MamaMancini's Holdings, Inc.
Form 10-K
May 01, 2015

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

[X] ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the year ended January 31, 2015

OR

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

MAMAMANCINI'S HOLDINGS, INC.
(Exact name of registrant as specified in its charter)

Nevada	**000-54954**	**27-0607116**
(State or other jurisdiction of incorporation or organization)	(Commission File Number)	(I.R.S. Employer Identification Number)

25 Branca Road

East Rutherford, NJ 07073

(Address of Principal Executive Offices)

(Former name or former address, if changed since last report)

(201) 531-1212

(Registrant's telephone number, including area code)

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

Securities registered pursuant to Section 12(g) of the Act: **Common Stock, $0.00001 par value**

Indicate by check mark whether the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes [ ] No [X]

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

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes [X] No [ ]

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

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

Large accelerated filer	[ ]	Accelerated filer	[ ]
Non-accelerated filer	[ ]	Smaller reporting company	[X]

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). Yes [ ] No [X]

The aggregate market value of the voting and non-voting common equity held by non-affiliates of the registrant on July 31, 2014, based on a closing price of $1.85 was approximately $23,590,184. As of January 31, 2015, the registrant had 26,047,376 shares of its common stock, 0.00001 par value per share, outstanding.

Documents Incorporated By Reference: None.

MAMAMANCINI'S HOLDINGS, INC.

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FORWARD LOOKING STATEMENTS

Included in this Form 10-K are “forward-looking” statements, as well as historical information. Although we believe that the expectations reflected in these forward-looking statements are reasonable, we cannot assure you that the expectations reflected in these forward-looking statements will prove to be correct. Our actual results could differ materially from those anticipated in forward-looking statements as a result of certain factors, including matters described in the section titled “Risk Factors.” Forward-looking statements include those that use forward-looking terminology, such as the words “anticipate,” “believe,” “estimate,” “expect,” “intend,” “may,” “project,” “plan,” “will,” “shall, similar expressions, including when used in the negative. Although we believe that the expectations reflected in these forward-looking statements are reasonable and achievable, these statements involve risks and uncertainties and we cannot assure you that actual results will be consistent with these forward-looking statements. We undertake no obligation to update or revise these forward-looking statements, whether to reflect events or circumstances after the date initially filed or published, to reflect the occurrence of unanticipated events or otherwise.

PART I

ITEM 1. BUSINESS.

Our History

MamaMancini’s Holdings, Inc. (formerly Mascot Properties, Inc.) was incorporated in the State of Nevada on July 22, 2009. Mascot Properties, Inc.’s (“Mascot”) activities since its inception consisted of trying to locate real estate properties to manage, primarily related to student housing, and services which included general property management, maintenance and activities coordination for residents. Mascot did not have any significant development of such business and did not derive any revenue. Due to the lack of results in its attempt to implement its original business plan, management determined it was in the best interests of the shareholders to look for other potential business opportunities.

On February 22, 2010, MamaMancini’s LLC was formed as a limited liability company under the laws of the state of New Jersey in order to commercialize our initial products. On March 5, 2012, the members of MamaMancini’s, LLC, holders of 4,700 units (the “Units”) of MamaMancini’s LLC, exchanged the Units for 15,000,000 shares of common stock and those certain options to purchase an additional 223,404 shares of MamaMancini’s Inc. (the “Exchange”). Upon consummation of the Exchange, MamaMancini’s LLC ceased to exist and all further business has been and continues to be conducted by MamaMancini’s Inc.

On January 24, 2013, Mascot, Mascot Properties Acquisition Corp, a Delaware corporation and wholly-owned subsidiary of the Company ("Merger Sub"), MamaMancini's Inc., a privately-held Delaware Corporation headquartered in New Jersey ("Mama's") and David Dreslin, an individual (the "Majority Shareholder"), entered into an Acquisition Agreement and Plan of Merger (the "Agreement") pursuant to which the Merger Sub was merged with and into Mama's, with Mama's surviving as a wholly-owned subsidiary of the Company (the "Merger"). The transaction (the "Closing") took place on January 24, 2013 (the "Closing Date"). Mascot acquired, through a reverse triangular merger, all of the outstanding capital stock of Mama's in exchange for issuing Mama's shareholders (the "Mama's Shareholders"), pro-rata, a total of 20,054,000 shares of the Company's common stock. As a result of the Merger, the Mama's Shareholders became the majority shareholders of Mascot.

Immediately following the Closing of the Agreement, Mascot changed its business plan to that of Mama's. On March 8, 2013, Mascot received notice from the Financial Industry Regulatory Authority ("FINRA") that its application to change its name and symbol had been approved and effective Monday, March 11, 2013, Mascot began trading under its new name, "MamaMancini's Holdings, Inc." ("MamaMancini's" or the "Company") and under its new symbol, "MMMB".

Our Company

MamaMancini’s roots go back to our founder Dan Dougherty, whose grandmother Anna “Mama” Mancini emigrated from Bari, Italy to Bay Ridge, Brooklyn in 1921. Our products were developed using her old world Italian recipes that were handed down to her grandson, Dan Dougherty. Today we market a line of all natural specialty prepared, frozen and refrigerated foods for sale in retailers around the country. Our primary products include beef, turkey, chicken and pork meatballs, all with slow cooked Italian Sauce.

Our products are all natural, contain a minimum number of ingredients and are generally derived from the original recipes of Anna “Mama” Mancini. Our products appeal to health-conscious consumers who seek to avoid artificial flavors, synthetic colors and preservatives that are used in many conventional packaged foods.

The United States Department of Agriculture (the “USDA”) defines all natural as a product that contains no artificial ingredients, coloring ingredients or chemical preservatives and is minimally processed. The Company’s products were submitted to the USDA and approved as all natural. The Food and Safety and Inspection Service (“FSIS”) Food Standards and Labeling Policy Book (2003) requires meat and poultry labels to include a brief statement directly beneath or beside the “natural” Label claim that “explains what is meant by the term natural i.e., that the product is a natural food because it contains no artificial ingredients and is only minimally processed”. The term “natural” may be used on a meat label or poultry label if the product does not contain any artificial flavor or flavoring, coloring ingredient, chemical preservative, or any other artificial or synthetic ingredient. Additionally, the term “all natural” can be used if the FSIS approves your product and label claims. The Company’s product and label claims have been approved by the FSIS to contain the all-natural label.

Our products are principally sold to supermarkets and mass-market retailers. Our products are sold in multiple sections of the supermarket, including: frozen food, fresh meat, prepared foods (meals), sandwich, hot bars and cold bars as well as cold deli and foods-to-go sections. Consumers can find our products at leading food retailers (supermarkets), including:

A&P	Kings	Shaws
BI-LO	Kroger	Shop Rite
BJ’s	Lucky	Stew Leonards
Costco	Lunds and Byerly’s	Stop & Shop
Foodtown	Marsh	The Food Emporium
Giant Eagle	Meatball Obsession	The Fresh Market
Giant	Price Chopper	Waldbaums
Gristedes	Publix	Wal-Mart
Harris Teeter	Rouses	Weis Markets
Jewel	Raleys	Whole Foods

Key Food	Save Mart	Winn-Dixie

We sell directly to both food retailers and food distributors. Some of the leading food distributors we sell to include:

Associated Wholesale Grocers	Gourmet Guru	Sysco
Bozzutos	Grocers Supply Stores	The Chef’s Warehouse
Burris Logistics	Monterrey Provision Co.	The Golub Corp
C&S Wholesale Grocers	Porky Products	Tony’s Fine Foods
Central Grocers	SpartanNash	Unified Grocers
Clover Mountain Foods	Super Store Industries	URM Stores
DPI Mid Atlantic	Supervalu	Wakerfern

Our ten largest customers accounted for approximately 86% for the year ended December 31, 2013, approximately 82% for the one month ended January 31, 2014 and approximately 81% for the year ended January 31, 2015. More specifically, for the year ended December 31, 2013, the one month ended January 31, 2014 and the year ended January 31, 2015 our four largest customers represented approximately 51%, 50% and 64% of our sales, respectively. We depend heavily on these customers and more information regarding the possible effects of any loss of these customers is discussed in the section entitled "Risk Factors".

We have grown the number of food retailers (supermarkets) carrying our products from approximately 7,040 supermarkets in January 2014 to approximately 10,800 supermarkets in January 2015. In the supermarkets that carry our products, we sell an average of 3.3 of our stock keeping units ("SKUs"). The number of supermarkets carrying our products multiplied by the number of our SKUs carried at those supermarkets equals shelf placements for our products. We have grown the number of shelf placements from approximately 22,600 in January 2014 to approximately 35,800 in January 2015.

Industry Overview

Our products are considered specialty prepared foods, in that they are all natural, taste great, are authentic Italian and are made with high quality ingredients. The market for specialty and prepared foods spans several sections of the supermarket, including frozen, deli-prepared foods, and the specialty meat segment of the meat department. The overall size of the specialty prepared food business was calculated by the National Association for the Specialty Food Trade in association with Mintel Research at over $80 billion in 2013 and has grown 18% since 2011.

Packaged Facts, a leading publisher of market research on the food, beverage, consumer packaged goods, and demographic sectors, projects the overall sales of Refrigerated Meats and Meals to be approximately $31 billion by 2018, up from $23 billion in 2013. According to Packaged Facts, this 5.5% implied CAGR is likely driven by trends including a focus on convenience and healthy and creative new products. In addition, Packaged Facts projects that retail sales of Natural/Organic Foods and Beverages will reach $53.5 billion in 2014 and will grow to $86.7 billion by 2019. This implied CAGR of 10.1% is likely driven by the growing social and environmental issues surrounding the interest in and health benefits of natural and organic foods.

Our Strengths

We believe that the following strengths differentiate our products and our brand:

Authentic recipes and great taste. Our products are founded upon Anna “Mama” Mancini’s old world Italian recipes. We believe the authenticity of our products has enabled us to build and maintain loyalty and trust among our current customers and will help us attract new customers. Additionally, we continuously receive positive customer testimonials regarding the great taste and quality of our products.

Healthy and convenient. Our products are made only from high quality natural ingredients, including domestic inspected beef, whole Italian tomatoes, genuine imported Pecorino Romano, real eggs, natural breadcrumbs, olive oil and other herbs and spices. Our products are also simple to prepare. Virtually every product we offer is ready-to-serve within 12 minutes, thereby providing quick and easy meal solutions for our customers. By including the sauce and utilizing a tray with our packaging, our meatballs can be prepared quickly and easily.

Great value. We strive to provide our customers with a great tasting product using all natural ingredients at an affordable price. Typical retail prices for 22 oz. packages ranges from $5.99 to $7.49, and $5.99 to $7.99 for bulk products sold in delis or hot bars. We believe the sizes of our product offerings represent a great value for the price.

New products and innovation. Since our inception, we have continued to introduce new and innovative products. While we pride on ourselves on our traditional beef, turkey, chicken and pork meatballs, we have continuously made efforts to grow and diversify our line of products while maintaining our high standards for all natural, healthy ingredients and great taste. We recently introduced Fusili Pasta with Bolognese Sauce and Mac N’ Mamas® (penne pasta, crushed meatballs, sauce and cheeses). Other recently introduced innovative products include:

Five Cheese Stuffed Beef Meatballs	Antibiotic Free Beef and Turkey Meatballs
Chicken Parmigiana Stuffed Meatballs	Gluten Free Beef and Turkey Meatballs
Chicken Florentine Stuffed Meatballs	

Strong consumer loyalty. Many of our consumers are loyal and enthusiastic brand advocates. Our consumers trust us to deliver great-tasting products made with all natural ingredients. Consumers have actively communicated with us through our website and/or social media channels. We believe that this consumer interaction has generated interest in our products and has inspired enthusiasm for our brand. We also believe that enthusiasm for our products has led and will continue to lead to repeat purchases and new consumers trying our products.

Experienced leadership. We have a proven and experienced senior management team. Our Chief Executive Officer and Chairman, Carl Wolf, has been with us since inception and has over 35 years of experience in the management and operations of food companies. Mr. Wolf was the founder, majority shareholder, Chairman of the Board, and CEO of Alpine Lace Brands, Inc., a public company engaged in the development, marketing and distribution of cheese, deli meats and other specialty food products, which was sold to Land O'Lakes, Inc. In addition, the other members of our board of directors also have significant experience in the food industry.

Our Growth Strategy

We are actively trying to build our brand's reputation, grow sales and improve our product and operating margins by pursuing the following growth strategies:

Increase retail locations. We intend to increase sales by expanding the number of retail stores that sell our products in the mainstream grocery and mass merchandiser channels.

Increase product placements within retail locations. We strive for product placements in the frozen, fresh, and deli segments of food retailers. We believe adding shelf placements within the supermarkets that carry our products will increase customer awareness, leading to more consumers purchasing our products and expanding our market share.

Grow sales staff. We have an experienced sales staff and now employ two full time regional Vice Presidents of sales as well as our Co-Founder Dan Dougherty, Carl Wolf, our Chief Executive Officer and Chairman, and Matthew Brown, our President, each of whom is involved with selling to, and managing sales with, major supermarket chains. We intend to add additional sales personnel in 2015.

Expand food brokerage network. We currently work with approximately 25 retail food brokers. In July 2014 we expanded our broker sales representative network, adding 9 within various territories and with specific accounts of focus. We intend to add additional food brokers in 2015.

Enhance awareness through marketing. Starting in 2013 we began a national radio campaign on Sirius XM Satellite Radio and also have commercials running on political talk radio. We have increased our social media activity with Facebook, Twitter, Pinterest, and YouTube. We also engage with consumers through newsletter mailings, blogs, and special projects, including a bank of recipe videos and contests and giveaways. Targeted

consumer merchandising activity, including virtual couponing, on-pack couponing, mail-in rebates, product demonstrations, and co-op retail advertising will continue into the future in order to increase sales and generate new customers.

Adding new products. Our market research and consumer testing enable us to identify attractive new product opportunities. We intend to continue to introduce new products in both existing and new product lines that appeal to a wide range of consumers. We currently have approximately 17 product offerings.

Products

Our principal products are meatballs with slow cooked Italian Sauce. We currently offer meatballs using the following meats: beef, turkey, chicken and pork.

Our current beef meatball products include:

Our current turkey meatball products include:

Our current chicken meatball products include:

Our current pork meatball products include:

Recently, we expanded our product line to include certain meatball inspired Italian prepared meal products including:

Sauce Products:

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Product Development

MamaMancini’s continues to improve products and to develop new products. We also contract with third parties in order to develop new products. We recently introduced new products, including:

“Mac and Mamas®” (penne pasta, crushed meatballs, sauce and cheeses)	Antibiotic Free Turkey Meatballs and Sauce
Gluten Free Beef Meatballs and Slow Cooked Italian Sauce	Bolognese Sauce
Gluten Free Turkey Meatballs and Slow Cooked Italian Sauce	Fusili Pasta and Bolognese Sauce
Five Cheese Stuffed Beef Meatballs	Stuffed Chicken Parmigiana Style Meatballs and Slow Cooked Italian Sauce
Antibiotic Free Beef Meatballs and Sauce	Stuffed Chicken Florentine Style Meatballs and Slow Cooked Italian Sauce

Our new product development strategy is inspired by Anna “Mama” Mancini’s old world recipes and new recipes derived from those original recipes. All new products currently under development are included with a Development and License Agreement entered into on January 1, 2009 with Dan Dougherty, the grandson of Anna “Mama” Mancini, relating to the use of her recipes for the products to be created by MamaMancini’s.

We are currently developing new products, some of which may include:

Pasta and Slow Cooked Italian Sauce n’ Beef Meatballs	Turkey Meatloaf
Pasta and Slow Cooked Italian Sauce n’ Turkey Meatballs	Chicken Parmagiana
Pasta and Slow Cooked Italian Sauce n’ Sausage	Italian Meatball Soup
Chicken Marsala	Traditional Italian Meatballs (Beef, Pork and Veal) and Slow Cooked Italian Sauce
Beef Meatloaf	

We cannot predict if or when any of the foregoing products under development will ever be available to consumers.

Pricing

Our pricing strategy focuses on being competitively priced with other premium brands. Since our products are positioned in the authentic premium prepared food category, we maintain prices competitive with those of similar products and prices slightly higher than those in the commodity prepared foods section. This pricing strategy also provides greater long-term flexibility as we grow our product line through the growth curve of our products. Current typical retail prices for 22 oz. packages range from $5.99 to $7.49, and $5.99 to $7.99 for bulk products sold in delis or hot bars. Increases in raw materials costs, among other factors, may lead to us consider price increases in the future.

Suppliers/Manufacturers

None of our raw materials or ingredients are grown or purchased directly by us. We employ one company, JEFE to order all raw materials or ingredients, as well as manufacture approximately 95% of our products to date. JEFE is owned by both the CEO and President of the Company.

We are negotiating with several other manufacturers to supplement the services provided by JEFE. We currently purchase modest quantities from other manufacturers. All of the raw materials and ingredients in our products are readily available and are readily ascertainable by our suppliers. We have not experienced any material shortages of ingredients or other products necessary to our operations and do not anticipate such shortages in the foreseeable future.

Sales/Brokers

As of January 31, 2015, our products are carried by approximately 10,800 food retail locations with an average of 3.3 different items per retail location, thereby totaling approximately 35,800 product placements on shelves in such retail locations. Our products are sold in the frozen meat case, the frozen Italian specialty section, the fresh meat case, the deli (in bulk and grab n’ go pre-packaged formats) as well as hot bars and sandwich shops in food retailers.

Our products are sold primarily through a commission broker network. We sell to large retail chains who direct our products to their own warehouses or to large food distributors. Such distributors include, but are not limited to: URM, a wholesaler to independent stores in Oregon and Washington State; Associated Wholesale Grocers, a wholesaler located in Louisiana; C&S Wholesale Grocers, an east coast distributor to A&P, Key Food, Waldbaums and other food retailers; SpartanNash; SuperValue, which distributes to Jewel, Lunds and Byerly’s; and Wakefern, the merchandising and distribution arm of Shop Rite stores.

In January of 2014 the Company reorganized its sales management with the result that the Company is now actively soliciting business with almost every major retail supermarket chain in the country. Currently, all of our full-time employees and Dan Dougherty sell our products directly to supermarkets and mass retailers. MamaMancini’s products are currently sold primarily in the Northeast and Southeast.

Marketing

The majority of our marketing activity has been generated through promotional discounts, consumer trial, consumer product tastings and demonstrations, in-store merchandising and signage, couponing, word of mouth, consumer public relations, social media, special merchandising events with retailers and consumer advertising.

The Company began a national radio campaign on Sirius radio in 2012 and added other national radio components such as political talk radio in 2013 that has continued through the present. The Company ran about 25,000 radio spots in 2014. The Company hopes to expand its radio campaign reach throughout 2015.

In August 2013, the Company began an active social media campaign with an emphasis on Facebook. Our Facebook campaign is being managed by a third party marketing firm and Dan Dougherty. We have gone from 800 “likes” to over 200,000 “likes” in April 2015, with 2,000 to 3,000 new “likes” being generated each week. We believe that this demonstrates that our products are resonating with consumers and that our brand awareness continues to grow.

The Company has also developed a brand ambassador program for consumer advocates of MamaMancini’s. Advocates receive coupons, hats, tote bags and other incentives to promote our brand. In addition, the Company has an active on-line and traditional paper couponing activity and employees outside services to deliver coupons to consumers such as Coupons.com, Ibotta, Facebook, newspaper free standing inserts, and on pack coupons as well as our web site. Dan Dougherty has been the principal spokesperson for MamaMancini’s, and has made appearances or had article features including the Martha Stewart Show, Entertainment Tonight, Today Cooking School, New York Times, Wall Street Journal, USA Today and People Magazine.

Additionally, in February 2015, the Company began a major initiative to merchandise its meatballs in a kettle program with 400 customers committed to the program. Potential customers include, food service distributors, supermarket and take out meal programs, kiosks at high volume public locations and mass market retailers.

Based on the Company’s metrics for determining brand awareness, which includes market studies and analysis of consumer recognition of the MamaMancini’s brand, the Company believes that brand awareness for MamaMancini’s has grown significantly in the past 12 months.

Investments - Meatball Obsession

In March of 2011, we invested $27,032 for a 35% interest in Meatball Obsession. Meatball Obsession offers a fast service menu of single-serve, take-out meatball offerings. As of January 31, 2015, we owned 13% of Meatball Obsession. Meatball Obsession has expanded into 4 locations from the first kiosk that opened in March 2012 in New York City, and plans to open additional kiosks at universities, airports, food courts and other high pedestrian traffic areas around the United States. Meatball Obsession has signed an exclusive supply agreement with MamaMancini’s whereby Meatball Obsession will sell MamaMancini’s branded products as its primary menu selections. One of our directors, Steven Burns, serves as the Chairman of the Board of Directors of Meatball Obsession.

Competition

The gourmet and specialty pre-packaged and frozen food industry has many large competitors specializing in various types of cuisine from all over the world. Our product lines are currently concentrated on Italian specialty foods. While it is our contention that our competition is much more limited than the entire frozen and pre-packaged food industry based on our products' niche market, there can be no assurances that we do not compete with the entire frozen and pre-packaged food industry. We believe our principal competitors include Quaker Maid / Philly-Gourmet Meat Company, Hormel, Rosina Company, Inc., Casa Di Bertacchi, Inc., Farm Rich, Inc., Mama Lucia, and Buona Vita, Inc.

Intellectual Property

Our current intellectual property consists of trade secret recipes and cooking processes for our products and three trademarks for "MamaMancini's", "Mac N' Mamas" and "The Meatball Lovers Meatball". The recipes and use of the trademarks have been assigned in perpetuity to the Company.

We rely on a combination of trademark, copyright and trade secret laws to establish and protect our proprietary rights. We will also use technical measures to protect our proprietary rights.

Royalty Agreement

In accordance with a Development and License Agreement (the "Development and License Agreement") entered into on January 1, 2009 with Dan Dougherty relating to the use of his grandmother's recipes for the products to be created by MamaMancini's, Mr. Dougherty granted us a 50 year exclusive license (subject to certain minimum payments being made), with a 25 year extension option, to use and commercialize the licensed items. Under the terms of the Development and License Agreement, Mr. Dougherty shall develop a line of beef meatballs with sauce, turkey meatballs with sauce and other similar meats and sauces for commercial manufacture, distribution and sale (each a "Licensor Product" and collectively the "Licensor Products"). Mr. Dougherty shall work with us to develop Licensor Products that are acceptable to us. Upon acceptance of a Licensor Product by us, Mr. Dougherty's trade secret recipes, formulas methods and ingredients for the preparation and production of such Licensor Products shall be subject to the Development and License Agreement. In connection with the Development and License Agreement, we pay Mr. Dougherty a royalty fee on net sales.

Supply Agreement

On March 1, 2010, the Company entered into a five-year agreement with JEFE. JEFE is owned by both the CEO and President of the Company. Under the terms of the agreement, the Company granted to JEFE a revocable license to use the Company's recipes, formulas, methods and ingredients for the preparation and production of Company's products, for manufacturing the Company's product and all future improvements, modifications, substitutions and replacements developed by the Company. JEFE in turn granted to the Company the exclusive right to purchase the product. Under the terms of the agreement JEFE agreed to manufacture, package, and store the Company's products. The Company has the right to purchase products from one or more other manufacturers, distributors or suppliers. The agreement contains a perpetual automatic renewal clause for a period of one year after the expiration of the initial term. During the renewal period either party may cancel the contract with written notice nine months prior to the termination date. The agreement was automatically renewed in February 2015 and will continue to automatically renew unless notice of termination is provided in writing by either party nine months prior to expiration.

Under the terms of the agreement if the Company specifies any change in packaging or shipping materials which results in JEFE incurring increased expense for packaging and shipping materials or in JEFE being unable to utilize obsolete packaging or shipping materials in ordinary packaging or shipping, the Company agrees to pay as additional product cost the additional cost for packaging and shipping materials and to purchase at cost such obsolete packaging and shipping materials. If the Company requests any repackaging of the product, other than due to defects in the original packaging, the Company will reimburse JEFE for any labor costs incurred in repackaging. Per the agreement, all product delivery shipping costs are the expense of the Company.

USDA approval / Regulations

Our food products, which are manufactured in third-party facilities, are subject to various federal, state and local regulations and inspection, and to extensive regulations and inspections, regarding sanitation, quality, packaging and labeling. In order to distribute and sell our products outside the State of New Jersey, the third-party food processing facilities must meet the standards promulgated by the U.S. Department of Agriculture (the "USDA"). Our third party manufacturers processing facilities and products are subject to periodic inspection by federal, state, and local authorities. In January 2011, the FDA's Food Safety Modernization Act was signed into law. The law will increase the number of inspections at food facilities in the U.S. in an effort to enhance the detection of food borne illness outbreaks and order recalls of tainted food products. The facilities in which our products are manufactured are inspected regularly and comply with all the requirements of the FDA and USDA.

We are subject to the Food, Drug and Cosmetic Act and regulations promulgated thereunder by the FDA. This comprehensive regulatory program governs, among other things, the manufacturing, composition and ingredients, packaging, and safety of food. Under this program, the FDA regulates manufacturing practices for foods through, among other things, its current "good manufacturing practices" regulations, or GMP's, and specifies the recipes for certain foods. Specifically, the USDA defines "all natural" as a product that contains no artificial ingredients, coloring ingredients or chemical preservatives and is minimally processed. The Company's products were submitted to the USDA and approved as "all natural". However, should the USDA change their definition of "all natural" at some point in the future, or should MamaMancini's change their existing recipes to include ingredients that do not meet the USDA's definition of "all natural", our results of operations could be adversely affected.

The FTC and other authorities regulate how we market and advertise our products, and we are currently in compliance with all regulations related thereto, although we could be the target of claims relating to alleged false or deceptive advertising under federal and state laws and regulations. Changes in these laws or regulations or the introduction of new laws or regulations could increase the costs of doing business for us or our customers or suppliers or restrict our actions, causing our results of operations to be adversely affected.

Quality Assurance

We take precautions designed to ensure the quality and safety of our products. In addition to routine third-party inspections of our contract manufacturer, we have instituted regular audits to address topics such as allergen control, ingredient, packaging and product specifications and sanitation. Under the FDA Food Modernization Act, each of our contract manufacturers is required to have a hazard analysis critical control points plan that identifies critical pathways for contaminants and mandates control measures that must be used to prevent, eliminate or reduce relevant food-borne hazards.

Our current contract manufacturer, JEFE, is certified in the Safe Quality Food Program. These standards are integrated food safety and quality management protocols designed specifically for the food sector and offer a comprehensive methodology to manage food safety and quality simultaneously. Certification provides an independent and external validation that a product, process or service complies with applicable regulations and standards.

We work with suppliers who assure the quality and safety of their ingredients. These assurances are supported by our purchasing contracts or quality assurance specification packets, including affidavits, certificates of analysis and analytical testing, where required. The quality assurance staff of both our contract manufacturer and our own internal operations department conducts periodic on-site routine audits of critical ingredient suppliers.

Where You Can Find More Information

The public may read and copy any materials the Company files with the U.S. Securities and Exchange Commission (the “SEC”) at the SEC’s Public Reference Room at 100 F Street, NE, Washington, DC 20549. The public may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0030. The SEC maintains an Internet website (http://www.sec.gov) that contains reports, proxy and information statements and other information regarding issuers that file electronically with the SEC.

Item 1A. Risk Factors.

RISKS RELATED TO OUR BUSINESS

We are not profitable and may never be profitable.

Since inception on February 22, 2010 and through January 31, 2015, MamaMancini's has raised approximately $12,050,000 in capital. During this same period, we have recorded net accumulated losses totaling $(10,603,761). As of January 31, 2015, we had working capital of $2,964,121. MamaMancini's net losses for the two most recent fiscal years ended January 31, 2015 and December 31, 2013 have been $4,060,476 and $2,947,608, respectively (not inclusive of the one month period ended January 31, 2014). We expect to incur significant increasing operating losses over the next several years. Negative cash flow from operations is expected in the foreseeable future. MamaMancini's ability to achieve profitability depends upon many factors, including its ability to develop and commercialize products. There can be no assurance that MamaMancini's will ever achieve any significant revenues or profitable operations.

MamaMancini's has a limited operating history.

MamaMancini's has been in existence for approximately four years. Our limited operating history means that there is a high degree of uncertainty in our ability to: (i) develop and commercialize our products; (ii) achieve market acceptance of our products; or (iii) respond to competition. Additionally, even if we do implement our business plan, we may not be successful. No assurances can be given as to exactly when, if at all, we will be able to recognize profits high enough to sustain our business. We face all the risks inherent in a new business, including the expenses, difficulties, complications, and delays frequently encountered in connection with conducting operations, including capital requirements. Given our limited operating history, we may be unable to effectively implement our business plan which would result in a loss of your investment.

We will need additional capital, which may be difficult to raise as a result of our limited operating history or any number of other reasons.

Since inception in 2010 and through January 31, 2015, MamaMancini's has incurred net accumulated losses of $(10,603,761). As of January 31, 2015 we had working capital of $2,964,121 and stockholders' equity of $2,162,616. The Company believes that it has adequate financing through the end of the current fiscal year to execute its current growth plan, however, in the case that the Company exceeds its expected growth, we would need to raise additional

capital and/or significantly cut expenses and overhead in order to operate the business through such date. Currently, we plan to raise additional capital, but we have no committed sources of additional capital and our access to capital funding is always uncertain. There is no assurance that additional equity or debt financing will be available to us when needed, on acceptable terms or even at all. In the event that we are not able to secure financing, we may have to scale back our development plans or cease operations.

The majority of our business depends on a limited number of principal customers.

Because we depend on a limited number of customers for a majority of our sales, a loss of one of these customers could materially adversely affect our business and financial condition. Our ten largest accounts represented approximately 86%, 82% and 81% for the year ended December 31, 2013, the one month period ended January 31, 2014 and the year ended January 31, 2015. For the year ended January 31, 2015 our three largest customers represented approximately 42% of our sales, respectively. Our principal customers only continue to purchase our products if they are able to sell them to their end consumers. We have no long-term contracts with our principal customers and thus our business would be negatively affected by the failure of our principal customers to purchase our products on a consistent basis. If these principal customers cease ordering products from us, our business could be materially adversely affected.

Competitive product and pricing pressures in the food industry and the financial condition of customers and suppliers could adversely affect our ability to gain or maintain market share and/or profitability.

We currently operate in the highly competitive food industry, competing with other companies that have varying abilities to withstand changing market conditions. Any significant change in our relationship with a major customer, including changes in product prices, sales volume, or contractual terms may impact financial results. Such changes may result because our competitors may have substantial financial, marketing, and other resources that may change the competitive environment. If we are unable to establish economies of scale, marketing expertise, product innovation, and category leadership positions to respond to changing market trends, or if we are unable to increase prices while maintaining a customer base, our profitability and volume growth could be impacted in a materially adverse way. The success of our business depends, in part, upon the financial strength and viability of our suppliers and customers. The financial condition of those suppliers and customers is affected in large part by conditions and events that are beyond our control. A significant deterioration of their financial condition would adversely affect our financial results.

We face competition from companies who produce similar frozen products and other prepared foods, many of whom have longer operating histories or who have substantially more financial resources.

Many of our competitors have been in business for a significantly longer period of time than we have and have learned manufacturing techniques which can aid in efficiently producing their products. Additionally, many of these companies have successfully acquired a loyal customer base that would be difficult for us to compete with. Such customers may be unwilling to purchase our products due to brand loyalty or uncertainty in the highly competitive market in which we compete. In addition, if we gain traction in our particular niche of creating gourmet Italian frozen foods, major food companies with substantial marketing and financial resources may attempt to compete more directly with us. In the event that such large companies do directly compete with us, our business may be adversely affected.

All of our manufacturing is outsourced to a related party manufacturer which we rely on for a significant amount of our manufacturing and supply.

Presently we do not own any manufacturing facilities. Approximately 95% of our manufacturing is outsourced to a food manufacturing facility in East Rutherford, New Jersey owned by Joseph Epstein Food Enterprises, Inc. ("JEFE"). JEFE is a related party entity owned by our Chief Executive Officer, Mr. Carl Wolf, and our President, Mr. Matthew Brown. We have a contract with JEFE that began on March 1, 2010 and is currently set to expire on February 28, 2016. Under a supply agreement with JEFE, we have granted JEFE a revocable license to use our recipes, formulas, methods and ingredients for the preparation and production of our products. JEFE in turn has granted us the exclusive right to purchase the product. Under the terms of the agreement, JEFE agrees to manufacture, package, and store our products and we have the right to purchase products from one or more other manufacturers, distributors or suppliers.

Although management believes that the contract will continue to be renewed on the same terms of the existing contract, there can be no assurances that this will occur. In the event that our contract with JEFE is not renewed, we would have to seek other suppliers for our products. However, we can make no assurance that we will be able to engage other suppliers on satisfactory terms or in a timely manner. In the event that JEFE ceases operations or stops manufacturing our products, our inability to secure an alternative supplier would materially adversely affect our business and financial condition.

Additionally, should we be forced to manufacture our own products, we cannot give any assurance that we will be able to develop internal manufacturing capabilities or procure third party suppliers. In the event we seek third party suppliers, they may require us to purchase a minimum amount of materials or could require other unfavorable terms. Any such event would materially adversely impact our prospects. Moreover, we cannot give any assurance that any alternate contract manufacturers or suppliers that we select will be able to supply our products in a timely or cost effective manner or in accordance with applicable regulatory requirements or our specifications. Anything that materially adversely impacts JEFE, including but not limited to labor stoppages, may have a materially adverse effect on our business.

We currently carry a large receivable from our related party manufacturer.

JEFE, owned by Matthew Brown and Karen Wolf and by Carl and Marion Wolf, is also contracted to produce and manufacture food products for the Company. Currently, JEFE serves as our principal food manufacturing company. For the year ended January 31, 2015 and December 31, 2013, we paid JEFE $8,803,541 and $6,190,595, respectively, for the manufacturing of products. At January 31, 2015 and 2014, we had a receivable in the amount of $2,213,037 and $1,373,036 from JEFE. Should JEFE default under its obligations to pay us our results of operations would be significantly impacted. The Company has taken measures to make certain that the receivable from JEFE does not increase. We believe that JEFE will continue to pay down the receivable throughout the current fiscal year.

Our operations are subject to regulation by the U.S. Food and Drug Administration ("FDA"), U.S. Department of Agriculture ("USDA"), Federal Trade Commission ("FTC") and other governmental entities and such regulations are subject to change from time to time which could impact how we manage our production and sale of products. Federal budget cuts could result in furloughs for government employees, including inspectors and reviewers for our supplier's plants and products which could materially impact our ability to manufacture regulated products.

Our food products which are manufactured in third-party facilities are subject to extensive regulation by the FDA, the USDA and other national, state, and local authorities. For example, we are subject to the Food, Drug and Cosmetic Act and regulations promulgated thereunder by the FDA. This comprehensive regulatory program governs, among other things, the manufacturing, composition and ingredients, packaging, and safety of food. Under this program, the FDA regulates manufacturing practices for foods through, among other things, its current "good manufacturing practices" regulations, or GMP's, and specifies the recipes for certain foods. Specifically, the USDA defines "all natural" as a product that contains no artificial ingredients, coloring ingredients or chemical preservatives and is minimally processed. The Company's products were submitted to the USDA and approved as "all natural". However, should the USDA change their definition of "all natural" at some point in the future, or should MamaMancini's change their existing recipes to include ingredients that do not meet the USDA's definition/ of "all natural", our results of operations could be adversely affected.

Our third party manufacturers processing facilities and products are subject to periodic inspection by federal, state, and local authorities. In January 2011, the FDA's Food Safety Modernization Act was signed into law. The law will increase the number of inspections at food facilities in the U.S. in an effort to enhance the detection of food borne illness outbreaks and order recalls of tainted food products.

The FTC and other authorities regulate how we market and advertise our products, and we could be the target of claims relating to alleged false or deceptive advertising under federal and state laws and regulations. Changes in these laws or regulations or the introduction of new laws or regulations could increase the costs of doing business for us or our customers or suppliers or restrict our actions, causing our results of operations to be adversely affected.

The need for and effect of product recalls could have a material adverse impact on our business.

If any of our products become misbranded or adulterated, we may need to conduct a product recall. The scope of such a recall could result in significant costs incurred as a result of the recall, potential destruction of inventory, and lost sales. Should consumption of any product cause injury and/or illness, we also may be liable for monetary damages as a result of one or more product liability judgments against us. A significant product recall or product liability case could cause a loss of consumer confidence in our food products and could have a material adverse effect on the value of our brand, results of operations and prospects.

We may be subject to significant liability if the consumption of any of our products causes illness or physical harm.

The sale of food products for human consumption involves the risk of injury or illness to consumers. Such injuries or illness may result from inadvertent mislabeling, tampering or product contamination or spoilage. Under certain circumstances, we may be required to recall or withdraw products, which may have a material adverse effect on our business. Even if a situation does not necessitate a recall or market withdrawal, product liability claims may be asserted against us. If the consumption of any of our products causes, or is alleged to have caused, a health-related illness, we may become subject to claims or lawsuits relating to such matters. Even if a product liability claim is unsuccessful, the negative publicity surrounding any assertion that our products caused illness or physical harm could adversely affect our reputation with existing and potential distributors, retailers and consumers and our corporate image and brand equity. Moreover, claims or liabilities of this sort might not be covered by insurance or by any rights of indemnity or contribution that we may have against others. A product liability judgment against us or a product recall or market withdrawal could have a material adverse effect on our business, reputation and operating results.

The impact of various food safety issues, environmental, legal, tax, and other regulations and related developments could adversely affect our sales and profitability.

Our products are subject to numerous food safety and other laws and regulations regarding the manufacturing, marketing, and distribution of food products, particularly the USDA, and state and local agencies. These regulations govern matters such as ingredients, advertising, taxation, relations with distributors and retailers, health and safety matters, and environmental concerns. The ineffectiveness of our or our manufacturer’s planning and policies with respect to these matters, and the need to comply with new or revised laws or regulations with regard to licensing requirements, trade and pricing practices, environmental permitting, or other food or safety matters, or new interpretations or enforcement of existing laws and regulations, as well as any related litigation, may have a material adverse effect on our sales and profitability.

Increases in the cost and restrictions on the availability of raw materials could adversely affect our financial results.

Our products include agricultural commodities such as tomatoes, onions, and meats and other items such as spices and flour, as well as packaging materials such as plastic, metal, paper, fiberboard, and other materials and inputs such as water, in order to manufacture products. The availability or cost of such commodities may fluctuate widely due to government policy and regulation, crop failures or shortages due to plant disease or insect and other pest infestation, weather conditions, potential impact of climate change, increased demand for biofuels, or other unforeseen circumstances. To the extent that any of the foregoing or other unknown factors increase the prices of such commodities or materials and we are unable to increase our prices or adequately hedge against such changes in a manner that offsets such changes, the results of its operations could be materially and adversely affected. Similarly, if supplier arrangements and relationships result in increased and unforeseen expenses, our financial results could be materially and adversely impacted.

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Disruption of our supply chain could adversely affect our business.

Damage or disruption to our manufacturing or distribution capabilities due to weather, natural disaster, fire, terrorism, pandemic, strikes, the financial and/or operational instability of key suppliers, distributors, warehousing and transportation providers, or brokers, or other reasons could impair our ability to manufacture or sell our products. To the extent that we are unable to, or cannot financially mitigate the likelihood or potential impact of such events, or to effectively manage such events if they occur, particularly when a product is sourced from a single location, our business and results of operations may be materially adversely affected, and additional resources could be required to restore our supply chain.

Higher energy costs and other factors affecting the cost of producing, transporting, and distributing our products could adversely affect our financial results.

Rising fuel and energy costs may have a significant impact on our cost of operations, including the manufacture, transportation, and distribution of products. Fuel costs may fluctuate due to a number of factors outside of our control, including government policy and regulation and weather conditions. Additionally, we may be unable to maintain favorable arrangements with respect to the manufacturing costs of our products as a result of the rise in costs of procuring raw materials and transportation by our manufacturers. This may result in increased expenses and negatively affect operations.

If we fail to establish and maintain an effective system of internal control, we may not be able to report our financial results accurately or to prevent fraud. Any inability to report and file our financial results accurately and timely could harm our reputation and adversely impact the trading price of our common stock.

Effective internal control is necessary for us to provide reliable financial reports and prevent fraud. If we cannot provide reliable financial reports or prevent fraud, we may not be able to manage our business as effectively as we would if an effective control environment existed, and our business and reputation with investors may be harmed.

We currently have insufficient written policies and procedures for accounting and financial reporting with respect to the requirements and application of US GAAP and SEC disclosure requirements. Additionally, there is a lack of formal process and timeline for closing the books and records at the end of each reporting period. Such a documented weakness could restrict our ability to timely gather, analyze and report information relative to our financial statements.

Because of our limited resources, there are limited controls over our information processing. There is inadequate segregation of duties consistent with control objectives. Our management is composed of a small number of individuals resulting in a situation where limitations on segregation of duties exist. In order to remedy this situation we would need to hire additional staff. Currently, we are unable to afford to hire additional staff to facilitate greater segregation of duties but will reassess our capabilities in the following year.

Management believes that the material weaknesses set forth above are the result of the lack of scale of our operations and are intrinsic to our small size. Nonetheless, our small size and our current internal control deficiencies may have a material adverse effect on our ability to accurately and timely report our financial information which, in turn, may have a material adverse effect on our financial condition.

As a result of our small size and our current internal control deficiencies, our financial condition, results of operation and access to capital may be materially adversely affected.

Global economic uncertainties continue to affect consumers' purchasing habits and customer financial stability, which may affect sales volume and profitability on some of our products and have other impacts that we cannot fully predict.

As a result of continuing global economic uncertainties, price-conscious consumers may replace their purchases of our premium and value-added products with lower-cost alternatives, which could affect the price and volume of some of these products. The volume or profitability of our products may be adversely affected if consumers are reluctant to pay a premium for higher quality frozen foods or if they replace purchases of our products with cheaper alternatives. Additionally, distributors and retailers may become more conservative in response to these conditions and seek to reduce their inventories. Our results of operations depend upon, among other things, our ability to maintain and increase sales volume with our existing distributors and retailers, to attract new consumers and to provide products that appeal to consumers at prices they are willing and able to pay. Prolonged unfavorable economic conditions may have an adverse effect on our sales and profitability.

We rely on key personnel and, if we are unable to retain or motivate key personnel or hire qualified personnel, we may not be able to grow effectively.

Our success depends in large part upon the abilities and continued service of our executive officers and other key employees, particularly Mr. Carl Wolf, our Chief Executive Officer and Chairman, and Mr. Matthew Brown, our President. There can be no assurance that we will be able to retain the services of such officers and employees. Our failure to retain the services of our key personnel could have a materially adverse effect on our business. In order to support our projected growth, we will be required to effectively recruit, hire, train and retain additional qualified management personnel. Our inability to attract and retain necessary personnel could have a materially adverse effect on our business.

Matthew Brown, our President, allocates his time between MamaMancini's and JEFE, thereby causing potential conflicts of interest in his determination as to how much time to devote to our affairs, which could materially adversely affect our business.

Our President, Matthew Brown, is not required to commit his full time to our affairs, which may result in a conflict of interest in allocating his time between our operations and those of JEFE. He currently devotes approximately 50% of his time to our Company and 50% to JEFE. Because Mr. Brown is required to devote such a significant amount of his time to other business affairs, even though it may indirectly benefit our Company, it could significantly impair his ability to devote sufficient time to our affairs, which would have a material adverse impact on our ability to execute our business plan.

The failure of new product or packaging introductions to gain trade and consumer acceptance and address changes in consumer preferences could adversely affect our sales.

Our success is dependent upon anticipating and reacting to changes in consumer preferences, including health and wellness. There are inherent marketplace risks associated with new product or packaging introductions, including uncertainties about trade and consumer acceptance. Moreover, success is dependent upon our ability to identify and respond to consumer trends through innovation. We may be required to increase expenditures for new product development and there is no guarantee that we will be successful in developing new products or improving upon products already in existence. Additionally, our new products may not achieve consumer acceptance and could materially negatively impact sales.

Changes in our promotional activities may impact, and may have a disproportionate effect on, our overall financial condition and results of operations.

We offer a variety of sales and promotion incentives to our customers and to consumers, such as price discounts, consumer coupons, volume rebates, cooperative marketing programs, slotting fees and in-store displays. Our net sales may periodically be influenced by the introduction and discontinuance of sales and promotion incentives. Reductions in overall sales and promotion incentives could impact our net sales and affect our results of operations in any particular fiscal quarter.

We may not be able to successfully implement our growth strategy on a timely basis or at all.

Our future success depends, in large part, on our ability to implement our growth strategy of expanding distribution and improving placement of our products, attracting new consumers to our brand and introducing new product lines and product extensions. Our ability to implement this growth strategy depends, among other things, on our ability to:

- enter into distribution and other strategic arrangements with third-party retailers and other potential distributors of our products;
- continue to compete in conventional grocery and mass merchandiser retail channels in addition to the natural and organic channel;
- secure shelf space in key supermarket locations;
- increase our brand awareness;
- expand and maintain brand loyalty; and
- develop new product lines and extensions.

We may not be able to successfully implement our growth strategy. Our sales and operating results will be adversely affected if we fail to implement our growth strategy or if we invest resources in a growth strategy that ultimately proves unsuccessful.

We are currently selling products in supermarkets in the United States. If we are unable to expand into mass-market retailers or sell products in a greater number of supermarkets we will fall short of our projections and our business and financial condition would be adversely affected.

As a smaller supplier, we may not sell in enough bulk in certain stores and as such our products may not be placed in the most ideal locations to catch the attention of end consumers. If we are unable to gain significant sales growth, our products may never be displayed in the most attractive locations in stores and our sales may suffer.

We may be unable to successfully execute our identified growth strategies or other growth strategies that we determine to pursue.

We currently have a limited corporate infrastructure. In order to pursue growth strategies, we will need to continue to build our infrastructure and operational capabilities. Our ability to do any of these successfully could be affected by any one or more of the following factors:

- our ability to raise substantial amounts of additional capital if needed to fund the implementation of our business plan;
- our ability to execute our business strategy;
- the ability of our products to achieve market acceptance;
- our ability to manage the expansion of our operations and any acquisitions we may make, which could result in increased costs, high employee turnover or damage to customer relationships;
- our ability to attract and retain qualified personnel;
- our ability to manage our third party relationships effectively; and
- our ability to accurately predict and respond to the rapid market changes in our industry and the evolving demands of the markets we serve.

Our failure to adequately address any one or more of the above factors could have a significant impact on our ability to implement our business plan and our ability to pursue other opportunities that arise.

We may be unable to maintain quality control.

All of our manufacturing is outsourced. Although we have entered into supply agreements specifying certain minimum acceptable quality standards, there is no assurance that our current quality assurance procedures will be able to effectively monitor compliance. Additionally, in the event that we expand our operations and increase our output volume, including securing additional manufacturers, there is no assurance that we will be able to adequately maintain quality controls or that our current manufacturing process is scalable.

There may be products liability and other legal claims.

We are currently a named insured party through the products liability insurance policy of JEFE, our food manufacturer, and we also carry our own product liability insurance policy. Although we believe that the amount of insurance coverage is sufficient for our operations, there is no assurance that the coverage will be adequate.

Our brand and reputation may suffer from real or perceived issues involving the labeling and marketing of our products as "natural."

Although the FDA and USDA have each issued statements regarding the appropriate use of the word "natural," there is no single, U.S. government-regulated definition of the term "natural" for use in the food industry. The resulting uncertainty has led to consumer confusion, distrust and legal challenges. Plaintiffs have commenced legal actions against a number of food companies that market "natural" products, asserting false, misleading and deceptive advertising and labeling claims. Should we become subject to similar claims, consumers may avoid purchasing products from us or seek alternatives, even if the basis for the claim is unfounded. Adverse publicity about these matters may discourage consumers from buying our products. The cost of defending against any such claims could be significant. Any loss of confidence on the part of consumers in the truthfulness of our labeling or ingredient claims would be difficult and costly to overcome and may significantly reduce our brand value. Uncertainty as to the ingredients used in our products, regardless of the cause, may have a substantial and adverse effect on our brand and our business, results of operations and financial condition.

Virtually all of our finished goods inventory is located in a single third-party warehouse facility. Any damage or disruption at this facility would have an adverse effect on our business, results of operations and financial condition.

Virtually all of our finished goods inventory is located in one warehouse facility owned and operated by a third party. A natural disaster, fire, power interruption, work stoppage or other unanticipated catastrophic event at this facility would significantly disrupt our ability to deliver our products and operate our business. If any material amount of our inventory were damaged, we would be unable to meet our contractual obligations and, as a result, our business, results of operations and financial condition would suffer.

We may be unable to defend our intellectual property.

Our business could be adversely affected if we are unable to adequately protect our intellectual property. Our current intellectual property consists of trade secret recipes and cooking processes for our products and trademarks. We rely on a combination of trademark, copyright and trade secret laws to establish and protect our proprietary rights. We will also use technical measures to protect our proprietary rights. We may, however, not be able to secure significant protection for service marks or trademarks that we obtain. Our inability to protect our intellectual property from others may impede our brand identity and could lead to consumer confusion.

Our intellectual property rights are valuable, and any inability to protect them could reduce the value of our services and brand.

Our business is largely based upon our recipes which are trade secrets and are not patentable. We may be unable to keep other companies from copying our recipes, or we may be subject to legal actions alleging intellectual property infringement, unfair competition or similar claims against us. Companies may have intellectual property rights covering aspects of our technologies or businesses. Defending ourselves against intellectual property infringement or similar claims would be expensive and would divert management’s attention. Additionally, there is no assurance that we would be successful in defending ourselves against such claims.

RISKS RELATED TO OUR SECURITIES

We currently have a limited trading volume, which results in higher price volatility for, and reduced liquidity of, our common stock.

Our shares of common stock have been listed for trading on the OTCQB since 2013. However, historically there has been limited daily volume of trading in our common stock on the OTCQB, which has limited the overall and perceived liquidity of our common stock on that market.

An active trading market for our shares may never develop or be sustained. Active trading markets generally result in lower price volatility and more efficient execution of buy and sell orders. The absence of an active trading market increases price volatility and reduces the liquidity of our common stock. As long as this condition continues, the sale of a significant number of shares of common stock at any particular time could be difficult to achieve at the market prices prevailing immediately before such shares are offered and, if an active market for our common stock does not develop, it may be difficult to sell shares without depressing the market price for the shares, or at all. In addition, in the event that an active trading market does not develop, the price of our common stock may not be a reliable indicator of the fair value of our common stock.

Furthermore, if our common stock ceases to be listed on the OTCQB, holders would find it more difficult to dispose of, or to obtain accurate quotations as to the market value of, our common stock, and the market value of our common stock would likely decline.

You will experience dilution of your ownership interest because of the future issuance of additional shares of our common stock and our preferred stock.

In the future, we may issue our authorized but previously unissued equity securities, resulting in the dilution of the ownership interests of our present stockholders. We are currently authorized to issue an aggregate of 270,000,000 shares of capital stock consisting of 20,000,000 shares of preferred stock, par value $0.00001 per share and 250,000,000 shares of common stock, par value $0.00001 per share.

We may also issue additional shares of our common stock or other securities that are convertible into or exercisable for common stock in connection with hiring or retaining employees or consultants, future acquisitions, future sales of our securities for capital raising purposes, or for other business purposes. The future issuance of any such additional shares of our common stock or other securities may create downward pressure on the trading price of our common

stock. There can be no assurance that we will not be required to issue additional shares, warrants or other convertible securities in the future in conjunction with hiring or retaining employees or consultants, future acquisitions, future sales of our securities for capital raising purposes or for other business purposes, including at a price (or exercise prices) below the price at which shares of our common stock are trading.

Our common stock is considered a penny stock, which may be subject to restrictions on marketability, so you may not be able to sell your shares.

We are currently listed on the OTCQB under the symbol “MMMB”, and are subject to the penny stock rules adopted by the SEC that require brokers to provide extensive disclosure to their customers prior to executing trades in penny stocks. These disclosure requirements may cause a reduction in the trading activity of our common stock, which in all likelihood would make it difficult for our shareholders to sell their securities.

Penny stocks generally are equity securities with a price of less than $5.00 (other than securities registered on certain national securities exchanges or quoted on the NASDAQ system). Penny stock rules require a broker-dealer, prior to a transaction in a penny stock not otherwise exempt from the rules, to deliver a standardized risk disclosure document that provides information about penny stocks and the risks in the penny stock market. The broker-dealer also must provide the customer with current bid and offer quotations for the penny stock, the compensation of the broker-dealer and its salesperson in the transaction, and monthly account statements showing the market value of each penny stock held in the customer’s account. The broker-dealer must also make a special written determination that the penny stock is a suitable investment for the purchaser and receive the purchaser’s written agreement to the transaction. These requirements may have the effect of reducing the level of trading activity, if any, in the secondary market for a security that becomes subject to the penny stock rules. The additional burdens imposed upon broker-dealers by such requirements may discourage broker-dealers from effecting transactions in our securities, which could severely limit the market price and liquidity of our securities. These requirements may restrict the ability of broker-dealers to sell our common stock and may affect your ability to resell our common stock.

The concentration of our capital stock ownership with insiders could limit your ability to influence the outcome of key transactions, including a change of control.

Our directors, executive officers and each of our stockholders who own greater than 5% of our outstanding common stock, in the aggregate, beneficially own approximately 50% of the outstanding shares of our common stock, based on the number of shares outstanding as of January 31, 2015. These stockholders are able to influence or control matters requiring approval by our stockholders, including the election of directors and the approval of mergers, acquisitions or other extraordinary transactions. They may have interests that differ from yours and may vote in a manner that is adverse to your interests. This concentration of ownership may have the effect of deterring, delaying or preventing a change of control of our company, could deprive our stockholders of an opportunity to receive a premium for their common stock as part of a sale of our company and might ultimately affect the market price of our common stock.

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If and when a larger trading market for our common stock develops, the market price of our common stock is still likely to be highly volatile and subject to wide fluctuations, and you may be unable to resell your shares at or above the price at which you acquired them.

The market price of our common stock is likely to be highly volatile and could be subject to wide fluctuations in response to a number of factors that are beyond our control, including, but not limited to:

- variations in our revenue and operating expenses;
- market conditions in our industry and the economy as a whole;
- actual or expected changes in our growth rates or our competitors' growth rates;
- announcements of innovations or new products or services by us or our competitors;
- announcements by the government relating to regulations that govern our industry;
- sales of our common stock or other securities by us or in the open market; and
- changes in the market valuations of other comparable companies.

In addition, if the market for food industry stocks or the stock market in general experiences loss of investor confidence, the trading price of our common stock could decline for reasons unrelated to our business, financial condition or operating results. The trading price of our shares might also decline in reaction to events that affect other companies in our industry, even if these events do not directly affect us. Each of these factors, among others, could harm the value of your investment in our common stock. In the past, following periods of volatility in the market, securities class-action litigation has often been instituted against companies. Such litigation, if instituted against us, could result in substantial costs and diversion of management's attention and resources, which could materially and adversely affect our business, operating results and financial condition.

We do not expect to pay dividends.

We have never declared or paid any cash dividends or distributions on our capital stock. We currently intend to retain our future earnings, if any, to support operations and to finance expansion and therefore we do not anticipate paying any cash dividends on our common stock in the foreseeable future.

The declaration, payment and amount of any future dividends will be made at the discretion of the board of directors, and will depend upon, among other things, the results of our operations, cash flows and financial condition, operating and capital requirements, and other factors as the board of directors considers relevant. There is no assurance that future dividends will be paid, and, if dividends are paid, there is no assurance with respect to the amount of any such dividend. If the Company does not pay dividends, the Company's common stock may be less valuable because a return on an investor's investment will only occur if the Company's stock price appreciates.

If securities or industry analysts do not publish research or reports about us, our business or our market, or if they change their recommendations regarding our stock adversely, our stock price and trading volume could decline.

The trading market for our common stock will be influenced by the research and reports that industry or securities analysts may publish about us, our business, our market or our competitors. If any of the analysts who may cover us change their recommendation regarding our stock adversely, or provide more favorable relative recommendations about our competitors, our stock price would likely decline. If any analyst who may cover us were to cease coverage of our company or fail to regularly publish reports on us, we could lose visibility in the financial markets, which in turn could cause our stock price or trading volume to decline.

Item 1B. Unresolved Staff Comments.

Not applicable.

Item 2. Properties.

Our principal executive office is located at 25 Branca Road East Rutherford, NJ 07073. We currently pay an administrative fee of $4,000 per month to JEFE which includes use of office space and telephones, computers and photocopy and fax use. We utilize approximately 1,000 square feet of office space on a month to month basis. This space is utilized for office purposes and it is our belief that the space is adequate for our immediate needs. Additional space may be required as we expand our business activities. We do not foresee any significant difficulties in obtaining additional facilities if deemed necessary.

Item 3. Legal Proceedings.

We are not currently involved in any litigation that we believe could have a materially adverse effect on our financial condition or results of operations. There is no action, suit, proceeding, inquiry or investigation before or by any court, public board, government agency, self-regulatory organization or body pending or, to the knowledge of the executive officers of our Company or any of our subsidiaries, threatened against or affecting our Company, our common stock, any of our subsidiaries or of our Company’s or our Company’s subsidiaries’ officers or directors in their capacities as such, in which an adverse decision could have a material adverse effect.

Item 4. Mine Safety Disclosures.

Not applicable.

PART II

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

(a) Market Information

Our shares of common stock are currently quoted on the OTCQB under the symbol “MMMB” The following table sets forth (i) the intra-day high and low sales price per share for our common stock, as reported on the OTC Market, for the period of April 11, 2013 to December 31, 2013, (ii) the one month period ended January 31, 2014, and (iii) the high and low bid prices for our common stock, as reported by the OTC Market, for the period of February 1, 2014 through January 31, 2015. The quotations reflect inter-dealer prices, without retail mark-up, mark-down or commission, and may not represent actual transactions.

Fiscal Year Ended January 31, 2015	**High**	**Low**
First Quarter	$3.00	$1.25
Second Quarter	$3.60	$1.15
Third Quarter	$2.83	$1.80
Fourth Quarter	$2.10	$1.00

Period Ended January 31, 2014	**High**	**Low**
January 1 through January 31	$4.00	$2.50

Fiscal Year Ended December 31, 2014	**High**	**Low**
Second Quarter	$2.00	$1.50
Third Quarter	$2.00	$2.00
Fourth Quarter	$2.50	$1.75

(b) Holders

As of April 30, 2015, a total of 26,085,916 shares of the Company’s common stock are currently outstanding held by approximately 112 shareholders of record. This figure does not take into account those shareholders whose certificates are held in the name of broker-dealers or other nominees.

(c) Dividends

We have not declared or paid any dividends on our common stock and intend to retain any future earnings to fund the development and growth of our business. Therefore, we do not anticipate paying dividends on our common stock for the foreseeable future. There are no restrictions on our present ability to pay dividends to stockholders of our common stock, other than those prescribed by Nevada law.

(d) Securities Authorized for Issuance under Equity Compensation Plans

At the present time, we have 450,000 shares of common stock authorized for issuance under our equity compensation plan. For more information on our equity compensation plan please refer to the Current Report on Form 8-K filed with the Securities and Exchange Commission on June 5, 2013.

Rule 10B-18 Transactions

During the fiscal year ended January 31, 2015, there were no repurchases of the Company’s common stock by the Company.

Recent Sales of Unregistered Securities

There were no sales of unregistered securities not already reported on the Company’s quarterly filings on Form 10-Q or on a Current Report on Form 8-K.

ITEM 6. SELECTED FINANCIAL DATA.

Pursuant to permissive authority under Regulation S-K, Rule 301, we have omitted Selected Financial Data.

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

THE FOLLOWING DISCUSSION OF OUR PLAN OF OPERATION AND RESULTS OF OPERATIONS SHOULD BE READ IN CONJUNCTION WITH THE FINANCIAL STATEMENTS AND RELATED NOTES TO THE FINANCIAL STATEMENTS INCLUDED ELSEWHERE IN THIS REPORT. THIS DISCUSSION CONTAINS FORWARD-LOOKING STATEMENTS THAT RELATE TO FUTURE EVENTS OR OUR FUTURE FINANCIAL PERFORMANCE. THESE STATEMENTS INVOLVE KNOWN AND UNKNOWN RISKS, UNCERTAINTIES AND OTHER FACTORS THAT MAY CAUSE OUR ACTUAL RESULTS, LEVELS OF ACTIVITY, PERFORMANCE OR ACHIEVEMENTS TO BE MATERIALLY DIFFERENT FROM ANY FUTURE RESULTS, LEVELS OF ACTIVITY, PERFORMANCE OR ACHIEVEMENTS EXPRESSED OR IMPLIED BY THESE FORWARD-LOOKING STATEMENTS. THESE RISKS AND OTHER FACTORS INCLUDE, AMONG OTHERS, THOSE LISTED UNDER “FORWARD-LOOKING STATEMENTS” AND “RISK FACTORS” AND THOSE INCLUDED ELSEWHERE IN THIS REPORT.

Plan of Operation

The Company plans to sell more of its products into new and existing food retail outlets. The Company has undertaken a national radio campaign on Sirius XM channels for a substantial portion of this year. Social media activity has increased with Facebook, Twitter, Pinterest, YouTube, newsletter mailings, blogs, and helpful consumer content and special projects including a recipe bank of videos and MamaMancini’s contest and giveaways. Increased consumer merchandising activity, including virtual couponing, on-pack couponing, mail-in rebates, product demonstrations, and co-op retail advertising has commenced to increase sales to existing customers and new customers.

We believe that the ongoing introduction of the Company’s new all natural brand Slow Cooked Italian Sauce and various meatball and entrée products show great promise for additional product placements and sales in 2015 and thereafter. These products include Five Cheese Stuffed Beef Meatballs, Chicken Parmigiana Style Stuffed Meatballs, Chicken Florentine Stuffed Meatballs, Gluten Free Beef and Turkey Meatballs, Antibiotic Free Beef and Turkey Meatballs and Mac N’ Mamas®. This line is available in bulk food service pack, retail packages in fresh and frozen varieties, and club store pack in fresh varieties. Additionally, the Company plans to continue expansion into various new retailers with placement of its existing product line of Beef, Turkey, Pork and Chicken Meatballs and Sauce, as well as Marinara and Italian Sauce with beef flavors.

The Company has key sales personnel and a sales network of paid broker representatives. Management continues to solicit all major supermarket retailers, club stores and mass-market accounts. Additionally, the Company has begun an effort to develop presentations to major entities in the sandwich, burger, and Italian sub quick-serve industry through a branded kettle program which the Company launched in February 2015. The Company is also soliciting business in Canada and Mexico.

The Company owns 13% of the common equity of Meatball Obsession, LLC ("Meatball Obsession") and is its exclusive supplier of meatballs. Meatball Obsession offers a fast service menu of single serve, take-out meatball offerings. At present, Meatball Obsession has 4 locations. However, there is no guarantee that Meatball Obsession will perform up to its expectations or be able to open any additional units in the future.

The Company currently has supply agreement with JEFE, a related party, which is set to expire on February 28, 2016. This agreement automatically renews for periods of one year unless otherwise terminated by nine months prior written notice. JEFE is owned by the CEO and President of the Company.

JEFE increased its manufacturing capacity in 2014 to meet the anticipated increased demand of the Company. Additions of high-speed equipment and new production order flow have occurred. As sales increase, the Company expects that its packaging costs will decrease as it purchases longer runs of material and supplies but cannot guarantee that such packaging costs will decrease with the purchase of such materials or at all. The Company also expects that the labor costs component of the cost of goods sold will decrease in the later part of the year with higher speed equipment and order flow but cannot guarantee any such decrease in the labor costs.

The Company expects to have an operating loss in fiscal year 2016 due to the investment in developing new and expanded existing business. These investments include slot fees to gain initial distribution, special marketing demo events to induce trial, major promotional campaigns for initial trial customers, short runs on new products, rising raw materials costs, sample expenses, market research, design and label costs, product development costs, and the cost of additional personnel or fee based marketing and sales support while this business is developing.

We believe that MamaMancini's products have the ability to expand sales and deliver more products within several areas of consumption by consumers such as frozen Italian specialties, frozen meat, fresh meat, prepared foods, hot bars, cold bars in delis, and sandwich sections of supermarkets and other food retailers. In addition, we believe that MamaMancini's products can be sold into food service channels, mass market, and exported or as a component of other products.

Results of Operations for the years ended January 31, 2015 and December 31, 2013

The following table sets forth the summary statements of operations for the years ended January 31, 2015 and December 31, 2013:

	Years Ended	*****
	January 31, 2015	**December 31, 2013**
Sales - Net of Slotting Fees and Discounts (1)	$12,339,256	$8,741,621
Gross Profit	$3,535,716	$2,551,026
Operating Expenses	$(7,285,906)	$(5,489,994)
Other Income (Expense)	$(310,286)	$(8,640)
Net Loss	$(4,060,476)	$(2,947,608)

*Does not include one month period ended January 31, 2014

(1) Slotting fees are required in new placements with some, but not a majority of supermarket chains that the Company does business with. They are negotiated with each chain depending upon the expected return to the Company. We believe that we have successfully negotiated such slotting fees to a relatively low expense. We have taken into account future fees currently being negotiated in preliminary negotiations for new placements. We do not believe our size or financial limitations are an impediment to being able to pay such slotting fees. Slotting fee costs are an expense in growing the business as are other marketing and sales costs and the Company has accounted for these fees in assessing its estimated working capital for the next 12 months.

For the year ended January 31, 2015 and December 31, 2013, the Company reported a net loss of $(4,060,476) and $(2,947,608), respectively. The change in net loss between the year ended January 31, 2015 and December 31, 2013 was primarily attributable to following significant events:

The Company commenced operations during 2010 and has experienced significant growth in sales for the comparable periods. The Company has sold into approximately 37,000 retail and grocery locations at January 31, 2015 as compared to approximately 22,600 at December 31, 2013. The Company has reinvested proceeds to further develop brand awareness.

Advertising, social media and promotional expense increased by $664,000 which does not include marketing and social media costs as discussed below and in Note 2 to the consolidated financial statements.

Stock-based compensation expense increased by $103,400.

Research and development costs increased by $81,500.

Commission expenses increased by $101,000.

Postage and freight increased by $265,800.

Depreciation expense increased $136,200.

Marketing research increased by $80,000.

Royalty expenses increased by $81,800.

Professional fees increased by $489,400.

Insurance expense increased by $17,300.

Trade show and travel expenses decreased by $63,900.

Payroll and related expenses decreased by $184,100.

Sales: Sales, net of slotting fees and discounts increased by approximately 41% to $12,339,256 during the year ended January 31, 2015, from $8,741,621 during the year ended December 31, 2013. The increase in sales is primarily related to the Company executing on their expansion strategy. The Company has sold into approximately 37,000 retail and grocery locations at January 31, 2015 as compared to approximately 22,600 at December 31, 2013.

Gross Profit: The gross profit margin was 29% for the years ended January 31, 2015 and December 31, 2013.

Operating Expenses: Operating expenses increased by 33% during the year ended January 31, 2015, as compared to the year ended December 31, 2013. The $1,795,912 increase in operating expenses is primarily attributable to the following approximate increases in operating expenses:

Stock-based compensation of $103,400 expensed during the period;

Advertising, social media and promotional expenses of $664,000 related to an increase in spending on our new radio advertising campaign and special promotions which does not include marketing and social media costs as discussed below and in Note 2 to the condensed consolidated financial statements;

Commission expenses of $101,000 related to increased sales;

Postage and freight of $265,800 due to higher sales slightly offset by some customers picking up their product in lieu of having it shipped to them;

Depreciation expense of $136,200 due to new fixed asset purchases during the period;

Marketing research increased by $80,000 due to the Company electing to spend more on market research and social media, which primarily consisted of four marketing research projects to develop new products; and

Royalty expenses increased by $81,800 due to the increase in sales;

Professional fees increased by $489,400 due to fees to an investment banker and financial consultants related to equity raises;

Research and development costs increased by $81,500 due to the Company expanding its line of products.

These expense increases were offset by decreases in the following expenses:

Trade show and travel expenses of $63,900 related to the members of the Company traveling and attending less trade shows; and

Payroll and related expense of $184,100 as compensation to a reduction in executive sales personnel.

Other Expense: Other expenses increased by $301,646 to $310,286 for the year ended January 31, 2015 as compared to $8,640 during the year ended December 31, 2013. For the year ended January 31, 2015, other expenses consisted of $163,136 in interest expense incurred on the Company's line of credit with FGI, the line of credit and term loan with EGC and the convertible note with Manatuck Hill. The Company also recorded $46,197 of amortization expense of the debt discount for the Manatuck note. In addition, the Company recorded $100,953 of amortization expense related to the closing costs incurred in conjunction with the finance arrangements during the year. For the year ended December 31, 2013, other expenses consisted of $8,640 in interest expense incurred on the Company's previous line of credit. This line of credit was repaid and cancelled on September 9, 2013.

Liquidity and Capital Resources

The following table summarizes total current assets, liabilities and working capital at January 31, 2015 compared to January 31, 2014:

	Period Ended		**Increase/**
	January 31, 2015	**January 31, 2014**	**(Decrease)**
Current Assets	$5,709,655	$4,244,648	$1,465,007
Current Liabilities	$2,745,534	$818,001	$1,927,533
Working Capital	$2,964,121	$3,426,647	$(462,526)

As of January 31, 2015, we had working capital of $2,964,121 as compared to working capital of $3,426,647 as of January 31, 2014, a decrease of $462,526. The decrease in working capital is primarily attributable to an increase in accounts receivable, inventory and deposit with related party manufacturer in addition to increases in accounts payable and accrued expenses and in the outstanding line of credit balance. During the year ended January 31, 2015, the Company raised net proceeds of the $1,180,003 from the sale of 1,620,001 shares of common stock and received proceeds of $100,000 for common stock subscribed.

Net cash used in operating activities for the year ended January 31, 2015 and December 31, 2013 was $5,007,364 and $3,821,598, respectively. The net loss for the years ended January 31, 2015 and December 31, 2013 was $4,060,476 and $2,947,608 respectively.

Net cash used in all investing activities for the year ended January 31, 2015 was $316,831 as compared to $1,172,522 for the year ended December 31, 2013. During the year ended January 31, 2015, the Company paid approximately $44,997 to acquire new machinery and equipment. In addition, the Company paid approximately $271,834 for improvements to the JEFE facility which have been capitalized and depreciated over the estimated life of the supply agreement. During the year ended December 31, 2013, the Company paid $877,522 for machinery and equipment, $295,000 for the acquisition of a company and $30,000 for a loan to a related party.

Net cash provided by all financing activities for the year ended January 31, 2015 was $4,637,550 as compared to $4,727,894 for the year ended December 31, 2013. During the year ended January 31, 2015, the Company raised net proceeds of $1,180,003 from the sale of 1,620,001 shares of common stock and $100,000 for common stock subscribed. During the year ended January 31, 2015, the Company had net borrowings of $1,186,394, $600,000 and $2,000,000 for transactions pursuant to the line of credit, term loan and convertible note agreements, respectively. These increases were offset by $174,211, $214,636, and $40,000 paid for stock issuance costs, debt issuance costs, and repayments on a term loan, respectively. During the year ended December 31, 2013 the Company raised net proceeds of the $5,000,000 from the sale of common stock and $800,000 for common stock subscribed. These increases were offset by $872,106 and $200,000 paid for stock issuance costs and repayments on a line of credit, respectively.

The Company believes that our existing available cash along with estimated net proceeds from the issuance of securities during January 2014 and the year ended January 31, 2015 in addition to the line of credit and convertible note entered into in October 2014 and December 2014, respectively, will enable the Company to meet the working capital requirements through the end of the current fiscal year, however, in the case that the Company exceeds its expected growth, we would need to raise additional capital and/or cut expenses and overhead in order to operate the business through such date. Currently, we plan to raise additional capital, but we have no committed sources of additional capital and our access to capital funding is always uncertain. There is no assurance that additional equity or debt financing will be available to us when needed, on acceptable terms or even at all. The estimated working capital requirement for the next 12 months is approximately $2,000,000 which equates to an estimated burn rate of $167,000 per month. The Company continues to explore potential expansion opportunities in the industry in order to boost sales while leveraging distribution systems to consolidate lower costs.

As reflected in the accompanying consolidated financial statements, the Company has a net loss and net cash used in operations of $4,060,476 and $5,007,364, respectively, for the year ended January 31, 2015.

The ability of the Company to continue its operations is dependent on Management’s plans, which include the raising of capital through debt and/or equity markets with some additional funding from other traditional financing sources, including term notes, until such time that funds provided by operations are sufficient to fund working capital requirements. The Company may need to incur additional liabilities with certain related parties to sustain the Company’s existence.

The Company may require additional funding to finance the growth of its current and expected future operations as well as to achieve its strategic objectives. There can be no assurance that financing will be available in amounts or terms acceptable to the Company, if at all. In that event, the Company would be required to change its growth strategy and seek funding on that basis, though there is no guarantee it will be able to do so.

During the month ended January 31, 2014 and the year ended January 31, 2015, Management raised capital through debt and equity financings. The Company intends to utilize the capital in order to further advertise and market the Company's brand and to assist in penetrating additional distribution channels.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk.

We do not hold any derivative instruments and do not engage in any hedging activities.

Item 8. Financial Statements.

Our consolidated financial statements are contained in pages F-1 through F-22 which appear at the end of this Annual Report.

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

There are no reportable events under this item for the year ended January 31, 2015.

Item 9A. Controls and Procedures.

(a) EVALUATION OF DISCLOSURE CONTROLS AND PROCEDURES

Based on their evaluation as of the end of the period covered by this Annual Report on Form 10-K, our principal executive officer and principal financial officer have concluded that our disclosure controls and procedures (as defined in Rules 13a-15(c) and 15d-15(e) under the Exchange Act) are not effective to ensure that information required to be disclosed by us in report that we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the U.S. Securities and Exchange Commission’s rules and forms and to ensure that information required to be disclosed by us in the reports that we file or submit under the Exchange Act is accumulated and communicated to our management, including our chief executive officer and chief financial officer, as appropriate to allow timely decisions regarding required disclosure.

(b) MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

This Company's management is responsible for establishing and maintaining internal controls over financial reporting and disclosure controls. Internal Control Over Financial Reporting is a process designed by, or under the supervision of, the Company's principal executive and principal financial officers, or persons performing similar functions, and effected by the issuer's board of directors, management and other personnel, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles and includes those policies and procedures that:

(1) Pertain to the maintenance of records that in reasonable detail accurately and fairly reflect the transactions and dispositions of the assets of the issuer;

(2) Provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the issuer are being made only in accordance with authorizations of management and directors of the registrant; and

(3) Provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of the issuer's assets that could have a material effect on the financial statements.

Disclosure controls and procedures are designed to ensure that information required to be disclosed in reports filed under the Securities Exchange Act of 1934, as amended, is appropriately recorded, processed, summarized and reported within the specified time periods.

Management has conducted an evaluation of the effectiveness of our internal control over financial reporting as of January 31, 2015, based on the framework established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO").

Based on this assessment, management concluded that as of the period covered by this Annual Report on Form 10-K, it had material weaknesses in its internal control procedures.

As of period covered by this Annual Report on Form 10-K, we have concluded that our internal control over financial reporting was ineffective. The Company's assessment identified certain material weaknesses which are set forth below:

Functional Controls and Segregation of Duties

Because of the Company's limited resources, there are limited controls over information processing.

There is an inadequate segregation of duties consistent with control objectives. Our Company's management is composed of a small number of individuals resulting in a situation where limitations on segregation of duties exist. In order to remedy this situation we would need to hire additional staff to provide greater segregation of duties. Currently, it is not feasible to hire additional staff to obtain optimal segregation of duties. Management will reassess this matter in the following year to determine whether improvement in segregation of duty is feasible.

Accordingly, as the result of identifying the above material weakness we have concluded that these control deficiencies resulted in a reasonable possibility that a material misstatement of the annual or interim financial statements will not be prevented or detected on a timely basis by the Company's internal controls.

Management believes that the material weaknesses set forth above were the result of the scale of our operations and are intrinsic to our small size. Management believes these weaknesses did not have a material effect on our financial results and intends to take remedial actions upon receiving funding for the Company's business operations.

This annual report does not include an attestation report of our registered public accounting firm regarding internal control over financial reporting. Management's report was not subject to attestation by our registered public accounting firm pursuant to temporary rules of the SEC that permit the Company to provide only management's report herein.

(c) CHANGES IN INTERNAL CONTROLS OVER FINANCIAL REPORTING

We are committed to improving our financial organization. As part of this commitment, we will create a position to segregate duties consistent with control objectives and will increase our personnel resources and technical accounting expertise within the accounting function when funds are available to us by preparing and implementing sufficient written policies and checklists which will set forth procedures for accounting and financial reporting with respect to the requirements and application of US GAAP and SEC disclosure requirements.

Management believes that preparing and implementing sufficient written policies and checklists will remedy the material weaknesses pertaining to insufficient written policies and procedures for accounting and financial reporting with respect to the requirements and application of US GAAP and SEC disclosure requirements.

We intend to take appropriate and reasonable steps to make the necessary improvements to remediate these deficiencies, including:

(1) We will revise processes to provide for a greater role of independent board members in the oversight and review until such time that we are adequately capitalized to permit hiring additional personnel to address segregation of duties issues, ineffective controls over the revenue cycle and insufficient supervision and review by our corporate management.

(2) We will update the documentation of our internal control processes, including formal risk assessment of our financial reporting processes.

We intend to consider the results of our remediation efforts and related testing as part of our year-end 2015 assessment of the effectiveness of our internal control over financial reporting.

Subsequent to January 31, 2015, we have undertaken the following steps to address the deficiencies stated above:

Continued the development and documentation of internal controls and procedures surrounding the financial reporting process, primarily through the use of account reconciliations, and supervision.

Added additional accounting staff to further segregate duties and help the Company maintain timely reporting of financial results.

Item 9B. Other Information.

None.

PART III

Item 10. Directors, Executive Officers and Corporate Governance.

Directors and Executive Officers

The following table discloses our directors and executive officers as of September 18, 2014.

Name	Age	Position
Carl Wolf	71	Chief Executive Officer and Chairman of the Board of Directors
Matthew Brown	46	President and Director
Lewis Ochs	68	Chief Financial Officer
Steven Burns	54	Director
Alfred D'Agostino	61	Director
Thomas Toto	60	Director
Dan Altobello	74	Director
Dean Janeway	71	Director

Carl Wolf, age 71, has over 35 years of experience in the management and operations of companies in the food industry. Mr. Wolf has served as Chief Executive Officer and Chairman of the Board of MamaMancini's from February 2010 through the Present. Mr. Wolf was the founder, majority shareholder, Chairman of the Board, and CEO of Alpine Lace Brands, Inc., a public company with over $125 million in wholesale sales. He also founded, managed, and sold MCT Dairies, Inc., a $60 million international dairy component resource company. Other experience in the food industry includes his role as Co-chairman of Saratoga Beverage Company, a publicly traded (formerly NASDAQ: TOGA) bottled water and fresh juice company prior to its successful sale to a private equity firm. Mr. Wolf served an advisor to Mamma Sez Biscotti, a snack and bakery product company (which was sold in a later period to Nonnis, the largest biscotti company in the United States) from 2002 to 2004. Previously he served as Director and on the Audit and Development committees of American Home Food Products, Inc. a publically traded marketer Artisanal Brand Cheeses, from 2007 to 2009. Mr. Wolf also served as Chairman of the Board of Media Bay a publically traded direct seller of spoken word through its audio book club and old time radio classic activities and download spoken content, from 2002 to 2004.

Mr. Wolf received his B.A. in 1965 from Rutgers University and his M.B.A. in 1966 from the University of Pittsburgh.

In evaluating Mr. Wolf's specific experience, qualifications, attributes and skills in connection with his appointment to our board, we took into account his numerous years of experience in the food industry, as a serial entrepreneur in growing business, his knowledge of publicly traded companies, and his proven track record of success in such endeavors.

Matthew Brown, age 46, has over 19 years of experience in the sales and marketing of products in the food industry. Beginning in February 2010 through the present, he has served as President of MamaMancini's. From April 2001 until January of 2012, he served as the President of Hors D'oeuvres Unlimited, overseeing the day to day operations of their food manufacturing business. He previously worked as a marketing associate from September 1993 to December 1998 at Kraft Foods, Inc., where he dealt with numerous aspects of the company's marketing of their food products.

Mr. Brown received his B.A. from the University of Michigan in 1991 and his M.B.A. from the University of Illinois in 1993.

In evaluating Mr. Brown's specific experience, qualifications, attributes and skills in connection with his appointment to our board, we took into account his numerous years of experience in sales and marketing, and his proven track record of success in such endeavors.

Lewis Ochs, age 68, has over 40 years of experience in the financial and accounting industry. From February 2010 through the present he has served as the Executive Vice President of Finance for MamaMancini's. Effective September 5, 2014 Mr. Ochs was named our Chief Financial Officer. Additionally, beginning in January 2003 and still presently, he serves as the CFO of Hors D'oeuvres Unlimited, overseeing all of the financial aspects of the company. From 1979 through 1991, he also was an owner of Captive Plastics, Inc., a large molding manufacturer, directly contributing to the overseeing of over 500 union and non-union employees. At various times in his career he also acted as an independent consultant utilizing his financial skills including forensic accounting, restructuring of businesses, and as a field examiner for lending institutions.

Mr. Ochs received his B.S. in Accounting from the University of Akron in 1970.

In evaluating Mr. Ochs' specific experience, qualifications, attributes and skills in connection with his appointment to our board, we took into account his numerous years of experience in finance and accounting, and his proven track record of success in such endeavors.

Steven Burns, age 54, has over 20 years of experience in the management and operations of various companies. Mr. Burns has served as a director of MamaMancini's from February 2010 through the present. Beginning in June 2011 and still presently, he serves as the Chairman of the Board of Directors of Meatball Obsession, LLC. Additionally, beginning in 2006 and still Presently he works as the President and CEO of Point Prospect, Inc., where he oversees the day to day operations of the company, which primarily deal with investments and services in real estate, clean and efficient energy sources, high-quality and healthy food services, and healthcare technology. Prior to that, for a period of 24 years he worked at and was senior executive at Accenture where he led the U.S. Health Insurance Industry Program comprised of approximately 600 professionals. He also has sat on various financial committees and boards of directors throughout his career.

Mr. Burns received his B.S. in Business Management from Boston College in 1982.

In evaluating Mr. Burns' specific experience, qualifications, attributes and skills in connection with his appointment to our board, we took into account his numerous years of experience in serving on board of directors, his knowledge of running and managing companies, and his proven track record of success in such endeavors.

Alfred D'Agostino, age 61, has over 34 years of experience in the management and ownership of food brokerage and food distribution companies. Mr. D'Agostino has served as a director of MamaMancini's from February 2010 through the Present. Beginning in March 2001 and still presently, he serves as the President for World Wide Sales Inc., a perishable food broker that services the New York / New Jersey Metropolitan and Philadelphia marketplace. Prior to this he worked from September 1995 until February 2001 as Vice-President of the perishable business unit at Marketing Specialists, a nationwide food brokerage. Previously, from February 1987 until August 1995 he worked as a Partner for the perishable division of Food Associates until its merger with Merket Enterprises.

In evaluating Mr. D'agostino's specific experience, qualifications, attributes and skills in connection with his appointment to our board, we took into account his numerous years of experience in the food brokerage and other food related industries, his knowledge of running and managing companies, and his proven track record of success in such endeavors.

Mr. D'Agostino received his B.S. in Business Management from the City College of New York in 1974.

Thomas Toto, age 60, has over 32 years of experience in the management and ownership of food brokerage and food distribution companies. Mr. Toto has served as a director of MamaMancini's from February 2010 through the Present. Beginning in June 2009 and still presently, he serves as the Senior Business manager for World Wide Sales Inc., a perishable food broker that services the New York / New Jersey Metropolitan and Philadelphia marketplace. Prior to this he worked from September 2007 until May 2009 as a Division President for DCI Cheese Co., a company that imported and distributed various kinds of cheeses. Previously from March 1993 until September 2007 he was the President and owner of Advantage International Foods Corporation, where he ran the day to day operations of importing and distributing cheeses around the world.

Mr. Toto received his B.A. from Seton Hall University in 1976 and his M.B.A. from Seton Hall University in 1979.

In evaluating Mr. Toto's specific experience, qualifications, attributes and skills in connection with his appointment to our board, we took into account his numerous years of experience in the food brokerage and other food related industries, his knowledge of running and managing companies, and his proven track record of success in such endeavors.

Dan Altobello, age 74, has served as a director of MamaMancini's since 2012. Since October 2000, Mr. Altobello, Chairman of Altobello Family LP, has been a private investor and active board member of several companies. From September 1995 until October 2000, Mr. Altobello was the Chairman of Onex Food Services, Inc., the parent of Caterair International, Inc. and LSG/SKY Chefs. He is a current member of the boards of directors of DiamondRock Hospitality Company, a publicly-traded hotel REIT, Northstar Senior Care Trust, Inc., a private company that intends to qualify as a REIT, Mesa Air Group, Inc. and Arlington Asset Investment, Corp , a principal investment firm that acquires and holds mortgage-related and other assets. From 2004 to December 2010, he served as a member of the board of JER Investors Trust, Inc., a specialty finance company. Mr. Altobello serves on the advisory board of Thayer | Hidden Creek, a private equity firm. Mr. Altobello is also a trustee of Loyola Foundation, Inc.

The Board of Directors determined that Mr. Altobello's qualifications to serve as a director include his notable business and leadership experience in the areas of specialty finance. He also has experience in the area of food service distribution, due to his past position as Chairman of Onex Food Services, Inc. His past and present service on multiple public and private company boards, including his service on the audit committee of DiamondRock Hospitality Company and Northstar Senior Care Trust, Inc., provides him with comprehensive experience in the area of corporate governance that can be extremely valuable to Board and Company operations.

Mr. Altobello, received his B.A. from Georgetown University in June 1963 and his M.B.A. from Loyola University Maryland in June 1978.

Dean Janeway, age 71, has served as a director of MamaMancini's since 2012. Mr. Janeway is an executive with more than 40 years of broad leadership skills and extensive experience in the areas of corporate strategy, business development, operational oversight and financial management. From 1966 through 2011, Mr. Janeway served in various positions at Wakefern Food Corp., the largest retailer-owned cooperative in the United States. From 1966 through 1990, Mr. Janeway advanced through various positions of increasing responsibility including positions in Wakefern's accounting, merchandising, dairy-deli, and frozen foods divisions. From 1990 through 1995 Mr. Janeway provided oversight for all of Wakefern's procurement, marketing, merchandising, advertising and logistics divisions. From 1995 until his retirement in 2011, Mr. Janeway served as President and Chief Operating Officer of "Wakefern" providing primary oversight for the company's financial and treasury functions, human resources, labor relations, new business development, strategic acquisitions, government relations, corporate social responsibility, sustainability initiatives and member relations. Mr. Janeway previously served as the chairman for the National Grocers Association

from 1993 through 2001. From 2009 through the present, Mr. Janeway has served as the Chairman of the Foundation for the University of Medicine and Dentistry of New Jersey.

The Board of Directors determined that Mr. Janeway’s qualifications to serve as a director include his notable business and leadership experience in the all areas of management, particularly in the food industry. He also has experience in the area of whole sale wholesale distribution, due to his past position at Wakefern and his knowledge of running and managing companies and his proven track record of success in such endeavors will be invaluable to the Company going forward.

Mr. Janeway received his B.A. in Marketing from Rutgers University, and his M.B.A from Wharton School of Business, University of Pennsylvania.

Family Relationships

Mr. Matthew Brown, our President, is the son-in-law of Mr. Carl Wolf, our Chief Executive Officer.

Board Committees and Charters

Our board of directors has established the following committees: an audit committee, a compensation committee and a nominating/corporate governance committee. Copies of each committee's charter are posted on our website, www.mamamancini's.com. Our board of directors may from time to time establish other committees.

Audit Committee

The purpose of the Audit Committee is to oversee the processes of accounting and financial reporting of the Company and the audits and financial statements of the Company. The Audit Committee's primary duties and responsibilities are to:

- Monitor the integrity of the Company's financial reporting process and systems of internal controls regarding finance, accounting and legal compliance.
- Monitor the independence and performance of the Company's independent auditors and the Company's accounting personnel.
- Provide an avenue of communication among the independent auditors, management, the Company's accounting personnel, and the Board.
- Appoint and provide oversight for the independent auditors engaged to perform the audit of the financial statements.
- Discuss the scope of the independent auditors' examination.
- Review the financial statements and the independent auditors' report.
- Review areas of potential significant financial risk to the Company.
- Monitor compliance with legal and regulatory requirements.
- Solicit recommendations from the independent auditors regarding internal controls and other matters.

Make recommendations to the Board.

Resolve any disagreements between management and the auditors regarding financial reporting.

Prepare the report required by Item 407(d) of Regulation S-K, as required by the rules of the Securities and Exchange Commission (the “SEC”).

Perform other related tasks as requested by the Board.

The Audit Committee has the authority to conduct any investigation appropriate to fulfilling its responsibilities, and it has direct access to the independent auditors as well as anyone in the organization. The Committee has the ability to retain, at the Company’s expense, special legal, accounting, or other consultants or experts it deems necessary in the performance of its duties.

Our Audit Committee consists of Mr. Burns, Mr. Toto and Mr. Altobello. Mr. Toto serves as the Chairman of our Audit Committee. Mr. Burns is our Audit Committee financial expert as currently defined under applicable SEC rules.

Compensation Committee

The Compensation Committee's responsibilities include, but are not limited to, the responsibilities which are required under the corporate governance rules of NYSE MKT, including the responsibility to determine compensation of the Chairman of the Board, the Chief Executive Officer ("CEO"), the President and all other executive officers. The Compensation Committee's actions shall generally be related to overall considerations, policies and strategies.

The following are specific duties and responsibilities of the Compensation Committee:

Review the competitiveness of the Company's executive compensation programs to ensure (a) the attraction and retention of corporate officers, (b) the motivation of corporate officers to achieve the Company's business objectives, and (c) the alignment of the interests of key leadership with the long-term interests of the Company's stockholders.

Review and determine the annual salary, bonus, stock options, other equity-based incentives, and other benefits, direct and indirect, of the Company's executive officers, including development of an appropriate balance between short-term pay and long-term incentives while focusing on long-term stockholder interests.

Determine salary increases and bonus grants for the Chairman of the Board, the CEO, the President and all other executive officers of the Company.

Review and approve corporate goals and objectives for purposes of bonuses and long- term incentive plans.

Review and approve benefit plans, including equity incentive plans, and approval of individual grants and awards.

Review and approve employment or other agreements relating to compensation for the Chairman of the Board, the CEO, the President and the other executive officers of the Company.

9/2013 to 8/2023	0.17	9,925	
	Limestone and Harrison Counties, TX	14,940	0.10 761

Enbridge Pipeline		Orange, TX		7/2012 to 6/2014		
Wyoming Interstate Company Pipeline	Meeker, CO	Opal, WY	35,000	8/2011 to 7/2021	0.31	35,536
Ruby Pipeline	Opal, WY	Malin, OR	35,000	8/2011 to 7/2021	0.95	110,072
Total						$245,079

(1) Based on weighted average cost.

(2) The planned expansion of the Chipeta Processing LLC natural gas plant was completed in February 2013, at which time transportation ceased under some related contracts and began under others.

Steaming Operations

Our California assets consist of heavy crude oil, which requires heat, supplied in the form of steam, injected into the oil producing formations to reduce the oil viscosity, thereby allowing the oil to flow to the wellbore for production. We utilize cyclic steam and/or steam flood recovery methods on such assets.

Cogeneration Steam Supply. In pursuing our goal of being a cost-efficient heavy oil producer in California, we have consistently focused on minimizing our steam cost. We believe one of the main methods to keep steam costs low is through the ownership and efficient operation of three cogeneration facilities located on our properties. These cogeneration facilities are all located on our SMWSS properties, including our 38 megawatt (MW) and 18 MW facilities at Homebase and our 42 MW facility at Placerita. Cogeneration, also called combined heat and power (CHP), extracts energy from the exhaust of a turbine

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that would otherwise be wasted to produce steam. This increases the efficiency of the combined process and consumes less fuel than would be required to produce the steam and electricity separately.

Conventional Steam Generation. We also own 49 fully permitted conventional steam generators. The quantity of generators operated at any point in time is dependent on (i) the steam volume required to achieve our targeted production and (ii) the price of natural gas compared to the realized price of crude oil sold. In 2012, we added ten additional steam generators including two for use at our McKittrick property, one for use at our Main Camp property and seven for use in our ongoing development of our Diatomite assets. In 2011, we added five additional steam generators, four for use in the development of our Diatomite property and one for use at our McKittrick property. In 2010, we added four additional steam generators for use in the development of our Diatomite assets.

Ownership of these varied steam generation facilities and sources allows for maximum operational control over the steam supply, location and, to some extent, the aggregated cost of steam generation. Our steam supply and flexibility are crucial for the maximization of California thermally enhanced heavy oil production, cost control and ultimate oil recovery.

Total steam capacity, measured in barrels of steam per day (BSPD), as of December 31, 2012 was as follows:

Steam generation capacity of conventional steam generators	213,911
Steam generation capacity of cogeneration plants	42,789
Additional steam purchased under contract with a third party	954
Total steam capacity	257,654

The average gross volume of steam injected in our California oil production operations for the years ended December 31, 2012 and 2011 was 170,884 BSPD and 133,404 BSPD, respectively.

During December 2012, approximately 85% of the natural gas we purchased to generate steam and electricity was based upon California indices. We pay distribution/transportation charges for the delivery of natural gas to our various locations where we use the natural gas for steam generation purposes. In some cases, this transportation cost is embedded in the price of the natural gas we purchase. Approximately 15% of the volume of natural gas purchased to generate steam and electricity was purchased in the Rockies and moved to the Midway-Sunset field using our firm transportation capacity on the Kern River Pipeline. This natural gas has historically been purchased based upon the Rocky Mountain NWPL index. Historical average prices of the natural gas indices key to our steaming operations are as follows:

	2012	2011	2010
Average SoCal Border Monthly Index Price per MMBtu	$3.00	$4.10	$4.34
Average PG&E Citygate Monthly Index Price per MMBtu	3.16	4.29	4.66
Average Rocky Mountain NWPL Monthly Index Price per MMBtu	2.68	3.80	3.94

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Historically we have been a net producer of natural gas and have benefited operationally when natural gas prices increase. Our production of natural gas provides a form of natural hedge against rising steam costs. As our natural gas production continued to decrease and our use of natural gas for steaming operations has increased, we have become a net consumer of natural gas. The following table shows our average and estimated average amount of production, consumption and hedged volumes for the following years:

(in MMBtu/D)	Estimated 2013	2012	2011
Natural gas produced	47,136	54,054	65,500
Natural gas consumed in operations			
Cogeneration operations	26,600	26,625	25,087
Conventional steam generators	62,000	43,330	34,377
Total natural gas consumed in operations	88,600	69,955	59,464
Less: Estimated natural gas volumes consumed to produce electricity(1)	(15,400)	(15,415)	(15,229)
Net estimated natural gas consumed in steam generation	73,200	54,540	44,235
Natural gas (purchases) sales volumes hedged(2)	(10,000)	10,000	15,000
Estimated net (deficit) excess of natural gas produced, consumed and hedged	(16,064)	(10,486)	6,265

(1) Estimate is based on the historical allocation of fuel costs to electricity.

(2) Beginning in 2013, our natural gas derivatives hedge against rising natural gas prices; in years previous to 2013, our natural gas derivatives hedged against falling natural gas prices.

Electricity

Generation. The total net electrical generation capacity of our three cogeneration facilities during 2012 was approximately 93 MW, of which we consumed approximately 8 MW for use in our operations. Each facility is centrally located on certain of our oil producing properties. Thus the steam generated by each facility is capable of being delivered to numerous wells that require steam for the EOR process. Our investment in our cogeneration facilities has been for the express purpose of lowering the steam costs in our heavy oil operations and securing operating control of the respective steam generation. Expenses of operating the cogeneration plants are analyzed regularly to determine whether they are advantageous versus conventional steam generators. Cogeneration costs are allocated between electricity generation and oil and natural gas operations based on the conversion efficiency (of fuel to electricity and steam) of each cogeneration facility and certain direct costs to produce steam. Cogeneration costs allocated to electricity will vary based on, among other factors, the thermal efficiency of our cogeneration plants, the price of natural gas used for fuel in generating electricity and steam and the terms of our power contracts. Although we account for cogeneration costs as described above, economically we view any profit or loss from the generation of electricity as a decrease or increase, respectively, to our total cost of producing heavy oil in California. Depreciation, depletion and amortization (DD&A) related to our cogeneration facilities is allocated between electricity operations and oil and natural gas operations using a similar allocation method.

Sales Contracts. We sell electricity produced by our cogeneration facilities under long-term contracts approved by the California Public Utilities Commission (CPUC) to two California investor owned utilities (IOUs): Southern California Edison Company (Edison) and Pacific Gas and Electric Company (PG&E). Under these power purchase agreements (PPAs), we are paid an energy payment that reflects the utility's Short Run Avoided Cost (SRAC) of energy plus a capacity payment that reflects a recovery of capital expenditures that would otherwise have been made by the utility. Beginning in 2015, the energy prices we will be paid under the contracts for our Cogen 18 and Cogen 38 facilities will be based on market prices for electricity in California.

Our legacy PPAs for our Cogen 42 facilities expired in May 2012, at which time a transition PPA with Edison became effective. On July 2, 2012, we and Edison executed a seven-year contract for our Cogen 42 facilities pursuant to a competitive solicitation (the RFO PPA). Subject to CPUC approval, the seven-year term will commence on July 1, 2014, at which time the transition PPA for Cogen 42 will terminate.

Our legacy PPA for our Cogen 38 facility expired in March 2012, at which time a transition PPA with PG&E became effective. We intend to participate in future CHP competitive solicitations for the sale of energy and capacity from our Cogen 38 facility, although there is no assurance we will be successful in entering into a new RFO PPA for this facility. Our transition PPA with PG&E will remain in effect until June 2015.

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Our legacy PPA with PG&E for our Cogen 18 facility terminated on September 30, 2012 and was replaced with a new Public Utilities Regulatory Policy Act of 1978, as amended (PURPA) PPA with PG&E, effective October 1, 2012, for a term of seven years. Because the rated capacity of our Cogen 18 facility is less than 20 MW, it continues to be eligible for PPAs pursuant to PURPA.

Under the PURPA PPA for our Cogen 18 facility and the transition PPAs for our Cogen 38 and Cogen 42 facilities, we will be paid the CPUC-determined SRAC energy price and a combination of firm and "as-available" capacity payments. Under the RFO PPA for our Cogen 42 facility, which will commence July 1, 2014, we will be paid a negotiated energy and capacity price stipulated in the contract.

See Item 1A. Risk Factors—"We are dependent on our cogeneration facilities and deteriorations in the electricity market and regulatory changes in California may materially and adversely affect our financial condition, results of operations and operating cash flows."

The following table sets forth information regarding our cogeneration facilities and contracts as of December 31, 2012:

Facility	Type of Contract	Purchaser	Contract Expiration		Approximate Megawatts Available for Sale(3)	Approximate Megawatts Consumed in Operations(3)	Approximate Barrels of Steam Per Day in 2012
Cogen 42	Transition	Edison	June 2015	(1)	37	4	13,000
Cogen 18	PURPA	PG&E	Sept 2019		11	4	6,500
Cogen 38	Transition	PG&E	June 2015	(2)	37	—	18,000

(1) Subject to CPUC approval, we have executed a seven-year contract with Edison that will commence on July 1, 2014, which will replace the current Transition contract.
(2) We anticipate the current transition contract will be replaced by a long-term contract with a term of up to seven years pursuant to a future competitive solicitation.
(3) Assumes operations at full capacity with no interruptions.

Competition

The oil and natural gas industry is highly competitive. As an independent producer, we have little control over the price we receive for our oil and natural gas. As such, higher costs, fees and taxes assessed at the producer level cannot necessarily be passed on to our customers. In acquisition activities, competition is intense as integrated and independent companies and individual producers are active bidders for desirable oil and natural gas properties and prospective acreage. Although many of these competitors have greater financial and other resources than we have, we are in a position to compete effectively due to our business strengths.

Title to Properties

Prior to the time we acquire undeveloped properties, we conduct a title investigation consistent with industry custom and practice. Most developed properties we acquire have existing title opinions. In addition, prior to commencement of drilling operations we obtain a drilling title opinion which, in the event production is achieved, is supplemented with a division order title opinion or its equivalent. To date, we have obtained or commissioned title opinions on virtually all of our producing properties and have satisfactory title to those properties in accordance with industry

standards. A majority of our oil and natural gas properties are subject to a mortgage or deed of trust under our senior secured revolving credit facility (credit facility), as well as to customary royalty interests, liens incidental to operating agreements, tax liens and other minor burdens, encumbrances, easements and restrictions that do not materially interfere with the use of or affect the value of such properties.

Employees

As of December 31, 2012 we had 374 full-time employees. We also contract for the services of independent consultants involved with land, regulatory, accounting, financial and other disciplines as needed. None of our employees are represented by labor unions or covered by a collective bargaining agreement. Our relations with our employees are good.

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Offices

Our corporate headquarters are located in Denver, Colorado, and we have regional offices in Bakersfield, California, Plano, Texas and Midland, Texas.

Available Information

Our website, located at http://www.bry.com, can be used to access recent news releases and SEC filings, crude oil price postings, hedging summaries, our Annual Report, Proxy Statement, Board Committee Charters, Corporate Governance Guidelines, Code of Business Conduct and Ethics, the Code of Ethics for Senior Financial Officers and other items of interest. Information on our website is not incorporated into this report. SEC filings, including supplemental schedules and exhibits, can also be accessed free of charge through the SEC website at http://www.sec.gov.

Environmental Matters and Other Regulations

General. Our operations are subject to stringent, complex and evolving federal, state and local laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection. Our operations are subject to the same environmental laws and regulations as other companies in the oil and natural gas exploration and production industry. These laws and regulations:

- require the acquisition of various permits or authorizations before drilling commences;
- require the installation of expensive pollution control equipment;
- require the purchase of emissions allowances and offsets for the emission of greenhouse gases above the amount of allowances granted to us;
- restrict the types, quantities and concentration of various substances that can be released into the environment in connection with drilling and production activities;
- require groundwater quality sampling and monitoring;
- limit or prohibit drilling activities on lands lying within environmentally sensitive areas, wilderness, wetlands and other protected areas;
- affect the location and size of our wells and facilities;
- require measures to prevent pollution from former operations, such as pit closure and plugging of abandoned wells;
- impose substantial liabilities for pollution resulting from our operations; and
- require time-consuming environmental analyses with uncertain outcomes.

Failure to comply with these laws and regulations may result in the assessment of significant administrative, civil, or criminal penalties, imposition of remedial obligations, incurrence of additional compliance costs and operational delays or injunctions.

These laws and regulations may also restrict the rate of oil and natural gas production below the rate that would otherwise be possible. The regulatory burden on the oil and natural gas industry increases the cost and timing of doing business and consequently affects profitability. Additionally, Congress and federal and state agencies frequently revise the environmental laws and regulations, and any changes that result in delay of oil and natural gas operations or more stringent and costly permitting, well drilling, construction, completions and water management activities, or waste handling, disposal and clean-up requirements for the oil and natural gas industry could materially and adversely affect our financial condition, results of operations and operating cash flows.

We believe that, in all material respects, we are in compliance with, and have complied with, all applicable environmental laws and regulations. We employ an environmental health and safety department whose responsibilities include providing assurance that our operations are carried out in accordance with applicable environmental guidelines and safety precautions. We have made and will continue to make expenditures in our efforts to comply with all environmental regulations and requirements. We consider these a normal, recurring cost of our ongoing operations and not an extraordinary cost of compliance with governmental regulations. We believe that our continued compliance with existing requirements has been accounted for and will not have a material and adverse impact on our financial condition, results of operations and operating cash flows. However, because environmental laws and regulations are subject to frequent changes, we are unable to predict the impact that compliance with future laws or regulations may have on our future financial condition, results of operations or operating cash flows. For the year ended December 31, 2012, we did not incur any material capital expenditures for remediation or retrofit of pollution control equipment at any of our facilities. As of the date of this report, we are not aware of any environmental issues or claims that will require material capital expenditures during the next 12 months.

Some of the more significant environmental laws and regulations that could have a material impact on the oil and natural gas exploration and production industry and our business are as follows:

National Environmental Policy Act. Oil and natural gas exploration and production activities on federal lands are subject to the National Environmental Policy Act (NEPA). NEPA requires federal agencies, including the Departments of Interior and Agriculture, to evaluate major agency actions having the potential to significantly impact the environment. In the course of such evaluations, an agency will have an environmental assessment prepared that assesses the potential direct, indirect and cumulative impacts of a proposed project and alternatives to the proposed project. If impacts are considered significant, the agency will prepare a more detailed environmental impact study that is made available for public review and comment. All of our current exploration and production activities on federal lands, as well as proposed exploration and development plans on federal lands, require governmental permits that may trigger the requirements of NEPA. Certain federal permits on non-federal lands may also trigger NEPA requirements. This process has the potential to delay or limit the development of oil and natural gas projects. Authorizations under NEPA also are subject to protest, appeal or litigation, which can delay or halt projects.

Waste Handling. The Resource Conservation and Recovery Act (RCRA) and comparable state laws regulate the generation, transportation, treatment, storage, disposal and cleanup of “hazardous wastes” and the disposal of non-hazardous wastes. RCRA imposes stringent operating requirements and liability for failure to meet such requirements on "generators" or "transporters" of waste or "owners" or "operators" of a waste treatment, storage or disposal facility. Under the auspices of the Environmental Protection Agency (EPA), the individual states administer some or all of the provisions of RCRA, sometimes in conjunction with their own, more stringent requirements. Drilling fluids, produced waters and most of the other wastes associated with the exploration, development and production of oil, natural gas, or geothermal energy constitute “solid wastes,” which are regulated under the less stringent, non-hazardous waste provisions; however, there is no guarantee that the EPA or the individual states will not adopt more stringent requirements for the handling of these non-hazardous wastes or categorize some non-hazardous wastes as hazardous for future regulation. Indeed, legislation has been proposed from time to time in Congress to re-categorize certain oil and natural gas exploration and production wastes as “hazardous wastes.” Any modification of state or federal laws that would cause oil and natural gas exploration and production wastes to be classified as hazardous would increase the volume of hazardous waste we are required to manage and dispose of and would cause us to incur increased operating expenses, and could have a material adverse effect on our results of operations and financial position.

Our operations produce wastewater some of which is disposed via injection in underground wells. These wells are regulated under the Safe Drinking Water Act (SDWA) and similar state and local laws. The underground injection well program under the SDWA requires permits from the EPA or analogous state agencies for our disposal wells, establishes minimum standards for injection well operations and restricts the types and quantities of fluids that may be injected. A change in the regulations or the inability to obtain permits for new injection wells in the future may affect our ability to dispose of produced waters and ultimately increase the cost of our operations.

Comprehensive Environmental Response, Compensation and Liability Act. The Comprehensive Environmental Response, Compensation and Liability Act (CERCLA), also known as the “Superfund” law, along with comparable state laws, impose strict, joint and several liability, without regard to fault or legality of conduct, on classes of persons who are considered to be responsible for a release or threatened release of a “hazardous substance” into the environment. These persons include the current and past owners or operators of the disposal site, or site where the release or threatened release of a “hazardous substance” occurred, and entities that disposed or arranged for the disposal of the hazardous substance. Under CERCLA, such persons may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies. In addition, it is not uncommon for neighboring landowners and other third

parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment. We currently own, lease, or operate numerous properties that have been used for oil and natural gas exploration and production for many years, and substances that could be subject to CERCLA and analogous state laws may have been released on or under these properties or on or under other locations, including off-site locations, where such substances have been taken for disposal. In addition, some of our properties have been operated by third parties or by previous owners or operators whose treatment and disposal of substances that could be subject to CERCLA and similar state laws was not under our control. Therefore, governmental agencies or third parties may seek to hold us jointly and severally liable under CERCLA or comparable state laws for all or part of the costs to remove such previously disposed substances, remediate contaminated property or perform remedial operations to prevent future contamination at sites at which such substances have been released.

OSHA and Other Laws and Regulation. We are subject to the requirements of the federal Occupational Safety and Health Act (OSHA) and comparable state laws. Pursuant to OSHA, the Occupational Safety and Health Administration has established a variety of standards relating to workplace exposure to hazardous substances and employee health and safety. Additionally, the

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OSHA hazard communication standard, the EPA community right-to-know regulations under the Title III of CERCLA and similar state statutes require that we organize and/or disclose information about hazardous materials used or produced in our operations.

Water Discharges. The federal Water Pollution Control Act (Clean Water Act) and comparable state laws impose restrictions and strict controls with respect to the discharge of pollutants, including produced waters and spills and leaks of oil and other substances, into waters of the United States. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA or an analogous state agency. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with discharge permits or other requirements of the Clean Water Act and analogous state laws and regulations.

Oil Pollution Act. The Oil Pollution Act of 1990 (“OPA”) and regulations issued under OPA impose strict, joint and several liability on “responsible parties” for removal costs and damages resulting from oil spills into or upon navigable waters, adjoining shorelines or in the exclusive economic zone of the United States. A “responsible party” includes the owner or operator of an onshore facility. OPA establishes a liability limit for onshore facilities of $350.0 million per spill. This limit does not apply if the spill is caused by a responsible party’s gross negligence or willful misconduct; the spill resulted from a responsible party’s violation of a federal safety, construction or operating regulation; or a responsible party fails to report a spill or to cooperate fully in a cleanup. The President may increase the amount of financial responsibility required under OPA by up to $150.0 million, depending on the risk represented by the quantity or quality of oil that is handled by the facility. Any failure to comply with OPA’s requirements or inadequate cooperation during a spill response action may subject a responsible party to administrative penalties up to $25,000 per day per violation.

Air Emissions. The federal Clean Air Act (CAA) and comparable state laws regulate emissions of various air pollutants through air emissions permitting programs and the imposition of monitoring, reporting and other requirements. In addition, the EPA has developed, and continues to develop, stringent regulations governing emissions of toxic air pollutants at specified sources. These laws and the implementing regulations may require us to obtain pre-approval for the construction or modification of certain projects or facilities expected to produce or significantly increase air emissions, obtain and strictly comply with stringent air permit requirements or utilize specific equipment or technologies to control emissions. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with air permits or other requirements of the federal Clean Air Act and associated state laws and regulations.

Climate Change. In December 2009, the EPA determined that emissions of carbon dioxide, methane and other “greenhouse gases” (GHGs) present an endangerment to public health and the environment because emissions of such gases are, according to the EPA, contributing to warming of the earth's atmosphere and other climatic changes. Based on these findings, the EPA has begun adopting and implementing regulations to restrict emissions of GHGs under existing provisions of the CAA. The EPA has adopted two sets of rules regulating GHG emissions under the CAA, one that requires a reduction in emissions of GHGs from motor vehicles and the other that regulates emissions of GHGs from certain large stationary sources under the CAA's Prevention of Significant Deterioration and Title V permitting programs. The EPA's rules relating to emissions of GHGs from large stationary sources of emissions are currently subject to a number of legal challenges, but the federal courts have thus far declined to issue any injunctions to prevent the EPA from implementing, or requiring state environmental agencies to implement, the rules. The EPA has also adopted rules requiring the monitoring and reporting of GHG emissions from specified sources in the United States, including, among other things, certain onshore oil and natural gas production facilities, on an annual basis. Legislation has from time to time been introduced in the United States Congress that would establish measures restricting GHG emissions in the United States. At the state level, almost one half of the states, including California, have begun taking actions to control and/or reduce emissions of GHGs. See "California GHG Regulations" below for

more detail on current GHG regulations in the state of California.

California GHG Regulations. In October 2006, California adopted the Global Warming Solutions Act of 2006 (Assembly Bill 32), which established a statewide "cap and trade" program with an enforceable compliance obligation beginning with 2013 GHG emissions. The program is designed to reduce the state's GHG emissions to 1990 levels by 2020. Assembly Bill 32 will set maximum limits or caps on total emissions of GHGs from all industrial sectors, including the oil and natural gas extraction sector of which we are a part, as our California heavy oil operations emit GHGs. The cap will decline annually thereafter through 2020. We will be required to remit compliance instruments for each metric ton of GHG that we emit, in the form of allowances (each the equivalent of one ton of carbon dioxide) or qualifying offset credits. The availability of allowances will decline over time in accordance with the declining cap, and the cost to acquire such allowances may increase over time. Under Assembly Bill 32, we will be granted a certain number of California Carbon Allowances (CCAs) and we will need to purchase CCAs and/or offset credits to cover the remaining amount of our emissions. Compliance with Assembly Bill

32 could significantly increase our capital, compliance, operating and maintenance costs and could also reduce demand for the oil and natural gas we produce. We continue to assess the impact of these regulations on our operations, including the cost to acquire allowances and to reduce emissions. Our current estimates indicate that, based on the current market price of allowances, the manner in which cost-free allowances are to be distributed by the California Air Resources Board to the oil and natural gas extraction industry and our current production and emissions estimates, among other factors, our cost of acquiring compliance instruments beginning in 2013 may be in the range of $1.00 to $2.50 per barrel of California production. The actual cost to acquire compliance instruments will depend on the market price for such instruments at the time they are purchased, the distribution of allowances among various industry sectors and our ability to limit our GHG emissions and implement cost-containment measures. The cap and trade program is currently scheduled to be in effect through 2020, although it may be continued thereafter.

Hydraulic Fracturing. Hydraulic fracturing is an important and common practice that involves the injection of water, sand and chemicals under pressure into the formation to fracture the rock and stimulate production of hydrocarbons. We routinely utilize hydraulic fracturing techniques in many of our drilling and completion programs. The process is typically regulated by state oil and natural gas commissions; however, the EPA has asserted federal regulatory authority over certain hydraulic fracturing activities involving diesel under the SDWA and has released draft permitting guidance documents related to this newly asserted regulatory authority. In addition, on November 23, 2011, the EPA announced that it was granting in part a petition to initiate a rulemaking under the Toxic Substances Control Act relating to chemical substances and mixtures used in oil and natural gas exploration and production. Moreover, legislation has been introduced before Congress to repeal an exemption in the federal SDWA for the underground injection of hydraulic fracturing fluids near drinking water sources. If adopted, the legislation would require the reporting and public disclosure of chemicals used in the fracturing process. Further, if enacted, the legislation could result in additional regulatory burdens such as permitting, construction, financial assurance, monitoring, recordkeeping and plugging and abandonment requirements.

We use a significant amount of water in our hydraulic fracturing operations. Our inability to locate sufficient amounts of usable water, or dispose of or recycle water used in our exploration and production operations, could adversely impact our operations. Compliance with environmental regulations and permit requirements governing the withdrawal, storage and use of surface water or groundwater necessary for hydraulic fracturing of wells may increase our operating costs and cause delays, interruptions or termination of our operations, the extent of which cannot be predicted, all of which could have an adverse effect on our operations and financial condition.

Certain states in which we operate, including Texas and Colorado, have adopted, and other states, including California, are considering adopting, regulations that could impose increased regulatory oversight of hydraulic fracturing through additional permit requirements, public disclosure, operational restrictions and temporary or permanent bans on hydraulic fracturing in certain environmentally sensitive areas such as watersheds. For example, the Railroad Commission of Texas adopted rules in December 2011 requiring disclosure of certain information regarding the components used in the hydraulic fracturing process. In addition to state laws, local land use restrictions, such as city ordinances, may restrict or prohibit the performance of well drilling in general and/or hydraulic fracturing in particular. In the event state, local or municipal legal restrictions are adopted in areas where we are currently conducting or in the future plan to conduct operations, we may incur additional costs to comply with such requirements that may be significant in nature, experience delays or curtailment in the pursuit of exploration, development, or production activities, and perhaps even be precluded from the drilling of wells.

A number of federal agencies are analyzing, or have been requested to review, a variety of environmental issues associated with hydraulic fracturing. The EPA is conducting a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater. The EPA released a progress report outlining work currently underway on December 21, 2012 and is expected to release results of the study in 2014. In addition, the EPA

announced on October 20, 2011 that it is launching a study of wastewater resulting from hydraulic fracturing activities and currently plans to propose pretreatment regulations by 2014. Also, certain members of the Congress have called upon the U.S. Government Accountability Office to investigate how hydraulic fracturing might adversely affect water resources, the SEC to investigate the natural gas industry and any possible misleading of investors or the public regarding the economic feasibility of pursuing natural gas deposits in shales by means of hydraulic fracturing, and the U.S. Energy Information Administration to provide a better understanding of that agency's estimates regarding natural gas reserves, including reserves from shale formations, as well as uncertainties associated with those estimates. These ongoing or proposed studies, depending on their degree of pursuit and any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing under the SDWA or otherwise. President Obama created the Interagency Working Group on Unconventional Natural Gas and Oil by Executive Order on April 13, 2012, which is charged with coordinating and aligning federal agency research and scientific studies on unconventional natural gas and oil resources.

Further, on August 16, 2012, the EPA published final rules that establish new air emission control requirements for natural gas production, processing and transportation activities, including New Source Performance Standards to address emissions of

sulfur dioxide and volatile organic compounds, and National Emission Standards for Hazardous Air Pollutants (NESHAPS) to address hazardous air pollutants frequently associated with gas production and processing activities. Among other things, these final rules require the reduction of volatile organic compound emissions from natural gas wells through the use of reduced emission completions or “green completions” on all hydraulically fractured wells constructed or refractured after January 1, 2015. In addition, gas wells are required to use completion combustion device equipment (i.e., flaring) by October 15, 2012 if emissions cannot be directed to a gathering line. Further, the final rules under NESHAPS include maximum achievable control technology (MACT) standards for “small” glycol dehydrators that are located at major sources of hazardous air pollutants and modifications to the leak detection standards for valves.

The adoption of any future federal or state laws or implementing regulations imposing reporting obligations on, or otherwise limiting, the hydraulic fracturing process could make it more difficult to perform hydraulic fracturing, complete natural gas wells in shale formations and obtain permits, and could increase our costs of compliance and doing business. Restrictions on hydraulic fracturing could also reduce the amount of oil and natural gas that we are ultimately able to produce from our reserves, and could materially and adversely affect our financial condition, results of operations and operating cash flows.

Endangered Species. The Endangered Species Act (ESA) may restrict activities that may affect endangered and threatened species or their habitats. Some of our facilities and drilling operations are located in areas that are designated as habitat for endangered or threatened species; therefore, we may be prohibited from conducting drilling operations in certain locations or during certain seasons, such as breeding or nesting seasons, when our operations could have an adverse effect on the species. The presence of a protected species or the designation of previously unprotected species in our operating areas as threatened or endangered could impair our ability to timely complete drilling and development activities, could cause us to incur additional costs in the affected areas and could adversely affect our future production from those areas.

Homeland Security. Legislation continues to be introduced in Congress, and development of regulations continues in the Department of Homeland Security and other agencies, concerning the security of industrial facilities, including oil and natural gas facilities. Our operations may become subject to such laws and regulations. We cannot presently estimate the costs we could incur to comply with any such facility security laws or regulations; however, such expenditures could be substantial.

Federal Energy Regulation. The enactment of the PURPA and the adoption of regulations thereunder by the Federal Energy Regulatory Commission (FERC) provided incentives for the development of cogeneration facilities such as ours. A domestic electricity generating project must be a Qualifying Facility (QF) under FERC regulations in order to benefit from certain rate and regulatory incentives provided by PURPA.

PURPA provides two primary benefits to QFs. First, QFs generally are relieved of compliance with extensive federal regulations, pursuant to the Public Utility Holding Company Act of 1935, as amended, that control the financial structure of an electricity generating plant. Second, FERC's regulations promulgated under PURPA require that electric utilities purchase electricity generated by QFs at a price based on the purchasing utility's avoided cost and that the utility sell back-up power to the QF on a non-discriminatory basis. The term “avoided cost” is defined as the incremental cost to an electric utility of electric energy or capacity, or both, which, but for the purchase from QFs, such utility would generate for itself or purchase from another source. The Energy Policy Act of 2005 amended PURPA to allow a utility to petition FERC to be relieved of its obligation to enter into any new contracts with QFs if FERC determines that a competitive wholesale electricity market is available to QFs in the service territory. Effective November 23, 2011, the California utilities have been relieved of their PURPA obligation to enter into new contracts with cogeneration QFs larger than 20 MW. While the California utilities are still required to enter into new contracts

with smaller facilities, such as our Cogen 18 facility, there is no assurance that we will be able to secure new contracts upon the expiration of the existing contracts for our Cogen 38 and Cogen 42 facilities. Even if new contracts are available for our Cogen 38 and Cogen 42 facilities, there is no assurance that the prices and terms of such contracts will not adversely affect our financial condition, results of operations and operating cash flows.

State Energy Regulation. The CPUC has broad authority to regulate both the rates charged by, and the financial activities of, electric utilities operating in California and to promulgate regulation for implementation of PURPA. Since a power sales agreement becomes a part of a utility's cost structure (generally reflected in its retail rates), power sales agreements with independent electricity producers, such as us, are under the regulatory purview of the CPUC and in particular the process by which the utility has entered into the power sales agreements and the prices paid under those agreements. While we are not subject to direct regulation by the CPUC, the CPUC's implementation of PURPA and its authority granted to the IOUs to enter into other PPAs are important to us, as is other regulatory oversight provided by the CPUC to the electricity market in California.

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Other Regulation of the Oil and Natural Gas Industry. The oil and natural gas industry is extensively regulated by numerous federal, state and local authorities, including Native American tribes. Such laws and regulations include requiring permits and bonds for the drilling of wells, reports concerning operations and production, as well as regulations concerning:

- the location of wells, including the distance by which wells must be set back from structures and other activities;
- the method of drilling and casing wells;
- the rates of production or “allowables;”
- surface use and reclamation of property;
- wildlife management and protection;
- the protection of archaeological and paleontological resources;
- property mitigation measures;
- site security;
- the plugging and abandoning of wells; and
- notice to, and consultation with, surface owners and other third parties.

In addition, state laws regulate the size and shape of drilling and spacing units or proration units governing the pooling of oil and natural gas properties. Some states allow forced pooling or integration of tracts to facilitate exploration while other states rely on voluntary pooling of lands and leases. In some instances, forced pooling or unitization may be implemented by third parties and may reduce our interest in the unitized properties. In addition, state conservation laws can establish maximum rates of production from oil and natural gas wells, generally prohibit the venting or flaring of natural gas and impose requirements regarding the ratability of production. These laws and regulations may limit the amount of natural gas and oil we can produce from our wells or limit the number of wells or the locations at which we can drill. Moreover, each state generally imposes a production or severance tax with respect to the production and sale of oil and natural gas within its jurisdiction.

Laws and regulations affecting the oil and natural gas industry are under constant review for amendment or expansion, frequently increasing the regulatory burden. Also, numerous departments and agencies, federal, state, local and Native American tribes are authorized by statute to issue rules and regulations binding on the oil and natural gas industry and its individual members, some of which carry substantial penalties for failure to comply. Although the regulatory burden on the oil and natural gas industry increases our cost of doing business and, consequently, affects our profitability, these burdens generally do not affect us any differently or to any greater or lesser extent than they affect other companies in the industry with similar types, quantities and locations of production.

Natural Gas Sales and Transportation. Section 1(b) of the Natural Gas Act (NGA) exempts natural gas gathering facilities from regulation by the FERC as a natural gas company under the NGA. We believe that the natural gas pipelines in our gathering systems meet the traditional tests FERC has used to establish a pipeline's status as a gatherer not subject to regulation as a natural gas company, but the status of these lines has never been challenged before FERC. The distinction between FERC-regulated transmission services and federally unregulated gathering services is subject to change based on future determinations by FERC, the courts, or Congress, and application of existing FERC policies to individual factual circumstances. Accordingly, the classification and regulation of some of our natural gas gathering facilities may be subject to challenge before FERC or subject to change based on future determinations by FERC, the courts, or Congress. In the event our gathering facilities are reclassified to FERC-regulated transmission services, we may be required to charge lower rates and our revenues could thereby be reduced.

FERC requires certain participants in the natural gas market, including natural gas gatherers and marketers, which engage in a minimum level of natural gas sales or purchases to submit annual reports regarding those transactions to FERC. Should we fail to comply with this requirement or any other applicable FERC-administered statute, rule,

regulation or order, we could be subject to substantial penalties and fines. Under the Energy Policy Act of 2005, FERC has civil penalty authority under the NGA to impose penalties for current violations of up to $1 million per day for each violation and disgorgement of profits associated with any violation.

Operations on Native American Reservations. A portion of our leases and drill-to-earn arrangements in the Uinta area and some of our future leases in this and other areas may be regulated by Native American tribes. In addition to regulation by various federal, state and local agencies and authorities, an entirely separate and distinct set of laws and regulations applies to lessees, operators and other parties within the boundaries of Native American reservations. Various federal agencies within the U.S. Department of the Interior, particularly the Office of Natural Resources Revenue and the Bureau of Indian Affairs, as well as the EPA, together with each Native American tribe, promulgate and enforce regulations pertaining to oil and natural gas operations on Native American reservations. These regulations include lease provisions, royalty matters, drilling and production requirements, environmental standards, Tribal employment and contractor preferences and numerous other matters.

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Native American tribes are subject to various federal statutes and oversight by the Bureau of Indian Affairs and Bureau of Land Management. However, each Native American tribe is a sovereign nation and has the right to enact and enforce certain other laws and regulations entirely independent from federal, state and local statutes and regulations, as long as they do not supersede or conflict with such federal statutes. These tribal laws and regulations include various fees, taxes, authorizations, requirements to employ Native American tribal members and numerous other conditions that apply to lessees, operators and contractors conducting operations within the boundaries of a Native American reservation. Further, lessees and operators within a Native American reservation are subject to the Native American tribal court system, unless there is a specific waiver of sovereign immunity by the Native American tribe allowing resolution of disputes between the Native American tribe and those lessees or operators to occur in federal or state court.

Therefore, we are subject to various laws and regulations pertaining to Native American tribal surface ownership. In addition, we are subject to the terms and conditions of Native American oil and natural gas leases, as well as fees, taxes, obligations and other issues unique to oil and natural gas ownership and operations within Native American reservations. These laws, regulations and other issues present unique risks that may impose additional requirements on our operations, cause delays in obtaining necessary approvals or permits, or result in losses or cancellations of our oil and natural gas leases, which in turn may materially and adversely affect our operations on Native American tribal lands.

Item 1A. Risk Factors

Oil and natural gas prices are volatile, and declines in prices could materially and adversely affect our business, financial condition, results of operations and operating cash flow. Our future financial condition, revenues, results of operations, rate of growth and the carrying amount of our oil and natural gas properties depend primarily upon the prices we receive for our oil and natural gas production and the prices prevailing from time to time for oil and natural gas. Oil and natural gas prices historically have been volatile, and are likely to continue to be volatile in the future, especially given current geopolitical conditions. This price volatility also affects the amount of cash flow we have available for capital expenditures and our ability to borrow money or raise additional capital. The prices for oil and natural gas are subject to a variety of factors beyond our control, including:

- the level of consumer demand for oil and natural gas;
- the domestic and foreign supply of oil and natural gas and the productive capacity of the industry as a whole;
- proximity, availability and capacity of oil and natural gas gathering systems, pipelines, rail cars, other transportation methods and commodity processing and refining facilities;
- the price and level of imports of foreign oil and natural gas;
- developments of the energy infrastructure in the United States, including pipelines and liquefied natural gas facilities;
- the actions of the members of the Organization of Petroleum Exporting Countries and their ability to agree to and maintain oil price and production controls;
- the global and domestic credit, financial and economic environment;
- domestic and foreign governmental regulations and taxes;
- the fluctuation of the United States dollar against other currencies;
- the price and availability of competitors' oil and natural gas supplies in captive markets and of alternative fuel sources;
- weather conditions;
- political and economic conditions, embargoes and political instability, insurgency, terrorism, or war in oil and natural gas producing regions, including the Middle East, Africa and South America, or otherwise affecting other oil and natural gas activities;
- technological advances affecting energy production and consumption;
- variations between product prices at sales points and applicable index prices; and
- acts of force majeure.

These factors and the volatility of oil and natural gas markets make it extremely difficult to predict future oil and natural gas price movements with any certainty. Declines in oil and natural gas prices would reduce our revenues and could also reduce the amount of oil and natural gas that we can produce economically, which could lower our recognized reserve quantities and could materially and adversely affect our financial condition, results of operations and operating cash flows.

Future oil and natural gas price declines may result in write-downs of the carrying amount of our assets, which could materially and adversely affect our results of operations and limit our ability to borrow funds. The value of our assets depends on oil and natural gas prices. Declines in these prices as well as increases in development costs, changes in well performance, delays in asset development or deterioration of drilling results may result in our having to make material

downward adjustments to our estimated proved reserves, and accounting rules may require us to write down, and incur a corresponding non-cash charge to earnings, the carrying amount of our oil and natural gas properties for impairments.

Proved oil and natural gas properties are reviewed for impairment on a field-by-field basis when events and circumstances indicate a possible decline in the recoverability of the carrying amount of such property. We estimate the expected future cash flows of our oil and natural gas properties and compare these undiscounted 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 write down the carrying amount of the oil and natural gas properties to fair value. The factors used to determine fair value include, but are not limited to, estimates of reserves, future commodity prices, future production estimates, estimated future capital expenditures and discount rates commensurate with the risk associated with realizing the projected cash flows. For example, in 2011 we recorded an impairment of $625.0 million related to our E. Texas natural gas assets, largely due to the impact of lower natural gas prices. See Notes 8 and 10 to the Financial Statements. If commodity prices decline in the future, we may incur additional impairment charges, which could materially and adversely affect our financial condition and results of operations.

The borrowing base of our credit facility is subject to semi-annual redeterminations in April and October of each year, based on the value of our oil and natural gas properties, in accordance with the lenders' customary procedures and practices. We and the lenders each have a right to one additional redetermination each year. As of December 31, 2012, the borrowing base under our credit facility was $1.4 billion and total lender commitments were $1.2 billion. Declines in oil or natural gas prices in the future could limit our borrowing base and reduce our ability to borrow under our credit facility. Additionally, divestitures of properties could result in a reduction of our borrowing base.

We require substantial capital expenditures to conduct our operations, engage in acquisition activities and replace our production, and we may be unable to obtain financing on satisfactory terms necessary to execute our operating strategy. The oil and natural gas industry is capital intensive. We require substantial capital expenditures to conduct our production, development and exploration activities, engage in acquisition activities and replace our production. Historically, we have funded our capital expenditures through a combination of our cash flows from operations, borrowings under our credit facility and the capital markets. Our access to capital is subject to a number of factors, some of which are outside our control. These factors include, among others:

- the market value and performance of our debt and equity securities;
- the credit ratings assigned to our debt by independent rating agencies; and
- the global and domestic credit, financial and economic environment.

If our cash flows from operations or the borrowing base under our credit facility decrease as a result of lower oil and natural gas prices, operating difficulties, declines in reserves or for any other reason, we may have limited ability to obtain the capital necessary to sustain our operations at current levels. Further, our credit facility places certain restrictions on our ability to obtain new financing, and we may not be able to obtain new financing on terms favorable to us, or at all. If cash generated by operations or borrowings under our credit facility are not sufficient to meet our capital requirements, the failure to obtain additional financing could result in a curtailment of our development and exploration activities, which in turn could lead to a possible loss of properties and a decline in our oil and natural gas reserves as well as our financial condition, results of operations and operating cash flows.

The actual quantities and present values of our proved oil and natural gas reserves may be less than we have estimated. It is not possible to measure underground accumulations of oil or natural gas in an exact way. Estimating accumulations of oil and natural gas is a complex process that relies on interpretations of available geologic,

geophysical, engineering and production data. The extent, quality and reliability of this data can vary. The process also requires certain economic assumptions, such as oil and natural gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds, some of which are mandated by the SEC.

Actual future production, oil and natural gas prices, revenues, production taxes, development expenditures, operating expenses and quantities of producible oil and natural gas reserves will most likely vary from those estimated. Any significant variance could materially and adversely affect the estimated quantities of and present values related to our proved reserves, and the actual quantities and present values may be less than we have previously estimated. In addition, we may adjust estimates of proved reserves to reflect production history, results of development and exploration activities, prevailing oil and natural gas prices, costs to develop and operate properties and other factors, many of which are beyond our control. Our properties may also be susceptible to hydrocarbon drainage from production on adjacent properties.

Further, it should not be assumed that any present value of future net cash flows from our estimated proved reserves represents the market value of our estimated oil and natural gas reserves. We base the estimated discounted future net cash flows from our estimated proved reserves on first-day-of-month average oil and natural gas prices for the twelve-month period preceding the estimate and on costs as of the date of the estimate. Actual future prices and costs may be materially higher or lower. Actual future net revenues will be affected by factors such as the amount and timing of actual development expenditures, the rate and timing of production and changes in governmental regulations or taxes.

Approximately 45% of our total estimated proved reserves at December 31, 2012, were undeveloped, and those reserves may not ultimately be developed. Recovery of undeveloped reserves generally requires significant capital expenditures and successful drilling operations. Our reserve estimates include the assumption that we will make significant capital expenditures to develop these undeveloped reserves and the actual costs, development schedule and results associated with these properties may not be as estimated. Our management has specifically identified and scheduled drilling locations as an estimation of our future multi-year drilling activities on our existing acreage. These identified drilling locations represent a significant part of our growth strategy. Our ability to drill and develop these locations depends on a number of uncertainties, including the availability of capital, seasonal conditions, access rights and constraints, regulatory approvals, oil and natural gas prices, costs and drilling results. Because of these uncertainties, we do not know if the numerous potential drilling locations we have identified will ever be drilled or if we will be able to produce oil or natural gas from these or any other potential drilling locations. As such, our actual drilling activities may materially differ from those presently identified, which could materially and adversely affect our financial condition, results of operations and operating cash flows.

In addition, the SEC rules generally require that reserves classified as proved undeveloped be capable of conversion into proved developed within five years of classification unless specific circumstances justify a longer time. Proved undeveloped reserves that are not timely developed are subject to possible reclassification as non-proved reserves. These requirements may limit our ability to classify additional reserves as proved undeveloped as we pursue our drilling program. Material downward adjustments to our estimated proved reserves could materially and adversely affect our financial condition, results of operations and operating cash flows.

We depend on successful exploration, development and acquisitions to maintain reserves and revenue in the future. Producing oil and natural gas reservoirs generally are characterized by declining production rates that vary depending upon reservoir characteristics and other factors. The rate of decline will change if production from our existing wells declines in a different manner than we have estimated. Our future oil and natural gas production is, therefore, highly dependent on our level of success in finding or acquiring additional reserves and efficiently developing and exploiting our current reserves. We may not be able to develop, find or acquire additional reserves to replace our current and future production at acceptable costs. Unless we replace our oil and natural gas reserves, our reserves and production will decline, which would materially and adversely affect our business, financial condition and results of operations and operating cash flows.

Recent regulatory changes in California have and may continue to materially and adversely impact our production and operating costs related to our Diatomite assets. Recent regulatory changes in California have impacted our Diatomite production. In 2010, Diatomite production decreased significantly due to the inability to drill new wells pending the receipt of permits from DOGGR. We received a new full-field development approval in late July 2011 from DOGGR, which contained stringent operating requirements. Revisions to the July 11 project approval letter were received in February 2012. Implementation of these new operating requirements negatively impacted the pace of drilling and steam injection and increased our operating costs for our Diatomite assets. The requirements continued to affect our operations through 2012, and we may not be successful in streamlining the review process with DOGGR or in taking additional steps to more efficiently manage our operations to avoid additional delays. In addition, DOGGR may

impose additional operational restrictions or requirements. In such case, we may experience additional delays in production and increased operating costs related to our Diatomite assets, which could materially and adversely affect our business, financial condition and results of operations and operating cash flows.

Market conditions or operational impediments may hinder our access to oil and natural gas markets or delay our production. Market conditions or the unavailability of satisfactory oil and natural gas transportation arrangements may hinder our access to oil and natural gas markets or delay our production. For example, refinery constraints in the Utah region, coupled with our increased production in the area, have impacted the immediate marketability of a portion of our Utah oil, and have caused us to pursue alternate transportation methods and sales outlets. Beginning in 2013, these constraints have caused us to initiate measures to reduce production, such as shutting in some of our wells and postponing completions of some of our newly drilled wells. We may not be successful in securing alternative sales outlets for our Utah production. The availability of a ready market for our oil and natural gas production depends on a number of factors, including the demand for and supply of oil and natural gas and the proximity of reserves to pipelines, rail transportation and terminal facilities. Our ability to market our production depends in substantial part on the availability and capacity of gathering systems, pipelines, processing facilities,

trucking and rail capability and refineries owned and operated by third parties. We may be required to shut in wells for a lack of a market or because of inadequacy or unavailability of oil and natural gas pipelines, gathering system capacity, storage capacity, processing facilities or refineries. Decreased access to oil and natural gas markets or access to such markets on unacceptable terms could result in increased costs, decreased margins, decreased production, or other factors which could materially and adversely affect our business, financial condition and results of operations and operating cash flows.

We may not be able to deliver minimum crude oil volumes required by our sales contract. Production volumes from our Uinta properties over the next several years are uncertain, and there is no assurance that we will be able to consistently meet the required volume under our refining contract relating to our production from these properties, which is 5,000 Bbl/d. In the event that we cannot produce the necessary volume, we may need to purchase crude to meet our contract requirements. Gross oil production from our Uinta properties subject to the terms of this contract averaged approximately 4,420 Bbl/d during 2012.

The inability of one or more of our customers to meet their obligations may adversely affect our financial results. We have significant concentrations of credit risk with the purchasers of our oil and natural gas. For example, 43% of our oil production is sold to one refiner in California. Due to the terms of supply agreements with our customers, we may not know that a customer is unable to make payment to us until months after production has been delivered. If the purchasers of our oil and natural gas become insolvent, we may be unable to collect amounts owed to us, which could materially and adversely affect our financial condition, results of operations and operating cash flows.

Drilling is a high-risk activity and as a result we may not adhere to our proposed drilling schedule or our drilling program may not result in commercially productive reserves. Our future success will partly depend on the success of our drilling program. Although we have identified or budgeted for numerous drilling prospects, we may not be able to lease or drill those prospects within our expected time frame, or at all. Our decisions to explore, develop or otherwise exploit prospects or properties will depend on a number of factors, including:

- results of our exploration efforts and the acquisition, review and analysis of our seismic data, if any;
- availability of sufficient capital resources to us and any other participants for the drilling of the prospects;
- approval of the prospects by other participants after additional data has been compiled;
- economic and industry conditions at the time of drilling, including prevailing and anticipated prices for oil and natural gas and the availability and prices of drilling rigs and crews;
- availability of leases, license options, farm-outs, other rights to explore and permits on reasonable terms for the prospects; and
- overruns in budgeted expenditures and future costs of drilling and completing wells.

Additionally, our drilling operations may be curtailed, delayed or canceled as a result of a variety of factors, including:

- unexpected drilling conditions;
- well integrity issues and surface expressions;
- pressure or irregularities in formations;
- equipment failures or accidents;
- adverse weather conditions;
- changes in regulations;
- compliance with governmental or landowner requirements;
- disputes with mineral interest or surface owners and access constraints or limitations on surface use on or near our operating areas;
- loss of title or other title related issues;

- availability, capacity, costs and contractual terms with respect to pipelines, rail transportation and facilities to gather, process, compress, transport and market oil and natural gas; and
- shortages or delays in the availability of drilling rigs and the delivery of equipment and/or services, including experienced labor.

Our drilling plans require drilling permits from state, local and other governmental authorities. Delays in obtaining regulatory approvals and drilling permits, including delays which jeopardize our ability to realize the potential benefits from leased properties within the applicable lease periods, the failure to obtain a drilling permit for a well or the receipt of a permit with unreasonable conditions or costs could have a material and adverse effect on our ability to explore on or develop our properties.

Shortages of oilfield equipment, services and qualified personnel could delay our drilling program and increase the prices we pay to obtain such equipment, services and personnel. The demand for qualified and experienced field personnel to drill wells and conduct field operations such as geologists, geophysicists, engineers and other professionals in the oil and natural gas industry can fluctuate significantly, often in correlation with oil and natural gas prices, causing periodic shortages. Historically, there have been shortages of drilling and workover rigs, pipe and other oilfield equipment as demand for rigs and equipment has increased along with the number of wells being drilled. These factors also cause significant increases in costs for equipment, services and personnel. Higher oil and natural gas prices generally stimulate demand and result in increased prices for drilling and workover rigs, crews and associated supplies, equipment and services. It is beyond our control and ability to predict whether these conditions will exist in the future and, if so, what their timing and duration will be. The availability of drilling rigs can vary significantly from region to region at any particular time. Although land drilling rigs can be moved from one region to another in response to changes in levels of demand, an undersupply of rigs in any region may result in drilling delays and higher drilling costs for the rigs that are available in that region. These types of shortages or price increases could restrict our ability to drill planned wells, conduct planned operations, or could otherwise materially and adversely affect our financial condition, results of operations and operating cash flows.

We may be unable to make attractive acquisitions or successfully integrate acquired operations, and any inability to do so may disrupt our business and hinder our ability to grow. Our business strategy has emphasized growth through strategic acquisitions. We may not be able to continue to identify properties for acquisition or we may not be able to make acquisitions on terms that we consider economically acceptable. There is intense competition for acquisition opportunities in our industry. Competition for acquisitions may increase the cost of, or cause us to refrain from completing, acquisitions. Our strategy of completing acquisitions is dependent upon, among other things, our ability to obtain debt and equity financing and, in some cases, regulatory approvals. If we are unable to achieve strategic acquisitions, our growth may be impaired, thus impacting our financial condition, results of operations, operating cash flows and reserves. In addition, we may have difficulty integrating the operations, systems, management and other personnel and technology of acquired assets or businesses with our own. These difficulties could disrupt our ongoing business, distract our management and employees, increase our expenses and adversely affect our results of operations. In addition, we may incur additional debt or issue additional equity to pay for any future acquisitions, which issuances may be substantial and could significantly affect our risk profile. Significant acquisitions or other transactions could change or alter the character of our operations and business if the character of acquired properties is different from that of our current properties.

Acquisitions are subject to the uncertainties of evaluating recoverable reserves and potential liabilities. Our recent growth is due in part to acquisitions of properties with additional development potential and properties with minimal production at acquisition but significant growth potential, and we expect acquisitions will continue to contribute to our future growth. Successful acquisitions require an assessment of a number of factors, many of which are beyond our control. These factors include: recoverable reserves, exploration potential, future oil and natural gas prices, operating costs, production taxes, access rights and potential environmental and other liabilities. Such assessments are inexact and their accuracy is inherently uncertain. In connection with our assessments, we perform a review of the acquired properties, which we believe is generally consistent with industry practices. However, such a review will not reveal all existing or potential problems. In addition, our review may not allow us to become sufficiently familiar with the properties, and we do not always discover structural, subsurface, environmental and access problems that may exist or arise. Our review prior to signing a definitive purchase agreement may be even more limited.

There may be threatened or contemplated claims against the assets or businesses we acquire related to environmental, title, regulatory, tax, contract, litigation or other matters of which we are unaware, which could materially and adversely affect our production, revenues and results of operations. We may not be entitled to contractual indemnification for pre-closing liabilities, including environmental liabilities, on acquisitions. We may acquire

interests in properties on an "as is" basis with limited remedies for breaches of representations and warranties. If material breaches are discovered by us prior to closing, we could require adjustments to the purchase price or, if the claims are significant, we or the seller may have a right to terminate the agreement. If we fail to discover breaches or defects prior to closing, we may incur significant unknown liabilities, including environmental liabilities, for which we would have limited or no contractual remedies or insurance coverage.

We may incur losses as a result of title deficiencies. We acquire working and revenue interests in the oil and natural gas leaseholds and estates upon which we will perform our exploration activities from third parties, or directly from the mineral fee owners. The existence of a material title deficiency can reduce the value or render a property worthless, thus materially and adversely affecting our financial condition, results of operations and operating cash flow. Title insurance covering mineral leaseholds is not always available, and when available is not always obtained. As is customary in our industry, we rely upon the judgment of staff and independent landmen who perform the field work of examining records in the appropriate governmental offices and abstract facilities before attempting to acquire or place under lease a specific mineral interest and/or undertake drilling activities. We, in some cases, perform curative work to correct deficiencies in the marketability of the title to us. In

cases involving material title problems, the amount paid for affected oil and natural gas leases or estates can be generally lost, and a prospect can become undrillable.

We may incur material losses and be subject to material liability claims as a result of our oil and natural gas operations. In addition, we may not be insured for, or our insurance may be inadequate to protect us against, these risks. Oil and natural gas operations are subject to many risks, including fires, explosions, well blowouts, surface expressions, uncontrollable flows of oil and natural gas, formation water or drilling fluids, adverse weather, freezing conditions in our various regions, natural disasters, pipe or cement failures, casing collapse, embedded oilfield drilling and service tools, formations with abnormal pressures, major equipment failures, including cogeneration facilities, pollution, releases of toxic gas and other environmental risks and hazards. The occurrence of these events could also impact other parties, including residential areas near our operations, our employees and employees of our contractors, leading to injuries, death, environmental damage, property damage, or suspension of operations. As a result, we face the possibility of liabilities from these events that could adversely affect our business, financial condition or results of operations as well as regulatory actions and adverse publicity that could lead to delays in or cessation of our operations in the affected area and loss of related assets or revenues.

Under certain circumstances, we may be liable for environmental damage caused by previous owners or operators of properties that we own, lease, or operate. As a result, we may incur material liabilities to third parties or governmental entities, which could reduce or eliminate funds available for exploration, development, or acquisitions, or cause us to incur losses.

We maintain insurance against some, but not all, of these potential risks and losses. We may elect not to obtain insurance if we believe that the cost of available insurance is excessive relative to the risks presented. In addition, pollution and environmental risks generally are not fully insurable. We currently have insurance policies covering our operations that include coverage for general liability, excess liability, physical damage to our oil and natural gas properties, operational control of wells, oil pollution, third-party liability, workers' compensation and employers' liability and other coverages. While we intend to obtain and maintain insurance coverage we deem appropriate for these risks, there can be no assurance that our operations will not expose us to liabilities exceeding such insurance coverage or to liabilities not covered by insurance. The occurrence of an event not fully covered by insurance could materially and adversely affect our financial condition, results of operations and operating cash flows.

Our use of hedging transactions could result in financial losses or reduce our earnings. To reduce our exposure to fluctuations in oil and natural gas prices, we have entered into and expect in the future to enter into derivative instruments (or hedging contracts) for a portion of our anticipated oil and natural gas production or natural gas consumption. Our hedging transactions expose us to certain risks and financial losses, including, among others, the risk that we may be limited in receiving the full benefit of increases in oil and natural gas prices as a result of these transactions, and that we may hedge too much or too little production or consumption depending on how oil and natural gas prices fluctuate in the future.

Due to the volatility of oil and natural gas prices, we may be required to recognize unrealized gains and losses (non-cash changes in fair value) on derivative instruments as the estimated fair value of our commodity derivative instruments is subject to significant fluctuations from period to period. The amount of any actual gains or losses recognized will likely differ from our period to period estimates and will be a function of the actual price of the commodities on the settlement date of the derivative instrument. We expect that commodity prices will continue to fluctuate in the future and, as a result, our periodic financial results will continue to be subject to fluctuations related to our derivative instruments.

Our financial counterparties may be unable to satisfy their obligations. We rely on financial institutions to fund their obligations under our credit facility and make payments to us under our commodity hedging contracts. Currently, all of our outstanding commodity derivative instruments are with lenders or affiliates of the lenders under our credit facility. The risk that a counterparty may default on its obligations was heightened by the recent financial crisis, global economic slowdown, European sovereign debt crisis and related losses incurred by many banks and other financial institutions, including some of our counterparties or their affiliates. If one or more of our financial counterparties becomes insolvent, they may not be able to meet their commitment to fund future borrowings under our credit facility which would reduce our liquidity and materially and adversely affect our ability to fund capital expenditures and make acquisitions. If our financial counterparties are unable to make payments under our commodity hedging contracts, our cash receipts from derivative settlements would decrease at a time when we would also be impacted by low commodity prices. As a result, this could materially and adversely affect our financial condition, results of operations and operating cash flows.

A widening of commodity differentials may materially and adversely impact our revenues and our economics. The oil and natural gas we produce is priced in local markets where production occurs and is based on local or regional supply and demand factors as well as other local market dynamics such as regional storage capacity and transportation. The prices that we receive for our oil and natural gas production are generally lower than the relevant benchmark prices, such as NYMEX or

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Brent, that are used for calculating commodity derivative positions. The difference between the benchmark price and the price we receive is called a differential.

We may be unable to accurately predict oil and natural gas differentials, which may widen significantly in the future. Numerous factors may influence local commodity pricing, such as refinery capacity, pipeline takeaway capacity and specifications, localized storage capacity, upsets in the mid-stream or downstream sectors of the industry, trade restrictions and governmental regulations. We may be materially and adversely impacted by a widening differential on the products we sell. Our commodity hedging contracts are typically based on West Texas intermediate (WTI) or other oil or natural gas index prices. As a result, we may be subject to “basis risk” if the differential on products we sell widens from the benchmarks used in our commodity hedging contracts. Additionally, regional capacity and storage issues may cause benchmark prices to become disconnected from regional oil and natural gas prices which may materially and adversely affect our ability to hedge using contracts based on such indices. Insufficient pipeline capacity, storage capacity or trucking or rail transportation capability and the lack of demand in any given operating area may cause the differential to widen in that area compared to other oil and natural gas producing areas. Increases in the differential between benchmark prices for oil and natural gas and the wellhead price we receive could materially and adversely affect our financial condition, results of operation and operating cash flows.

A shortage or increase in the price of natural gas in California could materially and adversely affect our business. The development of our heavy oil in California is subject to our ability to make sufficient quantities of steam at a an economic cost. We may be subject to the risks associated with a shortage of natural gas and/or the transportation of natural gas into and within California. We are highly dependent on sufficient volumes of natural gas necessary to use for fuel in generating steam in our heavy oil operations in California. If the required volume of natural gas for use in our operations were to be unavailable or too highly priced to produce heavy oil economically, our production could be materially and adversely impacted.

We are dependent on our cogeneration facilities and deteriorations in the electricity market and regulatory changes in California may materially and adversely affect our financial condition, results of operations and operating cash flows. We are dependent on three cogeneration facilities that, combined, provide approximately 17% of our steam capacity as of December 31, 2012. These facilities are dependent on viable contracts for the sale of electricity. Market fluctuations in electricity prices and regulatory changes in California could adversely affect the economics of our cogeneration facilities and the corresponding increase in the price of steam could significantly impact our operating costs. If we are unable to enter into new or replacement contracts or were to lose existing contracts, we may be unable to meet our steam requirements necessary to maximize production from our heavy oil assets. An additional investment in various steam sources may be necessary to replace such steam, and there may be risks and delays in being able to install conventional steam equipment due to permitting requirements and availability of equipment. The financial cost and timing of such new investment could materially and adversely affect our financial condition, results of operations and operating cash flows. For a more detailed discussion of our electricity sales contracts, see Part I, Item 1, "Business—Electricity."

Changes to current income tax laws may affect our ability to take certain deductions. Substantive changes to the existing federal income tax laws have been proposed that, if adopted, would affect, among other things, our ability to take certain deductions related to our operations, including depletion deductions, deductions for intangible drilling and development costs and deductions for United States production activities. These changes, if enacted into law, could materially and adversely affect our financial condition, results of operations and operating cash flows.

Recently enacted derivatives legislation could have an adverse impact on our ability to use derivative instruments to reduce the effect of commodity price, interest rate and other risks associated with our business. New comprehensive financial reform legislation was signed into law by the President on July 21, 2010. The legislation calls for the

Commodity Futures Trading Commission (CFTC) to regulate certain markets for over-the-counter (OTC) derivative products. In its rulemaking under the new legislation, the CFTC has proposed regulations to set position limits for certain futures and option contracts in the major energy markets and for swaps that are their economic equivalent. Certain bona fide hedging transactions or positions would be exempt from these position limits. The position limits rule was challenged in court by two industry associations and was vacated and remanded by a federal district court. The CFTC appealed the district court's ruling and that appeal is pending. The financial reform legislation may also require our swap-dealer counterparties to comply with margin requirements and/or capital requirements relating to our uncleared swaps with those counterparties, but the timing of any adoption of any such regulations, and their scope, are uncertain. These and other CFTC rules implementing Dodd-Frank could impose burdens on market participants to such an extent that liquidity in the bilateral OTC derivative market decreases substantially. The legislation and new regulations may also require counterparties to our derivative instruments to spin off some of their derivatives activities to separate entities, which may not be as creditworthy as the current counterparties. The new legislation and any new regulations, including determinations with respect to the applicability of margin and capital requirements for uncleared trades, could significantly increase the cost of derivative contracts, materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks we encounter, reduce our ability to monetize

or restructure our existing derivative contracts, and increase our exposure to less creditworthy counterparties. If we reduce our use of derivatives as a result of the legislation and regulations, our results of operations may become more volatile and our cash flows may be less predictable, which could limit our ability to plan for and fund capital expenditures. Any of these consequences could materially and adversely affect our financial condition, results of operations and operating cash flows.

Competition within our industry is intense and may materially and adversely affect our operations. We operate in a highly competitive environment. We compete with major and independent oil and natural gas companies in acquiring desirable oil and natural gas properties and in obtaining the equipment and labor required to develop and operate such properties. We also compete with major and independent oil and natural gas companies in the marketing and sale of oil and natural gas. Many of our competitors are larger, fully integrated energy companies that have financial, staff and other resources substantially greater than ours, may be less leveraged than we are and have a lower cost of capital. As a result, our competitors may have greater access to capital and may be able to pay more for development prospects and producing properties, or evaluate and bid for a greater number of properties and prospects than our financial and staffing resources permit. Our competitors may be able to expend greater resources on changing technologies that are increasingly important to efficiency and success in the industry and may also have a greater ability to continue drilling activities during periods of low oil and natural gas prices or to absorb the burden of present and future federal, state, local and other laws and regulations. From time to time, we have to compete with financial investors in the property acquisition market, including private equity sponsors with more funds and access to additional liquidity. Many of these competitors have financial and other resources substantially greater than ours.

In addition, oil and natural gas producers are increasingly facing competition from providers of alternative energy, and government policy may favor those competitors in the future. We can give no assurance that we will be able to compete effectively in the future, which could materially and adversely affect our financial condition, results of operations and operating cash flows.

Our oil and natural gas operations are subject to various environmental and other governmental laws and regulations that may materially affect our operations. Our oil and natural gas operations are subject to extensive U.S. federal, state, local and Tribal laws and regulations. These laws and regulations may be changed in response to economic, political or other conditions. There can be no assurance that present or future regulations will not materially and adversely affect our business and operations. Matters subject to regulation include the following:

- discharge permits for drilling operations;
- reports concerning operations;
- well spacing;
- unitization and pooling of properties; and
- taxation.

Failure to comply with these laws and regulations may result in the suspension or termination of our operations and subject us to administrative, civil and criminal penalties. See Part I, Item 1, “Business—Environmental Matters and Other Regulations" for additional information on the effect of environmental laws and regulations.

Many of the laws and regulations to which our operations are subject include those relating to the protection of the environment, including those governing the discharge of materials into the water and air, the generation, management and disposal of hazardous substances and wastes and the clean-up of contaminated sites. We may be required to incur material operating costs or significant additional capital expenditures in order to comply with environmental regulations and in connection with obtaining and maintaining construction and operating permits and approvals from state and federal regulatory agencies. The costs related to compliance with environmental regulations could include

costs to purchase and operate emissions control systems, to acquire emissions allowances or to comply with regulatory reporting requirements. We could also incur material costs, including clean-up costs, fines and civil and criminal sanctions and third-party claims for property damage and personal injury as a result of violations of, or liabilities under, environmental laws and regulations. Such laws and regulations not only expose us to liability for our own activities, but may also expose us to liability for the conduct of others or for actions by us that were in compliance with all applicable laws at the time those actions were taken. Any such legislation or regulatory programs could also increase the cost of consuming, and thereby reduce demand for, the oil and natural gas we produce.

In particular, regulation of GHG emissions by Congress, the EPA, or various other legislative or regulatory bodies in the United States could have an adverse effect on our operations, financial condition, and results of operations and demand for the oil and natural gas we produce. The level of expenditure required to comply with GHG laws and regulations is uncertain and is expected to vary depending on the laws and regulations enacted in each jurisdiction, our activities, and market conditions. The effect of GHG regulations on our financial performance will depend on the sectors covered, GHG emissions reductions required, the extent to which we would receive GHG allowance allocations or the extent to which we would need to purchase

compliance instruments in the open market or through auctions, the price and availability of compliance instruments and the impact of GHG laws and regulations on our ability to recover the costs incurred through the pricing of our products. For example, GHG regulations in the state of California will likely increase our operating costs in that state. See "California GHG Regulations" under Part I, Item 1, "Business—Environmental Matters and Other Regulations" for more detail. Finally, it should be noted that some scientists have concluded that increasing concentrations of GHGs in the earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts and floods and other climatic events. If any such effects were to occur, they could have an adverse effect on our financial condition, results of operations and operating cash flows.

In addition, we could incur material expenditures complying with environmental laws and regulations, including future environmental laws and regulations that may be more stringent including, for example, the regulation of GHG emissions under new federal legislation, the federal Clean Air Act, or state or regional regulatory programs. In addition, changes in interpretations of or enforcement of existing laws may cause us to incur substantial expenditures. Operating in densely populated regions may expose us to additional risk of regulation, as well as claims by property owners and others affected by such operations. See Part I, Item 1, "Business—Environmental Matters and Other Regulations" for more detail on both current and potential governmental regulation.

Federal and state legislation and regulatory initiatives related to hydraulic fracturing could result in increased costs and operating restrictions or delays. Hydraulic fracturing is an important and common practice that is used to stimulate production of hydrocarbons from tight formations. Due to concerns raised relating to potential impacts of hydraulic fracturing on groundwater quality, legislative and regulatory efforts at the Federal level and in some states have been initiated to render permitting and compliance requirements more stringent for hydraulic fracturing or prohibit the activity altogether. For example, the EPA has asserted federal regulatory authority over hydraulic fracturing involving fluids that contain diesel fuel under the SDWA's Underground Injection Control Program and has released draft permitting guidance for hydraulic fracturing operations that use diesel fuel in fracturing fluids in those states where the EPA is the permitting authority. In addition, both Texas and Colorado have adopted public disclosure regulations requiring varying degrees of disclosure of the constituents in hydraulic fracturing fluids. The adoption of any future federal or state laws or implementing regulations imposing reporting obligations on, or otherwise limiting, the hydraulic fracturing process could make it more difficult to perform hydraulic fracturing, complete oil and natural gas wells in shale formations, and obtain permits, and could increase our costs of compliance and doing business. For a more detailed discussion of hydraulic fracturing matters impacting our business, see Part I, Item 1, "Business—Environmental Matters and Other Regulations."

Our ability to produce oil and natural gas in commercial quantities could be impaired if we are unable to acquire adequate supplies of water for our drilling and completion operations or are unable to dispose of or recycle the water we use at a reasonable cost. The hydraulic fracturing process on which we depend to drill for commercial quantities of oil and natural gas requires the use and disposal of significant quantities of water. Our inability to secure sufficient amounts of water, or to dispose of or recycle the water used in our operations, could adversely impact our operations. Compliance with environmental regulations and permit requirements governing the withdrawal, storage, and use of surface water or groundwater necessary for hydraulic fracturing of wells may increase our operating costs and cause delays, interruptions, or termination of our operations, the extent of which cannot be predicted, all of which could materially and adversely affect our financial condition, results of operations and operating cash flows.

The loss of key personnel could materially and adversely affect our business. We depend to a large extent on the efforts and continued employment of our executive management team and other key personnel. The loss of the services of these or other key personnel could materially and adversely affect our business, and we do not maintain key man insurance on the lives of any of these persons. Our drilling success and the success of other activities integral to our operations will depend, in part, on our ability to attract, compensate and retain experienced geologists,

engineers, landmen and other professionals. Competition for many of these professionals is intense. If we cannot attract, compensate and retain experienced technical personnel and other professionals, our ability to compete could be harmed.

Interruptions in information technology systems and infrastructure could materially and adversely affect our business. Our business is increasingly dependent on information technology systems to conduct exploration, development and production activities. System failures, network disruptions and breaches of data security could lead to data corruption, communication interruption, or other operational disruptions in our exploration or production operations. In addition, the oil and gas distribution and transportation systems on which we rely to deliver our production to market depend upon information technology systems and infrastructure. Cyber attacks directed at the oil and gas industry could damage distribution and storage assets or the environment, delay or prevent delivery of production to markets and make it difficult or impossible to accurately account for production and settle transactions. While we have taken steps to address these concerns by implementing network

security and internal control measures, there can be no assurance that a system failure, network disruption or data security breach will not have a material adverse effect on our business, financial condition, results of operations and operating cash flows. Further, as technology continues to evolve, we may be required to expend significant additional resources to modify or enhance our protective measures or to investigate and remediate any vulnerabilities.

We have a substantial amount of debt and the cost of servicing that debt could adversely affect our business, and such risk could increase if we incur more debt. We have a substantial amount of indebtedness. As of December 31, 2012, we had approximately $1.7 billion of total outstanding long-term debt, including $562.9 million of outstanding borrowings under our credit facility (excluding $23.2 million of outstanding letters of credit). Total lender commitments under the facility are $1.2 billion, and the borrowing base is currently approximately $1.4 billion. Our level of indebtedness relative to our proved reserves and the significant demands on our cash resources could have important effects on our business. Despite current indebtedness levels, we may still be able to incur substantially more debt. The terms of the agreements governing our indebtedness permit us to incur substantial additional indebtedness, which additional indebtedness could:

- make it more difficult for us to satisfy our obligations with respect to our senior notes and our other debt;
- require us to dedicate a substantial portion of our operating cash flows to payments on our debt, thereby reducing the amount of our cash flow available for working capital, capital expenditures, acquisitions and other general corporate purposes;
- require us to make principal payments under our credit facility if the quantity of proved reserves attributable to our natural gas and crude oil properties are insufficient to support our level of borrowings under the credit facility;
- limit our flexibility in planning for, or reacting to, changes in the oil and natural gas industry;
- place us at a competitive disadvantage compared to our competitors that have lower debt service obligations and significantly greater operating and financing flexibility than we do;
- limit our financial flexibility, including our ability to borrow additional funds, pay dividends, make capital expenditures and other investments and acquisitions;
- increase our interest expense if interest rates increase;
- increase our vulnerability to general adverse economic and industry conditions; and
- result in an event of default upon a failure to comply with financial covenants contained in the agreements governing our indebtedness which, if not cured or waived, could have a material adverse effect on our business, financial condition or results of operations.

Our ability to pay the principal and interest on our long-term debt and to satisfy our other liabilities may depend upon our future performance and our ability to refinance our debt as it becomes due. Our future operating performance and ability to refinance will be affected by economic and capital markets conditions, oil and natural gas prices, our financial condition, results of operations and prospects and other factors, many of which are beyond our control. If we are unable to service our indebtedness and fund our operating costs, we will be forced to adopt alternative strategies that may include reducing or delaying capital expenditures, seeking additional debt financing or equity capital, selling assets or restructuring or refinancing debt. There can be no assurance that any such strategies could be implemented on satisfactory terms, if at all.

Restrictions in our existing and future debt agreements could limit our growth and our ability to respond to changing conditions. Agreements governing our outstanding debt restrict our ability to, among other things:

- incur, assume or guarantee additional indebtedness or issue redeemable stock;
- pay dividends or distributions or redeem or repurchase capital stock;
- prepay, redeem or repurchase debt that is junior in right of payment to our senior and subordinated notes;
- make loans and other types of investments;
- incur liens;
- sell or otherwise dispose of assets;

- consolidate or merge with or into, or sell substantially all of our assets to, another person;
- make capital expenditures or acquire assets or businesses;
- enter into transactions with affiliates; and
- enter into new lines of business.

In addition, our credit facility contains certain covenants, which, among other things, require the maintenance of (i) an interest coverage ratio of 2.75 to 1.0 and (ii) a minimum current ratio of 1.0 to 1.0. Our ability to borrow under our credit facility is dependent upon the quantity of proved reserves attributable to our oil and natural gas properties and the respective projected commodity prices as determined by the lenders under our credit facility. Our ability to meet these covenants or requirements may be affected by events beyond our control, and we cannot assure that we will satisfy such covenants and requirements.

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A downgrade in our credit rating could materially and adversely impact our cost of and ability to access capital. Our access to credit and capital markets also depends on the credit ratings assigned to our debt by independent credit rating agencies. We cannot provide assurance that any of our current ratings will remain in effect for any given period of time or that a rating will not be lowered or withdrawn entirely by a rating agency if, in its judgment, circumstances so warrant. Factors that may impact our credit ratings include debt levels, planned asset purchases or sales and near-term and long-term production growth opportunities, liquidity, asset quality, cost structure, product mix and commodity pricing levels. A ratings downgrade could adversely impact our ability to access capital or financial markets in the future, increase our borrowing costs and potentially require us to post letters of credit for certain obligations.

Risk Factors Related to the Proposed Merger with LinnCo, LLC

Failure to complete or delays in completing the merger could have an adverse impact on our stock price and our business. If the merger is not completed, or there are delays in completing the merger, our stock price and our business could be adversely affected and we would be subject to a number of risks, including the following:

- the current trading price of our common stock may reflect a market assumption that the merger will be completed and a failure to complete or delays in completing the merger could result in a decline in the price of our common stock;
- we may not realize the benefits expected from the merger, including cost savings, enhanced financial and competitive position and diversification of customer base, operating locations and assets;
- we will be required to pay certain costs relating to the merger, including certain investment banking, financing, legal and accounting fees and expenses, whether or not the merger is completed, and we may be required to pay LinnCo a termination fee of up to $83.7 million under certain circumstances; and
- the merger agreement places certain restrictions on the conduct of our business prior to completion of the merger or termination of the merger agreement, and such restrictions prevent us from making certain acquisitions or taking certain other specified actions during the pendency of the merger.

There can be no assurance that these risks will not materialize, and if any of them do, they may have an adverse effect on our financial position, results of operations and operating cash flows.

The merger may cause substantial disruption to our business, cause distraction to our management and employees and present difficulties retaining employees. The merger may cause substantial disruption to our business, cause distraction to our management and employees and present difficulties retaining employees. The merger may also cause uncertainty to our customers. Matters related to the merger may require substantial commitments of time and resources and distract our management and employees from day-to-day operations. These disruptions could have an adverse effect on our financial position, results of operations and cash flows. In addition, uncertainty among our employees may have an adverse effect on our business. This uncertainty may impair our ability to retain or attract personnel until the merger is completed. Employee retention may be particularly challenging, as employees may experience uncertainty about their future roles with the combined company.

The merger agreement restricts our ability to pursue alternatives to the merger. The merger agreement contains provisions that prohibit us from soliciting alternative acquisition proposals or offers for a competing transaction. Further, in certain circumstances, including if the merger agreement is terminated because our board of directors changes its recommendation for the merger, we are required to pay LinnCo a termination fee of up to $83.7 million. This obligation may discourage a third party that has an interest in acquiring all of or a significant part of our business from considering or proposing such acquisition.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

Information required by Item 2. Properties is included under Part I, Item 1, “Business—Properties.”

Item 3. Legal Proceedings

While we are, from time to time, a party to certain lawsuits in the ordinary course of business, we do not believe any of such existing lawsuits will have a material adverse effect on our operations, financial condition, or operating cash flows. For a

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description of legal matters see "Legal Matters" in Note 9 to the Financial Statements, which descriptions are incorporated by reference herein.

Item 4. Mine Safety Disclosure.

Not applicable.

Executive Officers

Presented below is information about our executive officers as of December 31, 2012. There are no family relationships between any of the executive officers and members of the Board of Directors.

ROBERT F. HEINEMANN, 59, has been President and Chief Executive Officer since June 2004. Mr. Heinemann was Chairman of the Board and interim President and Chief Executive Officer from April 2004 to June 2004. From December 2003 to March 2004, Mr. Heinemann acted as the director designated to serve as the presiding director at executive sessions of the Board in the absences of the Chairman and as liaison between the independent directors and the CEO. Mr. Heinemann joined the Board in March of 2002. From 2000 until 2002, Mr. Heinemann served as the Senior Vice President and Chief Technology Officer of Halliburton Company and as the Chairman of the Halliburton Technology Advisory Committee. He was previously with Mobil Oil Corporation (Mobil) where he served in a variety of positions for Mobil and its various affiliate companies in the energy and technical fields from 1981 to 1999, with his last responsibilities as Vice President of Mobil Technology Company and General Manager of the Mobil Exploration and Producing Technical Center.

DAVID D. WOLF, 42, has been Executive Vice President and Chief Financial Officer since August 2008. Mr. Wolf was previously employed by JPMorgan from 1995 to 2008 where he served as a Managing Director in JPMorgan's Oil and Gas Group and advised on numerous equity, debt and M&A transactions in the energy industry.

MICHAEL DUGINSKI, 46, has been Executive Vice President and Chief Operating Officer since September 2007. Mr. Duginski served as Executive Vice President of Corporate Development and California from October 2005 to August 2007; he acted as Senior Vice President of Corporate Development from June 2004 through October 2005 and as Vice President of Corporate Development from February 2002 through June 2004. Mr. Duginski, a mechanical engineer, was previously employed by Texaco, Inc. from 1988 to 2002 where his positions included Director of New Business Development, Production Manager and Gas and Power Operations Manager. Mr. Duginski is also an Assistant Secretary.

GEORGE T. CRAWFORD, 52, has been Senior Vice President of California Production since May 2009. Mr. Crawford served as Vice President of California Production from October 2005 until May 2009, Vice President of Production from December 2000 through October 2005 and as Manager of Production from January 1999 to December 2000. Mr. Crawford, a petroleum engineer, previously served as the Production Engineering Supervisor for Atlantic Richfield Corp. from 1989 to 1998, with numerous engineering and operational assignments, including Production Engineering Supervisor, Planning and Evaluation Consultant and Operations Superintendent.

WALTER B. AYERS, 69, has held the position of Vice President of Human Resources since May 2006. Mr. Ayers was previously a private consultant to the energy industry from January 2002 until his employment with the Company. Mr. Ayers served as a Manager of Human Resources for Mobil Oil Corporation from June 1965 until December 2000.

SHAWN M. CANADAY, 37, has held the position of Vice President of Finance and Treasurer since August 2009. Mr. Canaday was Vice President and Controller from June 2008 until July 2009 and was Interim Chief Financial Officer from June 2008 until August 2008. Mr. Canaday served as Controller from February 2007 to July 2009, as Treasurer from December 2004 to February 2007 and as Senior Financial Analyst from November 2003 until December 2004. Mr. Canaday has worked in the oil and natural gas industry since 1998 in various finance functions at Chevron and in public accounting. Mr. Canaday is also an Assistant Secretary.

GEORGE W. CIOTTI, 49, was promoted to Vice President of Rocky Mountain Production effective January 2012. Mr. Ciotti was Vice President, Corporate Development from January 2010 until December 2011. Mr. Ciotti was Manager of Business Development from January 2009 through December 2009 and Senior Financial Analyst from December 2007 until December 2008. Immediately prior to joining Berry, Mr. Ciotti was President and Founder of a consulting company focused on financial and business services. He also had ten years of experience with Texaco in positions such as Assistant Controller and Senior Project Economist.

JOHN R. MATSON, 57, has been Vice President of Texas Production since joining Berry Petroleum Company in July 2011 and was appointed an officer in May 2012. Mr. Matson, a petroleum engineer, previously consulted for E&P companies in the U.S. and internationally. Prior to that he held multiple leadership positions in Halliburton and Mobil Oil Corporation where he began his career.

DAVIS O. O'CONNOR, 58, has been the Vice President, General Counsel and Secretary since October 2010. He previously served as a partner and an associate with the Denver law firm of Holland and Hart LLP since 1979 where he

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practiced in the areas of domestic and international business transactions including mergers, acquisitions, divestitures, joint ventures and related transactions, primarily in the oil and natural gas industry.

JAMIE L. WHEAT, 42, has held the position of Controller since August 2009. Ms. Wheat was the Accounting Manager from August 2008 until August 2009. Prior to joining the Company, Ms. Wheat was a Senior Manager in the assurance practice group of KPMG, where she worked from 2001 to 2008.

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PART II

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

Shares of our Class A Common Stock and Class B Stock are each entitled to one vote and 95% of one vote, respectively. Each share of Class B Stock is entitled to a $0.50 per share preference in the event of liquidation or dissolution. Further, each share of Class B Stock is convertible into one share of Class A Common Stock at the option of the holder.

Our Class A Common Stock is listed on the New York Stock Exchange under the symbol BRY. Our Class B Stock is not publicly traded. The market data and dividends for 2012 and 2011 are shown below:

	2012			2011		
	Price Range		Dividends	Price Range		Dividends
	High	Low	Per Share	High	Low	Per Share
First Quarter	$57.20	$42.55	$.080	$52.32	$42.61	$.075
Second Quarter	49.27	31.93	.080	53.76	44.13	.075
Third Quarter	43.25	35.45	.080	61.17	36.53	.080
Fourth Quarter	42.18	30.21	.080	47.92	30.62	.080
Total Dividends Paid			$.320			$.310

There were 476 holders of record of our Class A Common Stock and one holder of record of our Class B Stock as of February 25, 2013.

Dividends

Our regular annual dividend is currently $0.32, payable quarterly in March, June, September and December.

Since our formation in 1985, we have paid dividends on our Common Stock, including eight consecutive semi-annual periods through September 1989 and 93 consecutive quarters thereafter. We intend to continue the payment of dividends, although future dividend payments will depend upon our level of earnings, operating cash flow, capital commitments, financial covenants and other relevant factors. Dividend payments are limited by covenants in our credit facility to the greater of $35 million or 75% of net earnings for any four quarter period. In addition, the indentures governing our senior notes contain provisions potentially restricting our ability to declare dividends if certain situations arise; provided that, notwithstanding such restrictions, we may declare dividends up to $0.36 per share annually (so long as such distributions are less than $20 million annually) in the event that we are not in default under such indentures and up to $10 million in the event we are in a non-payment default under such indentures.

Equity Compensation Plan Information

Plan category	Number of securities to be issued upon exercise of outstanding options, warrants and rights(1)	Weighted average exercise price of outstanding options, warrants and rights(1)	Number of securities remaining available for future issuance
Equity compensation plans approved by security holders	1,387,592	$33.71	599,970
Equity compensation plans not approved by security holders	—	—	—

(1) Excludes 545,914 shares of restricted stock units for which the vesting period has not lapsed. For additional information regarding our equity compensation plans, see Note 6 to the Financial Statements.

Issuer Purchases of Equity Securities

None.

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Performance Graph

This graph shall not be deemed "filed" for purposes of Section 18 of the Securities and Exchange Act of 1934 (the Exchange Act) or otherwise subject to the liabilities of that section, nor shall it be deemed incorporated by reference in any filing under the Securities Act of 1933 or the Exchange Act, regardless of any general incorporation language in such filing.

Total returns assume $100 invested on December 31, 2007 in shares of Berry Petroleum Company, the Russell 2000, the Standard & Poors 500 Index and a Peer Group, assuming reinvestment of dividends for each measurement period. The information shown is historical and is not necessarily indicative of future performance. The 14 companies which make up the "Previous Peer Group" are as follows: Bill Barrett Corp., Cabot Oil & Gas Corp., Cimarex Energy Co., Comstock Resources Inc., Denbury Resources Inc., Forest Oil Corp., Penn Virginia Corp., Plains Exploration & Production Co., Quicksilver Resources Inc., Sandridge Energy Inc., SM Energy Co., Stone Energy Corp., Swift Energy Co. and Whiting Petroleum Corp. The 15 companies which make up the "Current Peer Group" are as follows: Bill Barrett Corp., Cabot Oil & Gas Corp., Cimarex Energy Co., Denbury Resources Inc., Forest Oil Corp., Laredo Petroleum Holdings, Inc., Newfield Exploration CO., Plains Exploration & Production Co., Quicksilver Resources Inc., Rosetta Resources Inc., Sandridge Energy Inc., SM Energy Co., Stone Energy Corp., Swift Energy Co. and Whiting Petroleum Corp. We determined to remove Penn Virginia Corp. and Comstock Resources Inc. from our peer group due to differences in market capitalization of such companies relative to ours. In addition, we determined to include Laredo Petroleum Holdings, Inc., Newfield Exploration Company and Rosetta Resources, Inc. in our peer group because of similarities in market capitalization, the nature and location of such companies' properties, and the business strategies and structure of such companies.

	12/07	12/08	12/09	12/10	12/11	12/12
Berry Petroleum Company	100.00	17.24	67.91	102.78	99.52	80.11
S&P 500	100.00	63.00	79.68	91.68	93.61	108.60
Russell 2000	100.00	66.22	84.21	106.82	102.36	119.08
Current Peer Group	100.00	39.29	68.90	94.15	81.13	76.05
Previous Peer Group	100.00	43.76	66.19	84.15	76.72	74.06

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Item 6. Selected Financial Data

The following table sets forth certain financial information and is qualified in its entirety by reference to the historical financial statements and notes thereto included in Item 8. Financial Statements and Supplementary Data. The financial information at December 31, 2012 and 2011 and for the years ended December 31, 2012, 2011 and 2010 was derived from our audited financial statements and the accompanying notes to those financial statements included in Item 8. Financial Statements and Supplementary Data in this Annual Report on Form 10-K. The financial information at December 31, 2010, 2009 and 2008 and for the years ended December 31, 2009 and 2008 was derived from audited financial data not included in the report.

	Year Ended December 31,				
(in thousands, except per share, production and per BOE data)	2012	2011	2010	2009	2008
Statements of Operations Data:					
Operating Revenues (continuing operations)	$974,832	$919,558	$676,510	$559,403	$746,632
Net earnings (loss) from continuing operations(1)(2)	171,539	(228,063)	82,524	47,224	120,577
Basic earnings (loss) per share from continuing operations(1)(2)	3.11	(4.21)	1.54	1.03	2.67
Diluted net earnings (loss) per share from continuing operations(1)(2)	$3.09	$(4.21)	$1.52	$1.02	$2.64
Production Data (continuing operations):					
Oil production (MBOE)	10,026	9,041	7,925	7,186	7,441
Natural gas production (MMcf)	19,784	23,907	23,988	20,982	18,323
Operating Data (continuing operations) (per BOE):					
Average sales price(3)	$71.81	$71.59	$53.69	$41.23	$73.64
Average operating costs—oil and natural gas production	20.43	18.22	15.92	14.62	17.99
Production taxes	2.96	2.58	1.93	1.70	2.56
G&A	5.39	4.74	4.43	4.61	5.17
DD&A—oil and natural gas production	$16.95	$16.42	$15.05	$13.10	$11.97
Balance Sheet and Other Data (at period end):					
Total assets	$3,325,402	$2,734,952	$2,838,616	$2,240,135	$2,542,383
Long-term debt	1,665,817	1,380,192	1,108,965	1,008,544	1,131,800
Dividends per share	$0.32	$0.31	$0.30	$0.30	$0.30
Cash Flow Data:					
Cash flow from operations	$501,439	$455,899	$367,237	$212,576	$409,569
Development and exploration of oil and natural gas properties	675,951	527,112	310,139	134,946	397,601
Property acquisitions	$78,313	$158,090	$334,409	$13,497	$667,996

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(1) In 2011, we recorded an impairment of $625.0 million related to our E. Texas natural gas assets, largely due to the impact of lower natural gas prices.

(2) Due to the volatility of commodity prices, the estimated fair value of our commodity derivative instruments is subject to fluctuations. As a result, since discontinuing hedge accounting on January 1, 2010, we may recognize in earnings significant unrealized gains and losses (non-cash changes in fair value) on commodity derivative instruments from period to period.

(3) Excludes all effects of derivatives. See Part II, Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations" for additional information regarding the effect of derivatives on our average realized price.

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

The following discussion and analysis should be read in conjunction with Item 6. Selected Financial Data and the accompanying financial statements and related notes included elsewhere in this Annual Report on Form 10-K. The following discussion contains forward looking statements that reflect our future plans, estimates, beliefs and expected performance. Our actual results may differ materially because of a number of risks and uncertainties. Some of these risks and uncertainties are detailed in Part I, Item 1A. Risk Factors, and elsewhere in this Annual Report on Form 10-K.

Overview

We are an independent energy company engaged in the production, development, exploitation and acquisition of oil and natural gas. We were incorporated in Delaware in 1985. We have been publicly traded since 1987 and trace our roots in California oil production back to 1909. Since 2002, we have expanded our portfolio of assets through selective acquisitions driven by a consistent focus on properties with proved reserves and significant growth potential through low-risk development. Our principal reserves and producing properties are located in California, Texas (Permian and E. Texas), Utah (Uinta) and Colorado (Piceance).

Our revenue, profitability and future growth rate depend on many factors beyond our control, such as economic, political and regulatory developments and competition from other sources of energy. Oil and natural gas prices have been volatile and may fluctuate widely in the future. The following charts highlight the quarterly average NYMEX price trends for crude oil and natural gas since the first quarter of 2010:

Lower oil and natural gas prices may not only decrease our revenues, but may also reduce the amount of oil and natural gas that we can produce economically and therefore potentially lower our oil and natural gas reserves. A substantial or extended decline in oil or natural gas prices may result in impairments of our proved oil and natural gas properties and may materially and adversely affect our future business, financial condition, results of operations, operating cash flows, liquidity or ability to finance planned capital expenditures. Lower oil and natural gas prices may also reduce the amount of our borrowing base under our credit agreement, which is determined at the discretion of the lenders and is based on the collateral value of our proved reserves that have been mortgaged to the lenders. Alternatively, higher oil prices may result in significant non-cash fair value losses being incurred on our oil derivatives, which could cause us to experience net losses when prices rise.

Steam costs are a significant variable component of our operating costs and fluctuate based on the amount of steam we inject and the price of natural gas used to generate steam. We benefit from lower natural gas prices as a consumer of natural gas in our California operations. In the Permian, Uinta, E. Texas and Piceance, we benefit from higher natural gas pricing as a producer of natural gas. In addition, production rates, labor and equipment costs, maintenance expenses and production taxes influence our operating costs. Our results of operations may fluctuate from period to period based on such factors.

LinnCo, LLC Merger

On February 20, 2013, the Company, Linn Energy, LLC (Linn), LinnCo, LLC (LinnCo), Linn Acquisition Company, LLC, a direct wholly owned subsidiary of LinnCo (LinnCo Merger Sub), Bacchus HoldCo, Inc., a direct wholly owned subsidiary of the Company (HoldCo), and Bacchus Merger Sub, Inc., a direct wholly owned subsidiary of HoldCo (Bacchus Merger Sub), entered into a definitive Agreement and Plan of Merger (the “Merger Agreement”), pursuant to which LinnCo agreed to acquire

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the Company in an all-stock transaction in which the Company's stockholders would receive 1.25 shares representing limited liability company interests in LinnCo (LinnCo Shares) for each share of the Company's common stock.

The transaction will occur through multiple steps. First, the Company will engage in a holding company merger (the HoldCo Merger) involving HoldCo and Bacchus Merger Sub. In the HoldCo Merger, Bacchus Merger Sub will merge with and into the Company, with the Company surviving as a wholly owned subsidiary of HoldCo, and each issued and outstanding share of the Company's Class A common stock and Class B common stock will convert into the right to receive one equivalent share of Class A common stock and one equivalent share of Class B common stock, respectively, of HoldCo.

Second, promptly after the HoldCo Merger, the Company will be converted into a limited liability company. Third, promptly following such conversion, HoldCo will be merged with and into LinnCo Merger Sub, with LinnCo Merger Sub surviving as the surviving company (the LinnCo Merger). In the LinnCo Merger, each share of Holdco's Class A common stock and each share of Holdco's Class B common stock will be converted into 1.25 LinnCo Shares.

Finally, promptly following the LinnCo Merger, LinnCo will contribute all of the outstanding equity interests in LinnCo Merger Sub (and therefore also its indirect ownership interest in the Company) to Linn (the “Contribution”) in exchange for the issuance to LinnCo (the “Issuance”) of newly issued Linn common units. The number of Linn common units to be issued to LinnCo in the Issuance will be equal to the greater of (i) the aggregate number of LinnCo Shares issued in the LinnCo Merger and (ii) the number of Linn common units required to cause LinnCo to own no less than one-third of all of the outstanding Linn common units following the Contribution. In addition, for three years following the closing, Linn will pay to LinnCo additional cash distributions in the amount of $6 million per year.

The closing of the transactions is subject to customary closing conditions, including approval of the Merger Agreement and the transactions contemplated thereby by the stockholders of the Company and the holders of the shares of LinnCo and Linn, receipt of certain opinions by the parties with respect to the tax-free nature of the transactions, and other customary conditions such as expiration of the waiting period under the Hart-Scott-Rodino Act.

Notable Items - Full Year 2012

- Increased oil production 11% from 2011, offsetting a 17% decrease in natural gas production and increasing oil production to 75% of total production in 2012
- Generated an operating margin of $48.79 per BOE, supported by sales of our California heavy oil at a $8.93 average premium over WTI during 2012[(1)]
- Generated discretionary cash flow of $501.7 million from production of 36,402 BOE/D[(1)]
- Increased cash flow from operations by $45.5 million or 10% from 2011
- Increased oil reserves 10% from 2011, replacing 283% of oil production in 2012
- Increased oil reserves to 74% of total proved reserves
- Acquired approximately 28,000 net acres in or contiguous to our core operating areas in the Uinta
- Drilled 74 Permian wells and increased Permian production to 6,735 BOE/D, a 52% increase over 2011
- Increased production from our NMWSS—New Steam Floods by 73% to 1,827 BOE/D
- Drilled 102 Uinta wells and increased Uinta production to 6,133 BOE/D, an 11% increase over 2011
- Received final US Forest Service approval on our Environmental Impact Study for the Ashley Forest in the Uinta
- Drilled 120 Diatomite wells and increased Diatomite production from an intra-month low of 1,750 BOE/D during March 2012 to 4,090 BOE/D during December 2012; Diatomite production averaged 3,255 BOE/D for full-year 2012
- Issued $600 million aggregate principal amount of our 6.375% senior notes due 2022 (2022 Notes) and used the proceeds to, among other things, redeem part of our 2014 Notes and all of our 2016 Notes

Notable Items - Fourth Quarter 2012

- Increased total production 9% from the third quarter of 2012 to 39,500 BOE/D
- Increased production from the third quarter of 2012 in the Uinta by 26% to 7,500 BOE/D, Permian by 16% to 7,965 BOE/D, NMWSS—New Steam Floods by 11% to 2,130 BOE/D and Diatomite by 10% to 3,855 BOE/D compared to the third quarter of 2012
- Increased oil production to 78% of total production from the third quarter of 2012

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(1) Operating margin and discretionary cash flow are non-GAAP measures and reference should be made to "Reconciliation of Non-GAAP Measures" in Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations for further explanation as well as reconciliations to the most directly comparable GAAP measures.

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Results of Operations.

We had net earnings of $171.5 million, or $3.09 per diluted share, for the year ended December 31, 2012. Net earnings included a $26.3 million loss on extinguishment of debt associated with repurchasing all $200 million aggregate principal amount of our 8.25% Senior subordinated notes due 2016 (2016 Notes) and $150 million aggregate principal amount of our 10.25% Senior notes due 2014 (2014 Notes), a gain on derivatives of $22.9 million resulting from non-cash changes in fair values and amortization of accumulated other comprehensive income (AOCL) related to de-designated hedges, an expense of $1.8 million related to principal and interest paid in connection with the settlement of disputed royalty payments, dry hole expense of $9.3 million, a $9.3 million cash settlement related to the early termination of our natural gas derivatives, a gain of $0.9 million related to a retroactive payment adjustment for capacity from one of our electricity customers and a $1.0 million gain associated with the sale of our Nevada Assets, in each case net of income taxes. Net earnings also included a $7.2 million benefit from our research and development tax credit. Net cash provided by operating activities was $501.4 million and capital expenditures, excluding capitalized interest and property acquisitions and divestitures, totaled $676.0 million. We drilled 431 net wells during 2012 and achieved average daily production of 36,402 BOE/D in 2012, an increase of 2% from 2011.

We had net earnings of $38.5 million, or $0.69 per diluted share, for the fourth quarter of 2012. Net earnings included a gain on derivatives of $1.0 million resulting from non-cash changes in fair values and amortization of AOCL related to de-designated hedges, dry hole expense of $8.6 million and a gain of $0.9 million related to a retroactive payment adjustment for capacity from one of our electricity customers, in each case net of income taxes. Net earnings for the fourth quarter also included a $7.2 million benefit from our research and development tax credit. Net cash provided by operating activities was $109.8 million and capital expenditures, excluding capitalized interest and property acquisitions and divestitures, totaled $151.9 million. We drilled 88 net wells during the quarter and achieved average daily production of 39,500 BOE/D, an increase of 9% over the third quarter of 2012, primarily due to increased oil production from the Uinta, the Permian and our California properties.

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Operating Data.

The following table sets forth selected operating data for the years ended:

	December 31, 2012	%	December 31, 2011	%	December 31, 2010	%
Heavy oil production (BOE/D)	17,905	49	17,397	49	17,124	52
Light oil production (BOE/D)	9,488	26	7,374	21	4,589	14
Total oil production (BOE/D)	27,393	75	24,771	70	21,713	66
Natural gas production (Mcf/D)	54,054	25	65,498	30	65,720	34
Total (BOE/D)(1)	36,402	100	35,687	100	32,666	100
Oil and natural gas, per BOE:						
Average realized sales price	$ 71.00		$ 66.91		$ 52.14	
Average sales price including cash derivative settlements	$ 72.18		$ 65.68		$ 53.84	
Oil price, per BOE:						
Average WTI price	$ 94.15		$ 95.11		$ 79.59	
Price sensitive royalties(2)	(3.36	)	(3.60	)	(3.06	)
Quality differential and other(3)	(0.67	)	0.84		(8.92	)
Oil derivatives non-cash amortization(4)	(1.09	)	(6.77	)	(2.59	)
Oil revenue per BOE	$ 89.03		$ 85.58		$ 65.02	
Add: Oil derivatives non-cash amortization(4)	1.09		6.77		2.59	
Oil derivatives cash settlements(5)	0.07		(9.72	)	(0.90	)
Average realized oil price per BOE	$ 90.19		$ 82.63		$ 66.71	
Natural gas price, per Mcf:						
Average Henry Hub price per MMBtu	$ 2.79		$ 4.04		$ 4.39	
Conversion to Mcf	0.19		0.28		0.22	
Natural gas derivatives non-cash amortization(4)	0.01		0.01		0.08	
Location, quality differentials and other	(0.18	)	(0.23	)	(0.24	)
Natural gas revenue per Mcf	$ 2.81		$ 4.10		$ 4.45	
Add: Natural gas derivatives non-cash amortization(4)	(0.01	)	(0.01	)	(0.08	)
Natural gas derivative cash settlements(5)	0.22		0.46		0.37	
Average realized natural gas price per Mcf	$ 3.02		$ 4.55		$ 4.74	

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(1) Oil equivalents are determined using the ratio of six Mcf of natural gas to one barrel of oil.

(2) Our Formax property in S. Midway is subject to a price-sensitive royalty burden. The royalty is 53% of the amount of the heavy oil posted price above the 2012 base price of $17.43 per barrel as long as we maintain a minimum steam injection level. We met the steam injection level in 2012 and expect to meet the requirement going forward. The base price escalates at 2% annually and will be $17.78 in 2013.

(3) In California, the per barrel oil posting differential at December 31, 2012 was $11.02, ranged from $2.18 to $11.52 during 2012 and averaged $8.93 during 2012. In Utah, the per barrel oil posting differential at December 31, 2012 was ($15.50), ranged from ($12.49) to ($16.52) during 2012 and averaged ($15.63) during 2012.

(4) Non-cash amortization of AOCL resulting from discontinuing hedge accounting effective January 1, 2010. Recorded in the Statements of Operations under the caption oil and natural gas sales.

(5) Cash settlements on derivatives are recorded in the Statements of Operations under the caption realized and unrealized (gain) loss on derivatives, net.

The following table sets forth selected operating data for the three months ended:

	December 31, 2012	%	December 31, 2011	%	September 30, 2012	%
Heavy oil production (BOE/D)	19,058	48	17,497	49	18,149	50
Light oil production (BOE/D)	11,591	30	8,166	23	9,344	26
Total oil production (BOE/D)	30,649	78	25,663	72	27,493	76
Natural gas production (Mcf/D)	53,106	22	60,759	28	52,758	24
Total (BOE/D)(1)	39,500	100	35,790	100	36,286	100
Oil and natural gas, per BOE:						
Average realized sales price	$ 70.51		$69.29		$70.22	
Average sales price including cash derivative settlements	$ 72.47		$68.80		$71.45	
Oil price, per BOE:						
Average WTI price	$ 88.23		$94.06		$92.20	
Price sensitive royalties(2)	(2.65	)	(3.63	)	(3.12	)
Quality differential and other(3)	0.79		4.75		(0.68	)
Oil derivatives non-cash amortization(4)	(1.03	)	(6.76	)	(1.10	)
Oil revenue per BOE	$ 85.34		$88.42		$87.30	
Add: Oil derivatives non-cash amortization(4)	1.03		6.76		1.10	
Oil derivative cash settlements(5)	1.57		(8.89	)	0.64	
Average realized oil price per BOE	$ 87.94		$86.29		$89.04	
Natural gas price, per Mcf:						
Average Henry Hub price per MMBtu	$ 3.41		$3.54		$2.80	
Conversion to Mcf	0.24		0.21		0.19	
Natural gas derivatives non-cash amortization(4)	—		—		0.02	
Location, quality differentials and other	(0.14	)	(0.24	)	(0.13	)
Natural gas revenue per Mcf	$ 3.51		$3.51		$2.88	
Add: Natural gas derivatives non-cash amortization(4)	—		—		(0.02	)
Natural gas derivative cash settlements(5)	(0.03	)	0.61		(0.04	)
Average realized natural gas price per Mcf	$ 3.48		$4.12		$2.82	

(1) Oil equivalents are determined using the ratio of six Mcf of natural gas to one barrel of oil.

(2) Our Formax property in S. Midway is subject to a price-sensitive royalty burden. The royalty is 53% of the amount of the heavy oil posted price above the 2012 base price of $17.43 per barrel as long as we maintain a minimum steam injection level. We met the steam injection level in 2012 and expect to meet the requirement going forward. The base price escalates at 2% annually and will be $17.78 in 2013.

(3) In California, the per barrel oil posting differential at December 31, 2012 was $11.02, ranged from $9.83 to $11.04 during the fourth quarter of 2012 and averaged $10.37 during the fourth quarter of 2012. In Utah, the per barrel oil posting differential at December 31, 2012 was ($15.50), ranged from ($15.00) to ($15.50) during the fourth quarter of 2012 and averaged ($15.24) during the fourth quarter of 2012.

(4) Non-cash amortization of AOCL resulting from discontinuing hedge accounting effective January 1, 2010. Recorded in the Statements of Operations under the caption oil and natural gas sales.

(5) Cash settlements on derivatives are recorded in the Statements of Operations under the caption realized and unrealized (gain) loss on derivatives, net.

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The following table reflects our results of operations for the periods presented:

(in thousands, except per share data)	Year ended December 31, 2012	December 31, 2011	December 31, 2010	Three months ended December 31, 2012	December 31, 2011	September 30, 2012
Oil sales	$881,688	$772,685	$512,699	$231,766	$207,689	$218,952
Natural gas sales	55,573	98,088	106,909	17,145	19,609	13,964
Oil and natural gas sales	$937,261	$870,773	$619,608	$248,911	$227,298	$232,916
Electricity sales	29,940	34,953	34,740	8,586	10,750	9,514
Natural gas marketing	7,631	13,832	22,162	2,253	2,550	1,939
Gain on sale of assets	1,782	—	—	12	—	170
Settlement on Flying J bankruptcy claim	—	—	21,992	—	—	—
Interest and other income, net	1,985	1,784	3,300	307	390	286
Total revenues and other income	$978,599	$921,342	$701,802	$260,069	$240,988	$244,825
Net earnings (loss)	$171,539	$(228,063)	$82,524	$38,499	$(414,733)	$18,126
Diluted net earnings (loss) per share	$3.09	$(4.21)	$1.52	$0.69	$(7.62)	$0.33

Oil and Natural Gas Sales.

Oil and natural gas sales increased $66.5 million, or 8%, in 2012 compared to 2011. The increase was primarily due to a 6% increase in the average sales price in 2012 compared to 2011, largely as a result of an increase in oil sales volumes as a percentage of total sales volumes. Our oil sales volumes increased 10% in 2012 compared to 2011, while our natural gas sales volumes decreased 17%. The oil volume increase was primarily due to an increase in oil production from all of our oil properties except our legacy SMWSS—Steam Floods properties. In 2012, our oil production increased relative to 2011 as follows: Permian 1,800 BOE/D, or 48%; Uinta 440 BOE/D, or 14%; NMWSS—New Steam Floods 770 BOE/D, or 73%; and Diatomite 100 BOE/D, or 3%. These increases in oil production were partially offset by a decrease in production from our SMWSS—Steam Floods properties due to expected production declines. Additionally, the decrease in natural gas sales volumes was primarily due to expected production declines from our E. Texas and Piceance properties, partially offset by increased natural gas production from our Permian and Uinta properties. In addition to the increase in oil sales volumes, non-cash derivative losses decreased by $50.2 million related to de-designated commodity hedges reclassified from AOCL into oil and natural gas sales.

Oil and natural gas sales increased $251.2 million, or 41%, in 2011 compared to 2010. The increase was primarily due to a 28% increase in the average realized sales price and a 10% increase in sales volumes in 2011 compared to 2010. The increase in the average sales price was primarily due to a 19% increase in the average WTI price in 2011 compared to 2010. The increase in oil production as a percentage of total production from 2010 to 2011 also contributed to the increase in the average sales price over that time period. The increase in sales volume was primarily due to a 14% increase in oil sales volume in 2011 compared to 2010, largely due to increased oil production from the Permian, which increased 2,660 BOE/D, or 245%, from 2010 to 2011. Also increasing over the same period was Diatomite oil production, which increased 430 BOE/D, or 16%; NMWSS—New Steam Floods oil production, which increased 250 BOE/D, or 31%; and Uinta oil production, which increased 190 BOE/D, or 6%. These increases were offset by an increase in non-cash derivative losses of $42.5 million related to de-designated commodity hedges reclassified from AOCL into oil and natural gas sales.

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Electricity Sales.

The following table sets forth selected results of operations for the periods ended:

	Year Ended December 31,		
	2012	2011	2010
Electricity			
Electricity sales (in thousands)	$29,940	$34,953	$34,740
Operating costs (in thousands)	$19,975	$25,690	$31,295
Electric power produced (MWh/D)	2,097	1,968	2,088
Electric power sold (MWh/D)	1,918	1,806	1,925
Average sales price per MWh	$40.79	$47.00	$50.06
Fuel gas cost per MMBtu (including transportation)	$2.89	$4.20	$4.49
Estimated natural gas volumes consumed to produce electricity (MMBtu/D)(1)	15,415	15,229	18,171

Electricity sales in 2012 decreased 14% compared to 2011. In 2012 and 2011, electricity sales included retroactive payment adjustments for capacity of $1.3 million and $4.1 million, respectively, from our electricity customers. As a result of our previously disclosed global settlement with various parties that became effective on November 23, 2011, we received retroactive payments for firm capacity that had been originally paid at "as available" capacity rates, and these payments represent the difference in rates over the disputed period. Excluding the retroactive payment adjustments, electricity sales in 2012 would have decreased 7% compared to 2011. The decrease in electricity sales was primarily due to a 13% decrease in the average sales price of electricity, partially offset by a 6% increase in electric power sold period over period primarily due to a decrease in the downtime of our cogeneration facilities in 2012 compared to 2011. Electricity operating costs in 2012 decreased 22% compared to 2011 primarily due to a 31% decrease in fuel gas cost, partially offset by a 1% increase in fuel gas volumes purchased.

Electricity sales increased 1% in 2011 compared to 2010 primarily due to the retroactive capacity refund of $4.1 million received in December 2011 from one of our electricity customers. This increase was offset by a 6% decrease in the average sales price of electricity and a 6% decrease in electric power sold associated with an increase in cogeneration unit downtime in 2011. Electricity operating costs decreased 18% in 2011 compared to 2010 primarily due to a 6% decrease in fuel gas cost and a 6% decrease in electric power produced related to increased cogeneration unit downtime in 2011.

Natural Gas Marketing.

We have long-term firm transportation contracts on the Rockies Express, Wyoming Interstate Company and Ruby pipelines, each with a total average capacity of 35,000 MMBtu/D. Demand charges for our capacity are reflected in operating costs—oil and natural gas production in our Statements of Operations. Our current production is insufficient to fully utilize this capacity. To optimize our remaining capacity, we purchase third-party natural gas at the market rate in our producing areas and utilize FERC-approved asset management agreements. Sales and purchases of third-party natural gas are recorded under natural gas marketing in the revenues and expenses sections of the Statements of Operations, respectively.

The pre-tax net of our natural gas marketing revenue and our natural gas marketing expense for the years ended December 31, 2012, 2011 and 2010 was $0.8 million, $0.8 million and $2.3 million, respectively.

Settlement of Flying J Bankruptcy.

On July 6, 2010, the Joint Plan of Reorganization of Flying J, Inc., Big West of California, LLC, Big West Oil, LLC, Big West Transportation, LLC and Longhorn Partners Pipeline, L.P. was confirmed under Chapter 11 of the United States Bankruptcy Code. Additionally, the United States Bankruptcy Court approved and confirmed the June 15, 2010 Stipulation and Agreed Order (the Stipulation) with Flying J, Inc. and certain of its affiliates (collectively Flying J), regarding the resolution of our claim in Flying J's pending bankruptcy. Pursuant to the Stipulation, we and Flying J agreed that the total amount owed to us by Flying J for the purchases of our California production and other damages was $60.5 million and, as a result, we received $60.5 million in cash on July 23, 2010.

Gain on Sale of Assets.

In 2012, we recorded a $1.6 million gain in conjunction with the sale of assets related to our Nevada Assets. The gain was recorded in the Statements of Operations under the caption gain on sale of assets. In addition, all three of our drilling rigs were sold in the third quarter of 2012 for $1.8 million, which, less costs to sell of $0.2 million, resulted in a gain of $0.2 million.

Oil and Natural Gas Operating and Other Expenses.

The following table presents information about our oil and natural gas operating and other expenses for each of the years ended December 31:

	Amount per BOE			Amount (in thousands)		
	2012	2011	2010	2012	2011	2010
Operating costs—oil and natural gas production (1)	$20.43	$18.22	$15.92	$272,180	$237,296	$189,809
Production taxes	2.96	2.58	1.93	39,374	33,617	22,999
DD&A—oil and natural gas production	16.95	16.42	15.05	225,892	213,859	179,432
G&A	5.39	4.74	4.43	71,766	61,727	52,846
Interest	6.24	5.59	5.58	83,136	72,807	66,541
Total	$51.97	$47.55	$42.91	$692,348	$619,306	$511,627

(1) Operating costs—oil and natural gas production includes firm transportation costs of $28.6 million, $21.4 million and $16.2 million for the years ended December 31, 2012, 2011 and 2010, respectively.

- Operating costs—oil and natural gas production in 2012 were $272.2 million, or $20.43 per BOE, compared to $237.3 million, or $18.22 per BOE, in 2011. The increase was primarily due to a higher level of workover activity in the Permian and increased transportation costs due to the commencement of Ruby Pipeline operations in July 2011. The shift in production from our natural gas properties, which have lower operating costs, to our oil properties, which have higher operating costs, also contributed to the increase in operating costs from 2011 to 2012. Also increasing over the same time period were contract services, contract labor, chemicals, electricity, well maintenance costs and internal labor costs associated with net wells added during the last 12 months. These increases were partially offset by a $1.7 million decrease in steam costs, primarily due to a decrease in the price of natural gas used in steam generation and a decrease in compression, gathering, and dehydration costs due to the natural decline in production from our natural gas properties.

Operating costs—oil and natural gas production in 2011 were $237.3 million, or $18.22 per BOE, compared to $189.8 million, or $15.92 per BOE, in 2010. The increase primarily results from higher steam costs resulting from higher volumes of injected steam, partially offset by a decrease in the price of natural gas used in steam generation and increases in water hauling and disposal costs, well maintenance and workover costs, contract labor costs and transportation costs.

The following table presents steam information:

	Year Ended December 31,		
	2012	2011	2010
Average net volume of steam injected (Bbl/D)	169,605	132,083	115,651
Fuel gas cost/MMBtu (including transportation)	$2.89	$4.20	$4.49

Approximate net fuel gas volume consumed in steam generation (MMBtu/D)	54,540	44,235	36,020

- Production taxes in 2012 were $39.4 million, or $2.96 per BOE, compared to $33.6 million, or $2.58 per BOE, in 2011. The increase in production taxes was primarily due to an increase in the assessed ad valorem values attributed to our California and Permian properties and an increase in severance taxes, largely due to new wells drilled and increased production, primarily in the Permian, offset by certain tax exemptions in Utah and E. Texas.

Production taxes in 2011 were $33.6 million, or $2.58 per BOE, compared to $23.0 million, or $1.93 per BOE, in 2010. The increase in production taxes was primarily due to an increase in the assessed ad valorem values attributed to our

California properties and an increase in the number of wells outside California, where property taxes are based largely on assessed value per well. Additionally, our severance taxes increased in 2011, largely due to increased commodity prices.

- DD&A—oil and natural gas production in 2012 was $225.9 million, or $16.95 per BOE, compared to $213.9 million, or $16.42 per BOE, in 2011. On a BOE basis, the rate was 3% higher in 2012 compared to 2011, which contributed to a $6.9 million increase in DD&A—oil and natural gas production. The increase in the DD&A rate was largely due to capitalized costs associated with the development of our properties, partially offset by reserve additions. This increase was partially offset by the impairment of our E. Texas natural gas assets in the fourth quarter of 2011. The 2% increase in production from 2011 to 2012 also contributed to a $5.1 million increase in DD&A—oil and natural gas production.

DD&A—oil and natural gas production in 2011 was $213.9 million, or $16.42 per BOE, compared to $179.4 million, or $15.05 per BOE, in 2010. The increase in DD&A—oil and natural gas production per BOE was primarily due to an overall shift in production volumes to our assets outside of California, which have higher drilling and leasehold acquisition costs than our California properties. In 2011, 49% of our production volumes were heavy oil produced in California, compared to 52% of our production volumes in 2010.

- General and administrative expense (G&A) in 2012 was $71.8 million, or $5.39 per BOE, compared to $61.7 million, or $4.74 per BOE, in 2010. The increase in G&A period over period was primarily due to a $7.1 million increase in employee compensation and benefits resulting from new personnel hired and general pay increases and a $2.0 million increase in consulting costs. These increases are directly attributable to our growing capital program and oil production levels. As of December 31, 2012, we had 374 full-time employees compared to 317 full-time employees as of December 31, 2011. Employee travel costs also increased over the same time period.

G&A in 2011 was $61.7 million, or $4.74 per BOE, compared to $52.8 million, or $4.43 per BOE, in 2010. The increase was due in part to higher employee salary and benefit costs. As of December 31, 2011, we had 317 full-time employees compared to 270 as of December 31, 2010. The increase in employees was primarily due to our acquisitions in the Permian and additional personnel required for our growing capital program and production levels. Additionally, G&A increased due to higher consulting costs directly attributable to our efforts to comply with new regulations in California, as well as our growing capital program and production levels.

- The following table sets forth components of interest expense for the periods presented:

	Year Ended December 31,		
(in thousands)	2012	2011	2010
Senior subordinated notes	$4,492	$16,500	$16,500
Senior notes	76,137	63,288	49,500
Credit facility	9,679	8,314	6,263
Amortization of debt issuance costs and net discount	10,081	11,163	12,296
Amortization of AOCL	(1,785)	871	8,335
Other	2,447	1,788	1,968
Capitalized interest	(17,915)	(29,117)	(28,321)
	$83,136	$72,807	$66,541

Interest in 2012 was $83.1 million, or $6.24 per BOE, compared to $72.8 million, or $5.59 per BOE, in 2011. The increase in interest was primarily a result of the issuance of our 6.375% senior notes due 2022 (2022 Notes) in March 2012, as well as a decrease in capitalized interest and an increase in the average amount of borrowings under our

credit facility from 2011 to 2012. These increases were partially offset by a decrease in interest payments related to the repurchase of $150 million aggregate principal amount of our 10.25% Senior notes due 2014 (2014 Notes), a decrease in interest payments related to the redemption of our 8.25% Senior subordinated notes due 2016 (2016 Notes), a decrease in non-cash derivative losses of $2.7 million related to de-designated interest rate hedges reclassified from AOCL into interest expense and a decrease in amortized debt issuance costs and net discount related to the redemption of our 2016 Notes and the partial repurchase of our 2014 Notes.

Interest in 2011 was $72.8 million, or $5.59 per BOE, compared to $66.5 million, or $5.58 per BOE, in 2010. The increase in interest was a result the issuance of our 6.75% senior notes due 2020 (2020 Notes) in November 2010 and an increase in

the average amount of borrowings outstanding under our credit facility. These increases were partially offset by a $7.5 million decrease in non-cash derivative losses related to de-designated interest rate hedges reclassified from AOCL into interest expense and a decrease in interest payments related to the repurchase of $94.7 million aggregate principal amount of our 2014 Notes in September and October of 2011.

Dry Hole, Abandonment, Impairment and Exploration. We recorded dry hole, abandonment and impairment charges of $19.0 million, $5.2 million and $1.5 million in 2012, 2011 and 2010, respectively. In 2012, we recorded dry hole expense of $11.9 million related to our four appraisal wells in Borden county whose results were inconclusive for commercial quantities of oil and $2.8 million related to mechanical failure on one well near Lake Canyon, which was abandoned in favor of drilling a nearby replacement well. We also recorded approximately $4.1 million in 2012 related to plugging and abandonment activities in California. In 2011, we recorded a $4.3 million impairment charge related to the write-down of three drilling rigs to their fair value. These rigs were sold in the third quarter of 2012. In 2010, we recorded dry hole expense due to a mechanical failure encountered on one well in the Piceance. See Notes 8 and 10 to the Financial Statements.

We incurred exploration costs in 2012, 2011 and 2010, of $1.9 million, $0.3 million and $1.2 million, respectively. These costs consist primarily of geological and geophysical costs. The exploration costs in 2012 related largely to the purchase of seismic data.

Impairment of Oil and Natural Gas Properties. We recorded non-cash impairments of oil and natural gas properties of $0.1 million, $625.6 million and $0.0 million, in 2012, 2011 and 2010, respectively.

In the fourth quarter of 2011, we recorded a non-cash impairment of $625.0 million related our E. Texas natural gas properties. The impairment was due to decreases in natural gas prices and, as a result, changes in our development plans. In the fourth quarter of 2011, the NYMEX HH five-year future strip (the average of the settlement prices of the next 60 months' futures contracts) decreased approximately 15%. The assets were written down to their estimated fair value. Further, in 2012, 2011 and 2010, we recorded non-cash impairments of $0.1 million, $0.6 million and $0 million, respectively, related to the expiration of acreage, primarily in the Uinta. See Notes 8 and 10 to the Financial Statements.

Extinguishment of Debt. We recorded debt extinguishment costs of $41.5 million, $15.5 million and $0.6 million in 2012, 2011 and 2010, respectively. In 2012, we recorded debt extinguishment costs of $30.9 million in conjunction with the repurchase of $150.0 million aggregate principal amount of our 2014 Notes, consisting of $26.4 million in premiums paid over par and $4.5 million related to net discount and debt issuance costs. We also recorded debt extinguishment costs of $10.6 million in conjunction with the repurchase of all $200.0 million of our 2016 Notes, consisting of $8.3 million in premiums paid over par and $2.3 million related to debt issuance costs. In 2011, we recorded debt extinguishment costs of $15.0 million in conjunction with the repurchase of $94.7 million aggregate principal amount of our 2014 Notes, consisting of $11.5 million in premium paid over par and $3.5 million related to net discount and deferred financing costs. We also recorded debt extinguishment costs of $0.5 million associated with one lender that did not renew its commitment under our credit facility in October 2011. In 2010, we recorded debt extinguishment costs of $0.6 million associated with borrowing base changes under our credit facility.

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Realized and Unrealized (Gain) Loss on Derivatives, Net. The following table sets forth the components of realized and unrealized (gain) loss on derivatives, net, for the periods presented. See Notes 7 and 8 to the Financial Statements.

	Year Ended December 31,		
(in thousands)	2012	2011	2010
Cash (receipts) payments:			
Commodity derivatives—oil	$(671)	$87,747	$7,078
Commodity derivatives—natural gas(1)	(18,915)	(10,806)	(8,889)
Financial derivatives—interest(2)	—	—	17,499
Total realized (gain) loss	$(19,586)	$76,941	$15,688
Non-cash fair value (gain) loss:			
Commodity derivatives—oil	$(61,125)	$(89,478)	$37,440
Commodity derivatives—natural gas(1)	16,091	(1,371)	(12,424)
Financial derivatives—interest(2)	—	—	(8,857)
Total unrealized (gain) loss	$(45,034)	$(90,849)	$16,159
Realized and unrealized (gain) loss on derivatives, net	$(64,620)	$(13,908)	$31,847

(1) In March 2012, we terminated certain of our natural gas derivative instruments, which were associated with a total of 15,000 MMBtu/D for the remainder of 2012. The termination resulted in cash settlements of $14.7 million, offset by a non-cash fair value loss of $16.6 million.

(2) In the fourth quarter of 2010, we terminated certain interest rate derivative instruments for which we had previously elected hedge accounting. The termination resulted in a cash settlement of $10.8 million, offset by a fair value gain of $8.9 million.

Our open commodity derivative contracts at December 31, 2012 were in a net fair value asset position largely because the futures curve of forecasted commodity prices (forward price curve) at December 31, 2012 was generally lower than the forward price curves that were in effect when we entered into the majority of those contracts. Our open commodity derivative contracts at December 31, 2011 were in a net fair value liability position largely because the forward price curve at December 31, 2011 generally exceeded the forward price curves that were in effect when we entered into the majority of those contracts. The change in fair value from a liability position at December 31, 2011 to an asset position at December 31, 2012 resulted in a $45.0 million unrealized gain in 2012. Our open commodity derivative contracts at December 31, 2010 were in a net fair value liability position largely because the forward price curve at December 31, 2011 generally exceeded the forward price curves that were in effect when we entered into the majority of those contracts. The decrease in liability position from December 31, 2010 to December 31, 2011 resulted in a $90.8 million gain in 2011.

Gain on Purchase. In 2011, we recorded a $1.0 million gain (net of deferred income taxes of $0.7 million) in conjunction with usual and customary post-closing adjustments to the purchase price of a November 2010 acquisition in the Permian. The gain was recorded in the Statements of Operations under the caption gain on purchase.

Transaction Costs on Acquisitions. In 2010, we incurred $2.6 million of acquisition related expenses for the acquisition of certain properties in the Permian. See Note 2 to the Financial Statements.

Bad Debt (Recovery) Expense. On July 6, 2010, the Joint Plan of Reorganization of Flying J was confirmed under Chapter 11 of the United States Bankruptcy Code. Additionally, the United States Bankruptcy Court approved and confirmed the Stipulation, pursuant to which Flying J agreed that the total amount owed to us by Flying J was $60.5 million and, as a result, we received $60.5 million in cash on July 23, 2010. In 2010, we recorded a settlement of our Flying J bankruptcy claim of $22.0 million and a bad debt recovery of $38.5 million.

Income Tax (Benefit) Expense. Our effective income tax rates for the years ended December 31, 2012, 2011 and 2010 were 34%, 38% and 40%, respectively. In 2012, the effective income tax rate was reduced by a benefit recorded for research and development tax credits. In 2011, we recorded an income tax benefit due to a pre-tax loss resulting from the impairment of our E. Texas natural gas properties. Our estimated annual effective income tax rate varies from the 35% federal statutory rate primarily due to the effects of state income taxes, domestic production activities deduction, percentage depletion, nondeductible employee compensation, research and development credits and other permanent differences. See Note 4 to the Financial Statements.

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As part of the American Taxpayer Relief Act of 2012, passed on January 2, 2013, the Section 41 research and development tax credit was retroactively extended for the 2012 tax year. As a result, it is possible that we will record a benefit related to the 2012 tax year in 2013.

Financial Condition, Liquidity and Capital Resources.

Our development, exploitation and acquisition activities require us to make significant operating and capital expenditures. Historically, we have used cash flow from operations and borrowings under our credit facility as our primary sources of liquidity. The debt and equity capital markets have served as our primary source of financing to fund large acquisitions and other transactions. Our ability to access the debt and equity capital markets on economical terms is affected by general economic conditions, the financial markets, the credit ratings assigned to our debt by independent credit rating agencies, our operational and financial performance, the value and performance of equity and debt securities, prevailing commodity prices and other macroeconomic factors outside of our control. We have also engaged in asset monetization transactions as a source of financing, as market conditions have permitted. As we pursue profitable reserves and production growth, we continually monitor the capital resources, including the issuance of equity and debt securities, available to us to meet our future financial obligations, planned capital expenditure activity and liquidity.

At December 31, 2012, we had a working capital deficit of approximately $129.6 million. We generally maintain a working capital deficit because we use excess cash to reduce outstanding borrowings under our credit facility. Our working capital fluctuates for various reasons, including changes in the fair value of our commodity derivative instruments.

Changes in the market prices for oil and natural gas directly impact our level of cash flow generated from operations. We employ derivative instruments in our risk management strategy in an attempt to minimize the adverse effects of wide fluctuations in the commodity prices on our cash flows. As of December 31, 2012, we had hedged approximately 60% and 20% of our expected oil production in 2013 and 2014, respectively. This level of derivatives is expected to provide a measure of certainty of the cash flows that we will receive for a portion of our production in 2013 and 2014. In the future, we may increase or decrease our derivative positions. At December 31, 2012, all of our derivatives counterparties were commercial banks that are parties, or affiliates of parties, to our credit facility. See Part II, Item 7A. "Quantitative and Qualitative Disclosures About Market Risk" and Notes 7 and 8 to the Financial Statements for further details about our derivative positions.

Tender Offer and Redemption of Notes. On April 3, 2012, we repurchased $150.0 million aggregate principal amount of our 2014 Notes for an aggregate purchase price of $181.5 million, including accrued and unpaid interest. The 2014 Notes were repurchased using net proceeds from the issuance of $600 million aggregate principal amount of our 6.375% Senior notes due 2022 (2022 Notes).

On April 9, 2012, we redeemed all $200 million aggregate principal amount of our 2016 Notes for an aggregate purchase price of $215.5 million, including accrued and unpaid interest. The 2016 Notes were redeemed using net proceeds from the issuance of our 2022 Notes.

Senior Secured Revolving Credit Facility. On April 13, 2012, as part of the semi-annual borrowing base redetermination process, we entered into a fourth amendment to our credit facility. Among other things, the fourth amendment increased the borrowing base to $1.4 billion. Total lender commitments remained unchanged at $1.2 billion.

Borrowings under our credit facility bear interest at either (i) LIBOR plus a margin between 1.50% and 2.50% or (ii) the prime rate plus a margin between 0.50% and 1.50%, in each case, based on the amount utilized. The annual commitment fee on the unused portion of the credit facility ranges between 0.35% to 0.50% based on the amount utilized.

As of December 31, 2012, outstanding borrowings under the facility were $562.9 million and $23.2 million in outstanding letters of credit, leaving $613.9 million in borrowing capacity available under the credit facility. The maximum amount available under the credit facility is subject to semi-annual redeterminations of the borrowing base in April and October of each year, based on the value of our proved oil and natural gas reserves, in accordance with the lenders' customary procedures and practices. We and the lenders each have a right to one additional redetermination each year. The semi-annual redetermination in October 2012 did not result in any changes to the borrowing base, lender commitments, or other terms of the credit facility.

The credit facility contains certain covenants, which, among other things, require the maintenance of (i) an interest coverage ratio of at least 2.75 to 1.0 and (ii) a minimum current ratio of 1.0 to 1.0. The credit facility also contains other customary covenants, subject to certain agreed exceptions, including covenants restricting our ability to, among other

things, owe or be liable for indebtedness; create, assume or permit to exist liens; be a party to or be liable on any hedging contract; engage in mergers or consolidations; transfer, lease, exchange, alienate or dispose of our material assets or properties; declare dividends on or redeem or repurchase our capital stock; make any acquisitions of, capital contributions to or other investments in any entity or property; extend credit or make advances or loans; engage in transactions with affiliates; and enter into, create or allow to exist contractual obligations limiting our ability to grant liens on our assets to the lenders under the credit facility. As of December 31, 2012, we were in compliance with all financial covenants and have complied with all financial covenants for all prior periods presented.

Subject to certain agreed limitations, we granted first priority security interests over substantially all of our assets in favor of the lenders under the credit facility.

Senior Notes. On March 9, 2012, we issued $600 million aggregate principal amount of our 2022 Notes for net proceeds of $589.5 million. As of December 31, 2012, we had the following senior notes outstanding:

• $205.3 million aggregate principal amount of our 2014 Notes;

• $300.0 million aggregate principal amount of our 2020 Notes; and

• $600.0 million aggregate principal amount of our 2022 Notes.

Our senior notes are senior unsecured obligations, which rank effectively junior to all of our existing and any future secured debt, to the extent of the value of the collateral securing that debt, rank equally in right of payment with other senior unsecured debt, and senior in right of payment to any future subordinated debt. Interest on our senior notes is payable in arrears semi-annually.

The indentures governing our senior notes contain provisions that limit our ability to incur, assume or guarantee additional indebtedness; issue redeemable stock and preferred stock; pay dividends or distributions or redeem or repurchase capital stock; prepay, redeem or repurchase debt that is junior in right of payment to our senior and subordinated notes; make loans and other types of investments; incur liens; restrict dividends, loans or asset transfers from our subsidiaries; sell or otherwise dispose of assets, including capital stock of subsidiaries; consolidate or merge with or into, or sell substantially all of our assets to, another person; enter into transactions with affiliates; and enter into new lines of business. Upon specified change in control events, we will be required to make offers to repurchase our senior notes at amounts specified in the indentures governing such notes.

We may from time to time seek to repurchase our outstanding notes, through open market purchases, privately negotiated transactions or otherwise. Such repurchases, if any, will depend on prevailing market conditions, our liquidity requirements, contractual restrictions and other factors. The amounts repurchased may be material.

Credit Ratings. Our credit risk is evaluated by two independent rating agencies based on publicly available information and information obtained during our ongoing discussions with the rating agencies. Moody's Investor Services and Standard & Poor's Rating Services currently rate our outstanding notes and have assigned us a credit rating. We do not have any provisions that are linked to our credit ratings, nor do we have any credit rating triggers that would accelerate the maturity of amounts due under our currently outstanding debt. However, our ability to raise funds and the costs of any financing activities will be affected by our credit rating at the time any such financing activities are conducted.

Historical Cash Flows.

Year Ended December 31,

(in thousands)	2012	2011	2010
Net cash provided by operating activities	$ 501,439	$ 455,899	$ 367,237
Net cash used in investing activities	(758,172)	(711,019)	(672,869)
Net cash provided by financing activities	256,747	255,140	300,599
Net increase (decrease) in cash and cash equivalents	$ 14	$ 20	$ (5,033)

Operating Activities. Cash flows provided by operating activities are primarily affected by the price of oil and natural gas, sales volumes and changes in working capital. The increase in net cash provided by operating activities of $45.5 million in 2012 compared to 2011 was primarily due to a 6% increase in our average realized sales price, largely as a result

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of an increase in oil sales volumes as a percentage of total sales volumes in 2012 compared to 2011. The increase in net cash provided by operating activities of $88.7 million in 2011 compared to 2010 was primarily due to a 28% increase in average commodity sales prices and a 10% increase in sales volume.

Investing Activities. Cash flows used by investing activities are primarily comprised of development, exploitation and acquisition of oil and natural gas properties net of dispositions of oil and natural gas properties. The increase in net cash used in investing activities of $47.2 million in 2012 compared to 2011 was due to an increase in development activities, partially offset by decreases in acquisition activities and capitalized interest, as well as proceeds from the sale of our Nevada Assets. The increase in net cash used in investing activities of $38.2 million in 2011 compared to 2010 was due to an increase in development activities offset by a decrease in expenditures for property acquisitions in 2011 as compared with 2010.

Financing Activities. Net cash provided by financing activities in 2012 included net proceeds of $589.5 million from the issuance of $600 million aggregate principal amount of our 2022 Notes and net borrowings of $31.4 million of borrowings under our credit facility, partially offset by the repurchase of $150 million aggregate principal amount of our 2014 Notes and the repurchase of all $200 million aggregate principal amount of our 2016 Notes. Net cash provided by financing activities in 2011 included net borrowings under our credit facility of $361.5 million, partially offset by the repurchase of $94.7 million aggregate principal amount of our 2014 Notes. Net cash provided by financing activities in 2010 included net proceeds of $224.0 million from the issuance of 8 million shares of our Class A Common Stock and $300.0 million aggregate principal amount of our 2020 Notes, partially offset by debt issuance costs of $15.2 million and net repayment of our outstanding borrowings under our credit facility and our money market line of credit of $196.7 million.

Capital Expenditures.

The following is a summary of the drilling and development capital expenditures:

(in thousands)	Year Ended December 31,		
Asset Team	2012	2011	2010
SMWSS—Steam Floods	$51,000	$47,000	$45,000
NMWSS—Diatomite	85,000	105,000	42,000
NMWSS—New Steam Floods	104,000	51,000	15,000
Permian	272,000	218,000	42,000
Uinta	155,000	63,000	50,000
E. Texas	1,000	11,000	71,000
Piceance	5,000	31,000	45,000
Corporate	3,000	1,000	—
Total	$676,000	$527,000	$310,000

We continually evaluate our capital needs and compare them to our capital resources. We establish a capital budget for each calendar year based on our development opportunities and the expected cash flow from operations for that year. We may revise our capital budget during the year as a result of acquisitions and/or drilling outcomes or significant changes in cash flows. To the extent net cash provided by operating activities is higher or lower than currently anticipated, we may adjust our capital budget accordingly or adjust borrowings under our credit facility, as needed.

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Contractual Obligations.

Our contractual obligations as of December 31, 2012 are as follows:

(in millions)	Total	2013	2014	2015	2016	2017	Thereafter
Long-term debt and interest(1)	$2,306.5	$91.1	$284.0	$70.0	$625.6	$58.5	$1,177.3
Asset retirement obligations(2)	86.7	4.4	3.3	3.3	3.2	3.1	69.4
Operating leases(3)	18.0	5.1	5.3	3.6	2.9	1.1	—
Other commitments (4)	23.5	16.2	2.9	2.3	2.1	—	—
Drilling rig commitments(5)	9.4	9.4	—	—	—	—	—
Firm natural gas transportation contracts(6)	245.1	31.0	33.7	33.4	33.5	33.4	80.1
Derivative liabilities(7)	2.4	1.1	0.8	0.5	—	—	—
Total	$2,691.6	$158.3	$330.0	$113.1	$667.3	$96.1	$1,326.8

(1) Long-term debt consists of our 2014 Notes, 2020 Notes, 2022 Notes and outstanding debt under our credit facility, and assumes no principal repayment until the due date of the instruments. Cash interest expense on our credit facility is estimated assuming no principal repayment until the instrument due date and is estimated at a constant interest rate of 2.046%.

(2) The ultimate settlement amounts and the timing of the settlement of such obligations are unknown because they are subject to, among other things, federal, state, local and tribal regulation and economic factors. See Part II, Item 7. "Critical Accounting Policies and Estimates" for a more detailed discussion of the nature of the accounting estimates involved in estimating asset retirement obligations.

(3) Operating leases relate primarily to obligations associated with our office facilities, equipment, vehicles, rail cars and aircraft.

(4) Other commitments relate primarily to natural gas purchases, cogeneration facility management services, California carbon allowance forward purchase contracts and equipment rentals.

(5) We currently have seven drilling rigs under contract that require minimum payments for the full contract term or penalties upon early termination. All these drilling rig contracts expire in 2013. Contracts for all other rigs performing work for us at December 31, 2012 were on a well-by-well basis and could be released without penalty at the conclusion of drilling on the current well, and therefore have not been included in the table above.

(6) We enter into certain firm commitments to transport natural gas production to market and to transport natural gas for use in our cogeneration and conventional steam generation facilities. The remaining terms on these contracts range from one to ten years and require a minimum monthly charge regardless of whether the contracted capacity is used or not.

(7) Derivative liabilities represent the fair value of our derivatives presented as net liabilities in our Balance Sheets as of December 31, 2012. These amounts represent open commodity derivative instruments that were in a current or non-current net liability position with the counterparty at December 31, 2012. Our remaining commodity derivative instruments were in a current or non-current net asset position with the counterparty at December 31, 2012. The ultimate settlement amounts of our derivative liabilities are unknown because they are subject to continuing market fluctuations. See Notes 7 and 8 to the Financial Statements. Also, See Part II, Item 7A. "Quantitative and Qualitative Disclosures About Market Risk" for further details concerning our derivative activities.

Based on current oil and natural gas prices and anticipated levels of production, we believe that we have sufficient liquidity and capital resources to execute our business plans over the next 12 months and for the foreseeable future. In addition, with our expected cash flow streams, commodity price hedging strategies, current liquidity levels, access to debt and equity markets and flexibility to modify future capital expenditure programs, we expect to be able to fund all planned capital programs, dividend distributions and debt repayments while complying with our debt covenants and

meeting any other obligations that may arise from our oil and natural gas operations. However, if our revenue and cash flow decrease in the future as a result of a deterioration in domestic and global economic conditions or a significant decline in commodity prices, we may elect to reduce our planned capital expenditures. We believe that this financial flexibility to adjust our spending levels will provide us with sufficient liquidity to meet our financial obligations. See Part I, Item 1A—"Risk Factors," for a discussion of the risks and uncertainties that affect our financial condition, results of operations and operating cash flows.

Critical Accounting Policies and Estimates.

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make certain assumptions and estimates that affect the reported amounts of assets, liabilities, revenues and expenses and to disclose contingent assets and liabilities at the date of our Financial Statements. We base our assumptions on historical experience and other sources that we believe to be reasonable at the time. Actual results may vary from our estimates due to changes in circumstances, weather, politics, global economics, mechanical problems, general business conditions and other factors. A summary of our significant accounting policies is detailed in Note 1 to our Financial Statements. We have outlined below certain of these policies as being of particular importance to the portrayal of our financial position and results of operations and which require the application of significant judgment by management.

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Successful Efforts Method of Accounting. We account for our oil and natural gas exploration and development costs using the successful efforts method. Under this method, the fair value of property acquired and all costs associated with successful exploratory wells and all development wells are capitalized. Items charged to expense generally include geological and geophysical costs, costs of unsuccessful exploratory wells and oil and gas production costs.

Impairment of Oil and Natural Gas Properties. Proved oil and natural gas properties are reviewed for impairment when events and circumstances indicate a possible decline in the recoverability of the carrying amount of such property. We estimate the expected future cash flows of our oil and natural gas properties and compare these undiscounted 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 write down the carrying amount of the oil and natural gas properties to fair value. The factors used to determine fair value include, but are not limited to, estimates of reserves, future commodity prices, future production estimates, estimated future capital expenditures and discount rates commensurate with the risk associated with realizing the projected cash flows.

Unproved oil and natural gas properties are periodically assessed for impairment on a project-by-project basis. The impairment assessment is affected by the results of exploration activities, commodity price outlooks, planned future sales or expiration of all or a portion of such projects. If the quantity of potential reserves determined by such evaluations is not sufficient to fully recover the cost invested in each project, we will recognize an impairment loss at that time.

Oil and Natural Gas Reserves. Estimated proved reserves included in this Annual Report on Form 10-K were prepared by DeGolyer and MacNaughton (D&M), an independent petroleum engineering consulting firm that has provided consulting services throughout the world for over 70 years. There are numerous uncertainties inherent in estimating quantities of proved reserves, including many factors beyond our control. Reserve engineering is a process of estimating subsurface accumulations of oil and natural gas that cannot be measured in an exact manner, and the accuracy of any reserve estimate is a function of the quality of available data and its interpretation. As a result, estimates by different engineers often vary, sometimes significantly. In addition to the physical factors such as the results of drilling, testing and production subsequent to the date of an estimate, economic factors such as changes in commodity prices or development and production expenses, may require revision of such estimates. Accordingly, oil and natural gas quantities ultimately recovered will vary from reserve estimates. See Part I, Item 1A—"Risk Factors," for a description of some of the risks and uncertainties associated with our business and reserves.

DD&A—Oil and Natural Gas Production. Our rate of recording DD&A—oil and natural gas production is dependent upon our estimates of total proved and proved developed reserves, which estimates incorporate various assumptions and future projections. If the estimates of total proved or proved developed reserves decline, the rate at which we record DD&A—oil and natural gas production expense increases, which in turn reduces our net income. Such a decline in reserves may result from lower commodity prices, which may make it uneconomic to drill for and produce higher cost fields. We are unable to predict changes in reserve quantity estimates as such quantities are dependent on the success of our exploitation and development program, as well as future economic conditions.

Capitalized Interest. Acquisition costs of proved undeveloped and unproved properties qualify for interest capitalization during a period if interest cost is incurred and activities necessary to bring the properties into a productive state are in progress. As wells are drilled in a field with proved undeveloped or unproved reserves, a portion of the acquisition costs are either re-designated as proved developed or expensed, as appropriate. In fields with multiple potential drilling sites, we determine the amount of the acquisition cost to re-designate or expense through a systematic and rational basis that considers the total expected wells to be drilled in that field.

Valuations of Business Combinations. In connection with a purchase business combination, the assets and liabilities acquired are measured at their fair values, and the purchase price is allocated to the assets and liabilities based upon these fair values. The excess of the cost of an acquired entity, if any, over the net amounts assigned to assets acquired and liabilities assumed is recognized as goodwill. The excess of the fair value of assets acquired and liabilities assumed over the cost of an acquired entity, if any, is recognized immediately to earnings as a gain from bargain purchase.

In estimating the fair values of assets acquired and liabilities assumed in a business combination, we make various assumptions. The most significant assumptions relate to the estimated fair values assigned to proved and unproved oil and natural gas properties. Due to the unavailability of relevant comparable market data, a discounted cash flow method is used to determine the fair value of proved properties. The discounted cash flow method estimates future cash flows based on management's expectations of future recoverable proved and risk-adjusted probable reserves, commodity prices based on commodity futures price strips, production timing, drilling and production costs and a risk-adjusted discount rate.

Estimated fair values assigned to assets acquired can have a significant effect on results of operations in the future. A higher fair value assigned to a property results in higher DD&A—oil and natural gas production, which results in lower net earnings. Fair values are based on estimates of future commodity prices, reserves quantities, operating expenses and development costs. The likelihood of impairment increases if future commodity prices or reserves quantities are lower than those originally used to determine fair value or if future operating expenses or development costs are higher than those originally used to determine fair value. Impairment would have no effect on cash flows but would result in a decrease in net income for the period in which the impairment is recorded.

Derivatives and Hedging. We periodically enter into commodity derivative contracts to manage our exposure to oil and natural gas price volatility. All derivative instruments are recorded on the Balance Sheets at fair value, other than the derivative instruments that meet the “normal purchase normal sales” exclusion. If hedge accounting is not elected, changes in fair value are recognized immediately in earnings. We have elected not to use hedge accounting for our derivative instruments and, as a result, all changes in the fair values of our derivative instruments are recognized immediately in earnings under the caption realized and unrealized (gain) loss on derivatives, net.

We value our derivative instruments using industry-standard models that consider various assumptions, including quoted forward prices for commodities, time value, volatility factors and contractual prices for the underlying instruments, as well as other relevant economic measures. The discount rate used in the fair values of these instruments includes a measure of nonperformance risk by the counterparty or us, as appropriate. We utilize the counterparties’ valuations to assess the reasonableness of our valuations. The values we report in our Financial Statements change as these estimates are revised to reflect changes in market conditions (particularly those for oil and natural gas futures), actual results, or other factors, many of which are beyond our control.

Due to the volatility of oil and natural gas prices, the estimated fair values of our derivative instruments are subject to large fluctuations from period to period. See Part II, Item 7A—"Quantitative and Qualitative Disclosures about Market Risk" for a sensitivity analysis of the change in net fair values of our commodity derivatives based on a hypothetical change in commodity prices.

Income Taxes and Uncertain Tax Positions. Income taxes are recorded for the income tax effects of transactions reported in the financial statements and consist of income taxes currently payable plus deferred income taxes related to certain income and expenses recognized in different periods for financial and income tax reporting purposes. Deferred income taxes are also recognized for income tax credits that are available to offset future income taxes. Deferred income taxes are measured by applying currently enacted income tax rates to the differences between the financial statements and income tax reporting. We routinely assess the realizability of our deferred income tax assets, and we recognize a valuation allowance if we determine that deferred income tax assets may not be fully utilized in future periods. We consider future taxable earnings in making such assessments. Numerous judgments and assumptions are inherent in the determination of future taxable earnings, including factors such as future operating conditions (particularly as related to prevailing oil and natural gas prices). There can be no assurance that facts and circumstances will not materially change and require us to establish deferred income tax asset valuation allowances in a future period. We are subject to taxation in many jurisdictions, and the calculation of our income tax liabilities involves dealing with uncertainties in the application of complex income tax laws and regulations in various taxing jurisdictions. We recognize liabilities for certain income tax positions that meet a more-likely-than not recognition threshold. If we ultimately determine that the payment of these liabilities will be unnecessary, we will reverse the liability and recognize an income tax benefit during the period in which we determine the liability no longer applies.

Asset Retirement Obligations. Our asset retirement obligations (AROs) relate to future costs associated with the plugging and abandonment of oil and natural gas wells, removal of equipment facilities from leased acreage and land restoration in accordance with applicable local, state and federal laws. The discounted fair value of an ARO liability is

required to be recognized in the period in which it is incurred, with the associated asset retirement cost capitalized as part of the carrying cost of the oil and natural gas asset. The recognition of the ARO requires that management make numerous assumptions regarding such factors as the estimated probabilities; amounts and timing of settlements; the credit-adjusted-risk-free rate to be used; inflation rates; and future advances in technology. In periods subsequent to the initial measurement of the ARO, we must recognize period-to-period changes in the liability resulting from the passage of time and revisions to either the timing or the amount of the original estimate of undiscounted cash flows. Increases in the ARO liability due to the passage of time impact net earnings as accretion expense. The related capital cost, including revisions thereto, is charged to expense through DD&A—oil and natural gas production over the life of the oil and natural gas field.

Electricity Cost Allocation. Our investment in our cogeneration facilities has been for the express purpose of lowering steam costs in our California heavy oil operations and securing operating control of the respective steam generation. Such cogeneration operations produce electricity and steam and use natural gas as fuel. We allocate steam costs to our oil and natural

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gas operating costs based on the conversion efficiency (of fuel to electricity and steam) of the cogeneration facilities plus certain direct costs in producing steam. Electricity revenue represents sales to the utilities. A portion of the capital costs of the cogeneration facilities is allocated to DD&A—oil and natural gas production.

Environmental Remediation Liability. We review, on a quarterly basis, our estimates of costs of the cleanup of various sites including sites in which governmental agencies have designated us as a potentially responsible party. When it is probable that obligations have been incurred and where a minimum cost or a reasonable estimate of the cost of remediation can be determined, the applicable amount is accrued. Determining when expenses should be recorded for these contingencies and the appropriate amounts for accrual is an estimation process that includes the judgment of management. In many cases, management's judgment is based on the advice and opinions of legal counsel and other advisers and the interpretation of laws and regulations, which can be interpreted differently by regulators or courts of law. Our experience and the experience of other companies in dealing with similar matters influence the decision of management as to how it intends to respond to a particular matter. A change in estimate could impact our oil and natural gas operating costs and the related liability, if applicable, recorded on our Balance Sheets.

Recently Issued Accounting Standard Updates.

For further information on the effects of recently adopted accounting pronouncements and the potential effects of new accounting pronouncements, see Note 1 to the Financial Statements.

Reconciliation of Non-GAAP Measures.

Discretionary Cash Flow. Discretionary cash flow consists of cash provided by operating activities before changes in working capital items. Management uses discretionary cash flow as a measure of liquidity and believes it provides useful information to investors because it assesses cash flow from operations for each period before changes in working capital, which fluctuates due to the timing of collections of receivables and the settlements of liabilities. The following table provides a reconciliation of discretionary cash flow to cash provided by operating activities, the most directly comparable GAAP measure, for the periods presented.

	Year Ended December 31:		
(in thousands)	2012	2011	2010
Net cash provided by operating activities	$501,439	$455,899	$367,237
Net increase (decrease) in current assets	12,943	26,294	(12,502)
Net increase in current liabilities including book overdraft	(32,677)	(20,302)	(12,681)
Cash premiums for repurchases of notes	34,700	—	—
Cash settlements from early termination of natural gas derivatives	(14,700)	—	—
Cash settlements from early termination of interest rate derivatives	—	—	10,800
Recovery of Flying J bad debt	—	—	38,500
Discretionary cash flow	$501,705	$461,891	$391,354

Operating Margin per BOE. Operating margin per barrel consists of oil and natural gas revenues less oil and natural gas operating expenses and production taxes divided by the total BOEs produced during the period. Management uses operating margin per barrel as a measure of profitability and believes it provides useful information to investors because it relates our oil and natural gas revenue and oil and natural gas operating expenses to our total units of production providing a gross margin per unit of production, allowing investors to evaluate how our profitability varies on a per unit basis each period.

Year Ended December 31:

(per BOE)	2012	2011	2010
Average sales price including cash derivative settlements	$72.18	$65.68	$53.84
Average operating costs—oil and natural gas production	20.43	18.22	15.92
Average production taxes	2.96	2.58	1.93
Average operating margin	$48.79	$44.88	$35.99

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Item 7A. Quantitative and Qualitative Disclosures About Market Risk

Our primary market risk exposure is the commodity pricing applicable to our oil and gas production. Crude oil and natural gas are commodities; therefore, their prices are subject to wide fluctuations in response to relatively minor changes in supply and demand. The prices that we receive for our production or pay to purchase natural gas used to generate steam in California depend on numerous factors outside our control. In order to reduce the impact of fluctuations in commodity prices, or to ensure adequate cash flow to fund our development plans and to manage returns on acquisitions and our drilling program, we make use of a commodity hedging strategy. The amount of commodity derivatives that we enter into depend on various factors, including management's view of future crude oil and natural gas prices, our future financial commitments, as well as considerations of other factors.

Currently, our derivatives are primarily in the form of three-way costless collars. However, we may use a variety of derivative instruments in the future to hedge WTI or other oil or natural gas price indices. A three-way collar is a combination of three options. The base structure is a normal collar. A short option is added to fund the improvement of the long strike in the base collar. For oil sales three-way collars, a purchased put and a sold call comprise the base collar. A sold put below is added to fund the raising of the strike on the purchased put. The purchased put establishes a minimum price unless the market price falls below the sold put, at which point the minimum price would be NYMEX plus the difference between the purchased put and the sold put strike price. The sold call establishes a maximum price (the ceiling) we will receive for the volumes under contract. For natural gas purchase three-way collars, a purchased call and a sold put comprise the base collar. A sold call above is added to fund the lowering of the strike on the purchased call. The purchased call establishes a maximum price unless the market price rises above the sold call, at which point the maximum price would be NYMEX plus the difference between the purchased call and the sold call strike price. The sold put establishes a minimum price (the floor) we will pay for the volumes under contract.

As of December 31, 2012, we had approximately 60% and 20% of our expected 2013 and 2014 oil production, respectively, hedged. A hypothetical $10 increase in the oil prices used and $1 increase in the natural gas prices used to calculate the fair values of our derivative instruments at December 31, 2012 would decrease the fair value of our crude oil derivative instruments by $65.9 million and would increase the fair value of our natural gas derivative instruments by $2.2 million. A hypothetical $10 decrease in the oil prices used and $1 decrease in the natural gas prices used to calculate the fair values of our derivative instruments at December 31, 2012 would increase the fair value of our crude oil derivative instruments by $59.6 million and would decrease the fair value of our natural gas derivative instruments by $1.5 million.

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The following table summarizes our commodity hedge positions as of December 31, 2012:

Term	Average Barrels Per Day	Sold Put / Purchased Put / Sold Call
Crude Oil Sales (NYMEX WTI) Three-Way Collars		
Full year 2013	1,000	$65.00/$85.00/$95.00
Full year 2013	1,000	$65.00/$85.00/$97.25
Full year 2013	1,000	$70.00/$87.00/$105.00
Full year 2013	1,000	$70.00/$88.00/$106.00
Full year 2013	1,000	$60.00/$80.00/$103.30
Full year 2013	1,000	$70.00/$88.15/$100.00
Full year 2013	1,000	$70.00/$86.85/$100.00
Full year 2013	1,000	$69.70/$85.00/$100.00
Full year 2013	1,000	$70.00/$87.00/$108.50
Full year 2013	1,000	$70.00/$90.00/$116.50
Full year 2013	1,000	$70.00/$95.00/$120.10
Full year 2013	500	$70.00/$90.00/$100.00
Full year 2013	500	$70.00/$90.00/$100.00
Full year 2013	1,000	$75.00/$90.00/$101.85
Full year 2013	800	$75.00/$95.00/$101.70
Full year 2013 and 2014	1,000	$70.00/$90.00/$100.00
Full year 2013 and 2014	1,000	$70.00/$90.00/$120.00
Full year 2013 and 2014	1,000	$77.95/$105.00/$115.00
Full year 2013 and 2014	1,000	$80.00/$107.00/$119.60
Full year 2014	1,000	$70.00/$90.00/$121.80
Full year 2014	1,500	$70.00/$90.00/$100.00
Full year 2014 and 2015	1,000	$70.00/$90.00/$104.85
Full year 2015	2,000	$70.00/$90.00/$100.00
Crude Oil Sales (ICE Brent) Three-Way Collars		
Full Year 2013	1,000	$80.00/$100.00/$115.00

Term	Average MMBtu/D or MMTCDE	Average Prices
Natural Gas Purchases (NYMEX SoCal Border) Purchased Calls		
Full year 2013	5,000	$3.50
Natural Gas Purchases (NYMEX SoCal Border) Three-Way Collars		
Full year 2013	1,000	$2.90 / $4.00 / $5.00
Full year 2013	1,000	$2.96 / $4.25 / $5.25
Full year 2013	1,000	$2.70 / $4.00 / $5.00
Full year 2013	2,000	$3.03 / $4.25 / $5.25

Excluded from the table above are our calendar month average swaps, which protect us from variances in market pricing conditions of certain of our sales contracts. These derivative contracts protect 5,000 BOE/D of our Permian sales volumes and have differentials of $0.070 to $0.075 during 2013.

Interest Rate Risk

Our credit facility allows us to fix the interest rate for all or a portion of the principal balance for a period up to 12 months. To the extent the interest rate is fixed, interest rate changes affect the instrument's fair market value but do not impact results of operations or cash flows. Conversely, for the portion of the credit facility that has a floating interest rate, interest rate changes will not affect the fair market value but will impact future results of operations and cash flows. Changes in interest rates do not affect the amount of interest we pay on our fixed-rate debt. At December 31, 2012, our outstanding principal balance under our credit facility was $562.9 million and the weighted average interest rate on the outstanding principal balance was 2.046%. At December 31, 2012, the carrying amount approximated fair market value. Market risk is estimated as the change in fair value resulting from a hypothetical 100 basis point change in the interest rate on the outstanding balance under our credit facility. Assuming a constant debt

level of $1.7 billion, the cash flow impact resulting from a 100 basis point change in interest rates during periods when the interest rate is not fixed would be $3.7 million over a 12-month time period.

Item 8. Financial Statements and Supplementary Data

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Financial statement schedules have been omitted since they are either not required, are not applicable, or the required information is shown in the Financial Statements and related notes.

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of Berry Petroleum Company:

In our opinion, the financial statements listed in the accompanying index present fairly, in all material respects, the financial position of Berry Petroleum Company at December 31, 2012, and 2011, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2012 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2012, based on criteria established in Internal Control - Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in Management's Report on Internal Control over Financial Reporting appearing under Item 9A. Our responsibility is to express opinions on these financial statements and on the Company's internal control over financial reporting based on our integrated 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 audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ PricewaterhouseCoopers LLP

Denver, Colorado
February 28, 2013

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BERRY PETROLEUM COMPANY
Balance Sheets
December 31, 2012 and 2011
(In Thousands, Except Share Data)

	2012	2011
ASSETS		
Current assets:		
Cash and cash equivalents	$312	$298
Short-term investments	125	65
Accounts receivable	122,159	115,952
Deferred income taxes	703	13,779
Derivative instruments	14,661	6,117
Assets held for sale	—	14,622
Prepaid expenses and other	19,065	16,801
Total current assets	157,025	167,634
Oil and natural gas properties (successful efforts basis), buildings and equipment, net	3,128,502	2,531,393
Derivative instruments	10,891	7,027
Other assets	28,984	28,898
	$3,325,402	$2,734,952
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$175,893	$126,489
Revenue and royalties payable	57,021	49,253
Accrued liabilities	51,151	39,829
Derivative instruments	1,111	20,365
Deferred income taxes	1,456	—
Total current liabilities	286,632	235,936
Long-term liabilities:		
Deferred income taxes	255,471	185,450
Senior secured revolving credit facility	562,900	531,500
8.25% Senior subordinated notes due 2016	—	200,000
10.25% Senior notes due 2014, net of unamortized discount of $2,340 and $6,564, respectively	202,917	348,692
6.75% Senior notes due 2020	300,000	300,000
6.375% Senior notes due 2022	600,000	—
Asset retirement obligations	82,316	59,256
Derivative instruments	1,239	15,505
Other long-term liabilities	19,136	17,884
	2,023,979	1,658,287
Commitments and contingencies (Note 10)		
Shareholders' equity:		
Preferred stock, $0.01 par value, 2,000,000 shares authorized; no shares outstanding	—	—
Capital stock, $0.01 par value:		
Class A Common Stock, 100,000,000 shares authorized; 52,428,423 and 52,067,994 shares issued and outstanding, respectively	524	521
Class B Stock, 3,000,000 shares authorized; 1,763,866 and 1,797,784 shares issued and outstanding, respectively (liquidation preference of $0.50 per share)	18	18
Capital in excess of par value	364,710	350,158

Accumulated other comprehensive loss	—	(5,517)
Retained earnings	649,539	495,549
Total shareholders' equity	1,014,791	840,729
	$3,325,402	$2,734,952

The accompanying notes are an integral part of these Financial Statements.

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BERRY PETROLEUM COMPANY
Statements of Operations
Years ended December 31, 2012, 2011 and 2010
(In Thousands, Except Per Share Data)

	2012	2011	2010
REVENUES			
Oil and natural gas sales	$937,261	$870,773	$619,608
Electricity sales	29,940	34,953	34,740
Natural gas marketing	7,631	13,832	22,162
Gain on sale of assets	1,782	—	—
Settlement of Flying J bankruptcy claim	—	—	21,992
Interest and other income, net	1,985	1,784	3,300
	978,599	921,342	701,802
EXPENSES			
Operating costs—oil and natural gas production	272,180	237,296	189,809
Operating costs—electricity generation	19,975	25,690	31,295
Production taxes	39,374	33,617	22,999
Depreciation, depletion & amortization—oil and natural gas production	225,892	213,859	179,432
Depreciation, depletion & amortization—electricity generation	1,808	1,963	3,225
Natural gas marketing	6,873	13,038	19,896
General and administrative	71,766	61,727	52,846
Interest	83,136	72,807	66,541
Dry hole, abandonment, impairment and exploration	20,931	5,482	2,720
Impairment of oil and natural gas properties	79	625,564	—
Extinguishment of debt	41,545	15,544	573
Realized and unrealized (gain) loss on derivatives, net	(64,620)	(13,908)	31,847
Gain on purchase	—	(1,046)	—
Transaction costs on acquisitions	—	—	2,635
Bad debt recovery	—	—	(38,508)
	718,939	1,291,633	565,310
Earnings before income taxes	259,660	(370,291)	136,492
Income tax provision (benefit)	88,121	(142,228)	53,968
Net earnings (loss)	$171,539	$(228,063)	$82,524
Basic net earnings (loss) per share	$3.11	$(4.21)	$1.54
Diluted net earnings (loss) per share	$3.09	$(4.21)	$1.52
Dividends per share	$0.32	$0.31	$0.30

The accompanying notes are an integral part of these Financial Statements.

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BERRY PETROLEUM COMPANY
Statements of Comprehensive Earnings (Loss)
Years ended December 31, 2012, 2011 and 2010
(In Thousands)

	Year Ended December 31,		
	2012	2011	2010
Net earnings (loss)	$171,539	$(228,063)	$82,524
Other comprehensive earnings, net of income taxes:			
Amortization of accumulated other comprehensive loss related to de-designated hedges, net of income tax benefits of $3,382, $23,467 and $10,153, respectively	5,517	38,289	16,566
Other comprehensive earnings	$5,517	$38,289	$16,566
Comprehensive earnings (loss)	$177,056	$(189,774)	$99,090

The accompanying notes are an integral part of these Financial Statements.

BERRY PETROLEUM COMPANY
Statements of Shareholders' Equity
Years Ended December 31, 2012, 2011 and 2010
(In Thousands)

	Class A	Class B	Capital in Excess of Par Value	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total Shareholders' Equity
Balances at January 1, 2010	$430	$18	$89,068	$674,115	$ (60,372)	$703,259
Issuance of stock	80	—	224,233			224,313
Stock options and restricted stock issued	4	—	4,398	—	—	4,402
Stock based compensation expense	—	—	9,386	—	—	9,386
Income tax effect of stock option exercises	—	—	284	—	—	284
Dividends ($0.30 per share)	—	—	—	(16,181)	—	(16,181)
Net earnings	—	—	—	82,524	—	82,524
Amortization of accumulated other comprehensive loss related to de-designated hedges, net of income taxes	—	—	—	—	16,566	16,566
Balances at December 31, 2010	514	18	327,369	740,458	(43,806)	1,024,553
Stock options and restricted stock issued	7	—	10,106	—	—	10,113
Stock based compensation expense	—	—	9,636	—	—	9,636
Income tax effect of stock option exercises	—	—	3,047	—	—	3,047
Dividends ($0.31 per share)	—	—	—	(16,846)	—	(16,846)
Net loss	—	—	—	(228,063)	—	(228,063)
Amortization of accumulated other comprehensive loss related to de-designated hedges, net of	—	—	—	—	38,289	38,289

income taxes						
Balances at December 31, 2011	521	18	350,158	495,549	(5,517)	840,729
Stock options and restricted stock issued	3	—	3,684	—	—	3,687
Stock based compensation expense	—	—	9,819	—	—	9,819
Income tax effect of stock option exercises	—	—	1,049	—	—	1,049
Dividends ($0.32 per share)	—	—	—	(17,549)	—	(17,549)
Net earnings	—	—	—	171,539	—	171,539
Amortization of accumulated other comprehensive loss related to de-designated hedges, net of income taxes	—	—	—	—	5,517	5,517
Balances at December 31, 2012	$524	$18	$364,710	$649,539	$ —	$1,014,791

The accompanying notes are an integral part of these Financial Statements.

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BERRY PETROLEUM COMPANY
Statements of Cash Flows
Years Ended December 31, 2012, 2011 and 2010
(In Thousands)

	2012	2011	2010
Cash flows from operating activities:			
Net earnings (loss)	$171,539	$(228,063)	$82,524
Depreciation, depletion and amortization	227,700	215,822	182,657
Gain on purchase	—	(1,046)	—
Gain on sale of assets	(1,782)	—	—
Extinguishment of debt	6,842	4,072	573
Amortization of debt issuance costs and net discount	7,031	8,243	8,481
Impairment of oil and natural gas properties	79	625,564	—
Dry hole and impairment	14,945	4,616	1,478
Derivatives	(36,135)	(29,094)	42,609
Stock-based compensation expense	9,819	9,636	9,386
Deferred income taxes	82,881	(149,279)	54,698
Other, net	(1,628)	1,420	(1,844)
Allowance for bad debt	414	—	—
Bad debt recovery	—	—	(38,508)
Change in book overdraft	(1,220)	(156)	528
Changes in operating assets and liabilities:			
Accounts receivable	(6,740)	(23,526)	20,055
Inventories, prepaid expenses and other current assets	(6,203)	(2,768)	(7,553)
Accounts payable and revenue and royalties payable	19,967	25,019	5,273
Accrued interest and other accrued liabilities	13,930	(4,561)	6,880
Net cash provided by operating activities	501,439	455,899	367,237
Cash flows from investing activities:			
Development and exploration of oil and natural gas properties	(675,951)	(527,112)	(310,139)
Property acquisitions	(78,313)	(158,090)	(334,409)
Capitalized interest	(17,915)	(29,117)	(28,321)
Proceeds from sale of assets	17,307	—	—
Deposits on asset sales	(3,300)	3,300	—
Net cash used in investing activities	(758,172)	(711,019)	(672,869)
Cash flows from financing activities:			
Proceeds from issuances on line of credit	—	406,600	316,000
Repayments of borrowings under line of credit	—	(411,900)	(310,700)
Proceeds from issuance of 6.375% senior notes due 2022	600,000	—	—
Proceeds from issuance of 10.25% senior notes due 2014	—	—	300,000
Repurchase of 8.25% Senior subordinated notes due 2016	(200,000)	—	—
Repurchase of 10.25% senior notes due 2014	(149,999)	(94,744)	—
Long-term borrowings under credit facility	1,467,200	719,700	363,000
Repayments of long-term borrowings under credit facility	(1,435,800)	(358,200)	(565,000)
Financing obligation	(417)	(380)	(346)
Debt issuance costs	(11,424)	(2,250)	(15,173)
Dividends paid	(17,549)	(16,846)	(16,181)
Proceeds from issuance of stock	—	—	224,313
Proceeds from stock option exercises	3,687	10,113	4,402

Excess income tax benefit	1,049	3,047	284
Net cash provided by financing activities	256,747	255,140	300,599
Net increase (decrease) in cash and cash equivalents	14	20	(5,033)
Cash and cash equivalents at beginning of year	298	278	5,311
Cash and cash equivalents at end of year	$312	$298	$278
Supplemental disclosures of cash flow information:			
Interest paid, net of capitalized interest	$64,602	$59,853	$40,773
Income taxes paid	4,227	7,914	697
Noncash investing activities:			
Accrued capital expenditures	$98,020	$61,098	$51,095
Asset retirement obligations	18,248	7,448	3,721

The accompanying notes are an integral part of these Financial Statements.

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BERRY PETROLEUM COMPANY
Notes to the Financial Statements

1. Summary of Significant Accounting Policies

Description of the Business

Berry Petroleum Company (the Company) is an independent energy company engaged in the production, development, exploitation and acquisition of oil and natural gas. The Company has invested in cogeneration facilities, which provide steam required for the extraction of heavy oil and which generate electricity for sale.

Basis of Presentation

These statements have been prepared in accordance with accounting principles generally accepted in the United States of America (GAAP). Certain amounts in prior years' financial statements have been reclassified to conform to the 2012 financial statement presentation. In the 2011 Balance Sheets, $4.8 million was reclassified from asset retirement obligations (ARO) to accrued liabilities in order to conform to current and non-current presentation of ARO in the 2012 Balance Sheets.

Assumptions, Judgments and Estimates

In the course of preparing the Financial Statements, management makes various assumptions, judgments and estimates to determine the reported amounts of assets, liabilities, revenues and expenses, and in the disclosures of commitments and contingencies. Changes in these assumptions, judgments, and estimates will occur as a result of the passage of time and the occurrence of future events and, accordingly, actual results could differ from amounts previously established.

The more significant areas requiring the use of assumptions, judgments and estimates include: (1) oil and natural gas reserves; (2) cash flow estimates used in impairment tests of long-lived assets; (3) depreciation, depletion and amortization; (4) asset retirement obligations; (5) assigning fair value and allocating purchase price in connection with business combinations; (6) income taxes; (7) valuation of derivative instruments; and (8) accrued revenue and related receivables. Although management believes these estimates are reasonable, actual results could differ from these estimates.

Cash and Cash Equivalents

The Company considers all highly liquid investments purchased with a remaining maturity of three months or less to be cash equivalents. The Company's cash management process provides for the daily funding of checks as they are presented to the bank. Included in accounts payable at December 31, 2012 and 2011 was $14.9 million and $16.1 million, respectively, representing outstanding checks in excess of the bank balance (book overdraft).

Accounts Receivable

Trade accounts receivable consist mainly of receivables from oil and natural gas purchasers and from joint interest owners on properties the Company operates. For receivables from joint interest owners, the Company typically has the ability to withhold future revenue disbursements to recover non-payment of joint interest billings. Generally, oil and natural gas receivables are collected within two months.

Bad Debt Recovery

The Company recognized $38.5 million in bad debt expense in the year ended December 31, 2008 related to the Flying J bankruptcy. On July 6, 2010, the Joint Plan of Reorganization of Flying J was confirmed under Chapter 11 of the United States Bankruptcy Code. Additionally, the United States Bankruptcy Court approved and confirmed the June 15, 2010 Stipulation and Agreed Order (the Stipulation) with Flying J regarding the resolution of the Company's claim in Flying J's pending bankruptcy. Pursuant to the Stipulation, Flying J agreed that the total amount owed to the Company by Flying J was $60.5 million and, as a result, the Company received $60.5 million in cash on July 23, 2010. In the quarter ended September 30, 2010, the Company recorded a settlement of the Company's Flying J bankruptcy claim of $22.0 million and a bad debt recovery of $38.5 million.

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BERRY PETROLEUM COMPANY
Notes to the Financial Statements (Continued)
1. Summary of Significant Accounting Policies (Continued)

Oil and Natural Gas Properties, Buildings and Equipment

The Company accounts for its oil and natural gas exploration and development costs using the successful efforts method. Under this method, the fair value of property acquired and all costs associated with successful exploratory wells and all development wells are capitalized. Capitalized acquisition costs relating to proved properties are depleted using the unit-of-production method based on proved reserves. The depletion of capitalized exploratory drilling and development costs is based on the unit-of-production method using proved developed reserves. Items charged to expense generally include geological and geophysical costs, costs of unsuccessful exploratory wells and oil and gas production costs.

Exploratory well costs are capitalized pending further evaluation of whether economically recoverable reserves have been found. If economically recoverable reserves are not found, exploratory well costs are expensed as dry holes. Exploratory wells that discover potentially economic reserves in areas where a major capital expenditure would be required before production could begin, and where the economic viability of that major capital expenditure depends upon the successful completion of further exploratory work in the area, remain capitalized as long as the Company is making sufficient progress assessing the reserves and the economic and operating viability of the project. The costs of development wells are capitalized whether the development wells are productive or nonproductive.

Geological and geophysical costs, including exploratory seismic studies, and the costs of carrying and retaining unproved acreage are expensed as incurred. Costs of seismic and other studies that are utilized in development drilling within an area of proved reserves are capitalized as development costs. Amounts of seismic costs capitalized are based on only those blocks of data used in determining development well locations. To the extent that a seismic project covers areas of both developmental and exploratory drilling, those seismic costs are proportionately allocated between development costs and exploration expense.

Net carrying values of retired, sold or abandoned properties that constitute less than a complete unit of depreciable property are charged or credited, net of proceeds, to accumulated depreciation, depletion and amortization unless doing so significantly affects the unit-of-production amortization rate, in which case a gain or loss is recognized in income. Gains or losses from the disposal of complete units of depreciable property are recognized to earnings.

Unproved properties consist of costs to acquire undeveloped leases and to acquire unproved reserves. Costs related to acquiring undeveloped leases and unproved reserves are capitalized. When successful wells are drilled on undeveloped leaseholds, unproved property costs are reclassified to proved properties and depleted on a unit-of-production basis.

Buildings and equipment are recorded at cost. Depreciation is calculated on a straight-line basis over estimated useful lives ranging from five to 30 years for buildings and improvements and three to ten years for machinery and equipment.

Capitalized Interest

Acquisition costs of proved undeveloped and unproved properties qualify for interest capitalization during a period if interest cost is incurred and activities necessary to bring the properties into a productive state are in progress. As wells are drilled in a field with proved undeveloped or unproved reserves, a portion of the acquisition costs are either re-designated as proved developed or expensed, as appropriate. In fields with multiple potential drilling sites, the Company determines the amount of the acquisition cost to re-designate or expense through a systematic and rational

basis that considers the total expected wells to be drilled in that field.

Impairment of Proved and Unproved Properties

Proved oil and natural gas properties are reviewed for impairment when events and circumstances indicate a possible decline in the recoverability of the carrying amount of such property. The Company estimates the expected future cash flows of its oil and natural gas properties and compares these undiscounted 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, the Company will write down the carrying amount of the oil and natural gas properties to fair value. The factors used to determine fair value include, but are not limited to, estimates of reserves, future commodity prices, future production estimates, estimated future capital expenditures and discount rates commensurate with the risk associated with realizing the projected cash flows. See Notes 8 and 10 to the Financial Statements.

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BERRY PETROLEUM COMPANY
Notes to the Financial Statements (Continued)
1. Summary of Significant Accounting Policies (Continued)

Unproved oil and natural gas properties are periodically assessed for impairment on a project-by-project basis. The Company evaluates significant unproved properties for impairment based on remaining lease term, drilling results, reservoir performance, seismic interpretation or future plans to develop acreage. If the quantity of potential reserves determined by such evaluations is not sufficient to fully recover the cost invested in each project, the Company will recognize an impairment loss at that time.

Income Taxes and Uncertain Tax Positions

Income taxes are recorded for the income tax effects of transactions reported in the financial statements and consist of income taxes currently payable plus deferred income taxes related to certain income and expenses recognized in different periods for financial and income tax reporting purposes. Deferred income taxes are also recognized for income tax credits that are available to offset future income taxes. Deferred income taxes are measured by applying currently enacted income tax rates to the differences between the financial statements and income tax reporting. The Company routinely assess the realizability of its deferred income tax assets, and a valuation allowance is recognized if it is determined that deferred income tax assets may not be fully utilized in future periods. The Company considers future taxable earnings in making such assessments. Numerous judgments and assumptions are inherent in the determination of future taxable earnings, including factors such as future operating conditions (particularly as related to prevailing oil and natural gas prices). There can be no assurance that facts and circumstances will not materially change and require the Company to establish deferred income tax asset valuation allowances in a future period. The Company is subject to taxation in many jurisdictions, and the calculation of its income tax liabilities involves dealing with uncertainties in the application of complex income tax laws and regulations in various taxing jurisdictions. The Company recognizes certain income tax positions that meet a more-likely-than not recognition threshold. If the Company ultimately determines that the payment of these liabilities will be unnecessary, the Company will reverse the liability and recognize an income tax benefit during the period in which the Company determines the liability no longer applies.

Derivative Instruments

The Company records all derivative instruments as either assets or liabilities at fair value, other than the derivative instruments that meet the normal purchases and sales exception. Cash flow is affected by derivatives to the extent that actual cash settlements under these contracts result in payments made to or received from derivative counterparties. Realized and unrealized (gain) loss on derivatives, net represents both the realized cash settlements with derivative counterparties and unrealized non-cash mark to market gains and losses.

Effective January 1, 2010, the Company elected to prospectively discontinue all hedge accounting, under which changes in derivative fair values were deferred in accumulated other comprehensive income (AOCL) rather than being recognized immediately in earnings. Cash settlements of derivative instruments used to manage commodity price risk are classified as cash flows from operating activities in the Statements of Cash Flows along with the cash flows from the related oil and natural gas production activities. The Company nets derivative assets and liabilities of a given counterparty whenever it has a legally enforceable master netting agreement with the counterparty to a derivative contract. The Company does not enter into derivative instruments for speculative or trading purposes. See Notes 7 and 8 to the Financial Statements.

Assets Held for Sale

Any properties held for sale as of the date of presentation of the balance sheets have been classified as assets held for sale and are separately presented on the balance sheets at the lower of net book value or fair value less the cost to sell. See Note 2 to the Financial Statements.

Asset Retirement Obligations

The Company's asset retirement obligations (AROs) relate to future costs associated with the plugging and abandonment of oil and natural gas wells, removal of equipment facilities from leased acreage and land restoration in accordance with applicable local, state and federal laws. The discounted fair value of an ARO liability is required to be recognized in the period in which it is incurred, with the associated asset retirement cost capitalized as part of the carrying cost of the oil and natural gas asset. The recognition of the ARO requires that management make numerous assumptions regarding such factors as the estimated probabilities, amounts and timing of settlements; the credit-adjusted-risk-free rate to be used; inflation rates; and future advances in technology. In periods subsequent to the initial measurement of the ARO, the Company must recognize period-to-period changes in the liability resulting from the passage of time and revisions to either the timing or the amount of

the original estimate of undiscounted cash flows. Increases in the ARO liability due to the passage of time impact net earnings as accretion expense. The related capital cost, including revisions thereto, is charged to expense through DD&A—oil and natural gas production over the life of the oil and natural gas field.

Debt Issuance Costs

Debt issuance costs related to the Company's senior subordinated notes are amortized to interest expense using the effective interest method over the term of the related debt. Debt issuance costs related to the credit facility are amortized to interest expense on a straight-line basis over the borrowing term.

Prepaid Expenses and Other

The components of prepaid expenses and other are as follows:

	Year Ended December 31,	
(in thousands)	2012	2011
Prepaid expenses	$4,168	$5,275
California carbon allowance inventories	545	—
Oil inventories	1,216	—
Materials inventories	12,943	11,356
Other inventory	193	170
Total prepaid expenses and other	$19,065	$16,801

Inventories

Inventories consist primarily of tubular goods and production materials and equipment. Inventories also include crude oil and California carbon allowance instruments. Inventories are carried at the lower of cost or market, with cost being determined on a weighted average cost basis.

Accrued Liabilities

The components of accrued liabilities are as follows:

	Year Ended December 31,	
(in thousands)	2012	2011
Property taxes	$13,496	$10,430
Accrued interest	16,996	9,205
Accrued payroll	12,700	9,953
Asset retirement obligations (current portion)	4,430	4,763
Other accrued liabilities	3,529	5,478
Total accrued liabilities	$51,151	$39,829

Revenue Recognition

Revenues associated with sales of oil, natural gas, electricity and natural gas marketing are recognized when delivery has occurred and title has transferred, and if the collectability of the revenue is probable. The electricity and natural gas the Company produces and uses in its operations are not included in revenues. Revenues from oil and natural gas

production from properties in which the Company has an interest with other producers are recognized on the basis of its net working interest. Revenues are also derived from natural gas marketing sales, which represent excess capacity on the Rockies Express, Wyoming Interstate and Ruby pipelines used by the Company to market natural gas for its working interest partners and other third parties.

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BERRY PETROLEUM COMPANY
Notes to the Financial Statements (Continued)
1. Summary of Significant Accounting Policies (Continued)

Credit Risk and Other Concentrations

The Company sells oil and natural gas to various types of customers, including pipelines, refineries and other oil and natural gas companies, and sells electricity to utility companies. Credit is extended based on an evaluation of the customer's financial condition and historical payment record. The future availability of a ready market for oil and natural gas depends on numerous factors outside the Company's control, none of which can be predicted with certainty. See Item 1A. Risk Factors—"Market conditions or operational impediments may hinder the Company's access to oil and natural gas markets or delay our production."

At December 31, 2012, the Company had commodity derivative contracts with nine counterparties, all of which were part of the Company's credit facility and all of which had investment-grade ratings from Moody’s and Standard & Poor. The Company does not require collateral or other security from counterparties to support derivative instruments. However, the contracts with those counterparties typically contain netting provisions such that if a default occurs, the non-defaulting party can offset the amount payable to the defaulting party under the derivative contract with the amount due from the defaulting party. As a result of the netting provisions, the Company's maximum amount of loss due to credit risk is limited to the net amounts due to and from the counterparties under the derivative contracts. The maximum amount of loss due to credit risk that the Company would have incurred if all counterparties to its derivative contracts failed to perform at December 31, 2012 was $23.2 million.

During 2012, 2011 and 2010, the Company did not incur any credit losses with respect to counterparties to contracts for the sale of oil and natural gas or under the Company's derivative instruments.

The Company places its temporary cash investments with high-quality financial institutions and does not limit the amount of credit exposure to any one financial institution. For the three years ended December 31, 2012, the Company has not incurred losses related to these investments.

Major Customers

The following table presents the percentages of the Company's total oil and natural gas and electricity sales to each significant purchaser for the years ended December 31, 2012, 2011 and 2010:

	Year Ended December 31,					
	2012		2011		2010	
Oil and natural gas:						
ExxonMobil Oil Corporation	43	%	43	%	44	%
Shell Trading (US) Company	13	%	14	%	14	%
Enterprise Crude Oil LLC	9	%	8	%	4	%
HollyFrontier Corporation	9	%	8	%	9	%
Electricity:						
Pacific Gas and Electric Company	54	%	59	%	55	%
Southern California Edison	46	%	41	%	45	%

Based on the current demand for oil and natural gas and the availability of other purchasers, the Company believes that, with the exception of its primary customer in Utah, the loss of any one of its major purchasers would not have a material adverse effect on its financial condition, results of operations and operating cash flows. See Item 1A. Risk Factors—"Market conditions or operational impediments may hinder our access to oil and natural gas markets or delay

our production."

Electricity Cost Allocation

The Company owns three cogeneration facilities. Its investment in cogeneration facilities has been for the express purpose of lowering steam costs in its heavy oil operations and securing operating control of the respective steam generation.

BERRY PETROLEUM COMPANY
Notes to the Financial Statements (Continued)
1. Summary of Significant Accounting Policies (Continued)

Cogeneration, also called combined heat and power (CHP), extracts energy from the exhaust of a turbine, which would otherwise be wasted, to produce steam. Such cogeneration operations also produce electricity. The Company allocates steam costs to its oil and natural gas operating costs based on the conversion efficiency of the cogeneration facilities plus certain direct costs in producing steam. Electricity revenue represents sales to utility companies. A portion of the capital costs of the cogeneration facilities is allocated to DD&A—oil and natural gas production. Electricity production used in oil and natural gas operations is allocated to operating costs—oil and natural gas production, and totaled $2.0 million, $2.3 million and $2.8 million for the years ended December 31, 2012, 2011 and 2010, respectively.

Transportation Costs

Natural gas transportation costs are included in either operating costs—oil and natural gas production or operating costs—electricity generation, as applicable. Natural gas transportation costs included in operating costs—oil and natural gas production were $28.6 million, $21.4 million and $16.2 million for 2012, 2011 and 2010, respectively. Costs for transporting natural gas used in electricity generation were $3.8 million, $5.0 million and $4.7 million for 2012, 2011 and 2010, respectively; a portion of these costs are allocated to operating costs—oil and natural gas production, as described above, and the remainder are included in operating costs—electricity generation.

Stock-Based Compensation

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.

Earnings (Loss) Per Share

The two-class method of computing earnings per share is required for entities that have participating securities. The two-class method is an earnings allocation formula that determines earnings per share for participating securities according to dividends declared (or accumulated) and participation rights in undistributed earnings. Unvested restricted stock issued prior to January 1, 2010, under the Company's equity incentive plans, has the right to receive non-forfeitable dividends, participating on an equal basis with common stock, and thus these securities are classified as participating securities. Participating securities do not have a contractual obligation to share in the Company's losses. Therefore, in periods of net loss, no portion of the loss is allocated to participating securities. Unvested restricted stock issued subsequent to January 1, 2010, under the Company's equity incentive plans does not participate in dividends. Stock options issued under the Company's equity incentive plans do not participate in dividends.

Basic earnings (loss) per share is calculated by dividing earnings (loss) available to common shareholders by the weighted average shares-basic during each period. Diluted earnings (loss) per share is calculated by dividing earnings (loss) available to common shareholders by the weighted average shares-dilutive, which includes the effect of potentially dilutive securities. Potentially dilutive securities consist of non-participating unvested restricted stock awards and outstanding stock options. No potential shares of common stock are included in the computation of any diluted per share amount when a net loss exists.

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BERRY PETROLEUM COMPANY
Notes to the Financial Statements (Continued)
1. Summary of Significant Accounting Policies (Continued)

The following table shows the computation of basic and diluted net earnings per share for the years ended December 31, 2012, 2011 and 2010:

	Year Ended December 31,		
(in thousands, except per share data)	2012	2011	2010
Net earnings (loss)	$171,539	$(228,063)	$82,524
Less: Earnings allocable to participating securities	885		