DEUTSCHE BANK AKTIENGESELLSCHAFT
Form FWP
October 02, 2014

October 2014
Term Sheet No. 2225
Registration Statement No. 333-184193
Dated October 1, 2014
Filed pursuant to Rule 433

INTEREST RATE STRUCTURED INVESTMENTS

Callable Leveraged Steepener Notes due October 31, 2034

Based on the Spread between the 30-Year CMS Rate and the 2-Year CMS Rate

Unless redeemed by us, the notes will pay interest quarterly in arrears for the first year at a fixed rate of 10.00% per annum and thereafter at a rate per annum equal to the product of (i) 4.5 and (ii) the value of the spread between the 30-Year Constant Maturity Swap ("CMS") Rate and the 2-Year CMS Rate minus 0.25%, subject to the Maximum Interest Rate of 10.00% per annum and the Minimum Interest Rate of 0.00% per annum. After the first year, if the 30-Year CMS Rate does not exceed the 2-Year CMS Rate by more than 0.25% on any Interest Determination Date, you will receive no interest during the affected Interest Period. We have the right to redeem the notes, in whole but not in part, each year on October 31st*, beginning on October 31*, 2015. Therefore, the term of the notes could be as short as one year. The notes are senior unsecured obligations of Deutsche Bank AG. Any payment on the notes is subject to the credit of the Issuer.

KEY TERMS	
Issuer:	Deutsche Bank AG, London Branch
Aggregate Principal Amount:	$
Principal Amount:	$1,000
Issue Price:	At variable prices
Trade Date:	October 28*, 2014
Settlement Date:	October 31*, 2014
Maturity Date:	October 31*, 2034
Payment at Maturity:	Unless the notes are redeemed earlier by us, you will receive on the Maturity Date a cash payment, for each $1,000 Principal Amount of notes, of $1,000 plus any accrued and unpaid interest. If the scheduled Maturity Date is not a Business Day, the Maturity Date will be the first following day that is a Business Day, but no adjustment will be made to the interest payment made on such following Business Day. Any payment at maturity is subject to the credit of the Issuer.
Interest Rate:	Interest will be paid quarterly in arrears at the applicable Interest Rate set forth below on each Interest Payment Date, based on an unadjusted 30/360 day count convention. Interest will no longer accrue or be payable following the relevant Redemption Date. • For the first four Interest Periods from and including the Settlement Date to but excluding October 31*, 2015, the Interest Rate will be 10.00% per annum. • For each subsequent Interest Period, the applicable Interest Rate will be determined by the Calculation Agent on the relevant Interest Determination Date based on the following formula: Interest Rate = Multiplier x (Spread – Fixed Percentage Amount), subject to the Maximum Interest Rate and the Minimum Interest Rate After the first year, if the 30-Year CMS Rate does not exceed the 2-Year CMS Rate by more than 0.25% on any relevant Interest Determination Date, you will receive no interest on your notes for the relevant Interest Period, regardless of whether the Spread is greater than 0.25% during the relevant Interest Period. Furthermore, after the first year, the applicable Interest Rate will be subject to the Maximum Interest Rate of 10.00% per annum.

(Key Terms continued on the next page)

Investing in the notes involves a number of risks. See "Selected Risk Considerations" beginning on page 7 in this term sheet.

Commissions and Issue Price:	Price to Public(1)	Maximum Discounts and Commissions(2)	Minimum Proceeds to Us
Per note:	At variable prices	$35.00	$965.00
Total:	At variable prices	$	$

(1) The notes will be offered from time to time in one or more negotiated transactions at variable prices to be determined at the time of each sale, which may be at market prices prevailing, at prices related to such prevailing prices or at negotiated prices; provided, however, that such price will not be less than $970.00 or more than $1,000.00 per $1,000 Principal Amount of notes. See "Selected Risk Considerations — Variable Price Reoffering Risks."

(2) Deutsche Bank Securities Inc. ("DBSI") or one of our affiliates will pay varying discounts and commissions to dealers, including Morgan Stanley & Co. LLC ("MS & Co."), of up to $35.00 per $1,000 Principal Amount of notes depending on market conditions. For more detailed information about discounts and commissions, please see "Supplemental Plan of Distribution (Conflicts of Interest)" in this term sheet.

DBSI, an agent for this offering, is our affiliate. For more information, see "Supplemental Plan of Distribution (Conflicts of Interest)" in this term sheet.

The Issuer's estimated value of the notes on the Trade Date is approximately $900.00 to $930.00 per $1,000 Principal Amount of notes, which is less than the Issue Price. Please see "Issuer's Estimated Value of the Notes" on page 3 of this term sheet for additional information.

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

The notes are not bank deposits and are not insured or guaranteed by the Federal Deposit Insurance Corporation or any other governmental agency.

Deutsche Bank AG has filed a registration statement (including a prospectus) with the Securities and Exchange Commission ("SEC") for the offering to which this term sheet relates. Before you invest, you should read the prospectus in that registration statement and the other documents relating to this offering that Deutsche Bank AG has filed with the SEC for more complete information about Deutsche Bank AG and this offering. You may obtain these documents without cost by visiting EDGAR on the SEC website at.www.sec.gov. Alternatively, Deutsche Bank AG, any agent or any dealer participating in this offering will arrange to send you the prospectus, prospectus supplement, underlying supplement and this term sheet if you so request by calling toll-free 1-800-311-4409.

You should read this term sheet together with the prospectus supplement dated September 28, 2012 relating to our Series A global notes of which these notes are a part and prospectus dated September 28, 2012, each of which can be accessed via the hyperlinks below.

Prospectus supplement:
http://www.sec.gov/Archives/edgar/data/1159508/000119312512409437/d414995d424b21.pdf
Prospectus: http://www.sec.gov/Archives/edgar/data/1159508/000119312512409372/d413728d424b21.pdf

Callable Leveraged Steepener Notes due October 31, 2034
Based on the Spread between the 30-Year CMS Rate and the 2-Year CMS Rate

(Key Terms continued from previous page)	
Interest Period:	The period from (and including) an Interest Payment Date, or the Settlement Date in the case of the first Interest Period, to (but excluding) the following Interest Payment Date.
Interest Determination Date:	For each Interest Period commencing on or after October 31*, 2015, two U.S. Government Securities Business Days prior to the first day of such Interest Period.
Interest Payment Dates*:	The last calendar day of each January, April, July and October, beginning on January 30th, 2015 and ending on the Maturity Date. If any scheduled Interest Payment Date is not a Business Day, the interest will be paid on the first following day that is a Business Day, but no adjustment will be made to the interest payment made on such following Business Day.
Spread:	The 30-Year CMS Rate minus the 2-Year CMS Rate. See the "The CMS Rates" below for additional information on how the CMS Rates are calculated.
Maximum Interest Rate:	10.00% per annum
Minimum Interest Rate:	0.00% per annum
Multiplier:	4.5
Fixed Percentage Amount:	0.25%
Early Redemption at Issuer's Option:	We may, in our sole discretion, redeem your notes in whole but not in part on any Redemption Date for an amount in cash, per $1,000 Principal Amount of notes, equal to $1,000 plus any accrued but unpaid interest to but excluding the applicable Redemption Date. If we decide to redeem the notes, we will give you notice not less than five (5) Business Days prior to the applicable Redemption Date. If the Redemption Date is not a Business Day, the Redemption Date will be the first following day that is a Business Day, but no adjustment will be made to the interest payment made on such following Business Day.
Redemption Dates:	October 31st* each year beginning on October 31*, 2015
Business Day:	Any day other than a day that is (i) a Saturday or Sunday, (ii) a day on which banking institutions generally in the City of New York or London, England are authorized or obligated by law, regulation or executive order to close or (iii) a day on which transactions in U.S. dollars are not conducted in the City of New York or London, England.
U.S. Government Securities Business Day:	Any day, other than a Saturday, a Sunday or a day on which the Securities Industry and Financial Markets Association (or any successor thereto) recommends that the fixed income departments of its members be closed for the entire day for purposes of trading in U.S. government securities.
CUSIP/ISIN:	25152RXF5 / US25152RXF53
Listing:	The notes will not be listed on any securities exchange.
Settlement:	

	Delivery of the notes in book-entry form only will be made through The Depository Trust Company ("DTC")
Selected dealer:	Morgan Stanley & Co. LLC

* Expected. In the event that we make any change to the expected Trade Date or Settlement Date, the Maturity Date, the Redemption Dates and the Interest Payment Dates may be changed so that the stated term of the notes remains the same.

Issuer's Estimated Value of the Notes

The Issuer's estimated value of the notes is equal to the sum of our valuations of the following two components of the notes: (i) a bond and (ii) an embedded derivative(s). The value of the bond component of the notes is calculated based on the present value of the stream of cash payments associated with a conventional bond with a principal amount equal to the Principal Amount of the notes, discounted at an internal funding rate, which is determined primarily based on our market-based yield curve, adjusted to account for our funding needs and objectives for the period matching the term of the notes. The internal funding rate is typically lower than the rate we would pay when we issue conventional debt securities on equivalent terms. This difference in funding rate, as well as the agent's commissions, if any, and the estimated cost of hedging our obligations under the notes, reduces the economic terms of the notes to you and is expected to adversely affect the price at which you may be able to sell the notes in any secondary market. The value of the embedded derivative(s) is calculated based on our internal pricing models using relevant parameter inputs such as expected interest rates and mid-market levels of price and volatility of the assets underlying the notes or any futures, options or swaps related to such underlying assets. Our internal pricing models are proprietary and rely in part on certain assumptions about future events, which may prove to be incorrect.

The Issuer's estimated value of the notes on the Trade Date (as disclosed on the cover of this term sheet) is less than the Issue Price of the notes. The difference between the Issue Price and the Issuer's estimated value of the notes on the Trade Date is due to the inclusion in the Issue Price of the agent's commissions, if any, and the cost of hedging our obligations under the notes through one or more of our affiliates. Such hedging cost includes our or our affiliates' expected cost of providing such hedge, as well as the profit we or our affiliates expect to realize in consideration for assuming the risks inherent in providing such hedge.

The Issuer's estimated value of the notes on the Trade Date does not represent the price at which we or any of our affiliates would be willing to purchase your notes in the secondary market at any time. Assuming no changes in market conditions or our creditworthiness and other relevant factors, the price, if any, at which we or our affiliates would be willing to purchase the notes from you in secondary market transactions, if at all, would generally be lower than both the Issue Price and the Issuer's estimated value of the notes on the Trade Date. Our purchase price, if any, in secondary market transactions will be based on the estimated value of the notes determined by reference to (i) the then-prevailing internal funding rate (adjusted by a spread) or another appropriate measure of our cost of funds and (ii) our pricing models at that time, less a bid spread determined after taking into account the size of the repurchase, the nature of the assets underlying the notes and then-prevailing market conditions. The price we report to financial reporting services and to distributors of our notes for use on customer account statements would generally be determined on the same basis.

Callable Leveraged Steepener Notes due October 31, 2034
Based on the Spread between the 30-Year CMS Rate and the 2-Year CMS Rate

Additional Terms Specific to the Notes

Our Central Index Key, or CIK, on the SEC website is 0001159508. As used in this term sheet, “we,” “us” or “our” refers to Deutsche Bank AG, including, as the context requires, acting through one of its branches.

This term sheet, together with the documents listed above, contains the terms of the notes and supersedes all other prior or contemporaneous oral statements as well as any other written materials including preliminary or indicative pricing terms, correspondence, trade ideas, structures for implementation, sample structures, brochures or other educational materials of ours. You should carefully consider, among other things, the matters set forth in this term sheet and “Risk Factors” in the accompanying prospectus supplement and prospectus, as the notes involve risks not associated with conventional debt securities. We urge you to consult your investment, legal, tax, accounting and other advisers before deciding to invest in the notes.

You may revoke your offer to purchase the notes at any time prior to the time at which we accept such offer by notifying the applicable agent. We reserve the right to change the terms of, or reject any offer to purchase, the notes prior to their issuance. We will notify you in the event of any changes to the terms of the notes, and you will be asked to accept such changes in connection with your purchase of any notes. You may also choose to reject such changes, in which case we may reject your offer to purchase the notes.

We are offering to sell, and are seeking offers to buy, the notes only in jurisdictions where such offers and sales are permitted. Neither the delivery of this term sheet nor the accompanying prospectus supplement or prospectus nor any sale made hereunder implies that there has been no change in our affairs or that the information in this term sheet and accompanying prospectus supplement and prospectus is correct as of any date after the date hereof.

You must (i) comply with all applicable laws and regulations in force in any jurisdiction in connection with the possession or distribution of this term sheet and the accompanying prospectus supplement and prospectus and the purchase, offer or sale of the notes and (ii) obtain any consent, approval or permission required to be obtained by you for the purchase, offer or sale by you of the notes under the laws and regulations applicable to you in force in any jurisdiction to which you are subject or in which you make such purchases, offers or sales; neither we nor the agents shall have any responsibility therefor.

Callable Leveraged Steepener Notes due October 31, 2034
Based on the Spread between the 30-Year CMS Rate and the 2-Year CMS Rate

Hypothetical Examples

The table and hypothetical examples set forth below illustrate how the interest payments on the notes are calculated after the first year using the Multiplier of 4.5, the Fixed Percentage Amount of 0.25%, the Maximum Interest Rate of 10.00% per annum and the Minimum Interest Rate of 0.00% per annum. The actual interest payments on the notes after the first year will be determined on the relevant Interest Determination Dates. For purposes of these examples, we have assumed that the notes are not being redeemed prior to the Maturity Date. The following results are based solely on the hypothetical examples cited below. You should consider carefully whether the notes are suitable to your investment goals. The numbers appearing in the table and examples below may have been rounded for ease of analysis.

30-Year CMS Rate	2-Year CMS Rate	Spread	Multiplier x (Spread – Fixed Percentage Amount)	Applicable Interest Rate (per annum)	Hypothetical Interest Payment (per $1,000 Principal Amount of notes)
1.00%	1.75%	-0.75%	-4.50%	0.00%	$0.00
2.35%	2.10%	0.25%	0.00%	0.00%	$0.00
3.50%	1.85%	1.65%	6.30%	6.30%	$15.75
5.50%	2.25%	3.25%	13.50%	10.00%	$25.00

The following hypothetical examples illustrate how the hypothetical interest payments set forth in the table above are calculated.

Example 1: If on the Interest Determination Date for the relevant Interest Period the value of the 30-Year CMS Rate is 1.00% and the 2-Year CMS Rate is 1.75%, the Spread for the corresponding Interest Period would be -0.75% and the applicable Interest Rate would be 0.00%, calculated as follows:

Interest Rate	=	Multiplier x (Spread – Fixed Percentage Amount), subject to the Maximum Interest Rate and the Minimum Interest Rate
	=	4.5 x (-0.75% – 0.25%), subject to the Maximum Interest Rate of 10.00% and the Minimum Interest Rate of 0.00%
	=	-4.50%, subject to the Minimum Interest Rate of 0.00%
	=	0.00%

In this case, because the value of the Multiplier multiplied by the difference between the Spread and the Fixed Percentage Amount results in a per annum rate of -4.50%, which is less than the Minimum Interest Rate of 0.00%, the applicable Interest Rate for the corresponding Interest Period would be 0.00%, and you would receive no interest payment on the relevant Interest Payment Date.

Example 2: If on the Interest Determination Date for the relevant Interest Period the value of the 30-Year CMS Rate is 2.35% and the 2-Year CMS Rate is 2.10%, the Spread for the corresponding Interest Period would be 0.25% and the applicable Interest Rate would be 0.00%, calculated as follows:

Interest Rate	=	Multiplier x (Spread – Fixed Percentage Amount), subject to the Maximum Interest Rate and the Minimum Interest Rate
	=	4.5 x (0.25% – 0.25%), subject to the Maximum Interest Rate of 10.00% and the Minimum Interest Rate of 0.00%
	=	0.00%

In this case, because the difference between the Spread and the Fixed Percentage Amount is 0.00%, the applicable Interest Rate is equal to 0.00% and you will receive no interest payment on the relevant Interest Payment Date.

Example 3: If on the Interest Determination Date for the relevant Interest Period the 30-Year CMS Rate is 3.50% and the 2-Year CMS Rate is 1.85%, the Spread for the corresponding Interest Period would be 1.85% and the applicable Interest Rate would be 6.30%, calculated as follows:

Interest Rate	=	Multiplier x (Spread – Fixed Percentage Amount), subject to the Maximum Interest Rate and the Minimum Interest Rate
	=	4.5 x (1.85% – 0.25%), subject to the Maximum Interest Rate of 10.00% and the Minimum

		Interest Rate of 0.00%
	=	6.30%

In this case, because the value of the Multiplier multiplied by the difference between the Spread and the Fixed Percentage Amount results in a per annum rate of 6.30%, which is greater than the Minimum Interest Rate of 0.00% but less than the Maximum Interest Rate of 10.00%, the applicable Interest Rate would be 6.30% and you will receive an interest payment of $15.75 per $1,000 Principal Amount of notes on the relevant Interest Payment Date.

Example 4: If on the Interest Determination Date for the relevant Interest Period the 30-Year CMS Rate is 5.50% and the 2-Year CMS Rate is 2.25%, the Spread for the corresponding Interest Period would be 3.25% but the applicable Interest Rate for the corresponding Interest Period would nevertheless be only 10.00%, calculated as follows:

Interest Rate	=	Multiplier x (Spread – Fixed Percentage Amount), subject to the Maximum Interest Rate and the Minimum Interest Rate
	=	4.5 x (3.25% – 0.25%), subject to the Maximum Interest Rate of 10.00% and the Minimum Interest Rate of 0.00%
	=	13.50%, subject to the Maximum Interest Rate of 10.00%
	=	10.00%

In this case, because the value of the Multiplier multiplied by the difference between the Spread and the Fixed Percentage Amount results in a per annum rate of 13.50%, which is greater than the Maximum Interest Rate of 10.00%, the applicable Interest Rate would be 10.00% and you will receive an interest payment of $25.00 per $1,000 Principal Amount of notes on the relevant Interest Payment Date.

Callable Leveraged Steepener Notes due October 31, 2034
Based on the Spread between the 30-Year CMS Rate and the 2-Year CMS Rate

Selected Risk Considerations

An investment in the notes involves risks. This section describes the most significant risks relating to the notes. For a complete list of risk factors, please see the accompanying prospectus supplement and the accompanying prospectus.

§ After the first year, the notes are subject to interest payment risk based on the Spread — Investing in the notes is not equivalent to investing in securities directly linked to the CMS rates or the Spread. Instead, the applicable Interest Rate after the first year is equal to the product of (a) the Multiplier of 4.5 and (b) the Spread between the 30-Year CMS Rate and the 2-Year CMS Rate minus the Fixed Percentage Amount of 0.25%, subject to the Maximum Interest Rate of 10.00% per annum and the Minimum Interest Rate of 0.00% per annum. Accordingly, the amount of interest payable on the notes is dependent on whether, and the extent to which, the Spread minus the Fixed Percentage Amount is greater than the Minimum Interest Rate and less than the Maximum Interest Rate. If, after the first year, the 30-Year CMS Rate does not exceed the 2-Year CMS Rate by more than 0.25% on any relevant Interest Determination Date, you will receive no interest on your notes for the relevant Interest Period, regardless of whether the Spread is greater than 0.25% during the relevant Interest Period. It is possible that the Spread between the 30-Year CMS Rate and the 2-Year CMS Rate will stay below 0.25% for more than one Interest Determination Date, which means you will not receive any interest payment on your notes for a significant period of time. If the Spread between the 30-Year CMS Rate and the 2-Year CMS Rate is equal to or less than 0.25% on every Interest Determination Date, you will not receive any interest payment on your notes after the first year. Any payment on the notes is subject to our ability to satisfy our obligations as they become due.

§ In no event will the Interest Rate on the notes exceed the Maximum Interest Rate — The Maximum Interest Rate on the notes for the Interest Periods after the first year is limited to the Maximum Interest Rate of 10.00% per annum. Even if the product of (a) the Multiplier of 4.5 and (b) the Spread between the 30-Year CMS Rate and the 2-Year CMS Rate minus the Fixed Percentage Amount of 0.25% is greater than the Maximum Interest Rate, the notes will bear interest for such Interest Period only at that rate. The Maximum Interest Rate may be lower than the interest rates for similar debt securities then prevailing in the market, which will adversely affect the value of your notes.

§ An investment in the notes may be riskier than an investment in notes with a shorter term — The notes have a term of twenty years, subject to our right to redeem the notes on October 31st each year, beginning on October 31, 2015. By purchasing notes with a longer term, you will have greater exposure to the risk that the value of the notes may decline due to such factors as inflation, rising interest rates and changes in the constant maturity swap ("CMS") rate yield curve. If market interest rates rise during the term of the notes, the Interest Rate on the notes may be lower than the interest rates for similar debt securities then prevailing in the market. If this occurs, you will not be able to require the Issuer to redeem the notes and will, therefore, bear the risk of earning a lower return than you could earn on other investments until the Maturity Date and the risk that the value of your notes will decline.

§ The notes may be redeemed prior to the Maturity Date — We may, in our sole discretion, redeem the notes in whole but not in part on October 31st each year, beginning on October 31, 2015. We are more likely to redeem the notes during periods when interest on the notes is likely to accrue at a rate greater than what we would pay on a comparable debt security of ours with a maturity comparable to the remaining term of the notes. If we redeem the notes, you may not be able to reinvest your funds in another investment that provides a similar yield with a similar level of risk.

§

Variable price reoffering risks — We propose to offer the notes from time to time for sale to investors in one or more negotiated transactions, or otherwise, at market prices prevailing at the time of sale, at prices related to then-prevailing prices, at negotiated prices, or otherwise; provided, however, that such price will not be less than $970.00 or more than $1,000.00 per $1,000 Principal Amount of notes. Accordingly, there is a risk that the price you pay for the notes will be higher than the prices paid by other investors based on the date and time you make your purchase, from whom you purchase the notes (e.g., directly from DBSI or through a broker or dealer), any related transaction cost (e.g., any brokerage commission), whether you hold your notes in a brokerage account, a fiduciary or fee-based account or another type of account and other market factors beyond our control.

§ The notes are subject to our creditworthiness — The notes are senior unsecured obligations of the Issuer, Deutsche Bank AG, and are not, either directly or indirectly, an obligation of any third party. Any payment(s) to be made on the notes depends on the ability of Deutsche Bank AG to satisfy its obligations as they come due. An actual or anticipated downgrade in Deutsche Bank AG's credit rating or increase in the credit spreads charged by the market for taking our credit risk will likely have an adverse effect on the value of the notes. As a result, the actual and perceived creditworthiness of Deutsche Bank AG will affect the value of the notes, and in the event Deutsche Bank AG were to default on its obligations, you might not receive any amount(s) owed to you under the terms of the notes and you could lose your entire investment.

§ The Issuer's estimated value of the notes on the Trade Date will be less than the issue price of the notes — The Issuer's estimated value of the notes on the Trade Date (as disclosed on the cover of this term sheet) is less than the Issue Price of the notes. The difference between the Issue Price and the Issuer's estimated value of the notes on the Trade Date is due to the inclusion in the Issue Price of the agent's commissions, if any, and the cost of hedging our obligations under the

Callable Leveraged Steepener Notes due October 31, 2034
Based on the Spread between the 30-Year CMS Rate and the 2-Year CMS Rate

notes through one or more of our affiliates. Such hedging cost includes our or our affiliates' expected cost of providing such hedge, as well as the profit we or our affiliates expect to realize in consideration for assuming the risks inherent in providing such hedge. The Issuer's estimated value of the notes is determined by reference to an internal funding rate and our pricing models. The internal funding rate is typically lower than the rate we would pay when we issue conventional debt securities on equivalent terms. This difference in funding rate, as well as the agent's commissions, if any, and the estimated cost of hedging our obligations under the notes, reduces the economic terms of the notes to you and is expected to adversely affect the price at which you may be able to sell the notes in any secondary market. In addition, our internal pricing models are proprietary and rely in part on certain assumptions about future events, which may prove to be incorrect. If at any time a third party dealer were to quote a price to purchase your notes or otherwise value your notes, that price or value may differ materially from the estimated value of the notes determined by reference to our internal funding rate and pricing models. This difference is due to, among other things, any difference in funding rates, pricing models or assumptions used by any dealer who may purchase the notes in the secondary market.

§ If the CMS rates change, the value of your notes may not change in the same manner — Your notes may trade quite differently from the spread of the CMS rates. Changes in the spread of the CMS rates may not result in a comparable change in the value of your notes.

§ The Spread will be affected by a number of factors — After the first year, the amount of interest, if any, payable on the notes will depend primarily on the CMS rates and the Spread on the applicable Interest Determination Date. A number of factors can affect the Spread by causing changes in the relative values of the CMS rates including, but not limited to:

o changes in, or perceptions about, future CMS rates;

o general economic conditions;

o prevailing interest rates; and

o policies of the Federal Reserve Board regarding interest rates.

These and other factors may have adversely affect the return on the notes and the value of the notes.

§ Past performance of the CMS rates is no guide to future performance — The actual performance of the Spread over the term of the notes may bear little relation to the historical performance of the Spread and may bear little relation to the hypothetical return examples set forth elsewhere in this term sheet. We cannot predict the future performance of the Spread.

§ Assuming no changes in market conditions and other relevant factors, the price you may receive for your notes in secondary market transactions would generally be lower than both the issue price and the Issuer's estimated value of the notes on the Trade Date — While the payment(s) on the notes described in this term sheet is based on the full Principal Amount of your notes, the Issuer's estimated value of the notes on the Trade Date (as disclosed on the cover of this term sheet) is less than the Issue Price of the notes. The Issuer's estimated value of the notes on the Trade Date does not represent the price at which we or any of our affiliates would be willing to purchase your notes in the secondary market at any time. Assuming no changes in market conditions or our creditworthiness and other relevant factors, the price, if any, at which we or our affiliates would be willing to purchase the notes from you in secondary market transactions, if at all, would generally be lower than both the Issue Price and the Issuer's estimated value of the notes on the Trade Date. Our purchase price, if any, in secondary market transactions would be based on the estimated value of the notes determined by reference to (i) the then-prevailing internal funding rate (adjusted by a spread) or another appropriate measure of our cost of funds and (ii) our pricing models at that time, less a bid spread determined after taking into account the size of the repurchase, the nature of the assets underlying the notes and then-prevailing market conditions. The price we report to financial reporting services and to distributors of our notes for use on customer account statements would generally be determined on the same basis.

In addition to the factors discussed above, the value of the notes and our purchase price in secondary market transactions after the Trade Date, if any, will vary based on many economic and market factors, including our creditworthiness, and cannot be predicted with accuracy. These changes may adversely affect the value of your notes, including the price you may receive in any secondary market transactions. Any sale prior to the Maturity Date could result in a substantial loss to you.

§ The notes are not designed to be short-term trading instruments — The price at which you will be able to sell your notes to us or our affiliates prior to maturity, if at all, may be at a substantial discount from the Principal Amount of the notes. The potential returns described in this term sheet assume that your notes, which are not designed to be short-term trading instruments, are held to maturity.

§ The notes will not be listed and there will likely be limited liquidity — The notes will not be listed on any securities exchange. There may be little or no secondary market for the notes. We or our affiliates intend to act as market makers for the notes but are not required to do so and may cease such market making activities at any time. Even if there is a secondary market, it may not provide enough liquidity to allow you to sell the notes when you wish to do so or at a price advantageous to you. We expect that some dealers may act as market-makers for the notes they offer, but none of them is required to do so and they may cease such market-making activities at any time. If, at any time, we or our affiliates do not act as market

Callable Leveraged Steepener Notes due October 31, 2034
Based on the Spread between the 30-Year CMS Rate and the 2-Year CMS Rate

makers, it is likely that there would be little or no secondary market in the notes. If you have to sell your notes prior to maturity, you may not be able to do so or you may have to sell them at a substantial loss, even in cases where the Spread has increased since the Trade Date.

§ The value of the notes will be affected by a number of unpredictable factors — While we expect that, generally, the Spread between the 30-Year CMS Rate and the 2-Year CMS Rate will affect the value of the notes more than any other single factor, the value of the notes will also be affected by a number of other factors that may either offset or magnify each other, including:

- the volatility of the Spread between the 30-Year CMS Rate and the 2-Year CMS Rate;
- changes in the CMS rate yield curves;
- the time remaining to the maturity of the notes;
- trends relating to inflation;
- interest rates and yields in the market generally;
- a variety of economic, financial, political, regulatory or judicial events;
- the likelihood, or expectation, that the notes will be redeemed by us, based on prevailing market interest rates or otherwise; and
- our creditworthiness, including actual or anticipated downgrades in our credit ratings, financial condition or results of operations.

§ Trading and other transactions by us or our affiliates, or by a dealer or its affiliates, may impair the value of the notes — We or our affiliates and/or a dealer or its affiliates expect to hedge our exposure from the notes. Although it is not expected to, such hedging activity by us or other hedging parties may adversely affect the Interest Rates and, therefore, the value of the notes. In addition, we or the other hedging parties expect to make a profit on such hedge. Because hedging our obligations entails risk and may be influenced by market forces beyond our or the other hedging parties' control, such hedging may result in a profit that is more or less than expected, or it may result in a loss. It is possible that we or the other hedging parties could receive substantial returns from these hedging activities while the value of the notes decline. We or the other hedging parties may also issue or underwrite other securities or financial or derivative instruments with returns linked or related to the CMS rates. Introducing competing products into the marketplace in this manner could adversely affect the value of the notes. Any of the foregoing activities described in this paragraph may reflect trading strategies that differ from, or are in direct opposition to, investors' trading and investment strategies related to the notes. Furthermore, if you purchase the notes from a dealer or its affiliates and such dealer or its affiliates conduct trading and hedging activities for us in connection with the notes, such dealer or its affiliates may profit in connection with such trading and hedging activities and such profit, if any, will be in addition to the compensation that such dealer or its affiliates receive for the sale of the notes to you. You should be aware that the potential to earn a profit in connection with hedging activities may create a further incentive for such dealer or its affiliates to sell the notes to you in addition to the compensation it would receive for the sale of the notes.

§ We, our affiliates or our agents may publish research, express opinions or provide recommendations that are inconsistent with investing in or holding the notes. Any such research, opinions or recommendations could adversely affect the CMS rates, the Spread and the value of the notes — We, our affiliates or our agents may publish research from time to time on movements in interest rates and other matters that could adversely affect the value of the notes, or express opinions or provide recommendations that are inconsistent with purchasing or holding the notes. Any research, opinions or recommendations expressed by us, our affiliates or our agents may not be consistent with each other and may be modified from time to time without notice. You should make your own independent investigation of the merits of investing in the notes and the Interest Rates to which the notes are linked.

§ Potential conflicts of interest — We and our affiliates play a variety of roles in connection with the issuance of the notes, including acting as Calculation Agent, hedging our obligations under the notes and determining the Issuer's estimated value of the notes on the Trade Date and the price, if any, at which we or our affiliates would be willing to purchase the notes from you in secondary market transactions. In performing these roles, our economic interests and those of our affiliates are potentially adverse to your interests as an investor in the notes. The Calculation Agent will determine, among other things, all values and levels required to be determined for the purposes of the notes on any relevant date or time. Any determination by the Calculation Agent could adversely affect the return on the notes.

Historical Information

The first graph below shows the historical performance of the 30-Year CMS Rate and the 2-Year CMS Rate from September 29, 2004 through September 29, 2014. As of September 29, 2014, the 30-Year CMS Rate was 3.16% and the 2-Year CMS Rate was 0.82%. The second graph shows the historical Spread between the 30-Year CMS Rate and the 2-Year CMS Rate from September 29, 2004 through September 29, 2014. As of September 29, 2014, the Spread was 2.34%.

We obtained the various historical rates for the 30-Year CMS Rate and the 2-Year CMS Rate from Bloomberg, and we have not participated in the preparation of, or verified, such information. The historical rates of the 30-Year CMS Rate and the 2-Year CMS Rate should not be taken as an indication of future performance, and no assurance can be given as to the future movements of the 30-Year CMS Rate and the 2-Year CMS Rate during the term of the notes. In order for you to earn any interest after the first year, the Spread must be greater than the Fixed Percentage Amount of 0.25%. The Spread has been less than the Fixed Percentage Amount for an extended period of time in the past 10 years. We cannot give you assurance that the Spread will be greater than the Fixed Percentage Amount on any Interest Determination Date during the 15-year term of your notes. If the Spread is less than or equal to the Fixed Percentage Amount on all Interest Determination Dates, you will not receive any interest payments after the first year.

The CMS Rates

The "30-Year CMS Rate" for any U.S. Government Securities Business Day is the mid-market semi-annual swap rate expressed as a percentage for a U.S. dollar interest rate swap transaction with a term equal to 30 years, published on Reuters page ISDAFIX3 at 11:00 a.m., New York time. If the 30-Year CMS Rate does not appear on Reuters page ISDAFIX3 on such day, the 30-Year CMS Rate for such day shall be determined on the basis of the mid-market semi-annual swap rate quotations provided by five banking institutions selected by the Calculation Agent at approximately 11:00 a.m., New York time, on such day. For purposes of this definition, "semi-annual swap rate" means the mean of the bid and offered rates for the semi-annual fixed leg, calculated on a 30/360 day count basis, of a fixed-for-floating U.S. dollar interest rate swap transaction with a 30-year maturity commencing on that date and in an amount that is representative for a single transaction in the relevant manner at the relevant time with an acknowledged dealer of good credit in the swap market, where the floating leg, calculated on an actual/360 day count basis, is equivalent to USD-LIBOR-BBA with a designated maturity of three months. In such an event, the 30-Year CMS Rate for such day will be the arithmetic mean of the quotations, eliminating the highest quotation (or, in the event of equality, one of the highest) and the lowest quotation (or, in the event of equality, one of the lowest). If fewer than three quotations are provided as requested, the rate will be determined by the Calculation Agent in good faith and in a commercially reasonable manner. The 30-Year CMS Rate for any day which is not an U.S. Government Securities Business Day will be the 30-Year CMS Rate as in effect on the immediately preceding U.S. Government Securities Business Day.

The "2-Year CMS Rate": for any U.S. Government Securities Business Day is the mid-market semi-annual swap rate expressed as a percentage for a U.S. dollar interest rate swap transaction with a term equal to 2 years, published on Reuters page ISDAFIX3 at 11:00 a.m., New York time. If the 2-Year CMS Rate does not appear on Reuters page ISDAFIX3 on such day, the 2-Year CMS Rate for such day shall be determined on the basis of the mid-market semi-annual swap rate quotations provided by five banking institutions selected by the Calculation Agent at approximately 11:00 a.m., New York time, on such day. For purposes of this definition, "semi-annual swap rate" means the mean of the bid and offered rates for the semi-annual fixed leg, calculated on a 30/360 day count basis, of a fixed-for-floating U.S. dollar interest rate swap transaction with a 2-year maturity commencing on that date and in an amount that is representative for a single transaction in the relevant manner at the relevant time with an acknowledged dealer of good credit in the swap market, where the floating leg, calculated on an actual/360 day count basis, is equivalent to USD-LIBOR-BBA with a designated maturity of three months. In such an event, the 2-Year CMS Rate for such day will be the arithmetic mean of the quotations, eliminating the highest quotation (or, in the event of equality, one of the highest) and the lowest quotation (or, in the event of equality, one of the lowest). If fewer than three quotations are provided as requested, the rate will be determined by the Calculation Agent in good faith and in a commercially reasonable manner. The 2-Year CMS Rate for any day which is not an U.S. Government Securities Business Day will be the 2-Year CMS Rate as in effect on the immediately preceding U.S. Government Securities Business Day.

Callable Leveraged Steepener Notes due October 31, 2034
Based on the Spread between the 30-Year CMS Rate and the 2-Year CMS Rate

Additional Information about the Notes

Additional Provisions:	
General:	The notes are our Series A global notes referred to in the accompanying prospectus supplement and prospectus. The notes will be issued by Deutsche Bank AG, London Branch under an indenture among us, the Trustee, and Deutsche Bank Trust Company Americas, as issuing agent, paying agent and registrar. In addition, the Trustee has appointed Deutsche Bank Trust Company Americas as its authenticating agent with respect to our Series A global notes. The notes are not bank deposits and are not insured or guaranteed by the Federal Deposit Insurance Corporation or by any other governmental agency. The notes are our senior unsecured obligations and will rank pari passu with all of our other senior unsecured obligations, except for obligations to be preferred by law. The notes will be issued in registered form and represented by one or more permanent global notes registered in the name of DTC or its nominee, as described under “Description of Notes — Form, Legal Ownership and Denomination of Notes” in the accompanying prospectus supplement and “Forms of Securities — Legal Ownership — Global Securities” in the accompanying prospectus.
Trustee:	Law Debenture Trust Company of New York
Denominations:	Minimum denominations of $1,000 and integral multiples thereof
Minimum Ticketing Size:	$1,000 per $1,000 Principal Amount of notes
Payments on the Notes:	We will irrevocably deposit with DTC no later than the opening of business on the applicable Interest Payment Date and the Maturity Date (or the applicable Redemption Date) funds sufficient to make payments of the amount payable with respect to the notes on such date. We will give DTC irrevocable instructions and authority to pay such amount to the holders of the notes entitled thereto. Subject to the foregoing and to applicable law (including, without limitation, United States federal laws), we or our affiliates may, at any time and from time to time, purchase outstanding notes by tender, in open market transactions or by private agreement.
Tax Considerations:	In the opinion of our special tax counsel, Davis Polk & Wardwell LLP, which is based on current market conditions, the notes should

be treated for U.S. federal income tax purposes as "contingent payment debt instruments," with the tax consequences described under "—CPDI Notes," on page PS-40 of the accompanying prospectus supplement. Under this treatment, regardless of your method of tax accounting, you will be required to accrue interest in each year on a constant yield to maturity basis at the "comparable yield," as determined by us (with certain adjustments to reflect the difference, if any, between the actual and projected amounts of the contingent payments on the notes (as set forth in a "projected payment schedule" to be determined by us, which you may obtain as described below), and certain additional adjustments if the notes are purchased for an amount that differs from the issue price). Any income recognized upon a taxable disposition of the notes generally will be treated as interest income for U.S. federal income tax purposes.

Because the notes may be offered to investors at variable prices, the "issue price" of the notes for U.S. federal income tax purposes is uncertain. We intend to treat the issue price as $1,000 for each $1,000 principal amount note, and to determine the projected payment schedule accordingly. You should consult your tax adviser regarding the uncertainty with respect to the notes' issue price, including the tax consequences to you if the actual issue price of the notes for U.S. federal income tax purposes is not $1,000 per note. We will either specify the comparable yield and the projected payment schedule in the final pricing supplement or indicate how you may contact us to obtain this information. Neither the comparable yield nor the projected payment schedule constitutes a representation by us regarding the actual amounts that we will pay on a note.

It is possible that the Internal Revenue Service could determine that the notes are "variable rate debt instruments" for U.S. federal income tax purposes, which could have adverse U.S. federal income tax consequences for you. In that case, you would be required to include payments of stated interest in income when they are received or accrued, in accordance

	with your method of accounting for U.S. federal income tax purposes, as described under "—VRDI Notes," on page PS-40 of the accompanying prospectus supplement. You should consult your tax adviser regarding the U.S. federal income tax consequences to you if the notes are properly treated as variable rate debt instruments. You should review carefully the section of the accompanying prospectus supplement entitled "United States Federal Income Taxation." The preceding discussion, when read in combination with that section, constitutes the full opinion of our special tax counsel regarding the material U.S. federal income tax consequences of owning and disposing of the notes. Under current law, the United Kingdom will not impose withholding tax on payments made with respect to the notes. For a discussion of certain German tax considerations relating to the notes, you should refer to the section in the accompanying prospectus supplement entitled "Taxation by Germany of Non-Resident Holders." You should consult your tax adviser concerning the application of U.S. federal income tax laws to your particular situation, as well as any tax consequences arising under the laws of any state, local or non-U.S. jurisdictions.
Calculation Agent:	Deutsche Bank AG, London Branch. The Calculation Agent will determine, among other things, the amount of interest payable in respect of your notes on each Interest Payment Date. All determinations made by the Calculation Agent will be at the sole discretion of the Calculation Agent and will, in the absence of manifest error, be conclusive for all purposes and binding on you, the Trustee and us. We may appoint a different Calculation Agent from time to time after the date of this term sheet without your consent and without notifying you. The Calculation Agent will provide written notice to the Trustee at its New York office, on which notice the Trustee may conclusively rely, of the amount to be paid on each Interest Payment Date and at maturity (or upon early redemption) on or prior to 11:00 a.m. on the Business Day preceding each Interest Payment Date and the Maturity Date (or the applicable Redemption Date). All calculations with respect to the amount of interest payable on the notes will be rounded to the nearest one hundred-thousandth, with five one-millionths rounded upward (e.g., 0.876545 would be

	rounded to 0.87655); all dollar amounts related to determination of the payment per $1,000 Principal Amount of notes at maturity or upon earlier redemption will be rounded to the nearest ten-thousandth, with five one hundred-thousandths rounded upward (e.g., 0.76545 would be rounded up to 0.7655); and all dollar amounts paid on the aggregate Principal Amount of notes per holder will be rounded to the nearest cent, with one-half cent rounded upward.
Events of Default:	Under the heading "Description of Debt Securities — Events of Default" in the accompanying prospectus is a description of events of default relating to debt securities including the notes.
Payment upon an Event of Default:	If an event of default (as defined in the accompanying prospectus supplement) occurs, and the maturity of your notes is accelerated, we will pay a default amount for each $1,000 Principal Amount of notes equal to $1,000 plus any accrued but unpaid interest to (but excluding) the date of acceleration. If the maturity of the notes is accelerated because of an event of default as described above, we will, or will cause the Calculation Agent to, provide written notice to the Trustee at its New York office, on which notice the Trustee may conclusively rely, and to DTC of the cash amount due with respect to the notes as promptly as possible and in no event later than two Business Days after the date of acceleration.
Modification:	Under the heading "Description of Debt Securities — Modification of an Indenture" in the accompanying prospectus is a description of when the consent of each affected holder of debt securities is required to modify the indenture.
Defeasance:	The provisions described in the accompanying prospectus under the heading "Description of Debt Securities — Discharge and Defeasance" are not applicable to the notes.
Book-Entry Only Issuance — The Depository Trust Company:	DTC will act as securities depositary for the notes. The notes will be issued only as fully-registered securities registered in the name of Cede & Co. (DTC's nominee). One or more fully-registered global notes certificates, representing the total aggregate Principal Amount of the notes, will be issued and will be deposited with DTC. See the descriptions contained in the accompanying prospectus supplement under the headings "Description of Notes — Form, Legal Ownership and Denomination of Notes." The notes are offered on a global basis. Investors may elect to hold interests in the registered global notes held by DTC through Clearstream, Luxembourg or the Euroclear operator if they are participants in those systems, or indirectly through organizations

	that are participants in those systems. See "Series A Notes Offered on a Global Basis—Book Entry, Delivery and Form" in the accompanying prospectus supplement.
Governing Law:	The notes will be governed by and interpreted in accordance with the laws of the State of New York.
Use of Proceeds; Hedging:	The net proceeds we receive from the sale of the notes will be used for general corporate purposes and, in part, by us or by one or more of our affiliates in connection with hedging our obligations under the notes, as more particularly described in "Use of Proceeds" in the accompanying prospectus. We or our affiliates may acquire a long or short position in securities similar to the notes from time to time and may, in our or their sole discretion, hold or resell those securities. Although we have no reason to believe that any of these activities will have a material impact on the value of the notes, we cannot assure you that these activities will not have such an effect. We have no obligation to engage in any manner of hedging activity and will do so solely at our discretion and for our own account. No note holder shall have any rights or interest in our hedging activity or any positions we may take in connection with our hedging activity.
Supplemental Plan of Distribution (Conflicts Of Interest):	Under the terms and subject to the conditions contained in the Distribution Agreement entered into between Deutsche Bank AG and DBSI, as agent, DBSI has agreed to purchase, and we have agreed to sell, the Principal Amount of notes set forth on the cover page. The notes will be offered from time to time in one or more negotiated transactions at variable prices to be determined at the time of each sale, which may be at market prices prevailing, at prices related to such prevailing prices or at negotiated prices; provided, however, that such price will not be less than $970.00 or more than $1,000.00 per $1,000 Principal Amount of notes. DBSI will not receive a discount or commission, but will allow as a concession or reallowance to other dealers, including MS & Co., discounts and commissions of up to 3.50% or $35.00 per $1,000 Principal Amount of notes. DBSI will sell all of the notes that it purchases from us to such dealers, including MS & Co., at a price that is no less than 96.50% or $965.00 per $1,000 Principal Amount of notes. We own, directly or indirectly, all of the outstanding equity securities of DBSI. The net proceeds received from the sale of the notes will be

used, in part, by DBSI or one of its affiliates in connection with hedging our obligations under the notes. Because DBSI is both our affiliate and a member of FINRA, the underwriting arrangements for this offering must comply with the requirements of FINRA Rule 5121 regarding a FINRA member firm's distribution of the securities of an affiliate and related conflicts of interest. In accordance with FINRA Rule 5121, DBSI may not make sales in offerings of the notes to any of its discretionary accounts without the prior written approval of the customer.

DBSI may act as principal or agent in connection with offers and sales of the notes in the secondary market. Secondary market offers and sales will be made at prices related to market prices at the time of such offer or sale; accordingly, DBSI or a dealer may change the public offering price, concession and discount after the offering has been completed.

In order to facilitate the offering of the notes, DBSI may engage in transactions that stabilize, maintain or otherwise affect the price of the notes. Specifically, DBSI may sell more notes than it is obligated to purchase in connection with the offering, creating a naked short position in the notes for its own account. DBSI must close out any naked short position by purchasing the notes in the open market. A naked short position is more likely to be created if DBSI is concerned that there may be downward pressure on the price of the notes in the open market after pricing that could adversely affect investors who purchase in the offering. As an additional means of facilitating the offering, DBSI may bid for, and purchase, notes in the open market to stabilize the price of the notes. Any of these activities may raise or maintain the market price of the notes above independent market levels or prevent or retard a decline in the market price of the notes. DBSI is not required to engage in these activities, and may end any of these activities at any time.

No action has been or will be taken by us, DBSI or any dealer that would permit a public offering of the notes or possession or distribution of this term sheet, the accompanying prospectus supplement or prospectus other than in the United States, where action for that purpose is required. No offers, sales or deliveries of the notes, or distribution of this term sheet, the accompanying prospectus supplement or prospectus or any other offering material relating to the notes, may be made in or from any jurisdiction except in circumstances which will result in compliance with any applicable laws and regulations and will not impose any obligations on us, DBSI or any dealer.

DBSI has represented and agreed, and any other Agent through which we may offer the notes will represent and agree, that it (i) will comply with all applicable laws and regulations in force in each non-U.S. jurisdiction in which it purchases, offers, sells or delivers the notes or possesses or distributes this term sheet and the accompanying prospectus supplement and prospectus and (ii) will obtain any consent, approval or permission required by it for the purchase, offer or sale by it of the notes under the laws and regulations in force in each non-U.S. jurisdiction to which it is subject or in which it makes purchases, offers or sales of the notes. We shall not have responsibility for DBSI’s compliance with the applicable laws and regulations or obtaining any required consent,

	approval or permission.
ERISA:	See “Benefit Plan Investor Considerations” starting on page PS-46 in the accompanying prospectus supplement.

="2">$90.85 $90.34 $92.13

Average sales price per Mcf

5.13 4.45 7.64

Average production costs per net equivalent barrel(1)

25.21 23.14 22.05

(1) Net equivalent barrels are computed at a rate of 6 Mcf per barrel and costs exclude production taxes.

Average oil and gas prices received excluding the impact of derivatives were:

	2013	2012	2011
Oil Price per barrel	$ 93.75	$ 89.67	$ 90.04
Gas Price per Mcf	4.97	4.45	6.38

Undeveloped Acreage

The following table sets forth the approximate gross and net undeveloped acreage in which we have leasehold, mineral and royalty interests as of December 31, 2013. Undeveloped acreage is that acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and gas, regardless of whether or not such acreage contains proved reserves.

	Leasehold Interests		Mineral Interests		Royalty Interests	
State	**Gross Acres**	**Net Acres**	**Gross Acres**	**Net Acres**	**Gross Acres**	**Net Acres**
Colorado			799	23		
Montana			14,304	60		
Nebraska			2,554	331		
North Dakota			640	1		
Oklahoma	880	741	320		2,880	24
Texas	5,240	3,719	640	2		
Wyoming					140	35
TOTAL	6,120	4,460	19,257	417	3,020	59

Reserves

Our interests, including the interests held by the Partnerships, in proved developed and undeveloped oil and gas properties have been evaluated by Ryder Scott Company, L.P. for each of the three years ended December 31, 2013. The professional qualifications of the technical persons primarily responsible for overseeing the preparation of the reserves estimates can be found in Exhibit 99.1, the Ryder Scott Company, L.P. Report on Registrant s Reserves Estimates. In matters related to the preparation of our reserve estimates, our district managers report to the Houston Central manager, who maintains oversight and compliance responsibility for the internal reserve estimate process and provides oversight for the annual preparation of reserve estimates of 100% of our year-end reserves by our independent third party engineers, Ryder Scott Company, L.P. The members of our district and central groups consist of degreed engineers, geologists and geophysicists and technicians with between approximately ten and thirty-five years of industry experience, and between three and twenty years of experience managing our reserves. Our Houston Central manager, the technical person primarily responsible for overseeing the preparation of reserves estimates, has over twenty-five years of experience, holds a Bachelor of Science degree in Natural Gas Engineering and is a member of the Society of Petroleum Engineers and American Association of Petroleum Geologists. See Part II, Item 8., Financial Statements and Supplementary Data , for additional discussions regarding proved reserves and their related cash flows.

All of our reserves are located within the continental United States. The following table summarizes our oil and gas reserves at each of the respective dates:

	Reserve Category											
	Proved Developed				Proved Undeveloped				Total			
As of December 31,	**Oil (MBbls)**	**NGLs (MBbls) (a)**	**Gas (MMcf)**	**Total (MBoe) (b)**	**Oil (MBbls)**	**NGLs (MBbls) (a)**	**Gas (MMcf)**	**Total (MBoe) (b)**	**Oil (MBbls)**	**NGLs (MBbls) (a)**	**Gas (MMcf)**	**Total (MBoe) (b)**
2011	6,418		43,631	13,690	2,435		9,765	4,063	8,853		53,396	17,752
2012	7,178	2,909	27,833	14,726	5,907	2,877	12,613	10,886	13,085	5,786	40,446	25,612
2013	6,687	2,223	31,628	14,182	9,066	3,707	19,772	16,068	15,753	5,930	51,400	30,250

(a) Prior to December 31, 2012, natural gas liquids (NGLs) were included in the oil and gas reserve reports under the natural gas heading using a standard conversion factor of one barrel of NGLs to six thousand cubic feet (Mcf) of gas.

Table of Contents

(b) In computing total reserves on a barrels of oil equivalent (Boe), gas is converted to oil based on its relative energy content at the rate of six Mcf of gas to one barrel of oil and NGLs are converted based upon volume; one barrel of natural gas liquids equals one barrel of oil.

Our proved undeveloped reserves of 4,063 MBoe as of December 31, 2011 included 64 in-fill drilling locations in our West Texas drilling program and 5 drilling locations in our Mid-Continent region. During 2012 we drilled 29 West Texas wells and 7 Mid-Continent wells at a cost of $42.3 million converting 1,449 MBoe to proved developed producing reserves and added 85 additional proved undeveloped drilling locations. Proved undeveloped reserves of 10,886 MBoe as of December 31, 2012 included 127 drilling locations in our West Texas drilling program, 11 drilling locations in our Mid-Continent region and 2 drilling locations in our Gulf Coast region. During 2013 we drilled 9 West Texas wells and 14 Mid-Continent wells at a cost of $25.9 million converting 913 MBoe to proved developed producing reserves and added 40 additional proved undeveloped drilling locations. Proved undeveloped reserves of 16,068 MBoe as of December 31, 2013 included 148 drilling locations in our West Texas drilling program, 10 drilling locations in our Mid-Continent region and 4 drilling locations in our Gulf Coast region. We have no proved undeveloped reserves scheduled for development five years beyond date of first booking.

We employ technologies to establish proved reserves that have been demonstrated to provide consistent results capable of repetition. The technologies and economic data being used in the estimation of our proved reserves include, but are not limited to, electrical logs, radioactivity logs, geologic maps, production data and well test data. The estimated reserves of wells with sufficient production history are estimated using appropriate decline curves. Estimated reserves of producing wells with limited production history and for undeveloped locations are estimated using performance data from analogous wells in the area. These wells are considered analogous based on production performance from the same formation and with similar completion techniques.

The estimated future net revenue (using current prices and costs as of those dates) and the present value of future net revenue (at a 10% discount for estimated timing of cash flow) for our proved developed and proved undeveloped oil and gas reserves at the end of each of the three years ended December 31, 2013, are summarized as follows (in thousands of dollars):

	Proved Developed		Proved Undeveloped		Total			
As of December 31,	Future Net Revenue	Present Value 10 Of Future Net Revenue	Future Net Revenue	Present Value 10 Of Future Net Revenue	Future Net Revenue	Present Value 10 Of Future Net Revenue	Present Value 10 Of Future Income Taxes	Standardized Measure of Discounted Cash flow
2011	$ 394,662	$ 217,900	$ 121,547	$ 35,256	$ 516,209	$ 253,156	$ 68,648	$ 184,508
2012	380,346	214,533	290,594	73,340	670,940	287,873	74,600	213,273
2013	341,841	204,326	455,622	131,510	797,463	335,836	97,608	238,228

The PV 10 Value represents the discounted future net cash flows attributable to our proved oil and gas reserves before income tax, discounted at 10%. Although this measure is not in accordance with U.S. generally accepted accounting principles (GAAP), we believe that the presentation of the PV 10 Value is relevant and useful to investors because it presents the discounted future net cash flow attributable to proved reserves prior to taking into account corporate future income taxes and the current tax structure. We use this measure when assessing the potential return on investment related to oil and gas properties. The PV 10 of future income taxes represents the sole reconciling item between this non-GAAP PV 10 Value versus the GAAP measure presented in the standardized measure of discounted cash flow. A reconciliation of these values is presented in the last three columns of the table above. The standardized measure of discounted future net cash flows represents the present value of future cash flows attributable to proved oil and natural gas reserves after income tax, discounted at 10%.

Proved developed oil and gas reserves are reserves that can be expected to be recovered from existing wells with existing equipment and operating methods. Proved undeveloped oil and gas reserves are reserves

23

that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. Our reserves include amounts attributable to non-controlling interests in the Partnerships. These interests represent less than 10% of our reserves.

In accordance with U.S. generally accepted accounting principles, product prices are determined using the twelve-month average oil and gas index prices, calculated as the unweighted arithmetic average for the first day of the month price for each month, adjusted for oilfield or gas gathering hub and wellhead price differentials (e.g. grade, transportation, gravity, sulfur, and basic sediment and water) as appropriate. Also in accordance with SEC specifications and U.S. generally accepted accounting principles, changes in market prices subsequent to December 31 are not considered.

The range of Henry Hub daily gas prices per MMbtu during the year 2013 was a low of $3.08 and a high of $4.52 and the average was $3.73. The range during the first two months of 2014 has been from $3.95 to $8.15 with an average of $5.32. The recent futures market prices have traded in the range of $5.79 per MMbtu.

The range of NYMEX oil prices per barrel during the year 2013 was a low of $86.65 and a high of $110.62 and the average was $97.98. The range during the first two months of 2014 has been from $91.36 to $103.46 with an average of $97.56. The recent futures market prices have fluctuated around $102.00 per barrel.

While it may reasonably be anticipated that the prices received for the sale of our production may be higher or lower than the prices used in this evaluation, as described above, and the operating costs relating to such production may also increase or decrease from existing levels, such possible changes in prices and costs were, in accordance with rules adopted by the SEC, omitted from consideration in making this evaluation for the SEC case. Actual volumes produced, prices received and costs incurred may vary significantly from the SEC case.

Since January 1, 2014, we have not filed any estimates of our oil and gas reserves with, nor were any such estimates included in any reports to, any federal authority or agency, other than the Securities and Exchange Commission.

District Information

The following table presents certain reserve, production and well information as of December 31, 2013.

	Appalachian	Gulf Coast	Mid-Continent	West Texas	Other	Total
Proved Reserves at Year End (MBoe)						
Developed	1,087	1,030	3,167	8,768	130	14,182
Undeveloped		220	269	15,579		16,068
Total	1,087	1,250	3,436	24,347	130	30,250
Average Daily Production (Boe per day)	402	675	896	2,209	55	4,236
Gross Wells	725	370	727	577	107	2,506
Net Wells	370	152	257	202	17	998
Gross Operated Wells	496	292	383	380	58	1,609

In several of our regions we operate field service groups to service our operated wells and locations as well as third party operators in the area. These services consist of well service support, site preparation and construction services for drilling and workover operations. Our operations are performed utilizing workover or swab rigs, water transport trucks, saltwater disposal facilities, various land excavating equipment and trucks we own and that are operated by our field employees.

Table of Contents

Appalachian Region

Our Appalachian activities are concentrated primarily in West Virginia. This region is managed from our office in Charleston, West Virginia. Our assets in this region include a large acreage position and a high concentration of wells. At December 31, 2013, we had 725 wells (370 net), of which 496 wells are operated by us. There are multiple producing intervals that include the Big Lime, Injun, Blue Monday, Weir, Berea, Gordon and Devonian Shale formations at depths primarily ranging from 1,600 to 5,600 feet. Average net daily production in 2013 was 402 Boe. While natural gas production volumes from Appalachian reservoirs are relatively low on a per-well basis compared to other areas of the United States, the productive life of Appalachian reserves is relatively long. At December 31, 2013, we had 1,087 MBoe of proved reserves (substantially all natural gas) in the Appalachian region, constituting 4% of our total proved reserves. We operate a small field service group in this region utilizing one swab rig, one paraffin truck, one saltwater hauling truck and limited excavating equipment to primarily service our own operated wells and locations. As of March 1, 2014 the Appalachian region has no wells in the process of being drilled, no waterfloods in the process of being installed and no other related activities of material importance.

Gulf Coast Region

Our development, exploitation, exploration and production activities in the Gulf Coast region are primarily concentrated in Louisiana, southeast Texas and south Texas. This region is managed from our office in Houston, Texas. Principal producing intervals are in the Marg Tex, Wilcox, Pettit, Glenrose, Woodbine, San Miguel, Olmos, and Yegua formations at depths ranging from 3,000 to 12,500 feet. We had 370 wells (152 net) in the Gulf Coast region as of December 31, 2013, of which 292 wells are operated by us. Average daily production in 2013 was 675 Boe. At December 31, 2013, we had 1,250 MBoe of proved reserves (37% oil) in the Gulf Coast region, which represented 4% of our total proved reserves. We operate a field service group in this region from a field office in Carrizo Springs, Texas utilizing 3 workover rigs, 18 water transport trucks, one saltwater disposal well and several trucks and excavating equipment. Services including well service support, site preparation and construction services for drilling and workover operations are provided to third party operators as well as utilized in our own operated wells and locations. As of March 1, 2014 the Gulf Coast region has no wells in the process of being drilled, no waterfloods in the process of being installed and no other related activities of material importance.

Mid-Continent Region

Our Mid-Continent activities are concentrated in central Oklahoma. This region is managed from our office in Oklahoma City, Oklahoma. As of December 31, 2013, we had 727 wells (257 net) in the Mid-Continent area, of which 383 wells are operated by us. Principal producing intervals are in the Roberson, Avant, Skinner, Sycamore, Bromide, McLish, Hunton, Mississippian, Oswego, Red Fork, and Chester formations at depths ranging from 1,100 to 10,500 feet. Average net daily production in 2013 was 896 Boe. At December 31, 2013, we had 3,436 MBoe of proved reserves (51% oil) in the Mid-Continent area, or 11% of our total proved reserves. We operate a field service group in this region from a field office in Kingfisher, Oklahoma utilizing 4 workover rigs, 2 saltwater hauling trucks and several trucks and excavating equipment. Services including well service support, site preparation and construction services for drilling and workover operations are provided to third party operators as well as utilized in our own operated wells and locations. As of March 1, 2014 the Mid-Continent region has one well in the process of being drilled and two wells or awaiting completion, no waterfloods in the process of being installed and no other related activities of material importance.

West Texas Region

Our West Texas activities are concentrated in the Permian Basin in Texas and New Mexico. This region is managed from our office in Midland, Texas. As of December 31, 2013, we had 577 wells (202 net) in the West Texas area, of which 380 wells are operated by us. Principal producing intervals are in the Spraberry, Wolfcamp

Table of Contents

and San Andres formations at depths ranging from 5,500 to 12,500 feet. Average net daily production in 2013 was 2,209 Boe. At December 31, 2013, we had 24,347 MBoe of proved reserves (55% oil) in the West Texas area, or 80% of our total proved reserves. We operate a field service group in this region utilizing 8 workover rigs, 3 hot oiler trucks and several trucks. Services including well service support, site preparation and construction services for drilling and workover operations are provided to third party operators as well as utilized in our own operated wells and locations. As of March 1, 2014 the West Texas region has no wells in the process of being drilled and four wells awaiting completion, no waterfloods in the process of being installed and no other related activities of material importance.

Acreage subject to expiration in the next three years;

	2014		2015		2016	
State / Area	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Texas			1,640	1,032		
TOTAL			1,640	1,032		

Item 3. LEGAL PROCEEDINGS.

None.

Table of Contents

PART II

Item 5. MARKET FOR REGISTRANT S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES.

Our common stock is listed and principally traded on the NASDAQ Stock Market under the ticker symbol PNRG . The following table presents the high and low closing prices per share of our common stock during certain periods, as reported in the consolidated transaction reporting system.

	High	Low
2013		
First Quarter	$ 30.03	$ 22.70
Second Quarter	37.00	26.24
Third Quarter	53.25	33.62
Fourth Quarter	51.50	38.11
2012		
First Quarter	$ 28.55	$ 19.19
Second Quarter	27.34	21.43
Third Quarter	28.00	25.01
Fourth Quarter	28.25	22.00

The above quotations reflect inter-dealer prices, without retail mark-up, mark-down or commissions, and may not represent actual transactions.

As of March 23, 2014, there were 493 registered holders of the common stock.

No dividends have been declared or paid during the past two years on our common stock. Provisions of our line of credit agreement restrict our ability to pay dividends. Such dividends may be declared out of funds legally available therefore, when and as declared by our Board of Directors.

Table of Contents

Issuer Purchases of Equity Securities

In December 1993, we announced that the Board of Directors authorized a stock repurchase program whereby we may purchase outstanding shares of the common stock from time-to-time, in open market transactions or negotiated sales. On October 31, 2012, the Board of Directors of the Company approved an additional 500,000 shares of the Company s stock to be included in the stock repurchase program. A total of 3,500,000 shares have been authorized, to date, under this program. Through December 31, 2013, a total of 3,157,672 shares have been repurchased under this program for $48,907,683 at an average price of $15.49 per share. Additional purchases of shares may occur as market conditions warrant. We expect future purchases will be funded with internally generated cash flow or from working capital.

2013 Month	Number of Shares	Average Price Paid per share	Maximum Number of Shares that May Yet Be Purchased Under The Program at Month-End
January	2,712	$ 25.06	461,392
February	6,710	26.78	454,682
March	47,219	29.17	407,463
April	15,177	30.38	392,286
May	16,416	31.26	375,870
June	4,069	33.21	371,801
July	2,551	41.69	369,250
August	1,371	46.73	367,879
September	1,457	50.23	366,422
October	6,999	46.69	359,423
November	6,093	47.08	353,330
December	11,002	49.68	342,328
Total / Average	121,776	$ 33.98	

Item 6. SELECTED FINANCIAL DATA

We are a smaller reporting company and therefore no response is required pursuant to this Item.

Table of Contents

Item 7. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS
The following discussion is intended to assist you in understanding our results of operations and our present financial condition. Our Consolidated Financial Statements and the accompanying Notes to the Consolidated Financial Statements included elsewhere in this Report contains additional information that should be referred to when reviewing this material. Our subsidiaries are listed in Note 1 to the Consolidated Financial Statements.

Overview:

We are an independent oil and natural gas company engaged in acquiring, developing and producing oil and natural gas. We presently own producing and non-producing properties located primarily in Texas, Oklahoma, West Virginia, New Mexico, Colorado and Louisiana. In addition, we own a substantial amount of well servicing equipment. All of our oil and gas properties and interests are located in the United States. Assets in our principal focus areas include mature properties with long-lived reserves and significant development opportunities as well as newer properties with development and exploration potential. We believe our balanced portfolio of assets and our ongoing hedging program position us well for both the current commodity price environment and future potential upside as we develop our attractive resource opportunities. Our primary sources of liquidity are cash generated from our operations and our credit facility.

We attempt to assume the position of operator in all acquisitions of producing properties and will continue to evaluate prospects for leasehold acquisitions and for exploration and development operations in areas in which we own interests. We continue to actively pursue the acquisition of producing properties. In order to diversify and broaden our asset base, we will consider acquiring the assets or stock in other entities and companies in the oil and gas business. Our main objective in making any such acquisitions will be to acquire income producing assets so as to build stockholder value through consistent growth in our oil and gas reserve base on a cost-efficient basis.

Our cash flows depend on many factors, including the price of oil and gas, the success of our acquisition and drilling activities and the operational performance of our producing properties. We use derivative instruments to manage our commodity price risk. This practice may prevent us from receiving the full advantage of any increases in oil and gas prices above the maximum fixed amount specified in the derivative agreements and subjects us to the credit risk of the counterparties to such agreements. Since all of our derivative contracts are accounted for under mark-to-market accounting, we expect continued volatility in gains and losses on mark-to-market derivative contracts in our consolidated statement of operations as changes occur in the NYMEX price indices.

Critical Accounting Estimates:

Proved Oil and Gas Reserves

Proved oil and gas reserves directly impact financial accounting estimates, including depreciation, depletion and amortization. Proved reserves represent estimated quantities of natural gas, crude oil, condensate, and natural gas liquids that geological and engineering data demonstrate, with reasonable certainty, to be recoverable in future years from known reservoirs under economic and operating conditions existing at the time the estimates were made. The process of estimating quantities of proved oil and gas reserves is very complex, requiring significant subjective decisions in the evaluation of all available geological, engineering and economic data for each reservoir. The data for a given reservoir may also change substantially over time as a result of numerous factors including, but not limited to, additional development activity, evolving production history and continual reassessment of the viability of production under varying economic conditions. Consequently, material revisions (upward or downward) to existing reserve estimates may occur from time to time.

Table of Contents

Depreciation, Depletion and Amortization for Oil and Gas Properties

The quantities of estimated proved oil and gas reserves are a significant component of our calculation of depletion expense and revisions in such estimates may alter the rate of future expense. Holding all other factors constant, if reserves were revised upward or downward, earnings would increase or decrease respectively.

Depreciation, depletion and amortization of the cost of proved oil and gas properties are calculated using the unit-of-production method. The reserve base used to calculate depletion, depreciation or amortization is the sum of proved developed reserves and proved undeveloped reserves for leasehold acquisition costs and the cost to acquire proved properties. The reserve base includes only proved developed reserves for lease and well equipment costs, which include development costs and successful exploration drilling costs. Estimated future dismantlement, restoration and abandonment costs, net of salvage values, are taken into account.

Liquidity And Capital Resources:

Net cash provided by operating activities for the year ended December 31, 2013 was $36 million, compared to $40 million in the prior year. Excluding the effects of significant unforeseen expenses or other income, our cash flow from operations fluctuates primarily because of variations in oil and gas production and prices or changes in working capital accounts. Our oil and gas production will vary based on actual well performance but may be curtailed due to factors beyond our control.

Our realized oil and gas prices vary due to world political events, supply and demand of products, product storage levels, and weather patterns. We sell the vast majority of our production at spot market prices. Accordingly, product price volatility will affect our cash flow from operations. To mitigate price volatility we sometimes lock in prices for some portion of our production through the use of derivatives.

If our exploratory drilling results in significant new discoveries, we will have to expend additional capital in order to finance the completion, development, and potential additional opportunities generated by our success. We believe that, because of the additional reserves resulting from the successful wells and our record of reserve growth in recent years, we will be able to access sufficient additional capital through additional bank financing.

As of March 1, 2014, the Company maintains a credit facility totaling $250 million, with a borrowing base of $140 million. The bank reviews the borrowing base semi-annually and, at their discretion, may decrease or propose an increase to the borrowing base relative to a redetermined estimate of proved oil and gas reserves. Our oil and gas properties are pledged as collateral for the line of credit and we are subject to certain financial and operational covenants defined in the agreement. We are currently in compliance with these covenants and expect to be in compliance over the next twelve months. If we do not comply with these covenants on a continuing basis, the lenders have the right to refuse to advance additional funds under the facility and/or declare all principal and interest immediately due and payable.

In July 2013, we obtained a $10 million loan secured by most of the field service equipment that we own to conduct our field service operations. We used the funds from that loan to pay down our credit facility, and as a result, freed up additional funds under the credit facility for future acquisitions, development and operations. As of March 20, 2014, we had a total of $8.9 million outstanding on this loan.

It is our goal to increase our oil and gas reserves and production through the acquisition and development of oil and gas properties. We continued our drilling program in our West Texas and Mid-Continent regions. Based upon the results of horizontal wells drilled by us and other offsetting operators and historical vertical well performance we have decided to reduce the number of vertical wells in our drilling program and drill more horizontal wells. We believe horizontal development of our resource base will provide the opportunity to improve returns relative to vertical drilling by accessing a larger base of reserves in target zone with a lateral wellbore. During 2014, we intend to drill a total of approximately 20 gross (11 net) wells, primarily in the West Texas area, at a net cost of $60 million. We also continue to explore and consider opportunities to further expand our oilfield servicing revenues through additional investment in field service equipment. However, the majority of our capital spending is discretionary, and the ultimate level of expenditures will be dependent on our assessment of the oil and gas business environment, the number and quality of oil and gas prospects available, the market for oilfield services, and oil and gas business opportunities in general.

Table of Contents

The Company has in place both a stock repurchase program and a limited partnership interest repurchase program. Spending under these programs in 2013 was $4.2 million. The Company expects continued spending under these programs in 2014.

Results of Operations:

2013 and 2012 Compared

We reported net income for 2013 of $12.27 million, or $5.04 per share. During 2012, we reported net income of $15.06 million, or $5.74 per share. Net income decreased in 2013 by $2.79 million or 18%, primarily due to net decreases in gains from derivative instruments, increased lease operating and field service expenses partially offset by increases in oil and gas sales and field service income and decreased depreciation and depletion expenses. Operating revenues increased by $4.09 million in 2013 as compared to 2012 largely due to a slight increase in net production and increased commodity prices realized in 2013 and an increase in field service income with the addition of new service equipment during 2013 partially offset by losses on derivative instruments in 2013 versus gains on derivative instruments recognized in 2012. Lease operating and field service expenses increased $3.94 million and $3.45 million, respectively, in 2013 as compared to 2012 primarily from increased labor and chemical costs and an increase in services provided. Depreciation and depletion decreased by $1.41 million in 2013 as compared to 2012 primarily associated with offshore properties as our offshore properties were plugged and abandoned during 2012.

The significant components of net income are discussed below.

Oil and gas sales increased $4.96 million, or 6% from $87.83 million for the year ended December 31, 2012 to $92.79 million for the year ended December 31, 2013. Crude oil and natural gas sales vary due to changes in volumes of production sold and realized commodity prices. Our realized prices at the well head increased an average of $4.08 per barrel, or 5% on crude oil and $0.52 per Mcf, or 12% on natural gas during 2013 as compared to 2012.

Our crude oil production decreased by 15,000 barrels, or 2% from 745,000 barrels for the year ended December 31, 2012 to 730,000 barrels for the year ended December 31, 2013. Our natural gas production increased by 182 MMcf, or 4% from 4,715 MMcf for the year ended December 31, 2012 to 4,897 MMcf for the year ended December 31, 2013. The slight decrease in crude oil production volumes are a result of significant disruptions in our production due to the effects of the extreme cold weather in our producing areas particularly West Texas and Oklahoma and the natural decline of existing properties substantially offset by production from new wells we placed into production from our continued drilling success in West Texas and the Gulf Coast regions. The natural gas volume increases are primarily due to the natural gas production from wells in the West Texas region recently placed into production.

The following table summarizes the primary components of production volumes and average sales prices realized for the years ended December 31, 2013 and 2012 (excluding realized gains and losses from derivatives).

	Year Ended December 31,		Increase (Decrease)	
	2013	2012	Amount	Percent
Barrels of Oil Produced	730,000	745,000	(15,000)	(2)%
Average Price Received (excluding the impact of derivatives)	$ 93.75	$ 89.67	$ 4.08	5%
Oil Revenue (In 000 s)	$ 68,446	$ 66,830	$ 1,616	2%
Mcf of Gas Produced	4,897,000	4,715,000	182,000	4%
Average Price Received (excluding the impact of derivatives)	$ 4.97	$ 4.45	$ 0.52	12%
Gas Revenue (In 000 s)	$ 24,339	$ 21,004	$ 3,335	16%
Total Oil & Gas Revenue (In 000 s)	$ 92,785	$ 87,834	$ 4,951	6%

Realized net gains (losses) on derivative instruments include net losses of $1.3 million on the settlements of crude oil and natural gas derivatives for the year ended December 31, 2013. During 2012, we unwound and

monetized crude oil swaps with original settlement dates from January 2012 through December 2013 for net proceeds of $1.0 million. The $1.0 million gain associated with these early settlement transactions is included in realized gain on derivative instruments for the year ended December 31, 2012.

Oil and gas prices received including the impact of derivatives but excluding the early settlement transactions were:

	Year Ended December 31,		Increase (Decrease)	
	2013	2012	Amount	Percent
Oil Price	$ 90.85	$ 88.96	$ 1.89	2%
Gas Price	$ 5.13	$ 4.45	$ 0.68	15%

We do not apply hedge accounting to any of our commodity based derivatives thus changes in the fair market value of commodity contracts held at the end of a reported period, referred to as mark-to-market adjustments, are recognized as unrealized gains and losses in the accompanying consolidated statements of operations. As oil and natural gas prices remain volatile, mark-to-market accounting treatment creates volatility in our revenues. During the year ended December 31, 2013, we recognized $0.6 million in net unrealized losses. This unrealized loss primarily relates to held crude oil and natural gas fixed swaps and collars associated with future production due to an increase in crude oil and natural gas futures market prices between January 1, 2013 and December 31, 2013.

Field service income increased $4.51 million, or 22% from $20.42 million for the year ended December 31, 2012 to $24.93 million for the year ended December 31, 2013. This underlying increase is a result of adding service equipment and the market allowing us to charge slightly higher rates to customers. Workover rig services represent the bulk of our field service operations, and those rates have all increased between the periods in our most active districts.

Lease operating expense increased $3.94 million, or 10% from $39.87 million for the year ended December 31, 2012 to $43.81 million for the year ended December 31, 2013. This underlying increase is primarily due to higher pumper / labor costs and chemical expenses associated with new wells coming on line from the recent drilling success in West Texas and increased expensed workovers across all districts, partially offset by decreased operating expenses on the offshore properties during 2013.

Field service expense increased $3.45 million, or 20% from $17.58 million for the year ended December 31, 2012 to $21.03 million for the year ended December 31, 2013. Field service expenses primarily consist of salaries and vehicle operating expenses which have increased as a direct result of increased services and utilization of the equipment during the year ended December 31, 2013 as compared to the same period of 2012.

Depreciation, depletion, amortization and accretion on discounted liabilities decreased $1.41 million, or 6% from $23.27 million for the year ended December 31, 2012 to $21.86 million for the year ended December 31, 2013. This decrease is primarily due to decreased depletion rates recognized during 2013 associated with offshore properties as our offshore properties were plugged and abandoned during 2012, partially offset by increased depletion expenses related to new wells coming on line from the recent drilling success in West Texas.

General and administrative expense increased $0.79 million, or 5% from $15.87 million for the year ended December 31, 2012 to $16.66 million for the year ended December 31, 2013. This slight increase is largely due to increased personnel costs in 2013. The largest component of these personnel costs was salaries, employee related taxes and insurance.

Gain on sale and exchange of assets of $2.82 million for the year ended December 31, 2013 consists of sales of non-producing acreage and non-core oil and gas interests and non-essential field service equipment

Table of Contents

whereas the gain on sale and exchange of assets of $0.73 million for the year ended December 31, 2012 consists of sales of non-essential field service equipment.

Interest expense increased $0.64 million, or 18% from $3.58 million for the year ended December 31, 2012 to $4.22 million for the year ended December 31, 2013. This increase relates to an increase in average debt outstanding during 2013 as compared to 2012 slightly offset by a decrease in weighted average interest rates during the 2013 periods. The average interest rate paid on outstanding bank borrowings subject to interest during 2013 and 2012 were 3.58% and 3.81%, respectively. As of December 31, 2013 and 2012, the total outstanding borrowings were $121.89 million and $122.00 million, respectively.

A provision for income taxes of $6.82 million, or an effective tax rate of 36% was recorded for the year ended December 31, 2013 verses a provision of $6.86 million, or an effective tax rate of 31% for the year ended December 31, 2012. Our provision for income taxes varies from the federal statutory tax rate of 34% primarily due to percentage depletion. We are entitled to percentage depletion on certain of our wells for tax purposes, which is calculated without reference to the basis of the property. To the extent that such depletion exceeds a property s basis it creates a permanent difference, which lowers our effective rate.

Item 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK.

We are a smaller reporting company and therefore no response is required pursuant to this Item.

Item 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA.

The consolidated financial statements and supplementary information included in this Report are described in the Index to Consolidated Financial Statements at Page F-1 of this Report.

Item 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE.

None.

Item 9A. CONTROLS AND PROCEDURES.

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 evaluated the effectiveness of our disclosure controls and procedures (Disclosure Controls). Disclosure Controls, as defined in Rule 13a-15(e) of the Securities Exchange Act of 1934, as amended (the Exchange Act), are procedures that are designed with the objective of ensuring that information required to be disclosed in our reports filed under the Exchange Act, such as this Annual Report, is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission s rules and forms. Disclosure Controls are also designed with the objective of ensuring that such information is accumulated and communicated to our management, including the chief executive officer and chief financial officer, as appropriate to allow timely decisions regarding required disclosure.

Our management, including the chief executive officer and chief financial officer, does not expect that our Disclosure Controls will prevent all error and all fraud. A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Further, the design of a control system must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, within the Company have been detected. These inherent limitations include the realities that judgments in decision-making can be faulty, and that breakdowns can occur because of simple error or mistake. The design of any system of controls also is based in part upon certain assumptions about the likelihood of future events, and

Table of Contents

there can be no assurance that any design will succeed in achieving its stated goals under all potential future conditions.

Members of our management, including our chief executive officer and chief financial officer, have evaluated the effectiveness of our disclosure controls and procedures, as defined by paragraph (e) of Exchange Act Rules 13a-15 or 15d-15, as of December 31, 2013, the end of the period covered by this Report. Based upon that evaluation, these officers concluded that our disclosure controls and procedures were effective as of December 31, 2013.

Management s Report on Internal Control Over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act. Our internal control over financial reporting is a process designed to provide reasonable assurance that assets are safeguarded against loss from unauthorized use or disposition, transactions are executed in accordance with appropriate management authorization and accounting records are reliable for the preparation of financial statements in accordance with U.S. generally accepted accounting principles.

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.

Management assessed the effectiveness of our internal control over financial reporting as of December 31, 2013. Management based this assessment on criteria for effective internal control over financial reporting described in Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Management s assessment included an evaluation of the design of our internal control over financial reporting and testing of the operational effectiveness of its internal control over financial reporting. Management reviewed the results of its assessment with the Audit Committee of our Board of Directors.

Based on this assessment, management believes that the Company maintained effective internal control over financial reporting as of December 31, 2013.

This Annual Report does not include an attestation report of the Company s registered public accounting firm regarding internal control over financial reporting. Management s report was not subject to attestation by the Company s registered public accounting firm pursuant to rules of the Securities and Exchange Commission that permit the Company to provide only management s report in this Annual Report.

There have been no changes in our internal controls over financial reporting during the fourth fiscal quarter ended December 31, 2013 that have materially affected, or are reasonably likely to materially affect, our internal controls over financial reporting.

Item 9B. OTHER INFORMATION.

None.

Table of Contents

PART III

Item 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE.

Information relating to the Company s Directors, nominees for Directors and executive officers will be included in the Company s definitive proxy statement relating the Company s Annual Meeting of Stockholders to be held in May, 2014 which will be filed with the U.S. Securities and Exchange Commission within 120 days of December 31, 2013, and which is incorporated herein by reference.

Item 11. EXECUTIVE COMPENSATION.

Information relating to executive compensation will be included in the Company s definitive proxy statement relating to the Company s Annual Meeting of Stockholders to be held in May, 2014, which will be filed with the U. S. Securities and Exchange Commission within 120 days of December 31, 2013, and which is incorporated herein by reference.

Item 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS.

Information relating to security ownership of certain beneficial owners and management will be included in the Company s definitive proxy statement relating to the Company s Annual Meeting of Stockholders to be held in May, 2014, which will be filed with the U. S. Securities and Exchange Commission within 120 days of December 31, 2013, and which is incorporated herein by reference.

Item 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE.

Information relating to certain transactions by Directors and executive officers of the Company will be included in the Company s definitive proxy statement relating to the Company s Annual Meeting of Stockholders to be held in May, 2014, which will be filed with the U. S. Securities and Exchange Commission within 120 days of December 31, 2013, and which is incorporated herein by reference.

Item 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES.

Information relating to principal accountant fees and services will be included in the Company s definitive proxy statement relating to the Company s Annual Meeting of Stockholders to be held in May, 2014, which will be filed with the U. S. Securities and Exchange Commission within 120 days of December 31, 2013, and which is incorporated herein by reference.

Table of Contents

PART IV

Item 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES.
The following documents are filed as part of this Report:

1. Financial statements (Index to Consolidated Financial Statements at page F-1 of this Report)

2. Financial Statement Schedules (Index to Consolidated Financial Statements Supplementary Information at page F-1 of this Report)

3. Exhibits:

Exhibit No.	
3.1	Restated Certificate of Incorporation of PrimeEnergy Corporation (effective July 1, 2009) (Incorporated by reference to Exhibit 3.1 to PrimeEnergy Corporation Form 10-Q for the quarter ended June 30, 2009).
3.2	Bylaws of PrimeEnergy Corporation (Incorporated by reference to Exhibit 3.2 of PrimeEnergy Corporation Form 10-Q for the quarter ended June 30, 2010).
10.4	Amended and Restated Agreement of Limited Partnership, FWOE Partners L.P., dated as of August 22, 2005 (Incorporated by reference to Exhibit 10.3 of PrimeEnergy Corporation Form 8-K for events of August 22, 2005).
10.4.1	Contribution Agreement between F-W Oil Exploration L.L.C. and FWOE Partners L.P. dated as of August 22, 2005 (Incorporated by reference to exhibit 10.4 of PrimeEnergy Corporation Form 8-K for events of August 22, 2005).
10.18	Composite copy of Non-Statutory Option Agreements (Incorporated by reference to Exhibit 10.18 of PrimeEnergy Corporation Form 10-K for the year ended December 31, 2004).
10.22.5.9	Second Amended and Restated Credit Agreement dated July 30, 2010, by and among PrimeEnergy Corporation, the Guarantors Party Hereto (PrimeEnergy Management Corporation, Prime Operating Company, Eastern Oil Well Service Company, Southwest Oilfield Construction Company, and EOWS Midland Company), Compass Bank (successor in interest to Guaranty Bank, FSB) As Administrative Agent and Letter of Credit Issuer, BBVA Compass, As Sole Lead Arranger and Sole Bookrunner and The Lenders Signatory Hereto (BNP Paribas, JPMorgan Chase Bank, N.A. and Amegy Bank National Association) (Incorporated by reference to Exhibit 10.22.5.9 of PrimeEnergy Corporation Form 10-Q for the quarter ended June 30, 2010).
10.22.5.9.1	First Amendment To Second Amended and Restated Credit Agreement Among PrimeEnergy Corporation, The Guarantors Party Hereto (PrimeEnergy Management Corporation, Prime Operating Company, Eastern Oil Well Service Company, Southwest Oilfield Construction Company, E O W S Midland Company), Compass Bank (successor in interest to Guaranty Bank, FSB), As Administrative Agent, Letter of Credit Issuer and Collateral Agent and The Lenders Signatory Hereto (Compass Bank, BNP Paribas, JPMorgan Chase Bank, N.A., Amegy Bank National Association) effective September 30, 2010 (Incorporated by reference to Exhibit 10.22.5.9.1 to PrimeEnergy Corporation Form 10-Q for the quarter ended September 30, 2010).
10.22.5.9.2	Second Amendment To Second Amended and Restated Credit Agreement Among PrimeEnergy Corporation, The Guarantors Party Hereto (PrimeEnergy Management Corporation, Prime Operating Company, Eastern Oil Well Service Company, Southwest Oilfield Construction Company, E O W S Midland Company), Compass Bank (successor in interest to Guaranty Bank, FSB), As Administrative Agent, Letter of Credit Issuer and Collateral Agent and The Lenders Signatory Hereto (Compass Bank, BNP Paribas, JPMorgan Chase Bank, N.A., Amegy Bank National Association) effective June 22, 2011 (Incorporated by reference to Exhibit 10.22.5.9.2 to PrimeEnergy Corporation Form 10-Q for the quarter ended June 30, 2011).

Table of Contents

Exhibit No.	
10.22.5.9.3	Third Amendment To Second Amended and Restated Credit Agreement Among PrimeEnergy Corporation, The Guarantors Party Hereto (PrimeEnergy Management Corporation, Prime Operating Company, Eastern Oil Well Service Company, Southwest Oilfield Construction Company, E O W S Midland Company), Compass Bank (successor in interest to Guaranty Bank, FSB), As Administrative Agent, Letter of Credit Issuer and Collateral Agent and The Lenders Signatory Hereto (Compass Bank, BNP Paribas, JPMorgan Chase Bank, N.A., Amegy Bank National Association) effective December 8, 2011 (Incorporated by reference to Exhibit 10.22.5.9.3 to PrimeEnergy Corporation Form 10-K for the year ended December 31, 2011).
10.22.5.9.4	Fourth Amendment To Second Amended and Restated Credit Agreement Among PrimeEnergy Corporation, The Guarantors Party Hereto (PrimeEnergy Management Corporation, Prime Operating Company, Eastern Oil Well Service Company, Southwest Oilfield Construction Company, E O W S Midland Company), Compass Bank (successor in interest to Guaranty Bank, FSB), As Administrative Agent, Letter of Credit Issuer and Collateral Agent and The Lenders Signatory Hereto (Compass Bank, BNP Paribas, JPMorgan Chase Bank, N.A., Amegy Bank National Association) effective June 25, 2012 (Incorporated by reference to Exhibit 10.22.5.9.4 to PrimeEnergy Corporation Form 10-Q for the quarter ended June 30, 2012).
10.22.5.9.5	Fifth Amendment To Second Amended and Restated Credit Agreement Among PrimeEnergy Corporation, The Guarantors Party Hereto (PrimeEnergy Management Corporation, Prime Operating Company, Eastern Oil Well Service Company, Southwest Oilfield Construction Company, E O W S Midland Company, Prime Offshore L.L.C.), Compass Bank (successor in interest to Guaranty Bank, FSB), As Administrative Agent, Letter of Credit Issuer and Collateral Agent and The Lenders Signatory Hereto (Compass Bank, Wells Fargo Bank National Association, JPMorgan Chase Bank, N.A., Amegy Bank National Association, KeyBank National Association) effective November 26, 2012 (Incorporated by reference to Exhibit 10.22.5.9.5 to PrimeEnergy Corporation Form 10-K for the year ended December 31, 2012).
10.22.5.9.6	Sixth Amendment To Second Amended and Restated Credit Agreement Among PrimeEnergy Corporation, The Guarantors Party Hereto (PrimeEnergy Management Corporation, Prime Operating Company, Eastern Oil Well Service Company, Southwest Oilfield Construction Company, E O W S Midland Company, Prime Offshore L.L.C.), Compass Bank (successor in interest to Guaranty Bank, FSB), As Administrative Agent, Letter of Credit Issuer and Collateral Agent and The Lenders Signatory Hereto (Compass Bank, Wells Fargo Bank National Association, JPMorgan Chase Bank, N.A., Amegy Bank National Association, KeyBank National Association) effective June 28, 2013 (Incorporated by reference to Exhibit 10.22.5.9.6 to PrimeEnergy Corporation Form 10-Q for the quarter ended June 30, 2013).
10.22.5.9.7	Assignment Agreement made by and among Amegy Bank National Association, as Assignor, and Compass Bank (successor in interest to Guaranty Bank, FSB), Wells Fargo Bank, National Association, JPMorgan Chase Bank and KeyBank National Association, as Assignees, effective December 23, 2013 (filed herewith).
10.23.1	Loan and Security Agreement dated July 31, 2013, by and between JP Morgan Chase Bank, N.A. and Eastern Oil Well Service Company, EOWS Midland Company and Southwest Oilfield Construction Company (Incorporated by reference to Exhibit 10.23.1 to PrimeEnergy Corporation Form 10-Q for the quarter ended September 30, 2013).
10.23.2	Business Purpose Promissory Note dated July 31, 2013, made by Eastern Oil Well Service Company, EOWS Midland Company and Southwest Oilfield Construction Company to JP Morgan Chase Bank N.A. (Incorporated by reference to Exhibit 10.23.2 to PrimeEnergy Corporation Form 10-Q for the quarter ended September 30, 2013).

Table of Contents

Exhibit No.	
10.23.3	Guaranty dated July 31, 2013, made by PrimeEnergy Corporation in favor of JP Morgan Chase Bank, N.A. Incorporated by reference to Exhibit 10.23.3 to PrimeEnergy Corporation Form 10-Q for the quarter ended September 30, 2013).
14	PrimeEnergy Corporation Code of Business Conduct and Ethics, as amended December 16, 2011 (Incorporated by reference to Exhibit 14 of PrimeEnergy Corporation Form 10-K for the year ended December 31, 2011).
21	Subsidiaries (filed herewith).
23	Consent of Ryder Scott Company, L.P. (filed herewith).
31.1	Certification of Chief Executive Officer pursuant to Rule 13(a)-14(a)/15d-14(a) of the Securities Exchange Act of 1934, as amended (filed herewith).
31.2	Certification of Chief Financial Officer pursuant to Rule 13(a)-14(a)/15d-14(a) of the Securities Exchange Act of 1934, as amended (filed herewith).
32.1	Certification of Chief Executive Officer pursuant to 18 U.S.C. Section 1350, adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (filed herewith).
32.2	Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350, adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (filed herewith).
99.1	Summary Reserve Report dated March 7, 2014, of Ryder Scott Company, L.P. (filed herewith).
101.INS	XBRL (eXtensible Business Reporting Language) Instance Document (filed herewith)
101.SCH	XBRL Taxonomy Extension Schema Document (filed herewith)
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document (filed herewith)
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document (filed herewith)
101.LAB	XBRL Taxonomy Extension Label Linkbase Document (filed herewith)
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document (filed herewith)

Table of Contents

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this Report to be signed on its behalf by the undersigned, thereunto duly authorized, on the 25th day of March, 2014

PrimeEnergy Corporation

By: /s/ CHARLES E. DRIMAL, JR.
Charles E. Drimal, Jr.
Chairman, Chief Executive Officer and President

Pursuant to the requirements of the Securities Exchange Act of 1934, this Report has been signed below by the following persons on behalf of the Registrant and in the capacities indicated and on the 25th day of March, 2014.

/s/ CHARLES E. DRIMAL, JR.	Chairman, Chief Executive Officer and President;
Charles E. Drimal, Jr.	The Principal Executive Officer
/s/ BEVERLY A. CUMMINGS	Director, Executive Vice President and Treasurer;
Beverly A. Cummings	The Principal Financial Officer

/s/ MATTHIAS ECKENSTEIN Matthias Eckenstein	Director	/s/ CLINT HURT Clint Hurt	Director
/s/ H. GIFFORD FONG H. Gifford Fong	Director	/s/ JAN K. SMEETS Jan K. Smeets	Director
/s/ THOMAS S.T. GIMBEL Thomas S.T. Gimbel	Director		

39

Table of Contents

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

Report of Independent Registered Public Accounting Firm	F-2
Financial Statements	
Consolidated Balance Sheet As of December 31, 2013 and 2012	F-3
Consolidated Statement of Operations For the years ended December 31, 2013 and 2012	F-4
Consolidated Statement of Comprehensive Income For the years ended December 31, 2013 and 2012	F-5
Consolidated Statement of Equity For the years ended December 31, 2013 and 2012	F-6
Consolidated Statement of Cash Flows For the years ended December 31, 2013 and 2012	F-7
Notes to Consolidated Financial Statements	F-8
Supplementary Information:	
Capitalized Costs Relating to Oil and Gas Producing Activities, years ended December 31, 2013 and 2012	F-21
Costs Incurred in Oil and Gas Property Acquisition, Exploration and Development Activities, years ended December 31, 2013 and 2012	F-21
Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves, years ended December 31, 2013 and 2012	F-21
Standardized Measure of Discounted Future Net Cash Flows and Changes Therein Relating to Proved Oil and Gas Reserves, years ended December 31, 2013 and 2012	F-22
Reserve Quantity Information, years ended December 31, 2013 and 2012	F-23
Results of Operations from Oil and Gas Producing Activities, years ended December 31, 2013 and 2012	F-23
Notes to Supplementary Information	F-24

Table of Contents

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of

PrimeEnergy Corporation and Subsidiaries:

We have audited the accompanying consolidated balance sheets of PrimeEnergy Corporation and Subsidiaries (the Company) as of December 31, 2013 and 2012, and related consolidated statements of operations, comprehensive income, equity, and cash flows for each of the years then ended. The Company s management is responsible for these financial statements. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the consolidated financial position of PrimeEnergy Corporation and Subsidiaries as of December 31, 2013 and 2012, and the results of its operations and its cash flows for each of the years then ended, in conformity with accounting principles generally accepted in the United States of America.

/s/ Grassi & Co., CPAs, P.C.

GRASSI & CO., CPAs, P.C.

New York, New York

March 20, 2014

Table of Contents

PRIMEENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEET

(Thousands of dollars)

	As of December 31, 2013	2012
ASSETS		
Current Assets		
Cash and cash equivalents	$ 9,526	$ 8,602
Restricted cash and cash equivalents	2,065	4,672
Accounts receivable, net	17,693	13,212
Prepaid obligations	1,188	1,656
Derivative contracts	357	1,229
Other current assets	1,846	1,081
Total Current Assets	32,675	30,452
Property and Equipment		
Oil and gas properties at cost	364,123	338,204
Less: Accumulated depletion and depreciation	(169,100)	(150,276)
	195,023	187,928
Field and office equipment at cost	26,653	23,974
Less: Accumulated depreciation	(13,251)	(15,052)
	13,402	8,922
Total Property and Equipment, Net	208,425	196,850
Derivative Contracts Long-Term	1,066	118
Other Assets	756	666
Total Assets	$ 242,922	$ 228,086
LIABILITIES AND EQUITY		
Current Liabilities		
Accounts payable	$ 16,249	$ 19,568
Accrued liabilities	6,832	7,618
Current portion of long-term debt	1,870	
Current portion of asset retirement and other long-term obligations	3,310	2,148
Derivative liability short-term	2,194	994
Due to related parties	23	67
Total Current Liabilities	30,478	30,395
Long-Term Bank Debt	120,023	122,000
Asset Retirement Obligations	7,227	6,864
Derivative Liability Long-Term	94	431
Deferred Income Taxes	31,962	24,194
Total Liabilities	189,784	183,884
Commitments and Contingencies		
Equity		

Common stock, $.10 par value; 2013 and 2012: Authorized: 4,000,000 shares, issued: 3,836,397 shares; outstanding 2013: 2,388,784 shares; 2012: 2,510,560 shares	383	383
Paid-in capital	6,803	6,690
Retained earnings	78,616	66,345
Accumulated other comprehensive loss, net	(123)	(35)
Treasury stock, at cost; 2013: 1,447,613 shares; 2012: 1,325,837 shares	(40,251)	(36,113)
Total Stockholders Equity PrimeEnergy	45,428	37,270
Non-controlling interest	7,710	6,932
Total Equity	53,138	44,202
Total Liabilities and Equity	$ 242,922	$ 228,086

The accompanying Notes are an integral part of these Consolidated Financial Statements

F-3

PRIMEENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENT OF OPERATIONS

(Thousands of dollars, except per share amounts)

	For the Year Ended December 31, 2013	2012
Revenues		
Oil and gas sales	$ 92,785	$ 87,834
Realized gain (loss) on derivative instruments, net	(1,322)	502
Field service income	24,934	20,421
Administrative overhead fees	9,255	8,585
Unrealized gain (loss) on derivative instruments	(649)	3,483
Other income	64	154
Total Revenues	125,067	120,979
Costs and Expenses		
Lease operating expense	43,809	39,868
Field service expense	21,027	17,576
Depreciation, depletion, amortization and accretion on discounted liabilities	21,861	23,269
Loss on settlement of asset retirement obligations	40	
General and administrative expense	16,659	15,870
Exploration costs	8	10
Total Costs and Expenses	103,404	96,593
Gain on Sale and Exchange of Assets	2,816	730
Income from Operations	24,479	25,116
Other Income and Expenses		
Less: Interest expense	4,223	3,577
Add: Interest income	2	91
Income Before Provision for Income Taxes	20,258	21,630
Provision for Income Taxes	6,818	6,856
Net Income	13,440	14,774
Less: Net Income (Loss) Attributable to Non-Controlling Interest	1,169	(282)
Net Income Attributable to PrimeEnergy	$ 12,271	$ 15,056
Basic Income Per Common Share	$ 5.04	$ 5.74
Diluted Income Per Common Share	$ 3.86	$ 4.48

The accompanying Notes are an integral part of these Consolidated Financial Statements

Table of Contents

PRIMEENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME

(Thousands of dollars)

	For the Year Ended December 31, 2013	2012
Net income	$ 13,440	$ 14,774
Other Comprehensive Loss, net of taxes:		
Changes in fair value of hedge positions, net of taxes of $50 and $19, respectively	(88)	(35)
Total other comprehensive loss	(88)	(35)
Comprehensive income	13,352	14,739
Less: Comprehensive income (loss) attributable to non-controlling interest	1,169	(282)
Comprehensive income attributable to PrimeEnergy	$ 12,183	$ 15,021

The accompanying Notes are an integral part of these Consolidated Financial Statements

Table of Contents

PRIMEENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENT OF EQUITY

(Thousands of dollars)

	Common Stock		Additional		Accumulated Other		Total Stockholders		
	Shares	Amount	Paid-In Capital	Retained Earnings	Comprehensive Loss	Treasury Stock	Equity PrimeEnergy	Non-Controlling Interest	Total Equity
Balance at December 31, 2011	3,836,397	$ 383	$ 6,446	$ 51,289	$	$ (31,120)	$ 26,998	$ 8,755	$ 35,753
Purchase 191,309 shares of common stock						(4,993)	(4,993)		(4,993)
Net income				15,056			15,056	(282)	14,774
Other comprehensive loss, net of taxes					(35)		(35)		(35)
Purchase of non-controlling interest			244				244	(393)	(149)
Distributions to non-controlling interest								(1,148)	(1,148)
Balance at December 31, 2012	3,836,397	$ 383	$ 6,690	$ 66,345	$ (35)	$ (36,113)	$ 37,270	$ 6,932	$ 44,202
Purchase 121,776 shares of common stock						(4,138)	(4,138)		(4,138)
Net income				12,271			12,271	1,169	13,440
Other comprehensive loss, net of taxes					(88)		(88)		(88)
Purchase of non-controlling interest			113				113	(161)	(48)
Distributions to non-controlling interest								(230)	(230)
Balance at December 31, 2013	3,836,397	$ 383	$ 6,803	$ 78,616	$ (123)	$ (40,251)	$ 45,428	$ 7,710	$ 53,138

The accompanying Notes are an integral part of these Consolidated Financial Statements

F-6

Table of Contents

PRIMEENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENT OF CASH FLOWS

(Thousands of dollars)

	For the Year Ended December 31, 2013	2012
Cash Flows from Operating Activities:		
Net income	$ 13,440	$ 14,774
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion, amortization and accretion on discounted liabilities	21,861	23,269
Gain on sale of properties	(2,816)	(730)
Unrealized (gain) loss on derivative instruments	649	(3,483)
Provision for deferred income taxes	7,014	6,970
Loss on settlement of asset retirement obligations	40	
Changes in assets and liabilities:		
(Increase) decrease in accounts receivable	(4,481)	3,294
Increase in due from related parties	(96)	(25)
(Increase) decrease in inventories	91	(2)
Decrease in prepaid expenses and other assets	378	5,761
Decrease in accounts payable	(712)	(9,500)
Increase (decrease) in accrued liabilities	332	(616)
Net Cash Provided by Operating Activities	35,700	39,712
Cash Flows from Investing Activities:		
Capital expenditures, including exploration expense	(33,934)	(86,305)
Proceeds from sale of properties and equipment	3,681	881
Net Cash Used in Investing Activities	(30,253)	(85,424)
Cash Flows from Financing Activities:		
Purchase of stock for treasury	(4,138)	(4,993)
Purchase of non-controlling interests	(48)	(149)
Increase in long-term bank debt and other long-term obligations	68,750	111,800
Repayment of long-term bank debt and other long-term obligations	(68,857)	(59,857)
Distribution to non-controlling interest	(230)	(1,148)
Net Cash (Used in) Provided by Financing Activities	(4,523)	45,653
Net Increase (Decrease) in Cash and Cash Equivalents	924	(59)
Cash and Cash Equivalents at the Beginning of the Year	8,602	8,661
Cash and Cash Equivalents at the End of the Year	$ 9,526	$ 8,602
Supplemental Disclosures:		
Income taxes paid during the year	$ 754	$ 536
Interest paid during the year	$ 4,183	$ 3,535

The accompanying Notes are an integral part of these Consolidated Financial Statements

Table of Contents

PRIMEENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Description of Operations and Significant Accounting Policies

Nature of Operations:

PrimeEnergy Corporation (PEC), a Delaware corporation, was organized in March 1973 and is engaged in the development, acquisition and production of oil and natural gas properties. PrimeEnergy Corporation and its subsidiaries are herein referred to as the Company. The Company owns leasehold, mineral and royalty interests in producing and non-producing oil and gas properties across the United States, including Colorado, Kansas, Louisiana, Mississippi, Montana, New Mexico, North Dakota, Oklahoma, Texas, West Virginia and Wyoming and the Gulf of Mexico. The Company operates approximately 1,600 wells and owns non-operating interests in over 800 additional wells. Additionally, the Company provides well-servicing support operations, site-preparation and construction services for oil and gas drilling and reworking operations, both in connection with the Company s activities and providing contract services for third parties. The Company is publicly traded on the NASDAQ under the symbol PNRG. PEC owns Eastern Oil Well Service Company (EOWSC), EOWS Midland Company (EMID) and Southwest Oilfield Construction Company (SOCC), all of which perform oil and gas field servicing. PEC also owns Prime Operating Company (POC), which serves as operator for most of the producing oil and gas properties owned by the Company and affiliated entities. PEC also owns Prime Offshore L.L.C. (Prime Offshore), formerly F-W Oil Exploration LLC, which has owned and operated properties in the Gulf of Mexico. PrimeEnergy Management Corporation (PEMC), a wholly-owned subsidiary, acts as the managing general partner, providing administration, accounting and tax preparation services for 18 limited partnerships and 2 trusts (collectively, the Partnerships). The markets for the Company s products are highly competitive, as oil and gas are commodity products and prices depend upon numerous factors beyond the control of the Company, such as economic, political and regulatory developments and competition from alternative energy sources.

Consolidation and Presentation:

The consolidated financial statements include the accounts of PrimeEnergy Corporation, its subsidiaries and the Partnerships, using the full consolidation method for those partnerships which are controlled by the Company. The proportionate consolidation method is used to account for those undivided interests in oil and gas properties owned by the Company as well as interests held in unincorporated legal entities, such as partnerships, engaged in oil and gas production, which are not controlled by the Company. For those entities which are proportionately consolidated, the proportionate share of each entity s assets, liabilities, revenue and expenses is included in the appropriate classifications in the consolidated financial statements. Reserve estimates associated with the proportionately consolidated oil and gas interests are calculated for each property at the Partnership level, and depletion, depreciation and amortization (DD&A) rates are determined at the Partnership level. The Company s reserve estimates are based on the ownership percentage of Partnership reserve reports. DD&A expense and evaluation of impairment may differ from the Partnership as the Company s cost basis for the Partnership interests acquired may be different than the cost basis at the Partnership level for properties acquired by the Partnership. All significant intercompany balances and transactions are eliminated in preparing the consolidated financial statements.

Reclassifications:

Certain reclassifications have been made to prior year statements to conform with the current year presentation. These reclassifications have no impact on net income and no material impact on any other financial statement captions.

Table of Contents

Subsequent Events:

Subsequent events have been evaluated through the date that the consolidated financial statements were issued. During this period, there were no material subsequent items requiring disclosure.

Use of Estimates:

The preparation of financial statements in conformity with U.S. generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Estimates of oil and gas reserves, as determined by independent petroleum engineers, are continually subject to revision based on price, production history and other factors. Depletion expense, which is computed based on the units of production method, could be significantly impacted by changes in such estimates. Additionally, U.S. generally accepted accounting principles require that if the expected future undiscounted cash flows from an asset is less than its carrying cost, that asset must be written down to its fair market value. As the fair market value of an oil and gas property will usually be significantly less than the total undiscounted future net revenues expected from that asset, slight changes in the estimates used to determine future net revenues from an asset could lead to the necessity of recording a significant impairment of that asset.

Property and Equipment:

The Company follows the successful efforts method of accounting for its oil and gas properties. Under the successful efforts method, costs of acquiring undeveloped oil and gas leasehold acreage, including lease bonuses, brokers fees and other related costs are capitalized. Provisions for impairment of undeveloped oil and gas leases are based on periodic evaluations. Annual lease rentals and exploration expenses, including geological and geophysical expenses and exploratory dry hole costs, are charged against income as incurred. Costs of drilling and equipping productive wells, including development dry holes and related production facilities, are capitalized. All other property and equipment are carried at cost. Depreciation and depletion of oil and gas production equipment and properties are determined under the unit-of-production method based on estimated proved developed recoverable oil and gas reserves. Depreciation of all other equipment is determined under the straight-line method using various rates based on useful lives generally ranging from 5 to 10 years. The cost of assets and related accumulated depreciation is removed from the accounts when such assets are disposed of, and any related gains or losses are reflected in current earnings.

Capitalization of Interest:

Interest costs related to financing major oil and gas projects in progress are capitalized until the projects are evaluated or until the projects are substantially complete and ready for their intended use if the projects are evaluated and successful.

Impairment of Long-Lived Assets:

The Company reviews long-lived assets, including oil and gas properties, for impairment whenever events or changes in circumstances indicate that the carrying amounts may not be recovered. If the carrying amounts are not expected to be recovered by undiscounted cash flows, the assets are impaired and an impairment loss is recorded. The amount of impairment is based on the estimated fair value of the assets determined by discounting anticipated future net cash flows.

Fair Value:

The Company follows the authoritative guidance that establishes a formal framework for measuring fair values of assets and liabilities in financial statements that are already required by U.S. generally accepted accounting principles to be measured at fair value. The guidance defines fair value as the price that would be

Table of Contents

received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). The transaction is based on a hypothetical transaction in the principal or most advantageous market considered from the perspective of the market participant that holds the asset or owes the liability.

The Company utilizes market data or assumptions that market participants who are independent, knowledgeable and willing and able to transact would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, market corroborated or generally unobservable. The Company attempts to utilize valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs. The Company is able to classify fair value balances based on the observability of those inputs. The guidance establishes a formal fair value hierarchy based on the inputs used to measure fair value. The hierarchy gives the highest priority to Level 1 inputs, which consist of unadjusted quoted prices for identical instruments in active markets. Level 2 inputs consist of quoted prices for similar instruments. Level 3 valuations are derived from inputs that are significant and unobservable; hence, these valuations have the lowest priority.

Asset Retirement Obligation:

The Company follows the accounting standard for asset retirement obligation. The asset retirement obligation primarily represents the estimated present value of the amount the Company will incur to plug, abandon and remediate producing properties (including removal of offshore platforms) at the end of their productive lives, in accordance with applicable state laws. The Company determined its asset retirement obligation by calculating the present value of estimated cash flows related to the liability. The asset retirement obligation is recorded as a liability at its estimated present value at its inception, with an offsetting increase to producing properties. Periodic accretion of discount of the estimated liability is recorded as an expense in the statement of operations.

Income Taxes:

The Company follows the asset and liability method of accounting for income taxes. Under this method, deferred tax assets and liabilities are recorded for the estimated future tax consequences attributable to the differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax basis. Deferred tax assets and liabilities are measured using the tax rate in effect for the year in which those temporary differences are expected to turn around. The effect of a change in tax rates on deferred tax assets and liabilities is recognized in the year of the enacted rate change. A valuation allowance is established to reduce deferred tax assets if it is more likely than not that the related tax benefits will not be realized.

The Company is required to make judgments, including estimating reserves for potential adverse outcomes regarding tax positions that the Company has taken. The Company accounts for uncertainty in income taxes using a recognition and measurement threshold for tax positions taken or expected to be taken in a tax return. The effective tax rate and the tax basis of assets and liabilities reflect management s estimates of the ultimate outcome of various tax uncertainties.

General and Administrative Expenses:

General and administrative expenses represent cost and expenses associated with the operation of the Company.

Earnings Per Common Share:

Basic earnings per share are computed by dividing earnings available to common stockholders by the weighted average number of common shares outstanding during the period. Diluted earnings per share reflect per share amounts that would have resulted if dilutive potential common stock had been converted to common stock in gain periods.

Table of Contents

Statements of Cash Flows:

For purposes of the consolidated statements of cash flows, the Company considers short-term, highly liquid investments with original maturities of less than ninety days to be cash equivalents.

Concentration of Credit Risk:

The Company maintains significant banking relationships with financial institutions in the State of Texas. The Company limits its risk by periodically evaluating the relative credit standing of these financial institutions. The Company s oil and gas production purchasers consist primarily of independent marketers and major gas pipeline companies.

Hedging:

The Company periodically enters into oil and gas financial instruments to manage its exposure to oil and gas price volatility. The oil and gas reference prices upon which the price hedging instruments are based reflect various market indices that have a high degree of historical correlation with actual prices received by the Company.

The financial instruments are accounted for in accordance with applicable accounting standards for derivative instruments and hedging activities. Such standards require that applicable derivative instruments be measured at fair market value and recognized as assets or liabilities in the balance sheet. The accounting for changes in the fair value of a derivative depends on the intended use of the derivative and the resulting designation is generally established at the inception of a derivative. For derivatives designated as cash flow hedges and meeting applicable effectiveness guidelines, changes in fair value, to the extent effective, are recognized in other comprehensive income until the hedged item is recognized in earnings. At December 31, 2013 and 2012, the entire other comprehensive income amount comprised of the impact of cash flow hedges. Hedge effectiveness is measured at least quarterly based on the relative changes in fair value between the derivative contract and the hedged item over time. Any change in fair value of a derivative resulting from ineffectiveness or an excluded component of the gain/loss is recognized immediately in the statement of operations.

Recently Adopted Accounting Standards:

In December 2011, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) 2011-11, Disclosures about Offsetting Assets and Liabilities. This ASU requires enhanced disclosures including both gross and net information about financial and derivative instruments eligible for offset or subject to an enforceable master netting arrangement or similar agreement. This new guidance is effective for annual reporting periods beginning on or after January 1, 2013 and subsequent interim periods. In January 2013, the FASB issued ASU 2013-01, Clarifying the Scope of Disclosures about Offsetting Assets and Liabilities. ASU 2013-01 clarifies the scope of ASU 2011-11 to apply to derivative instruments that are offset or subject to an enforceable master netting arrangement or similar agreement. This clarified guidance is effective for annual reporting periods beginning on or after January 1, 2013 and subsequent interim periods. The revised requirements of ASU 2011-11 and ASU 2013-01 impacted the disclosures associated with the Company s derivative instruments (Note 11) and did not have a material impact on the Company s consolidated financial statements for the year ended December 31, 2013.

In February 2013, the FASB issued ASU 2013-02, Reporting of Amounts Reclassified Out of Accumulated Other Comprehensive Income (AOCI). ASU 2013-02 requires a rollforward of changes in AOCI by component and information about significant reclassifications from AOCI to net earnings to be presented in one location, either on the face of the financial statements or in the notes. This new guidance is effective for fiscal years beginning after December 15, 2012 and subsequent interim periods. There was no amounts reclassified out of accumulated other comprehensive income for the year ended December 31, 2013. The requirements of ASU 2013-02 did not have a material impact on the Company s consolidated financial statements for the year ended December 31, 2013.

Table of Contents

In July 2013, the FASB issued ASU 2013-11, Presentation of an Unrecognized Tax Benefit When a Net Operating Loss Carryforward, a similar Tax Loss, or a Tax Credit Carryforward Exists. ASU 2013-11 provided guidance on the presentation of an unrecognized tax benefit when a net operating loss carryforward, a similar tax loss, or a tax credit carryforward exists. This guidance requires entities to present unrecognized tax benefits as a decrease in a net operating loss, similar tax loss, or tax credit carryforward if certain criteria are met. The guidance will eliminate the diversity in practice in the presentation of unrecognized tax benefits but will not alter the way in which entities assess deferred tax assets for realizability. ASU No. 2013-11 is effective for annual and interim reporting periods beginning after December 15, 2013. The Company will apply all changes prospectively and does not expect the adoption of this amendment to have a material impact on its consolidated financial statements.

2. Acquisitions and Dispositions

Historically, the Company has repurchased the noncontrolling interests of the partners and trust unit holders in certain of the Partnerships, which consist primarily of oil and gas interests. The Company purchased such noncontrolling interests in an amount totaling $48,000 in 2013 and $149,000 in 2012.

3. Additional Balance Sheet Information

Accounts receivable at December 31, 2013 and 2012 consisted of the following:

	December 31,	
(Thousands of dollars)	**2013**	**2012**
Joint interest billings	$ 6,287	$ 2,189
Trade receivables	2,014	1,580
Oil and gas sales	9,604	9,362
Other	122	436
	18,027	13,567
Less: Allowance for doubtful accounts	(334)	(355)
Total	$ 17,693	$ 13,212

Accounts payable at December 31, 2013 and 2012 consisted of the following:

	December 31,	
(Thousands of dollars)	**2013**	**2012**
Trade	$ 1,596	$ 3,968
Royalty and other owners	7,391	9,652
Partner advances	3,378	3,589
Prepaid drilling deposits	978	306
Other	2,906	2,053
Total	$ 16,249	$ 19,568

Accrued liabilities at December 31, 2013 and 2012 consisted of the following:

	December 31,	
(Thousands of dollars)	**2013**	**2012**
Compensation and related expenses	$ 3,062	$ 2,517
Property costs	3,119	4,549

Income tax	268	
Other	383	552
Total	$ 6,832	$ 7,618

Table of Contents

4. Property and Equipment

Capitalized interest is included as part of the cost of oil and gas properties. The capitalized rates are based upon the Company s weighted-average cost of borrowings used to finance the expenditures. There was no interest capitalized during 2013 or 2012.

5. Long-Term Debt

Bank Debt:

Effective July 30, 2010, the Company entered into a Second Amended and Restated Credit Agreement between Compass Bank as agent and a syndicated group of lenders (Credit Agreement). The Credit Agreement has a revolving line of credit and letter of credit facility of up to $250 million with a final maturity date of July 30, 2017. The credit facility is secured by substantially all of the Company s oil and gas properties. The credit facility is subject to a borrowing base determined by the lenders taking into consideration the estimated value of PEC s oil and gas properties in accordance with the lenders customary practices for oil and gas loans. This process involves reviewing PEC s estimated proved reserves and their valuation. The borrowing base is redetermined semi-annually, and the available borrowing amount could be increased or decreased as a result of such redetermination. In addition, PEC and the lenders each have at their discretion the right to request the borrowing base be redetermined with a maximum of one such request each year. A revision to PEC s reserves may prompt such a request on the part of the lenders, which could possibly result in a reduction in the borrowing base and availability under the credit facility. At any time if the sum of the outstanding borrowings and letter of credit exposures exceed the applicable portion of the borrowing base, PEC would be required to repay the excess amount within a prescribed period.

The Credit Agreement has been amended from time to time to further define the limitations on loans or advances and investments made in the Company s limited partnerships; modify the Company s borrowing base and monthly reduction amounts; remove the floor rate component of LIBO rate loans; modify financial reporting requirements to the agent; increase hedging allowances; allow for a one-time advance to be made to the Company s offshore subsidiary; and amend restrictions on the payments for dividends, distributions or repurchase of PEC s stock.

The Credit Agreement includes terms and covenants that require the Company to maintain a minimum current ratio, total indebtedness to EBITDAX (earnings before depreciation, depletion, amortization, taxes, interest expense and exploration costs) ratio and interest coverage ratio, as defined, and restrictions are placed on the payment of dividends, the amount of treasury stock the Company may purchase, commodity hedge agreements, and loans and investments in its consolidated subsidiaries and limited partnerships.

Under the Credit Agreement, the maximum percentage of production available to enter into commodity hedge agreements is 90% of proved developed producing reserves for each of the next succeeding four calendar years for crude oil and natural gas computed separately. In addition, the Company s restrictions on the payment of dividends, distributions or purchase of treasury stock is limited to an aggregate of $5.0 million in each calendar year.

At December 31, 2013, the credit facility borrowing base was $140.0 million with no monthly reduction amount. The borrowings made within the credit facility may be placed in a base rate loan or LIBO rate loan. The Company s borrowing rates in the credit facility provide for base rate loans at the prime rate (3.25% at December 31, 2013) plus applicable margin utilization rates that range from 1.50% to 2.00%, and LIBO rate loans at LIBO published rates plus applicable utilization rates that range from 2.50% to 3.00%. At December 31, 2013, the Company had in place one base rate loan and one LIBO rate loan with effective rates of 5.00% and 2.92%, respectively.

At December 31, 2013, the Company had $112.5 million of borrowings outstanding under its revolving credit facility at a weighted-average interest rate of 3.06%, and $27.5 million available for future borrowings.

Table of Contents

The combined weighted average interest rate paid on outstanding bank borrowings subject to base rate and LIBO interest was 3.58% for the year ended December 31, 2013, as compared to 3.81% for the year ended December 31, 2012.

The Company has entered into interest rate hedge agreements to help manage interest rate exposure. These contracts include interest rate swaps. Interest rate swap transactions generally involve the exchange of fixed and floating rate interest payment obligations without the exchange of the underlying principal amounts. In July 2012, the Company entered into interest swap agreements for a period of two years, which commence in January 2014, related to $75 million of the Company s bank debt resulting in a fixed rate of 0.563% plus the Company s current applicable margin.

Equipment Loan:

On July 31, 2013, the Company entered into a $10.0 million Loan and Security Agreement with JP Morgan Chase Bank (Equipment Loan). The Equipment Loan is secured by substantially all of the Company s field service equipment, carries an interest rate of 3.95% per annum, requires monthly payments (principal and interest) of $184,000, and has a final maturity date of July 31, 2018. As of December 30, 2013, the Company had a total of $9.4 million outstanding on the Equipment Loan.

6. Commitments

Operating Leases:

The Company has several non-cancelable operating leases, primarily for rental of office space, that have a term of more than one year. The future minimum lease payments for the operating leases at December 31, 2013 are as follows.

(Thousands of dollars)	**Operating Leases**
2014	$ 747
2015	651
2016	545
2017	46
Total minimum payments	$ 1,989

Rent expense for office space for the years ended December 31, 2013 and 2012 was $699,000 and $755,000, respectively.

***Asset Retirement Obligation*:**

A reconciliation of the liability for plugging and abandonment costs for the years ended December 31, 2013 and 2012 is as follows:

	Year Ended December 31,	
(Thousands of dollars)	**2013**	**2012**
Asset retirement obligation at beginning of period	$ 9,012	$ 19,013
Liabilities incurred	338	733
Loss on settlement of obligations	40	
Liabilities settled	(776)	(15,361)
Accretion expense	394	1,053
Revisions in estimated liabilities	1,529	3,574
Asset retirement obligation at end of period	$ 10,537	$ 9,012

Table of Contents

The Company s liability is determined using significant assumptions, including current estimates of plugging and abandonment costs, annual inflation of these costs, the productive life of wells and a risk-adjusted interest rate. Changes in any of these assumptions can result in significant revisions to the estimated asset retirement obligation. Revisions to the asset retirement obligation are recorded with an offsetting change to producing properties, resulting in prospective changes to depreciation, depletion and amortization expense and accretion of discount. Because of the subjectivity of assumptions and the relatively long life of most of the Company s wells, the costs to ultimately retire the wells may vary significantly from previous estimates. During 2013 and 2012 revisions in estimated liabilities for asset retirement obligation resulted primarily from the enactment of new federal regulation requirements for plugging and abandonment.

7. Contingent Liabilities

The Company, as managing general partner of the affiliated Partnerships, is responsible for all Partnership activities, including the drilling of development wells and the production and sale of oil and gas from productive wells. The Company also provides the administration, accounting and tax preparation work for the Partnerships, and is liable for all debts and liabilities of the affiliated Partnerships, to the extent that the assets of a given limited Partnership are not sufficient to satisfy its obligations. At December 31, 2013, the affiliated Partnerships have established cash reserves in excess of their debts and liabilities, and the Company believes these reserves will be sufficient to satisfy Partnership obligations.

The Company is subject to environmental laws and regulations. Management believes that future expenses, before recoveries from third parties, if any, will not have a material effect on the Company s financial condition. This opinion is based on expenses incurred to date for remediation and compliance with laws and regulations, which have not been material to the Company s results of operations.

From time to time, the Company is party to certain legal actions arising in the ordinary course of business. While the outcome of these events cannot be predicted with certainty, management does not expect these matters to have a materially adverse effect on the financial position or results of operations of the Company.

8. Stock Options and Other Compensation

In May 1989, non-statutory stock options were granted by the Company to four key executive officers for the purchase of shares of common stock. At December 31, 2013 and 2012, options on 767,500 shares were outstanding and exercisable at prices ranging from $1.00 to $1.25. According to their terms, the options have no expiration date.

9. Income Taxes

The components of the provision (benefit) for income taxes for the years ended December 31, 2013 and 2012 are as follows:

	Year Ended December 31,	
(Thousands of dollars)	**2013**	**2012**
Current:		
Federal	$ (462)	$ 16
State	266	(130)
Total current	(196)	(114)
Deferred:		
Federal	6,549	7,009
State	465	(39)
Total deferred	7,014	6,970
Total income tax provision	$ 6,818	$ 6,856

F-15

Table of Contents

The components of net deferred tax assets and liabilities are as follows:

(Thousands of dollars)	At December 31, 2013	2012
Current Assets:		
Accrued liabilities	$ 683	$ 613
Allowance for doubtful accounts	118	124
Derivative contracts	677	(83)
Total current deferred income tax assets	$ 1,478	$ 654
Non-Current Assets:		
Alternative minimum tax credits	$ 5,852	$ 5,890
Net operating loss carry-forwards	168	114
Percentage depletion carry-forwards	4,543	4,287
Derivative contracts		91
Total non-current assets	10,563	10,382
Non-Current Liabilities:		
Basis differences relating to managed partnerships	2,462	1,492
Depletion and depreciation	39,694	33,084
Derivative contracts	369	
Total non-current liabilities	42,525	34,576
Net non-current deferred income tax liabilities	$ 31,962	$ 24,194

The total provision for income taxes for the years ended December 31, 2013 and 2012 varies from the federal statutory tax rate as a result of the following:

(Thousands of dollars)	Year Ended December 31, 2013	2012
Expected tax expense	$ 6,491	$ 7,450
State income tax, net of federal benefit	488	(112)
Percentage depletion	(422)	(902)
Other, net	261	420
Total income tax provision	$ 6,818	$ 6,856

The Company showed a net operating loss on its 2012 federal income tax return, which was carried back to the 2010 and 2011 tax years, resulting in total refunds of $685,000. The net operating loss and related refunds were the result of elections to deduct intangible drilling costs in 2012 which was made upon filing the return in 2013, and the refunds result in the lowering of the current federal income tax expense in 2013.

Deferred income taxes reflect the impact of temporary differences between the amount of assets and liabilities recognized for financial reporting purposes and such amounts recognized for tax purposes. Differences relating to oil and gas properties owned through Prime Offshore are reflected under Depletion and depreciation, while basis differences relating to the managed partnerships are reflected under Basis differences relating to managed partnerships.

The Company is entitled to percentage depletion on certain of its wells, which is calculated without reference to the basis of the property. To the extent that such depletion exceeds a property s basis, it creates a permanent difference, which lowers the Company s effective rate.

Table of Contents

The Company has $5.9 million in alternative minimum tax (AMT) credits which can be used to lower the regular tax liability to the tentative AMT amount in years where the tentative AMT amount is less. These credits do not expire.

The Company has not recorded any provision for uncertain tax positions. The Company files income tax returns in the U.S. federal jurisdiction and various state and local jurisdictions. The 2004, 2005, 2006, and 2009 federal income tax returns have been audited by the Internal Revenue Service, while the 2010, 2011 and 2012 returns remain open for examination. Returns for unexamined earlier years may be examined and adjustments made to the amount of percentage depletion and AMT credit carryforwards flowing from those years into an open tax year, although in general no assessment of income tax may be made for those years on which the statute has closed. State returns for the years 2010, 2011 and 2012 remain open for examination by the relevant taxing authorities.

10. Segment Information and Major Customers

The Company operates in one industry oil and gas exploration, development, operation and servicing. The Company s oil and gas activities are entirely in the United States.

The Company sells its oil and gas production to a number of purchasers. Listed below are the percent of the Company s total oil and gas sales made to each of the customers whose purchases represented more than 10% of the Company s oil and gas sales in the year 2013.

Oil Purchasers:		Gas Purchasers:	
Plains All American Inc.	52%	Atlas Pipeline Mid-Continent	40%
Sunoco, Inc.	28%	Unimark LLC	13%

Although there are no long-term oil and gas purchasing agreements with these purchasers, the Company believes that they will continue to purchase its oil and gas products and, if not, could be replaced by other purchasers.

11. Financial Instruments

Fair Value Measurements:

Authoritative guidance on fair value measurements defines fair value, establishes a framework for measuring fair value and stipulates the related disclosure requirements. The Company follows a three-level hierarchy, prioritizing and defining the types of inputs used to measure fair value. The fair values of the Company s interest rate swaps, natural gas and crude oil price collars and swaps are designated as Level 3. The following fair value hierarchy table presents information about the Company s assets and liabilities measured at fair value on a recurring basis at December 31, 2013 and 2012:

December 31, 2013 *(Thousands of dollars)*	**Quoted Prices in Active Markets For Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**Balance at December 31, 2013**
Assets				
Commodity derivative contracts	$	$	$ 1,337	$ 1,337
Interest rate derivative contracts			86	86
Total assets	$	$	$ 1,423	$ 1,423
Liabilities				
Commodity derivative contracts	$	$	$ (2,010)	$ (2,010)
Interest rate derivative contracts			(278)	(278)
Total liabilities	$	$	$ (2,288)	$ (2,288)

Table of Contents

December 31, 2012 (Thousands of dollars)	Quoted Prices in Active Markets For Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance at December 31, 2012
Assets				
Commodity derivative contracts	$	$	$ 1,347	$ 1,347
Total assets	$	$	$ 1,347	$ 1,347
Liabilities				
Commodity derivative contracts	$	$	$ (1,371)	$ (1,371)
Interest rate derivative contracts			(54)	(54)
Total liabilities	$	$	$ (1,425)	$ (1,425)

The derivative contracts were measured based on quotes from the Company s counterparties. Such quotes have been derived using valuation models that consider various inputs including current market and contractual prices for the underlying instruments, quoted forward prices for natural gas and crude oil, volatility factors and interest rates, such as a LIBOR curve for a similar length of time as the derivative contract term as applicable. These estimates are verified using comparable NYMEX futures contracts or are compared to multiple quotes obtained from counterparties for reasonableness.

The significant unobservable inputs for Level 3 derivative contracts include basis differentials and volatility factors. An increase (decrease) in these unobservable inputs would result in an increase (decrease) in fair value, respectively. The Company does not have access to the specific assumptions used in its counterparties valuation models. Consequently, additional disclosures regarding significant Level 3 unobservable inputs were not provided.

The following table sets forth a reconciliation of changes in the fair value of financial assets and liabilities classified as Level 3 in the fair value hierarchy for the years ended December 31, 2013 and 2012.

(Thousands of dollars)	Year Ended December 31, 2013	2012
Net liabilities at beginning of period	$ (78)	$ (3,507)
Total realized and unrealized (gains) losses:		
Included in earnings[(a)]	(1,971)	3,985
Included in other comprehensive loss	(138)	(54)
Purchases, sales, issuances and settlements	1,322	(502)
Net liabilities at end of period	$ (865)	$ (78)

[(a)] Derivative instruments are reported in revenues as realized gain/loss and on a separately reported line item captioned unrealized gain/loss on derivative instruments, and interest rate swap instruments are reported as a reduction to interest expense.

Derivative Instruments:

The Company is exposed to commodity price and interest rate risk, and management considers periodically the Company s exposure to cash flow variability resulting from the commodity price changes and interest rate fluctuations. Futures, swaps and options are used to manage the Company s exposure to commodity price risk inherent in the Company s oil and gas production operations. The Company does not apply hedge accounting to any of its commodity based derivatives. Both realized and unrealized gains and losses associated with commodity derivative instruments are recognized in earnings.

Interest rate swap derivatives continue to be treated as cash-flow hedges and are used to fix or float interest rates on existing debt. The value of these interest rate swaps at December 31, 2013 is located in accumulated other comprehensive loss, net of tax. Settlement of the swaps, currently scheduled to begin in January 2014, will be recorded within interest expense.

Table of Contents

The following table sets forth the effect of derivative instruments on the consolidated balance sheets at December 31, 2013 and 2012:

(Thousands of dollars)	**Balance Sheet Location**	**Fair Value at December 31, 2013**	**2012**
Asset Derivatives:			
Derivatives designated as cash-flow hedging instruments:			
Interest rate swap contracts	Other assets	$ 86	$
Derivatives not designated as cash-flow hedging instruments:			
Crude oil commodity contracts	Derivative contracts	307	189
Natural gas commodity contracts	Derivative contracts	50	1,040
Crude oil commodity contracts	Other assets	980	118
Total		$ 1,423	$ 1,347
Liability Derivatives:			
Derivatives designated as cash-flow hedging instruments:			
Interest rate swap contracts	Derivative liability short-term	$ (209)	$
Interest rate swap contracts	Derivative liability long-term	(69)	(54)
Derivatives not designated as cash-flow hedging instruments:			
Crude oil commodity contracts	Derivative liability short-term	(1,667)	(994)
Natural gas commodity contracts	Derivative liability short-term	(318)	
Crude oil commodity contracts	Derivative liability long-term	(25)	(377)
Total		$ (2,288)	$ (1,425)
Total derivative instruments		$ (865)	$ (78)

The following table sets forth the effect of derivative instruments on the consolidated statements of operations for the years ended December 31, 2013 and 2012:

(Thousands of dollars)	**Location of gain/loss recognized in income**	**Amount of gain/loss recognized in income 2013**	**2012**
Derivatives not designated as cash-flow hedge instruments:			
Natural gas commodity contracts	Unrealized gain (loss) on derivative instruments, net	$ (1,309)	$ 1,040
Crude oil commodity contracts	Unrealized gain on derivative instruments, net	660	2,443
Natural gas commodity contracts[(a)]	Realized gain on derivative instruments, net	796	
Crude oil commodity contracts[(a)]	Realized gain (loss) on derivative instruments, net	(2,118)	502
		$ (1,971)	$ 3,985

(a) In January 2012, March 2012 and May 2012, the Company unwound and monetized crude oil swaps with original settlement dates from January 2012 through December 2013 for aggregated net proceeds of $1.03 million. The $1.03 million gain associated with these early settlement transactions is included in realized gain on derivative instruments for the year ended December 31, 2012.

Table of Contents

12. Related Party Transactions

The Company, as managing general partner or managing trustee, makes an annual offer to repurchase the interests of the partners and trust unit holders in certain of the Partnerships or Trusts. The Company purchased such interests in an amount totaling $48,000 during 2013 and $149,000 during 2012.

Treasury stock purchases in any reported period may include shares from a related party. In April 2012, the Company purchased 45,179 shares of common stock as treasury shares from a Director for $1.13 million. In December 2013, the Company purchased 4,500 shares of common stock as treasury shares from a Director for $222,750. There were no other related party treasury stock purchases during the years ended December 31, 2013 and 2012.

Receivables from related parties consist of reimbursable general and administrative costs, lease operating expenses and reimbursement for property development and related costs. These receivables are due from joint venture partners, which may include members of the Company s Board of Directors.

Payables owed to related parties primarily represent receipts collected by the Company as agent for the joint venture partners, which may include members of the Company s Board of Directors, for oil and gas sales net of expenses.

13. Restricted Cash and Cash Equivalents

Restricted cash and cash equivalents include $2.01 million and $4.44 million at December 31, 2013 and 2012, respectively, of cash primarily pertaining to oil and gas revenue payments. There were corresponding accounts payable recorded at December 31, 2013 and 2012 for these liabilities. Both the restricted cash and the accounts payable are classified as current on the accompanying consolidated balance sheets.

14. Salary Deferral Plan

The Company maintains a salary deferral plan (the Plan) in accordance with Internal Revenue Code Section 401(k), as amended. The Plan provides for matching contributions of which $525,000 and $463,000 were made in 2013 and 2012, respectively.

15. Earnings per Share

Basic earnings per share are computed by dividing earnings available to common stockholders by the weighted average number of common shares outstanding during the period. Diluted earnings per share reflect per share amounts that would have resulted if dilutive potential common stock had been converted to common stock in gain periods. The following reconciles amounts reported in the financial statements:

	Year Ended December 31,					
	2013			2012		
	Net Income (In 000 s)	Weighted Average Number of Shares Outstanding	Per Share Amount	Net Income (In 000 s)	Weighted Average Number of Shares Outstanding	Per Share Amount
Basic	$ 12,271	2,436,821	$ 5.04	$ 15,056	2,624,335	$ 5.74
Effect of dilutive securities:						
Options		746,085			735,244	
Diluted	$ 12,271	3,182,906	$ 3.86	$ 15,056	3,359,579	$ 4.48

16. Shareholder s Equity

The Company has in place a stock repurchase program whereby it may purchase outstanding shares of its common stock from time-to-time, in open market transactions or negotiated sales. The Company uses the cost method to account for its treasury share purchases.

Table of Contents

PRIMEENERGY CORPORATION AND SUBSIDIARIES

SUPPLEMENTARY INFORMATION

CAPITALIZED COSTS RELATING TO

OIL AND GAS PRODUCING ACTIVITIES

Years Ended December 31, 2013 and 2012

(Unaudited)

	As of December 31,	
(Thousands of dollars)	**2013**	**2012**
Proved Developed oil and gas properties	$ 362,186	$ 336,135
Proved Undeveloped oil and gas properties	1,937	2,069
Unproved oil and gas properties		
Total Capitalized Costs	364,123	338,204
Accumulated depreciation, depletion and valuation allowance	169,100	150,276
Net Capitalized Costs	$ 195,023	$ 187,928

COSTS INCURRED IN OIL AND GAS PROPERTY ACQUISITION,

EXPLORATION AND DEVELOPMENT ACTIVITIES

Years Ended December 31, 2013 and 2012

(Unaudited)

	Year Ended December 31,	
(Thousands of dollars)	**2013**	**2012**
Acquisition of Properties, Developed	$ 7	$ 6,482
Acquisition of Properties, Undeveloped		2,030
Exploration Costs	8	10
Development Costs	25,912	66,671

STANDARDIZED MEASURE OF DISCOUNTED FUTURE

NET CASH FLOWS RELATING TO PROVED OIL AND GAS RESERVES

Years Ended December 31, 2013 and 2012

(Unaudited)

	As of December 31,	
(Thousands of dollars)	**2013**	**2012**
Future cash inflows	$ 1,880,389	$ 1,524,137
Future production costs	(769,172)	(673,629)
Future development costs	(313,754)	(179,568)
Future income tax expenses	(234,191)	(186,072)
Future Net Cash Flows	563,272	484,868
10% annual discount for estimated timing of cash flows	(325,044)	(271,595)
Standardized Measure of Discounted Future Net Cash Flows	$ 238,228	$ 213,273

See accompanying Notes to Supplementary Information

Table of Contents

PRIMEENERGY CORPORATION AND SUBSIDIARIES

SUPPLEMENTARY INFORMATION

STANDARDIZED MEASURE OF DISCOUNTED FUTURE

NET CASH FLOWS AND CHANGES THEREIN

RELATING TO PROVED OIL AND GAS RESERVES

Years Ended December 31, 2013 and 2012

(Unaudited)

The following are the principal sources of change in the standardized measure of discounted future net cash flows during 2013 and 2012:

	Year Ended December 31,	
(Thousands of dollars)	**2013**	**2012**
Sales of oil and gas produced, net of production costs	$ (48,976)	$ (48,673)
Net changes in prices and production costs	(10,149)	504
Extensions, discoveries and improved recovery	218,648	164,557
Revisions of previous quantity estimates	(733)	40,964
Net change in development costs	(129,672)	(145,382)
Reserves sold		
Reserves purchased		6,563
Accretion of discount	21,327	18,451
Net change in income taxes	(23,007)	(5,952)
Changes in production rates (timing) and other	(2,483)	(2,267)
Net change	24,955	28,765
Standardized measure of discounted future net cash flow:		
Beginning of year	213,273	184,508
End of year	$ 238,228	$ 213,273

See accompanying Notes to Supplementary Information

Table of Contents

PRIMEENERGY CORPORATION AND SUBSIDIARIES

SUPPLEMENTARY INFORMATION

RESERVE QUANTITY INFORMATION

Years Ended December 31, 2013 and 2012

(Unaudited)

	As of December 31,					
	2013			2012		
	Oil (MBbls)	NGLs (MBbls)	Gas (MMcf)	Oil (MBbls)	NGLs (MBbls)	Gas (MMcf)
Proved Developed Reserves:						
Beginning of year	7,178	2,909	27,833	6,418		43,631
Extensions, discoveries and improved recovery	87		402	224	49	1,000
Revisions of previous estimates	(361)	(712)	6,456	252	2,860	(15,821)
Converted from undeveloped reserves	513	199	1,207	861		3,527
Reserves sold						
Reserves purchased				168		211
Production	(730)	(173)	(4,270)	(745)		(4,715)
End of year	6,687	2,223	31,628	7,178	2,909	27,833
Proved Undeveloped Reserves:						
Beginning of year	5,907	2,877	12,613	2,435		9,765
Extensions, discoveries and improved recovery	4,536	1,541	9,538	3,446	1,401	6,158
Revisions of previous estimates	864	(512)	(1,172)	887	1,476	217
Converted to developed reserves	(513)	199	(1,207)	(861)		(3,527)
Reserves sold						
Reserves purchased						
End of year	9,066	3,707	19,772	5,907	2,877	12,613
Total Proved Reserves at the End of the Year	15,753	5,930	51,400	13,085	5,786	40,446

RESULTS OF OPERATIONS FROM OIL AND GAS PRODUCING ACTIVITIES

Years Ended December 31, 2013 and 2012

(Unaudited)

(Thousands of dollars)	**Year Ended December 31, 2013**	**2012**
Revenue:		
Oil and gas sales	$ 92,785	$ 88,336
Costs and Expenses:		
Lease operating expenses	43,809	39,868
Exploration costs	8	10
Depreciation, depletion and accretion	19,218	19,883
Income tax expense	10,012	8,941
Total Costs and Expenses	73,047	68,702
Results of Operations From Producing Activities (excluding corporate overhead and interest costs)	$ 19,738	$ 19,634

See accompanying Notes to Supplementary Information

Table of Contents

PRIMEENERGY CORPORATION AND SUBSIDIARIES

NOTES TO SUPPLEMENTARY INFORMATION

(Unaudited)

1. Presentation of Reserve Disclosure Information

Reserve disclosure information is presented in accordance with U.S. generally accepted accounting principles. The Company s reserves include amounts attributable to non-controlling interests in the Partnerships. These interests represent less than 10% of the Company s reserves.

2. Determination of Proved Reserves

The estimates of the Company s proved reserves were determined by an independent petroleum engineer in accordance with U.S. generally accepted accounting principles. The estimates of proved reserves are inherently imprecise and are continually subject to revision based on production history, results of additional exploration and development and other factors. Estimated future net revenues were computed by reserves, less estimated future development and production costs based on current costs.

Proved reserve quantity estimates are subject to numerous uncertainties inherent in the estimation of quantities of proved reserves and in the projection of future rates of production and the timing of development expenditures. The accuracy of such estimates is a function of the quality of available data and of engineering and geological interpretation and judgment. Results of subsequent drilling, testing and production may cause either upward of downward revision of previous estimates. Further, the volumes considered to be commercially recoverable fluctuate with changes in prices and operating costs. The Company emphasizes that proved reserve estimates are inherently imprecise and that estimates of new discoveries are more imprecise than those of currently producing oil and gas properties. Accordingly, these estimates are expected to change as additional information becomes available in the future.

3. Results of Operations from Oil and Gas Producing Activities

The results of operations from oil and gas producing activities were prepared in accordance with U.S. generally accepted accounting principles. General and administrative expenses, interest costs and other unrelated costs are not deducted in computing results of operations from oil and gas activities.

4. Standardized Measure of Discounted Future Net Cash Flows and Changes Therein Relating to Proved Oil and Gas Reserves

The standardized measure of discounted future net cash flows relating to proved oil and gas reserves and the changes of standardized measure of discounted future net cash flows relating to proved oil and gas reserves were prepared in accordance with U.S. generally accepted accounting principles.

Future cash inflows are computed as described in Note 2 by applying current prices to year-end quantities of proved reserves.

Future production and development costs are computed estimating the expenditures to be incurred in developing and producing the oil and gas reserves at year-end, based on year-end costs and assuming continuation of existing economic conditions.

Future income tax expenses are calculated by applying the year-end U.S. tax rate to future pre-tax cash inflows relating to proved oil and gas reserves, less the tax basis of properties involved. Future income tax expenses give effect to permanent differences and tax credits and allowances relating to the proved oil and gas reserves.

Table of Contents

Future net cash flows are discounted at a rate of 10% annually (pursuant to applicable guidance) to derive the standardized measure of discounted future net cash flows. This calculation does not necessarily represent an estimate of fair market value or the present value of such cash flows since future prices and costs can vary substantially from year-end and the use of a 10% discount figure is arbitrary.

5. Changes in Reserves

The 2013 and 2012 extensions and discoveries reflect the successful drilling activity in the Company s West Texas and Mid-Continent areas. The Company is employing technologies to establish proved reserves that have been demonstrated to provide consistent results capable of repetition. The technologies and economic data being used in the estimation of its proved reserves include, but are not limited to, electrical logs, radioactivity logs, geologic maps, production data and well test data. The estimated reserves of wells with sufficient production history are estimated using appropriate decline curves. Estimated reserves of producing wells with limited production history and for undeveloped locations are estimated using performance data from analogous wells in the area. These wells are considered analogous based on production performance from the same formation and with similar completion techniques.