years, it is still a factor in the United States economy and we tend to experience inflationary pressure on the cost of oilfield services and equipment as increasing oil and gas prices increase drilling activity in our areas of operations.

Off-balance sheet arrangements

Currently, we do not have any off-balance sheet arrangements.

Item 7A. *Quantitative and Qualitative Disclosures About Market Risks.*

Oil and Natural Gas Prices. Our financial condition, results of operations and capital resources are highly dependent upon the prevailing market prices of oil and natural gas. These commodity prices are subject to wide fluctuations and market uncertainties due to a variety of factors that are beyond our control. Factors influencing oil and natural gas prices include the level of global demand for oil, the global supply of oil and natural gas, the establishment of and compliance with production quotas by oil exporting countries, weather conditions which determine the demand for natural gas, the price and availability of alternative fuels and overall economic conditions. It is impossible to predict future oil and natural gas prices with any degree of certainty. Sustained weakness in oil and natural gas prices may adversely affect our financial condition and results of operations, and may also reduce the amount of oil and natural gas reserves that we can produce economically. Any reduction in our oil and natural gas reserves, including reductions due to price fluctuations, can have an adverse affect on our ability to obtain capital for our exploration and development activities. Similarly, any improvements in oil and natural gas prices can have a favorable impact on our financial condition, results of operations and capital resources. If oil prices decline by $10.00 per Bbl, then our PV-10 as of December 31, 2011 would have been lower by approximately $129.4 million.

Our primary commodity risk management objective is to reduce volatility in our cash flows. Management makes recommendations on hedging that are approved by the board of directors before implementation. We enter into hedges for oil and natural gas using NYMEX futures or over-the-counter derivative financial instruments with only certain well-capitalized counterparties which have been approved by our board of directors.

The use of financial instruments may expose us to the risk of financial loss in certain circumstances, including instances when (1) sales volumes are less than expected requiring market purchases to meet commitments, or (2) our counterparties fail to purchase the contracted quantities of natural gas or otherwise fail to perform. To the extent that we engage in hedging activities, we may be prevented from realizing the benefits of favorable price changes in the physical market. However, we are similarly insulated against decreases in such prices.

Presently, all of our hedging arrangements are concentrated with three counterparties, one of which is a lender under our credit facility. If this counterparty fails to perform its obligations, we may suffer financial loss or be prevented from realizing the benefits of favorable price changes in the physical market.

The result of oil market prices exceeding our swap prices or collar ceilings requires us to make payment for the settlement of our hedge derivatives, if owed by us, generally up to three business days before we receive market price cash payments from our customers. This could have a material adverse effect on our cash flows for the period between hedge settlement and payment for revenues earned.

The following table provides a summary of derivative contracts as of February 29, 2012:

Settlement Period	Derivative Instrument	Total Notional Amount (Bbl/Mmbtu)	Average Floor Price	Average Ceiling Price	Fair Market Value of Asset (Liability) (In thousands)
Oil					
2012	Collar	679,560	$ 90.00	$ 106.45	$ (4,600,114)
	Swap	96,917	63.03	63.03	(4,339,442)
2013	Collar	410,616	92.10	108.91	(1,294,425)
	Swap	75,417	61.50	61.50	(3,280,439)
Gas					
2012	Swap	168,081	6.75	6.75	651,976
2013	Swap	154,806	6.40	6.40	436,028
					$ (12,426,416)

Interest Rates. At February 29, 2012 we had $16.6 million outstanding under our credit facility, which is subject to floating market rates of interest. Borrowings under our credit facility bear interest at a fluctuating rate that is tied to an adjusted base rate or LIBOR, at our option. Any increases in these interest rates can have an adverse impact on our results of operations and cash flow. Based on borrowings outstanding at February 29,2012, a 100 basis point change in interest rates would change our annualized interest expense by approximately $0.2 million.

Counterparty and customer credit risk. In connection with our hedging activity, we have exposure to financial institutions in the form of derivative transactions. The lenders under our credit facility are currently the counterparties on our derivative instruments currently in place and have investment grade credit ratings. We expect that any future derivative transactions we enter into will be with these or other lenders under our credit facility that will carry an investment grade credit rating.

We are also subject to credit risk due to concentration of our oil and natural gas receivables with certain significant customers. See “Item 1. Business−Principal Customers” for further detail about our significant customers. The inability or failure of our significant customers to meet their obligations to us or their insolvency or liquidation may adversely affect our financial results. We review the credit rating, payment history and financial resources of our customers, but we do not require our customers to post collateral.

The marketability of our production from the Mid-Continent, Rocky Mountain and California regions depends in part upon the availability, proximity and capacity of third-party refineries, natural gas gathering systems and processing facilities. We deliver crude oil and natural gas produced from these areas through trucking services and pipelines that we do not own. The lack of availability or capacity on these systems and facilities could reduce the price offered for our production or result in the shut-in of producing wells or the delay or discontinuance of development plans for properties.

A portion of our production may also be interrupted, or shut in, from time to time for numerous other reasons, including as a result of accidents, field labor issues or strikes, or we might voluntarily curtail production in response to market conditions. If a substantial amount of our production is interrupted at the same time, it could adversely affect our cash flow.

Currently, there are no natural gas pipeline systems that service wells in the North Park Basin, which is prospective for the Niobrara oil shale. In addition, we are not aware of any plans to construct a facility necessary to process natural gas produced from this basin. If neither we nor a third party constructs the required pipeline system and processing facility, we may not be able to fully develop our resources in the North Park Basin.

Exhibit 99.3

Item 8. ***Financial Statements and Supplementary Data.***

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders
Bonanza Creek Energy, Inc.

We have audited the accompanying consolidated balance sheets of Bonanza Creek Energy, Inc. and subsidiaries as of December 31, 2011 and 2010, and the related consolidated statements of operations, stockholders' equity, and cash flows for the year ended December 31, 2011 and the period from its inception (December 23, 2010) to December 31, 2010, and the Bonanza Creek Energy Company, LLC and subsidiaries (predecessor) consolidated statements of operations, members' equity, and cash flows for the period January 1, 2010 to December 23, 2010 and the year ended December 31, 2009. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Bonanza Creek Energy, Inc. and subsidiaries and its predecessor as of December 31, 2011 and 2010, and the results of their operations and their cash flows for the year ended December 31, 2011, the periods December 23, 2010 to December 31, 2010 and January 1, 2010 to December 23, 2010, and the year ended December 31, 2009, in conformity with U.S. generally accepted accounting principles.

As discussed in Note 13, the Company adopted a plan in 2012 to dispose of certain assets. The accompanying consolidated financial statements have been reclassified to reflect these assets as held for sale as of December 31, 2011 and 2010, and to reflect the results of the operations of the assets held for sale as discontinued operations for all periods presented.

Hein & Associates LLP

Denver, Colorado
March 22, 2012, except for the third paragraph of Note 13, which is dated January 28, 2013

BONANZA CREEK ENERGY, INC.

CONSOLIDATED BALANCE SHEETS

	December 31, 2011	December 31, 2010
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 2,089,674	$ –
Accounts receivable:		
Oil and gas sales	17,850,719	8,894,831
Other	5,696,825	2,940,590
Prepaid expenses and other	1,868,016	703,063
Inventory of oilfield equipment	3,324,368	415,650
Derivative asset	1,297,403	1,396,472
Total current assets	32,127,005	14,350,606
OIL AND GAS PROPERTIES–using the successful efforts method of accounting		
Proved properties	547,878,188	426,189,861
Unproved properties	15,848,703	14,717,104
Wells in progress	23,783,142	8,253,906
	587,510,033	449,160,871
Less: accumulated depreciation, depletion and amortization	(26,759,043)	(399,635)
	560,750,990	448,761,236
NATURAL GAS PLANT	56,910,232	31,840,475
Less: accumulated depreciation	(1,286,129)	(20,017)
	55,624,103	31,820,458
PROPERTY AND EQUIPMENT	1,983,037	802,679
Less: accumulated depreciation	(128,731)	(10,008)
	1,854,306	792,671
OIL AND GAS PROPERTIES HELD FOR SALE, LESS ACCUMULATED DEPRECIATION AND DEPLETION	9,895,508	15,207,724
LONG-TERM DERIVATIVE ASSET	678,474	2,045,182
OTHER ASSETS	3,418,626	3,125,670
TOTAL ASSETS	$ 664,349,012	$ 516,103,547
LIABILITIES AND STOCKHOLDERS' EQUITY		
CURRENT LIABILITIES:		
Accounts payable and accrued expenses	$ 27,068,326	$ 16,101,536
Oil and gas revenue distribution payable	6,185,983	3,444,077
Derivative liability	5,276,633	3,691,998
Total current liabilities	38,530,942	23,237,611
LONG-TERM LIABILITIES:		
Bank revolving credit	6,600,000	55,400,000
Ad valorem taxes	3,014,023	1,213,445
Derivative liability	2,579,175	5,854,980
Deferred income taxes, net	79,603,633	68,405,393
Asset retirement obligations	6,039,723	5,611,709
TOTAL LIABILITIES	136,367,496	159,723,138
COMMITMENTS AND CONTINGENCIES (Notes 7 and 10)		
STOCKHOLDERS' EQUITY:		
Preferred stock, $.001 par value, 25,000,000 shares authorized, – outstanding	–	–

Common stock, $.001 par value, 225,000,000 shares authorized, 39,477,584 and 29,122,521 issued and outstanding, respectively	39,478	29,123
Additional paid-in capital	515,412,583	356,513,012
Retained earnings (deficit)	12,529,455	(161,726)
Total stockholders' equity	527,981,516	356,380,409
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$ 664,349,012	$ 516,103,547

BONANZA CREEK ENERGY, INC. AND SUBSIDIARIES AND PREDECESSOR

CONSOLIDATED STATEMENT OF OPERATIONS

	Bonanza Creek Energy, Inc. For the Year Ended December 31,2011	Bonanza Creek Energy, Inc. For the Period From Inception (December 23, 2010) to December 31, 2010	Bonanza Creek Energy Company, LLC (Predecessor) For the Period January 1, 2010 to December 23, 2010	Bonanza Creek Energy Company, LLC (Predecessor) For the Year Ended December 31, 2009
NET REVENUES:				
Oil and gas sales	$ 105,723,993	$ 1,620,192	$ 43,506,084	$ 29,201,514
OPERATING EXPENSES:				
Lease operating	18,252,963	419,100	11,947,925	10,744,621
Severance and ad valorem taxes	5,918,566	66,460	1,467,477	1,984,434
Exploration	876,971	–	226,452	–
Depreciation, depletion and amortization	28,014,077	435,552	12,598,429	12,593,807
Impairment of oil and gas properties	623,039	–	–	–
General and administrative (including $4,436,794, $–,$–, and $–, respectively, of stock compensation)	17,612,943	323,545	8,374,875	7,610,252
Cancelled private placement	–	–	2,378,468	–
Total operating expenses	71,298,559	1,244,657	36,993,626	32,933,114
INCOME (LOSS) FROM OPERATIONS	34,425,434	375,535	6,512,458	(3,731,600)
OTHER INCOME (EXPENSE):				
Realized gain (loss) on settled commodity derivatives	(3,024,136)	(46,742)	5,918,702	13,450,810
Interest expense	(4,017,230)	(57,656)	(18,000,796)	(16,581,566)
Unrealized gain (loss) in fair value of commodity derivatives	225,393	(514,627)	(7,604,742)	(34,589,118)
Other income (loss)	(110,276)	–	19,173	(179,840)
Write off of deferred financing costs	–	–	(1,663,167)	–
Change in fair value of warrant put option	–	–	34,344,894	(80,639,866)
Accretion of debt discount	–	–	(8,861,955)	(7,963,031)
Total other income (expense)	(6,926,249)	(619,025)	4,152,109	(126,502,611)
INCOME FROM CONTINUING OPERATIONS BEFORE TAXES	27,499,185	(243,490)	10,664,567	(130,234,211)

Deferred income tax (expense) benefit (Note 9)	(12,890,328)	89,775	–*	–*
INCOME (LOSS) FROM CONTINUING OPERATIONS	$ 14,608,857	$ (153,715)	$ 10,664,567	$ (130,234,211)
DISCONTINUED OPERATIONS (Note 13)				
(Loss) income from operations associated with oil and gas properties held for sale (including impairments in 2011 and 2009 of $3,443,984 and $579,337, respectively)	(3,609,764)	(12,689)	63,962	147,662
Gain on sale of oil and gas properties	–	–	4,055,153	303,085
Income tax (expense) benefit	1,692,088	4,678	–*	–*
(Loss) income from discontinued operations	(1,917,676)	(8,011)	4,119,115	450,747
NET INCOME	$ 12,691,181	$ (161,726)	$ 14,783,682	$ 129,783,464
BASIC AND DILUTED INCOME PER SHARE				
Income from continuing operations	$ 0.49	–	–*	–*
Income (loss) from discontinued operations	$ (0.06)	–	–*	–*
Net income per common share	$ 0.43	–	–*	–*
WEIGHTED AVERAGE NUMBER OF SHARES OF COMMON STOCK–BASIC AND DILUTED:	29,576,442	29,122,521	–*	–*

* Bonanza Creek Energy Company, LLC was a limited liability company. See note 1 to Bonanza Creek Energy, Inc.' s annual financial statements.

BONANZA CREEK ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENT OF STOCKHOLDERS' EQUITY

FOR THE PERIOD FROM INCEPTION (DECEMBER 23, 2010) TO DECEMBER 31, 2011

	Common Stock		Class B	Additional Paid-In	Accumulated	
	Shares	Amount	Shares	Capital	Deficit	Total
BALANCES at December 23, 2010	–	–	–	$ –	$ –	$ –
Contribution of capital	29,122,521	$ 29,123	7,500	356,513,012	–	356,542,135
Net (loss)	–	–	–	–	(161,726)	(161,726)
BALANCES at December 31, 2010	29,122,521	$ 29,123	7,500	356,513,012	$ (161,726)	356,380,409
Issuance of common stock to directors for services	–	–	–	167,500	–	167,500
Issuance of Class B common stock	–	–	4,600	–	–	–
Forfeiture of Class B common stock	–	–	(2,100)	–	–	–
Sale of common stock, net of underwriting discounts and offering costs of $14,121,680	10,000,000	10,000	–	155,868,320	–	155,878,320

Exchange of Class B common stock for issuance of restricted common stock to officers and employees	437,787	438	(10,000)	7,441,941	–	7,442,379
Unrecognized future non-cash compensation expense for issuance of restricted common stock to employees for services	–	–	–	(7,320,150)	–	(7,320,150)
Issuance of outstanding common stock previously held in trust to employees	–	–	–	4,147,065	–	4,147,065
Common stock returned for tax withholdings	(82,724)	(83)	–	(1,405,105)	–	(1,405,188)
Net Income	–	–	–	–	12,691,181	12,691,181
BALANCES at December 31, 2011	39,477,584	$ 39,478	–	$ 515,412,583	$ 12,529,455	$ 527,981,516

BONANZA CREEK ENERGY, INC. AND SUBSIDIARIES AND PREDECESSOR CONSOLIDATED

STATEMENT OF CASH FLOWS

	Bonanza Creek Energy, Inc. For the Year Ended December 31, 2011	Bonanza Creek Energy, Inc. For the Period From Inception December 23, 2010 to December 31, 2010	Bonanza Creek Energy Company, LLC (Predecessor) For the Period January 1, 2010 to December 23, 2010	Bonanza Creek Energy Company, LLC (Predecessor) For the Year Ended December 31, 2009
CASH FLOWS FROM OPERATING ACTIVITIES:				
Net income (loss)	$ 12,691,181	$ (161,726)	$ 14,783,682	$ (129,783,464)
Adjustments to reconcile net income (loss) to net cash provided by operating activities				
Depreciation, depletion and amortization	31,507,596	506,307	14,225,309	14,107,774
Change in unrealized loss on derivative liability assumed	–	–	(4,811,518)	(5,779,144)
Deferred income taxes	11,198,240	(94,453)	–	–
Impairment of oil and gas properties	4,067,023	–	–	579,337
Non-cash stock compensation	4,436,794			
Amortization of deferred financing costs	1,004,225	15,589	1,641,209	1,643,883
Write off of deferred financing costs	–	–	1,663,167	–
Amortization of deferred novation fees	–	–	403,676	341,314
Accretion of debt discount	–	–	8,861,955	7,963,031
Payment in kind interest	–	–	10,991,527	9,778,365
Gain on sale of oil and gas properties	–	–	(4,055,153)	(303,085)
Valuation (increase) decrease in outstanding warrants	–	–	(34,344,894)	80,639,866
Valuation (increase) decrease in commodity derivatives	(225,393)	514,627	7,604,742	34,589,118
Other	(40,368)	–	42,758	137,712

(Increase) decrease in operating assets:				
Accounts receivable	(11,712,123)	(2,104,097)	(726,157)	(100,356)
Prepaid expenses and other assets	(1,164,953)	–	27,358	544,913
(Decrease) increase in operating liabilities:				
Accounts payable and accrued liabilities	5,996,440	(309,076)	6,495,772	(3,183,544)
Settlement of asset retirement obligations	(155,558)	–	(44,758)	(41,664)
Net cash provided by operating activities	57,603,104	(1,632,829)	22,758,675	11,134,056
CASH FLOWS FROM INVESTING ACTIVITIES:				
Acquisition of oil and gas properties	(1,809,657)	–	(1,066,277)	(650,306)
Exploration and development of oil and gas properties	(134,183,772)	(817,362)	(30,733,263)	(6,216,067)
Natural gas plant capital expenditures	(22,687,197)	–	(3,994,304)	(395,889)
Proceeds from note receivable	986,906	–	103,903	238,544
Proceeds from sale of properties	–	–	7,475,654	307,257
Decrease in restricted cash	–	–	250,000	–
Increase in receivable from Holmes Eastern Company, LLC	–	–	(3,665,703)	–
Additions to property and equipment–non oil and gas	(1,208,755)	–	(497,073)	(468,588)
Net cash used in investing activities	(158,902,475)	(817,362)	(32,127,063)	(7,185,049)
CASH FLOWS FROM FINANCING ACTIVITIES:				
Increase in bank revolving credit and subordinated debt	108,100,000	–	118,200,000	3,000,000
Payment on bank revolving credit and subordinated debt	(156,900,000)	–	(105,500,000)	(8,300,000)
Proceeds from sale of Bonanza Creek Energy, Inc. common stock	155,878,320	–	–	–
Common stock returned for tax withholdings	(1,405,188)	–	–	–
Deferred financing costs	(2,284,087)	–	(3,075,534)	(215,439)
Deferred novation fees	–	–	(327,400)	–
Net cash (used in) provided by financing activities	103,389,045	–	9,297,066	(5,515,439)
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	2,089,674	(2,450,191))	(71,322)	(1,566,432)
CASH AND CASH EQUIVALENTS:				
Beginning of period	–	2,450,191	2,521,513	4,087,945
End of period	$ 2,089,674	$ –	$ 2,450,191	$ 2,521,513
SUPPLEMENTAL CASH FLOW DISCLOSURE:				
Cash paid for interest	$ 3,101,074	$ –	$ 5,410,127	$ 5,159,318
Value of stock issued to acquire BCEC and HEC, 7,966,387 shares at $12.52 per share	–	$ 99,613,966	–	–
Changes in working capital related to drilling expenditures and property acquisition	$ 9,555,592	$ –	$ 2,723,130	$ (70,292)

Bonanza Creek Energy, Inc.

Notes to the Consolidated Financial Statements as of December 31, 2011

1. ORGANIZATION AND BUSINESS:

On December 23, 2010, Bonanza Creek Energy, Inc., a Delaware Subchapter C corporation formed on December 2, 2010 (the "Company" or "BCEI") participated in following transactions which were accomplished simultaneously:

(1) The contribution by Bonanza Creek Energy Company, LLC ("BCEC") of all of its ownership in Bonanza Creek Energy Operating Company, LLC (a wholly owned subsidiary) to BCEI and the assumption by BCEI of BCEC' s remaining debt (as described below) in exchange for a 21.55% ownership interest of BCEI. BCEC had no other significant assets or subsidiaries at such time. BCEC was an operating oil and gas company that was initially founded in 2006;

(2) The sale of $265 million of Class A common stock of BCEI which constituted an ownership interest of 72.68% of BCEI to Project Black Bear LP ("Black Bear"), an entity advised by West Face Capital Inc. ("West Face Capital"), and to certain clients of Alberta Investment Management Corporation ("AIMCo"); and

(3) The exchange of shares of 5.77% of BCEI' s Class A common stock together with $59 million in cash (which came from the $265 million sale of common stock of BCEI described in (2) above), for all of the equity interests of Holmes Eastern Company, LLC, a Delaware limited liability company ("HEC"), that was majority owned by a minority member of Bonanza Creek Oil Company, LLC ("BCOC"). BCOC was the predecessor of BCEC and owned 29.9% of BCEC on a fully diluted basis at the time of such transaction. HEC was initially formed in 2009 and has been an operating oil and gas exploration and production business since its formation.

The BCEC ownership (21.55%) of BCEI was subsequently distributed to or for the benefit of BCEC' s members based on management' s estimate of fair value of the BCEI shares received by BCEC to holders of the equity interests of BCEC in connection with the redemption of BCEC' s equity and BCEC' s dissolution to or for the benefit of:

(1) BCOC in the amount of 5.5% (for its Class A Units of BCEC);

(2) D.E. Shaw Laminar Portfolios, L.L.C. ("Laminar") in the amount of 12.91% (for its Class A Units of BCEC); and

(3) The management and employees of BCEC, in the amount of 3.14% (for their Class B Units of BCEC).

Cash proceeds of approximately $182 million were used to retire BCEC' s second lien term loan, senior subordinated notes and a related party note payable, and to reduce the outstanding principal balance on BCEC' s bank revolving credit facility by $29 million thereby reducing the balance outstanding to approximately $55.4 million as of December 31, 2010. This loan at the same time was assumed by BCEI.

The Company is engaged primarily in acquiring, developing, exploiting and producing oil and gas properties. As of December 31, 2011, the Company' s assets and operations are concentrated primarily in southern Arkansas and in the Denver Julesburg and North Park Basins in the Rocky Mountains.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES:

Principles of Consolidation−The consolidated balance sheet includes the accounts of the Company and its wholly owned subsidiaries, Bonanza Creek Energy Operating Company, LLC, Bonanza Creek Energy Resources Company, LLC and HEC. All significant intercompany accounts and transactions have been eliminated.

Fair Value of Financial Instruments−The Company' s financial instruments consist of trade receivables, trade payables, accrued liabilities, a revolving credit facility and derivative instruments. Trade receivables, trade payables and accrued liabilities are carried at cost and approximate fair value due to the short term nature of these accounts. Our revolving credit facility has a variable interest rate so it also approximates fair value. Derivative instruments are adjusted to fair value every accounting period.

Use of Estimates−The preparation of this balance sheet in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of oil and gas reserves, assets and liabilities and disclosure of contingent assets and liabilities at the date of the balance sheet and the reported amounts of revenue and expenses during the reporting period. Actual results could differ from those estimates.

Cash and Cash Equivalents−The Company considers all highly liquid investments with original maturity dates of three months or less to be cash equivalents.

Accounts Receivable−Trade accounts receivable are recorded at net realizable value which is estimated to be fair value at December 31, 2011 and 2010. If the financial condition of the Company' s customers were to deteriorate, resulting in an impairment of their ability to make payments, additional allowances may be required. Delinquent trade accounts receivable are charged against the allowance for doubtful accounts once collectibility has been determined.

The Company' s crude oil and natural gas receivables are generally collected within two months. The Company accrues an allowance on a receivable when, based on the judgment of management, it is probable that a receivable will not be collected and the amount of any allowance may be reasonably estimated.

Inventory of Oilfield Equipment−Inventory consists of material and supplies used in connection with the Company' s drilling program. These inventories are stated at the lower of average cost or market which as of December 31, 2011 and 2010 approximated fair value.

Oil and Gas Producing Activities−The Company follows the successful efforts method of accounting for its oil and gas properties. Under this method of accounting, all property acquisition costs and costs of exploratory and development wells will be capitalized at cost when incurred, pending determination of whether the well has found proved reserves. If an exploratory well has not found proved reserves, the costs of drilling the well and other associated costs will be charged to expense. The costs of development wells will be capitalized whether productive or nonproductive. Costs incurred to maintain wells and related equipment and lease and well operating costs are charged to expense as incurred. Gains and losses arising from sales of properties will be included in income. However, sales that do not significantly affect a field' s unit-of-production depletion rate will be accounted for as normal retirements with no gain or loss recognized. Geological and geophysical costs of exploratory prospects and the costs of carrying and retaining unproved properties are expensed as incurred.

Depletion, depreciation and amortization ("DD&A") of capitalized costs of proved oil and gas properties are provided for on a field-by-field basis using the units of production method based upon proved reserves. The computation of DD&A takes into consideration the anticipated proceeds from equipment salvage and the Company' s expected cost to abandon its well interests.

The Company assesses its proved oil and gas properties for impairment whenever events or circumstances indicate that the carrying value of the assets may not be recoverable. The impairment test compares undiscounted future net cash flows to the assets' net book value. If the net capitalized costs exceed future net cash flows, then the cost of the property will be written down to "fair value." Fair value for oil and natural gas properties is generally determined based on discounted future net cash flows.

For the year ended December 31, 2011, the Company recorded $3.5 million of proved property impairments on the Company' s legacy California assets and $0.6 million of proved property impairment in one non-core field in Southern Arkansas. The impairments of the Company' s legacy assets in California were related to steam flooding results that were lower than expected and the impairment of the non-core field in Southern Arkansas was related to the loss of a lease. For the year ended December 31, 2009, our predecessor; BCEC, recorded proved property impairment expense of $0.6 million to write off the remainder of the property balance for the Red Springs field in Wyoming. These calculations involved significant unobservable inputs and, therefore, they are Level 3 fair value estimates.

The Company records the fair value of a liability for an asset retirement obligation as an asset and a liability when there is a legal obligation associated with the retirement of a long-lived asset and the amount can be reasonably estimated. Refer also to Note 10 for additional information on the Company' s asset retirement obligations.

Long-Lived Assets−Long-lived assets to be held and used or disposed of other than by sale are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. When required, impairment losses on assets to be held and used or disposed of other than by sale are recognized based on the fair value of the asset. Long-lived assets to be disposed of by sale are reported at the lower of their carrying amount or fair value less cost to sell.

Other Property and Equipment−Property and equipment acquired at the time of the Company' s corporate restructuring at December 23, 2010 as described in Note 1, were recorded at fair value as of December 23, 2010. Property additions subsequent to December 23, 2010 have been recorded at cost. Depreciation is calculated using the straight-line method over the estimated useful lives of the assets, which range from three to ten years.

Revenue Recognition−The Company records revenues from the sales of crude oil and natural gas when delivery to the customer has occurred and title has transferred, net of royalties, discounts and allowances, as applicable. This occurs when oil or gas has been delivered to a pipeline or a tank lifting has occurred. The Company has interests with other producers in certain properties in which case the Company uses the entitlement method to account for gas imbalances. Gas imbalances as of December 31, 2011 and 2010 were immaterial.

For gathering and processing services, the Company either receives fees or commodities from natural gas producers depending on the type of contract. Under the percentage-of-proceeds contract type, the Company is paid for its services by keeping a percentage of the natural gas liquids ("NGL") produced and a percentage of the residue gas resulting from processing the natural gas. Commodities received are, in turn, sold and recognized as revenue in accordance with the criteria outline above.

Income Taxes−The Company accounts for income taxes under the liability method, which requires recognition of deferred tax assets and liabilities for the expected future tax consequences of events that have been included in the balance sheet or tax returns. Under this method, deferred tax assets and liabilities are determined based on the difference between the financial statements and tax basis of assets and liabilities using enacted tax rates in effect for the year in which the differences are expected to reverse.

Uncertain Tax Positions−The Company recognizes interest and penalties related to uncertain tax positions in income tax expense. The tax returns for 2008, 2009, and 2010 are still subject to audit by the internal revenue service.

Concentrations of Credit Risk−The Company has maintained cash balances in excess of the Federal Deposit Insurance Corporation (FDIC) insured limit.

As of December 31, 2011, Lion Oil Trading & Transport and Plains Marketing accounted for 34% and 47%, respectively, of oil and natural gas sales. For the year ended December 31, 2011, Lion Oil Trading & Transport and Plains Marketing accounted for 35% and 45%, respectively, of oil and natural gas sales. For the year ended December 31, 2010 Lion Oil Trading & Transport and Plains Marketing accounted for 52% and 30%, respectively, of oil and natural gas sales.

Risks and Uncertainties−Historically, oil and gas prices have experienced significant fluctuations and have been particularly volatile in recent years. Price fluctuations can result from variations in weather, levels of regional or national production and demand, availability of transportation capacity to other regions of the country and various other factors.

Oil and Gas Derivative Activities−The Company recognizes all derivative instruments on the balance sheet as either assets or liabilities at fair value.

The Company is exposed to commodity price risk related to oil and gas prices. To mitigate this risk, the Company enters into oil and gas forward contracts as economic hedges. The contracts, which are generally placed with major financial institutions or with counter parties which management believes to be of high credit quality, may take the form of futures contracts, swaps or options. The oil and gas reference prices of these contracts are based upon oil and natural gas futures, which have a high degree of historical correlation with actual prices received by the Company.

Prior Year Reclassifications−Certain predecessor balances have been reclassified to conform to the current year presentation, and such reclassifications had no impact on net income or stockholders equity previously reported.

In December 2011, the FASB issued Accounting Standards Update No. 2011-11, *Balance Sheet: Disclosures about Offsetting Assets and Liabilities* ("ASU 2011-11"). The objective of ASU 2011-11 is to require an entity to provide enhanced disclosures that will enable users of its financial statements to evaluate the effect or potential effect of netting arrangements on an entity' s financial position. ASU 2011-11 is effective for interim and annual reporting periods beginning on or after January 1, 2013

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and should be applied retrospectively. The adoption of this standard will not have an impact on the Company' s consolidated financial statements.

In May 2011, the FASB issued Accounting Standards Update No. 2011-04, *Fair Value Measurement: Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRSs* ("ASU 2011-04"), which provides amendments to FASB ASC Topic 820, *Fair Value Measurement*. The objective of ASU 2011-04 is to create common fair value measurement and disclosure requirements between GAAP and International Financial Reporting Standards ("IFRS"). The amendments clarify existing fair value measurement and disclosure requirements and make changes to particular principles or requirements for measuring or disclosing information about fair value measurements. These amendments are not expected to have a significant impact on companies applying GAAP. ASU 2011-04 is effective for interim and annual periods beginning after December 15, 2011. The adoption of this standard will not have an impact on the Company' s consolidated financial statements other than additional disclosures

In December 2010, the FASB issued Accounting Standards Update No. 2010-29, *Business Combinations: Disclosure of Supplementary Pro Forma Information for Business Combinations* (ASU 2010-29), which provides amendments to FASB ASC Topic 805, *Business Combinations*. The objective of ASU 2010-29 is to clarify and expand the pro forma revenue and earnings disclosure requirements for business combinations. ASU 2010-29 was adopted effective January 1, 2011 and did not have an impact on the Company' s consolidated balance sheet other than additional disclosures.

In January 2010, the FASB issued Accounting Standards Update No. 2010-06, *Improving Disclosures about Fair Value Measurements* (ASU 2010-06), which provides amendments to FASB ASC Topic 820, *Fair Value Measurements and Disclosures.* The objective of ASU 2010-06 is to provide more robust disclosures about (i) the different classes of assets and liabilities measured at fair value, (ii) the valuation techniques and inputs used, (iii) the activity in Level 3 fair value measurements, and (iv) significant transfers between Levels 1, 2 and 3. ASU 2010-06 was effective for fiscal years and interim periods beginning after December 15, 2009, except for the activity in Level 3 measurement disclosures which was effective January 1, 2011. The Company adopted ASU 2010-06 effective December 31, 2010.

In December 2008, the SEC issued *Modernization of Oil and Gas Reporting: Final Rule,* which published the final rules and interpretations updating its oil and gas reporting requirements. The final rule includes updated definitions in the existing oil and gas rules to make them consistent with the petroleum resource management system, which is a widely accepted standard for the management of petroleum resources that was developed by several industry organizations. Key revisions included the ability to include nontraditional resources in reserves, the use of new technology for determining reserves, permitting disclosure of probable and possible reserves, and changes to the pricing used to determine reserves in that companies must use a 12-month average price. The average is calculated using the first-day-of-the-month price for each of the 12 months that make up the reporting period. In January 2010, the FASB issued Accounting Standards Update No. 2010-03, *Oil and Gas Reserve Estimation and Disclosures* (ASU 2010-03), which provides amendments to FASB ASC topic *Extractive Activities-Oil and Gas.* The objective of ASU 2010-03 is to align the oil and gas reserve estimation and disclosure requirements of the FASB ASC with the requirements in the SEC' s *Modernization of Oil and Gas Reporting: Final Rule*. BCEC and HEC, the predecessor companies adopted the new rules effective December 31, 2009, and as a result, the Company' s reserves were prepared in accordance with the new reserve definitions in ASU 2010-03 that conform to the SEC' s revised reserve definitions. Oil and gas reserve quantities or their values are a significant component of the Company' s depreciation, depletion and amortization, asset retirement obligation, and proved property impairment analyses. Due to the number of estimates that rely upon reserve quantities and values, any significant changes to the Company' s oil and gas reserves has a pervasive effect on the Company' s consolidated balance sheet, and it is therefore impracticable to estimate the effect that the adoption of ASU 2010-03 had on the Company' s consolidated balance sheet.

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3. ACQUISITIONS:

On December 23, 2010, the Company completed the following transactions: (i) the sale of 21,166,134 shares of common stock for $12.52 per share; (ii) the issuance of 6,272,851 shares of common stock valued at $12.52 per share to the holders of BCEC in exchange for all of BCEC' s ownership in Bonanza Creek Energy Operating Company, LLC (a wholly owned subsidiary); and (iii) the acquisition of all of the ownership of HEC for approximately $59 million in cash and 1,683,536 shares of its common stock valued at $12.52 per share. As part of the transactions, the Company also retired debt of approximately $182 million for cash and paid approximately $17 million for debt extinguishment penalties assumed as part of the merger. Because the penalties for the extinguishment of debt were considered as part of the liabilities assumed, the penalties were allocated to the assets acquired and the liabilities assumed as part of the purchase price. Furthermore, a deferred tax liability was recorded based on the difference between the tax basis of the contributed assets and liabilities and their fair value at an effective tax rate of approximately 37%. Fair value was allocated to the assets contributed and liabilities assumed as follows:

	Bonanza Creek Energy Company, LLC	Holmes Eastern Company, LLC	Debt Extinguishment	Deferred Tax Adjustment	Bonanza Creek Energy, Inc.
Current assets, including cash and commodity derivatives	$ 10,917,445	$ 3,848,328	$ –	$ –	$ 14,765,773
Proved oil and gas properties	280,831,550	77,985,048	16,680,311	65,806,160	441,303,069
Unproved oil and gas properties	11,376,727	–	678,704	2,693,686	14,749,117
Wells in progress	5,782,885	1,786,917	–	–	7,569,802
Natural gas plant	31,840,475	–	–	–	31,840,475
Property and equipment	777,564	25,115	–	–	802,679
Other noncurrent assets, including commodity derivatives	5,357,346	–	–	–	5,357,346
Current liabilities, including commodity derivatives	(19,894,250)	(3,559,307)	–	–	(23,453,557)
Bank revolving credit	(84,400,000)	–	29,000,000	–	(55,400,000)
Senior subordinated notes, including pre-payment penalty of $14,327,348	(125,145,205)	–	125,145,205	–	–
Second lien term loan, including pre-payment penalty of $3,031,667	(33,031,667)	–	33,031,667	–	–
Note payable–related party	(12,276,228)	–	12,276,228	–	–

Commodity derivatives, noncurrent	(5,673,460)	–	–	–	(5,673,460)
Deferred income taxes, net	–	–	–	(68,499,846)	(68,499,846)
Other noncurrent liabilities, including asset retirement obligations	(5,917,784)	(901,479)	–	–	(6,819,263)
Value of common stock issued as consideration	$ 60,545,398	$ 79,184,622	$ 216,812,115	$ –	$ 356,542,135

Supplemental Pro Forma Results (unaudited)–The following unaudited pro forma financial information represents the combined results for BCEI, BCEC, and HEC for year ended December 31, 2010 as if the contribution and acquisition had occurred on January 1, 2010. The adjustment to depreciation, depletion and amortization assumes that the oil and gas property step up in basis occurred January 1, 2010.

The pro forma financial information is not intended to represent or be indicative of the consolidated results of operations or financial condition of the Company that would have been reported had the acquisition been completed as of the dates presented, and should not be taken as representative of the future consolidated results of operations of the Company.

	Bonanza Creek Energy Company, LLC	**Holmes Eastern Company, LLC**	**Bonanza Creek Energy, Inc.**	**Pro Forma Adjustments**	**Bonanza Creek Energy, Inc.**
Net revenues:					
Oil and gas sales	$ 43,506,084	$ 13,957,560	$ 1,620,192	$ –	$ 59,083,836
Operating expenses:					
Lease operating	11,947,925	2,010,187	419,100	–	14,377,212
Severance and ad valorem taxes	1,467,477	834,282	66,460	–	2,368,219
Exploration	226,452	19,234	–	–	245,686
Depreciation, depletion and amortization	12,598,429	3,005,888	435,552	2,815,872	18,855,741
General and administrative	8,374,875	639,598	323,545	–	9,338,018
Cancelled private placement	2,378,468	–	–	–	2,378,468
Total operating expenses	36,993,626	6,509,189	1,244,657	2,815,872	47,563,344
Income (loss) from operations	6,512,458	7,448,371	375,535	(2,815,872)	11,520,492
Other income (expense):					
Other income (loss)	19,173	(65,694)	–	–	(46,521)
Write-off of deferred financing costs	(1,663,167)	–	–	–	(1,663,167)
Change in fair value of warrant put option	34,344,894	–	–	(34,344,894)	–
Amortization of debt discount	(8,861,955)	–	–	8,861,955	–
Realized gain on settled commodity derivatives	5,918,702	–	(46,742)	–	5,871,960
Unrealized loss in fair value of commodity derivatives	(7,604,742)	–	(514,627)	–	(8,119,369)
Interest expense	(18,000,796)	(439,171)	(57,656)	17,234,623	(1,263,000)
Total other income (expense)	4,152,109	(504,865)	(619,025)	(8,248,316)	(5,220,097)
Income (loss) from continuing operations	10,664,567	6,943,506	(243,490)	(11,064,188)	6,300,395
(Loss) income from operations associated with oil and gas properties held for sale	63,962	–	(12,689)	(363,624)	(312,351)
Gain on sale of oil and gas properties	4,055,153	–	–	–	4,055,153
Income (loss) before taxes	$ 14,783,682	$ 6,943,506	$ (256,179)	$ (11,427,812)	$ 10,043,197

4. OTHER ASSETS:

The Company has multiple certificates of deposit at three financial institutions to meet financial bonding requirements in the states of Colorado, Wyoming and California. As of December 31, 2011 and 2010 the certificates of deposit totaled $645,000.

As of December 31, 2011 and 2010, the Company had a note receivable of $0 and approximately $987,000, respectively from the operator of the Sargent field. This note receivable was paid in full during February of 2011.

As of December 31, 2011 and 2010, the Company had approximately $2,774,000, and $1,494,000, respectively of unamortized deferred financing costs related to the bank revolving credit agreement that was retained by the Company.

	2011	2010
Certificates of deposit	$ 645,000	$ 645,000
Note receivable	–	986,906
Deferred financing costs	2,773,626	1,493,764
	$ 3,418,626	$ 3,125,670

5. ACCOUNTS PAYABLE AND ACCRUED EXPENSES:

Accounts payable and accrued expenses contain the following:

	2011	2010
Drilling and completion costs	$ 14,153,449	$ 4,597,857
Accounts payable trade	4,976,979	6,213,962
Ad valorem taxes	1,781,021	1,373,548
Accrued general and administrative cost	1,713,708	1,808,995
Accrued initial public offering expenses	1,258,791	–
Lease operating expense	2,128,470	1,240,481
Accrued reclamation cost	400,000	400,000
Interest	17,965	106,034
Accrued oil and gas hedging	353,897	244,527
Production taxes and other	284,046	116,132
	$ 27,068,326	$ 16,101,536

6. LONG-TERM DEBT:

Senior Secured Revolving Credit Facility–On March 29, 2011, the Company entered into a Senior Secured Revolving Credit Agreement, (the “Revolver”), with a syndication of banks, with BNP Paribas as the administrative agent and issuing lender, which provides for borrowings of up to $300 million. The Revolver provides for interest rates plus an applicable margin to be determined based on LIBOR or a bank base rate (the “Base Rate”), at the Company’ s election. LIBOR borrowings bear interest at LIBOR plus 1.75% to 2.75% depending on the utilization level and the Base Rate borrowings bear interest at the “Bank Prime Rate,” as defined plus .75% to 1.75%.

The Revolver has a $220 million borrowing base as of December 31, 2011 and is subject to semi-annual re-determinations in April and October of each year. The Revolver provides for commitment fees of .375% to 0.50%, depending on utilization, and restricts, among other items, the payment of dividends, certain additional indebtedness, sale of assets, loans, certain investments and mergers. The Revolver also contains certain financial covenants, which require the maintenance of a minimum current ratio and a minimum debt coverage ratio, as defined. The Company was in compliance with these covenants as of December 31, 2011. The Revolver is collateralized by substantially all the Company' s assets and matures on September 15, 2016.

7. COMMITMENTS AND CONTINGENT LIABILITIES:

Office Leases−The Company rents office facilities under various noncancelable operating lease agreements. The Company' s noncancelable operating lease agreements result in total future minimum noncancelable lease payments are presented below. The Company also has principal payment requirements for its line of credit which is also presented below:

	Office Leases	Line of Credit	Total
2012	$ 568,241	$ −	$ 568,241
2013	744,242	−	744,242
2014	763,847	−	763,847
2015	785,424	−	785,424
2016 and thereafter	1,562,913	6,600,000	8,162,913
	$ 4,424,667	$ 6,600,000	$ 11,024,667

Environmental−The Company is engaged in oil and gas exploration and production and may become subject to certain liabilities as they relate to environmental cleanup of well sites or other environmental restoration procedures as they relate to the drilling of oil and gas wells and the operations. Relative to the Company' s acquisition of existing or previously drilled well bores, the Company may not be aware of what environmental safeguards were taken at the time such wells were drilled or during such time the wells were operated. Should it be determined that a liability exists with respect to any environmental clean up or restoration, the liability to cure such a violation could fall upon the Company. Management believes its properties are operated in conformity with local, state and federal regulations. No claims have been made, nor is the Company aware of any uninsured liability which the Company may have, as it relates to any environmental cleanup, restoration or the violation of any rules or regulations.

Legal Proceedings−The Company may from time to time be involved in various other legal actions arising in the normal course of business. During the second quarter of 2011, our Board of Directors formed a Special Litigation Committee comprised of three non-executive directors to investigate the merits of a demand for arbitration against our current President and Chief Executive Officer from the former Chairman of BCEC related to the management of BCOC and BCEC during 2005 and 2006. These demands do not allege any wrongdoing by or claims against the Company. The Special Litigation Committee retained outside independent advisors to conduct the investigation and concluded that the allegations were without merit. The Company' s general and administrative expense includes approximately $1.0 million related to this matter for the year ended December 31, 2011.

8. STOCKHOLDERS' EQUITY:

Common Stock−On December 15, 2011 the Company sold 10,000,000 shares of common stock in our initial public offering at $17.00 per share, less $1.105 per share for underwriting discounts and commissions. Other expense related to the issuance and distribution of these shares were approximately $3 million.

On December 23, 2010 the Company issued 21,166,134 shares of common stock to West Face Capital and to certain clients of AIMCo at $12.52 per share. Also as part of the formation on December 23, 2010 BCEC contributed all of its ownership interest in Bonanza Creek Energy Operating Company, LLC to the Company for 6,272,851 shares of its common stock valued at $12.52 per share. In addition, on December 23, 2010, the Company issued 1,683,536 shares of its common stock valued at $12.52 per share to the majority owner of HEC and a member of Bonanza Creek Energy, Inc.' s management who also owned a minority interest of HEC (refer to Note 3).

Management Incentive Plan−On December 23, 2010, the Company established the Management Incentive Plan (the "Plan" or "MIP") for the benefit of certain employees, officers and other individuals performing services for the Company. The maximum number of shares of Class B common stock available under the Plan is 10,000 and these shares were converted into 437,787 shares of restricted common stock upon completion of our initial public offering. The conversion rate was determined based on a formula factoring in the rate of return to the common stockholders. The 437,787 shares of common stock that were granted to employees were valued at $17.00 per share on the grant date and vest over a three year period. Non-cash compensation expense of $122,000 was recorded during the year ended December 31, 2011 and there was $7,320,000 of unrecognized compensation costs related to the unvested restricted common stock granted under the plan. That cost is expected to be recognized over a period of 2.9 years.

BCEC Management Incentive Plan−In connection with the corporate restructuring described in Note 1, 317,142 shares of common stock of BCEI were designated for holders of BCEC' s Class B units. These shares were held in trust for the benefit of employees. On December 15, 2011, 243,945 of these shares were valued at $17.00 per share and granted to employees without vesting requirements and the Company recorded a non-cash compensation charge in the amount of $4,147,000. As of December 31, 2011, 73,197 shares of BCEI common stock remain held in trust and designated for holders of BCEC' s Class B units. When and if such shares are issued, they will be valued based on the market price of the Company' s common stock on the grant date.

9. INCOME TAXES:

Deferred tax assets and liabilities are measured by applying the provisions of enacted tax laws to determine the amount of taxes payable or refundable currently or in future years related to cumulative temporary differences between the tax bases of assets and liabilities and amounts reported in the Company' s balance sheet. The tax effect of the net change in the cumulative temporary differences during each period in the deferred tax assets and liabilities determines the periodic provision for deferred taxes. The provision for income taxes consists of the following:

	2011	2010
Current tax (expense) benefit	$ −	$ −
Deferred tax (expense) benefit	(11,198,240)	94,453
Total income tax (expense) benefit	$ (11,198,240)	$ 94,453

Temporary differences between the financial statement carrying amounts and tax bases of assets and liabilities that give rise to the net deferred tax liability result from the following components:

	2011	2010
Property and equipment	$ 94,695,252	$ 72,577,610
Net operating loss carryforward	(10,431,642)	−
Stock compensation	(110,041)	−
Abandonment obligations	(2,293,919)	(1,921,385)
Derivative liability	(2,233,229)	(2,250,832)
Deferred deductions and other	(22,788)	−
Total long-term liability	$ 79,603,633	$ 68,405,393

At December 31, 2011, the Company had net operating loss carryforwards for federal tax purposes of approximately $27,465,761. The net operating loss carryforwards will expire in 2031. Reconciliation of the Company' s effective tax rate to the expected federal tax rate of 34% is as follows:

	2011	2010
Expected federal tax rate	34%	34%
State income taxes	3.98%	2.87%
Change in tax rate	8.9%	
Effective tax rate	46.88%	36.87%

During the year ended December 31, 2011, the estimated effective tax rate was revised to reflect significant capital expenditures in Arkansas and the effective tax rate increased from 36.87% to 37.98%. The increase in the effective tax rate was applied to the January 1, 2011 deferred income tax liability resulting in an increase to the net deferred tax liability and deferred income tax expense of $2.1 million with an additional $9.1 million incurred for federal and state income taxes for the year ended December 31, 2011 for a total deferred income tax expense in our consolidated statement of operations of $11.2 million.

10. ASSET RETIREMENT OBLIGATIONS:

In connection with the Company' s acquisition of BCEC and HEC, asset retirement obligations in the amount of $4,970,441, and $641,268, respectively, were assumed.

The fair value of asset retirement obligation is recorded as a liability when incurred, which is typically at the time the assets are acquired or placed in service. Amounts recorded for the related assets are increased by a corresponding amount of these obligations. Prospectively, the liabilities are accreted for the change in their present value and the initial capitalized costs are depleted, depreciated and amortized over the productive lives of the related assets.

	2011	2010
Beginning of year	$ 5,611,709	$ −
Additional liabilities incurred	1,308,122	−
Accretion expense	443,801	−
Obligations on properties acquired	−	5,611,709
Liabilities settled	(155,558)	
Revisions to estimate	(1,168,351)	−
End of year	$ 6,039,723	$ 5,611,709

The downward revision to asset retirement obligations recorded during 2011 was related to revised costs to abandon a well and longer well life due to higher oil prices.

11. FAIR VALUE MEASUREMENTS:

The Company follows FASB ASC 820, *Fair Value Measurements and Disclosures*, which defines fair value, establishes a framework for using fair value to measure assets and liabilities, and expands disclosures about fair value measurements. The statement establishes a hierarchy for inputs used in measuring fair value that maximizes the use of observable inputs and minimizes the use of unobservable inputs by requiring that the most observable inputs be used when available. Observable inputs are inputs that market participants would use in pricing the asset or liability developed based on market data obtained from sources independent of the Company. Unobservable inputs are inputs that reflect the Company' s assumptions of what market participants would use in pricing the asset or liability developed based on the best information available in the circumstances. The hierarchy is broken down into three levels based on the reliability of the inputs as follows:

Level 1: Quoted prices are available in active markets for identical assets or liabilities;
Level 2: Quoted prices in active markets for similar assets and liabilities that are observable for the asset or liability; or
Level 3: Unobservable pricing inputs that are generally less observable from objective sources, such as discounted cash flow models or valuations.

ASC 820 requires financial assets and liabilities to be classified based on the lowest level of input that is significant to the fair value measurement. The Company' s assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of the fair value of assets and liabilities and their placement within the fair value hierarchy levels.

The Company' s commodity swaps are valued using a market approach based on several factors, including observable transactions for the same or similar commodity options using the NYMEX futures index, and are designated as Level 2 within the valuation hierarchy. The Company' s collars, which are designated as Level 3 within the valuation hierarchy, are also valued using a market approach, but are not validated by observable transactions with respect to volatility. The counterparty in all of the commodity derivative financial instruments is the lender on the Company' s Senior Secured Revolving Credit facility (Note 6).

The following tables present the Company' s financial assets and liabilities that were accounted for at fair value on a recurring basis as of December 31, 2011 and 2010 by level within the fair value hierarchy:

	Fair Value Measurements Using		
December 31, 2011	**Level 1**	**Level 2**	**Level 3**
Commodity derivative assets	$ –	$ 1,094,055	$ 881,822
Commodity derivative liabilities	$ –	$ 6,740,213	$ 1,115,595

	Fair Value Measurements Using		
December 31, 2010	**Level 1**	**Level 2**	**Level 3**
Commodity derivative assets	$ –	$ 1,062,025	$ 2,379,629
Commodity derivative liabilities	$ –	$ 9,546,979	$ –

The following table reflects the activity for the commodity derivatives measured at fair value using Level 3 inputs during the period from January 1, 2011 through December 31, 2011:

	Derivative Asset	**Derivative Liability**
Beginning balance	$ 2,379,629	$ –
Net increase (decrease) in fair value	(1,308,501)	–
Net realized gain on settlement	(189,306)	–
New derivatives	–	1,115,595
Transfers in (out) of Level 3	–	–
Ending balance	$ 881,822	$ 1,115,595

The allocation of the purchase price to the assets acquired and the liabilities assumed of BCEC and HEC was determined using Level 3 inputs.

Proved Oil and Gas Properties−Proved oil and gas property costs are evaluated for impairment and reduced to fair value when there is an indication that the carrying costs exceed the sum of the undiscounted cash flows. The Company uses Level 3 inputs and the income valuation technique, which converts future amounts to a single present value amount, to measure the fair value of proved properties through an application of discount rates and price forecasts selected by the Company' s management. The calculation of the discount rate is a significant management estimate based on the best information available and estimated to be 10 percent for the one year period ended December 31, 2011. Management believes that the discount rate is representative of current market conditions and reflects the following factors: estimate of future cash payments, expectations of possible variations in the amount and/or timing of cash flows, the risk premium, and nonperformance risk. The price forecast is based on the New York Mercantile Exchange ("NYMEX") strip pricing, adjusted for basis differentials. Future operating costs are also adjusted as deemed appropriate for these estimates.

Asset Retirement Obligation−Upon completion of wells and natural gas plants, the Company records an asset retirement obligation at fair value using Level 3 assumptions.

12. DERIVATIVES:

As of December 31, 2011, the Company' s derivative commodity contracts with BNP Paribas, Wells Fargo Bank, and KeyBank are as follows:

Contract Term	Notional Volume	Floor	Ceiling	Fixed Price
January 1 - December 31, 2012	13,956 Bbl./Month	$ 90.00	$ 123.00	−
January 1 - December 31, 2012	30,000 Bbl./Month	$ 90.00	$ 102.00	−
January 1 - December 31, 2012	24,000 Bbl./Month	$ 90.00	$ 102.40	−
January 1 - April 30, 2013	12,654 Bbl./Month	$ 90.00	$ 123.00	−
January 1 - December 31, 2012	8,206 Bbl./Month	−	−	$ 62.95
January 1 - October 31, 2013	7,542 Bbl./Month	−	−	$ 61.50
January 1 - December 31, 2012	16,860 MMBTU/Month	−	−	$ 6.75
January 1 - October 31, 2013	15,481 MMBTU/Month	−	−	$ 6.40

The table below contains a summary of all the Company' s derivative positions reported on the consolidated balance sheet as of December 31, 2011:

Derivatives	Balance Sheet Location	Fair Value
Asset		
Commodity derivatives	Current derivative assets	$ 1,297,403
Commodity derivatives	Long-term derivative assets	678,474
Liability		
Commodity derivatives	Current derivative liability	(5,276,633)
Commodity derivatives	Long-term derivative liability	(2,579,175)
Total net derivative liability		$ (5,879,931)

13. SUBSEQUENT EVENTS:

Subsequent events have been evaluated by management through the date of issuance of these financial statements.

During February of 2012, the Company executed a derivative commodity contract with Key Bank covering 10,000 BBLs per month for the period from January 1, 2013 through December 31, 2013. This contract has a floor price of $93.00 per BBL with a ceiling price of $108.60 per BBL.

Divestitures:

The Company' s decision to begin marketing, with an intent to sell, all of its oil and gas properties in California during June of 2012 required retrospective revision to the Company' s year-end financial statements that were previously filed in our Annual Report on Form 10-K. The retrospective revision to reflect the discontinued operations had no impact on net income (loss), total assets or net assets for any of the years presented. The carrying amounts of the major classes of assets related to the operation of the properties that are now classified as held for sale as of December 31, 2011 and 2010 are presented below:

	As of December 31, 2011	As of December31, 2010
ASSETS HELD FOR SALE, NET:		
Oil and gas properties, successful efforts method:		
Proved properties	$ 13,060,597	$ 15,113,208
Unproved properties	32,013	32,013
Wells in progress	167,198	133,258
Total property and equipment	13,259,808	15,278,479
Less accumulated depletion and depreciation	(3,364,300)	(70,755
Net property and equipment	$ 9,895,508	$ 15,207,724

The current assets and liabilities related to the properties are immaterial. The total revenues and costs and expenses, and the income associated with the operation of the oil and gas properties held for sale are presented below.

	Bonanza Creek Energy, Inc. For the Year Ended December 31, 2011	Bonanza Creek Energy, Inc. For the Period From Inception December 23, 2010 to December 31, 2010	Bonanza Creek Energy Company, LLC (Predecessor) For the Period January 1, 2010 to December 23, 2010	Bonanza Creek Energy Company, LLC (Predecessor) For the Year Ended December 31, 2009
NET REVENUES:				
Oil and gas sales	$ 6,739,479	$ 125,223	$ 4,822,010	$ 5,239,939
OPERATING EXPENSES:				
Lease operating	3,234,575	63,728	2,843,860	2,704,625
Severance and ad valorem taxes	169,705	3,429	153,018	163,289
Exploration	7,460	–	134,290	131,059
Depreciation, depletion and amortization	3,493,519	70,755	1,626,880	1,513,967
Impairment of proved properties	3,443,984	–	–	579,337
TOTAL COSTS AND EXPENSES	10,349,243	137,912	4,758,048	5,092,277
(LOSS) INCOME FROM				
OPERATIONS ASSOCIATED WITH	$ (3,609,764)	(12,689)	$ 63,962	$ 147,662

OIL AND GAS PROPERTIES HELD FOR SALE

14. OIL AND GAS ACTIVITIES:

The Company' s oil and natural gas activities are entirely within the United States. Costs incurred in oil and natural gas producing activities are as follows:

	2011	2010
Unproved property acquisitions	$ 1,131,599	$ −
Proved property acquisitions	762,701	−
Development(a)	84,161,794	817,362
Gas plant capital expenditures	25,069,757	−
Exploration(b)	58,034,514	−
Total	$ 169,160,365	$ 817,362

(a) Development costs include workover costs of $2,808,663 and $−charged to lease operating expense during 2011 and 2010, respectively.

(b) Exploration costs include $884,431 and $−charged to exploration expense during 2011 and 2010, respectively.

The net changes in capitalized exploratory well costs are as follows:

	2011	2010
Beginning balance at January 1	$ 974,000	$ −
Additions to capitalized exploratory well costs pending the determination of proved reserves	7,075,921	974,000
Reclassifications to wells, facilities and equipment based on the determination of proved reserves	(2,611,618)	−
Capitalized exploratory well costs charged to expense	−	−
Ending balance at December 31	$ 5,438,303	$ 974,000

At December 31, 2011, the Company had capitalized $974,000 for exploratory wells in progress for a period of greater than one year.

15. DISCLOSURES ABOUT OIL AND GAS PRODUCING ACTIVITIES (UNAUDITED):

In December 2008, the SEC published the final rules and interpretations updating its oil and gas reporting requirements. The Company adopted the rules effective December 31, 2010, and the rule changes, including those related to pricing and technology, are included in the Company' s reserve estimates.

In January 2010, the FASB aligned ASC Topic 932 with the aforementioned SEC requirements. Please refer to the section entitled "Adopted and Recently Issued Accounting Pronouncements" under Note 2−Summary of Significant Accounting Policies for additional discussion regarding both adoptions.

The estimate of proved reserves and related valuations for the years ended December 31, 2010 and 2011 were based upon a report prepared by Cawley, Gillespie & Associates, Inc. Petroleum Consultants. The estimates of proved reserves are inherently imprecise and are continually subject to revision based on production history, results of additional exploration and development, price changes and other factors.

All of BCEI' s oil and natural gas reserves are attributable to properties within the United States. A summary of BCEI' s changes in quantities of proved oil and natural gas reserves for the period ended December 31, 2010 and the year ended December 31, 2011 are as follows:

	Oil (MBbl)	Natural Gas (MMcf)
Balance–December 23, 2010	–	–
Extensions and discoveries	–	–
Purchases of minerals in place	22,398	62,926
Production	(19)	(42)
Revisions to previous estimates	–	–
Balance–December 31, 2010	22,379	62,884
Extensions and discoveries(a)	7,182	29,608
Purchases of minerals in place	–	–
Production	(1,137)	(2,776)
Revisions to previous estimates(b)	(208)	3,266
Balance–December 31, 2011	28,216	92,982
Proved developed reserves:		
December 23, 2010	–	–
December 31, 2010	8,180	20,074
December 31, 2011	11,842	31,313
Proved undeveloped reserves:		
December 23, 2010	–	–
December 31, 2010	14,199	42,810
December 31, 2011	16,374	61,669

(a) Extensions and discoveries are fully associated with the Rocky Mountain region and is comprised of 168 new Proved Undeveloped locations plus 54 Unproved locations that were drilled in year 2011 and moved directly to Proved Developed Producing. The 168 new Proved Undeveloped locations are comprised of 26 horizontal Niobrara locations, 27 vertical Codell/Niobrara offset locations that were the result of year 2011 PUD drilling and 115 20 acre locations that were moved from Unproved to Proved Undeveloped.

(b) Revisions are comprised of positive revisions resulting mainly from the commodity price increase of $16.76/ Bbl from $79.43/Bbl at December 31, 2010 to $96.19 at December 31, 2011. The positive change in price was partially offset by performance revisions in the Rocky Mountain region due to surface pressure limitations and in the Mid-Continent regions due to timing and forecast changes for the Proved Developed Non-Producing recompletions.

The standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves were prepared in accordance with the provisions of ASC Topic 932. Future cash inflows were computed by applying prices to estimated future production. Future production and development costs are computed by estimating the expenditures to be incurred in developing and producing the proved oil and natural gas reserves at year-end, based on costs and assuming continuation of existing economic conditions.

Future income tax expenses are calculated by applying appropriate year-end tax rates to future pretax net cash flows relating to proved oil and natural gas reserves. Future income tax expenses give effect to permanent differences, tax credits and loss carryforwards relating to the proved oil and natural gas reserves. Future net cash flows are discounted at a rate of 10% annually to derive the standardized measure of discounted future net cash flows. This calculation procedure does not necessarily result in an estimate of the fair market value or the present value of BCEI' s oil and natural gas properties.

The standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves are as follows (in thousands):

	December 31, 2011	December 31, 2010
Future cash flows	$ 2,887,010	$ 1,894,178
Future production costs	(805,466)	(572,553)
Future development costs	(514,256)	(351,392)
Future income tax expense	(252,265)	(182,725)
Future net cash flows	1,315,023	787,508
10% annual discount for estimated timing of cash flows	(648,837)	(412,854)
Standardized measure of discounted future net cash flows	$ 666,186	$ 374,654

Future cash flows as shown above were reported without consideration for the effects of derivative transactions outstanding at period end. The effect of hedging transactions in place as of year-end on the future cash flows for the period ended December 31, 2010 and 2011 was immaterial.

The changes in the standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves are as follows (in thousands):

	2011	2010
Beginning of period	$ 374,654	$ –
Sale of oil and gas produced, net of production costs	(84,888)	(1,193)
Net changes in prices and production costs	123,154	–
Extensions, discoveries and improved recoveries	204,000	–
Development costs incurred	93,916	817
Changes in estimated development cost	(62,175)	(817)
Purchases of mineral in place	–	374,803
Revisions of previous quantity estimates	8,113	–
Net change in income taxes	(40,866)	249
Accretion of discount	46,158	1,012
Changes in production rates and other	4,120	(217)
End of period	$ 666,186	$ 374,654

The average wellhead prices used in determining future net revenues related to the standardized measure calculation as of December 31, 2010 and 2011 were calculated using the first-day-of-the-month price inclusive of adjustments for quality and location for each of the 12 months of calendar year 2010.

	2011	2010
Oil (per Bbl)	$ 89.80	$ 74.93
Gas (per Mcf)	$ 4.82	$ 4.81

16. QUARTERLY FINANCIAL DATA (UNAUDITED)

The following is a summary of the unaudited quarterly financial data for the years ended December 31, 2011 and period ended December 31, 2010 (in thousands, except per share data):

	Three Months Ended			
	March 31, 2011	June 30, 2011	September 30, 2011	December 31, 2011
Year ended December 31, 2011:				
Oil and natural gas sales	$ 20,541,995	$ 24,151,668	$ 25,915,330	$ 35,115,000
Operating profit (loss)(1)	10,308,846	12,451,574	13,556,361	17,221,606
Net income (loss)	326,920	7,707,745	4,833,352	(176,836)
Basic and diluted earnings (loss) per share	0.01	0.26	0.17	(0.01)

	Three Months Ended				
	March 31, 2010(2)	June 30, 2010(2)	September 30, 2010(2)	Period from October 1, 2010 to December 23, 2010	Period from Inception to December 31, 2010(4)
Year ended December 31, 2010:					
Oil and natural gas sales	$ 9,539,813	$ 9,159,227	$ 12,496,769	$ 12,310,275	$ 1,620,192
Operating profit (loss)(1)	3,462,810	3,239,633	4,615,282	6,159,094	699,080
Net income (loss)	(24,323,457)	64,639,085	(29,173,733)	3,641,787	(161,726)
Basic and diluted earnings (loss) per share(2)(3)	–	–	–	–	–

(1) Oil and natural gas sales less lease operating expense, production taxes and depreciation, depletion and amortization and adjusted to reflect retrospective application of discontinued operations.

(2) Bonanza Creek Energy Company, LLC was a limited liability company; as such, earnings per share were not disclosed. See note 1 to Bonanza Creek Energy, Inc.' s annual financial statements.

(3) Bonanza Creek Energy Company, LLC' s results for the period from October 1, 2010 through December 23, 2010.

(4) Bonanza Creek Energy, Inc. generated a net loss during the period from inception on December 23, 2010 to December 31, 2010; such loss per share was de minimus.