UNIT CORP
Form 10-K
February 24, 2015
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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549
FORM 10-K
ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE
SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2014
OR
TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE
SECURITIES EXCHANGE ACT OF 1934
For the transition period from to
Commission file number: 1-9260
UNIT CORPORATION
(Exact name of registrant as specified in its charter)

Delaware	73-1283193
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
7130 South Lewis, Suite 1000 Tulsa, Oklahoma	74136
(Address of principal executive offices)	(Zip Code)

(Registrant's telephone number, including area code) (918) 493-7700
Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Common Stock, par value $.20 per share	NYSE
Rights to Purchase Series A Participating Cumulative Preferred Stock	NYSE

Securities registered pursuant to Section 12(g) of the Act: None
Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.
Yes [x] No [ ]
Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Exchange Act.
Yes [ ] No [x]
Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes [x] No [ ]
Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes [x] No [ ]
Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. [x]
Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer", "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

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

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

As of June 30, 2014, the aggregate market value of the voting and non-voting common equity (based on the closing price of the stock on the NYSE on June 30, 2014) held by non-affiliates was approximately $1,841,089,922 Determination of stock ownership by non-affiliates was made solely for the purpose of this requirement, and the registrant is not bound by these determinations for any other purpose.

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

Class	Outstanding at February 13, 2015
Common Stock, $0.20 par value per share	49,824,530 shares

DOCUMENTS INCORPORATED BY REFERENCE

Document	Parts Into Which Incorporated
Portions of the registrant's definitive proxy statement (the "Proxy Statement") with respect to its annual meeting of shareholders scheduled to be held on May 6, 2015. The Proxy Statement will be filed within 120 days after the end of the fiscal year to which this report relates.	Part III

Exhibit Index—See Page 120

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FORM 10-K
UNIT CORPORATION

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DEFINITIONS

The following are explanations of some of the terms used in this report.
ARO – Asset retirement obligations.
ASC – FASB Accounting Standards Codification.
ASU – Accounting Standards Update.
Bcf – Billion cubic feet of natural gas.
Bcfe – Billion cubic feet of natural gas equivalent. Determined using the ratio of one barrel of crude oil or NGLs to six Mcf of natural gas.
Bbl – Barrel, or 42 U.S. gallons liquid volume.
Boe – Barrel of oil equivalent. Determined using the ratio of six Mcf of natural gas to one barrel of crude oil or NGLs.
BOKF – Bank of Oklahoma Financial Corporation.
Btu – British thermal unit, used in terms of gas volumes. Btu is used to refer to the amount of natural gas required to raise the temperature of one pound of water by one degree Fahrenheit at one atmospheric pressure.
Development drilling – The drilling of a well within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive.
DD&A – Depreciation, depletion, and amortization.
FASB – Financial and Accounting Standards Board.
Finding and development costs – Costs associated with acquiring and developing proved natural gas and oil reserves which are capitalized under generally accepted accounting principles, including any capitalized general and administrative expenses.
Gross acres or gross wells – The total acres or wells in which a working interest is owned.
IF – Inside FERC (U.S. Federal Energy Regulatory Commission).
LIBOR – London Interbank Offered Rate.
MBbls – Thousand barrels of crude oil or other liquid hydrocarbons.
Mcf – Thousand cubic feet of natural gas.
Mcfe – Thousand cubic feet of natural gas equivalent. Determined using the ratio of one barrel of crude oil or NGLs to six Mcf of natural gas.
MMBbls – Million barrels of crude oil or other liquid hydrocarbons.
MMBoe – Million barrels of oil equivalents.
MMBtu – Million Btu's.
MMcf – Million cubic feet of natural gas.
MMcfe – Million cubic feet of natural gas equivalent. Determined using the ratio of one barrel of crude oil or NGLs to six Mcf of natural gas.
Net acres or net wells – The sum of the fractional working interests owned in gross acres or gross wells.
NGLs – Natural gas liquids.
NGPL-TXOK – Natural Gas Pipeline Co. of America/Texok zone.
NYMEX – The New York Mercantile Exchange.
OPIS – Oil Price Information Service.
PEPL – Panhandle East Pipeline Co.
Play – A term applied by geologists and geophysicists identifying an area with potential oil and gas reserves.
Producing property – A natural gas or oil property with existing production.
Proved developed reserves – Reserves that can be expected to be recovered through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and through installed extraction equipment and infrastructure operational at the time of the reserves estimate . For additional information, see the SEC's definition in Rule 4-10(a)(3) of Regulation S-X.
Proved reserves – Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geosciences and engineering data, can be estimated with reasonable certainty to be economically producible – from a given date forward, from known reservoirs and under existing economic conditions, operating methods, and government regulations – prior to the time at which contracts providing the right to operate expire, unless evidence indicates that

renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time. For additional information, see the SEC's definition in Rule 4-10(a)(2)(i) through (iii) of Regulation S-X.

Proved undeveloped reserves – Proved reserves 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. For additional information, see the SEC's definition in Rule 4-10(a)(4) of Regulation S-X.

Reasonable certainty (in regards to reserves) – If deterministic methods are used, reasonable certainty means a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate.

Reliable technology – A grouping of one or more technologies (including computational methods) that has been field tested and has been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.

SARs – Stock appreciation rights.

Unconventional play – Plays targeting tight sand, carbonates, coal bed, or oil and gas shale reservoirs. The reservoirs tend to cover large areas and lack the readily apparent traps, seals, and discrete hydrocarbon-water boundaries that typically define conventional reservoirs. These reservoirs generally require horizontal wells and fracture stimulation treatments or other special recovery processes in order to produce economically.

Undeveloped acreage – Lease acreage on which wells have not been drilled or completed to a point that would permit the production of economic quantities of natural gas or oil regardless of whether the acreage contains proved reserves.

Well spacing – The regulation of the number and location of wells over an oil or gas reservoir, as a conservation measure. Well spacing is normally accomplished by order of the appropriate regulatory conservation commission.

Workovers – Operations on a producing well to restore or increase production.

WTI – West Texas Intermediate, the benchmark crude oil in the United States.

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UNIT CORPORATION
Annual Report
For The Year Ended December 31, 2014

PART I

Item 1. Business

Unless otherwise indicated or required by the context, the terms “Company”, “Unit”, “us”, “our”, “we”, and “its” refer to Unit Corporation or, as appropriate, one or more of its subsidiaries.

Our executive offices are at 7130 South Lewis, Suite 1000, Tulsa, Oklahoma 74136; our telephone number is (918) 493-7700.

Information regarding our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and any amendments to these reports, will be made available in print, free of charge, to any shareholders who request them. They are also available on our internet website at www.unitcorp.com, as soon as reasonably practicable after we electronically file these reports with or furnish them to the Securities and Exchange Commission (SEC). Materials we file with the SEC may be read and copied at the SEC’s Public Reference Room at 100 F. Street, N.E. Room 1580, N.W., Washington, D.C. 20549. Information on the operation of the Public Reference Room may be obtained by calling the SEC at 1-800-SEC-0330. The SEC also maintains an Internet website at www.sec.gov that contains reports, proxy and information statements, and other information regarding our company that we file electronically with the SEC.

In addition, we post on our Internet website, www.unitcorp.com, copies of our corporate governance documents. Our corporate governance guidelines and code of ethics, and the charters of our Board’s Audit, Compensation, and Nominating and Governance Committees, are available free of charge on our website or in print to any shareholder who requests them. We may from time to time provide important disclosures to investors by posting them in the investor information section of our website, as allowed by SEC rules.

GENERAL

We were founded in 1963 as an oil and natural gas contract drilling company. Today, in addition to our drilling operations, we have operations in the exploration and production and mid-stream areas. We operate, manage, and analyze our results of operations through our three principal business segments:

- Oil and Natural Gas – carried out by our subsidiary Unit Petroleum Company. This segment explores, develops, acquires, and produces oil and natural gas properties for our own account.
- Contract Drilling – carried out by our subsidiary Unit Drilling Company and its subsidiaries. This segment contracts to drill onshore oil and natural gas wells for others and for our own account.
- Mid-Stream – carried out by our subsidiary Superior Pipeline Company, L.L.C. and its subsidiaries. This segment buys, sells, gathers, processes, and treats natural gas for third parties and for our own account.

Each of these companies may conduct operations through subsidiaries of their own.

The following table provides certain information about us as of February 13, 2015:

Oil and Natural Gas	
Completed gross wells in which we own an interest	8,271
Contract Drilling	

Number of drilling rigs available for use	90
Mid-Stream	
Number of natural gas treatment plants we own	3
Number of processing plants we own	14
Number of natural gas gathering systems we own [1]	29

(1) Effective January 1, 2015, nine gathering systems were transferred to our oil and natural gas segment.

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2014 SEGMENT OPERATIONS HIGHLIGHTS

Oil and Natural Gas

- Attained net proved oil, NGLs, and natural gas reserves of 179.0 MMBoe, a 12% increase over 2013 reserves.
- Increased net proved oil and NGLs reserves by 13% over 2013.
- Total production of 18.3 MMBoe or an 9% increase over 2013.
- Participated in the drilling of 186 gross wells.
- Sold non-core assets with proceeds of $33.1 million.

Contract Drilling

- Averaged 75.4 drilling rigs running, a 16% increase over 2013.
- Built and put into service three of the new proprietary 1,500 horsepower AC electric BOSS drilling rigs. Five additional BOSS drilling rigs are expected to be completed and put into service during the first half of 2015, the first went into service in January 2015.
- Moved eight rigs into the Permian Basin of West Texas for a total of ten rigs in this new market area.
- Sold four 3,000 horsepower electric drilling rigs to unaffiliated third-parties.

Mid-Stream

- Gas gathered increased from 309,554 Mcf per day in 2013 to 319,348 Mcf per day in 2014, a 3% increase.
- Gas processed increased from 140,584 Mcf per day in 2013 to 161,282 Mcf per day in 2014, a 15% increase.
- Liquids sold increased from 543,602 gallons per day in 2013 to 733,406 gallons per day in 2014, a 35% increase.
- Added 67 miles of pipeline (approximately a 5% increase) and connected 177 new wells to our various gathering systems.
- Completed construction of a nine mile pipeline and related compression facilities connecting the Buffalo Wallow gathering system to the Hemphill processing plant which allows us the ability to process Buffalo Wallow production.
- Completed the installation of a 60 MMcf per day processing plant at our Bellmon facility increasing our total processing capacity to 90 MMcf per day.
- Completed upgrade of Perkins processing facility increasing our total processing capacity to 27 MMcf per day and improving our recovery capabilities.
- Began phase iii expansion of Pittsburgh Mills gathering system in Butler County, Pennsylvania, which will allow us to connect additional well pads from an existing producer.
- Began construction of our Snow Shoe gathering system and compressor station in Centre County, Pennsylvania. Construction should be completed and operational in late 2015.
- Increased the contract mix as a percent of volume for fee-based contracts from 62% in 2013 to 69% in 2014.

FINANCIAL INFORMATION ABOUT SEGMENTS

See Note 17 of our Notes to Consolidated Financial Statements in Item 8 of this report for information with respect to each of our segment's revenues, profits or losses, and total assets.

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OIL AND NATURAL GAS

General. We began to develop our exploration and production operations in 1979. Today, our wholly owned subsidiary, Unit Petroleum Company, conducts our exploration and production activities. Our producing oil and natural gas properties, unproved properties, and related assets are in the following locations:

Division	Location
West division	Western and Southern Texas, Colorado, Wyoming, Montana, North Dakota, New Mexico, Southern Louisiana, and Mississippi
East division	East Texas, Eastern Oklahoma, Arkansas, and Northern Louisiana
Central division	Western Oklahoma, Texas Panhandle, and Kansas

When we are the operator of a property, we generally attempt to use a drilling rig owned by our contract drilling segment, and we use our mid-stream segment to gather our gas if it is economical for us to develop a system in the area.

The following table presents certain information regarding our oil and natural gas operations as of December 31, 2014:

Our Divisions/Area	Number of Gross Wells	Number of Net Wells	Number of Gross Wells in Process	Number of Net Wells in Process	2014 Average Net Daily Production Natural Gas (Mcf)	Oil (Bbls)	NGLs (Bbls)
West division	1,475	510.80	4	3.75	43,694	1,735	3,353
East division	1,450	469.70	—	—	21,146	23	17
Central division	5,346	1,919.64	13	7.13	96,404	8,773	9,311
Total	8,271	2,900.14	17	10.88	161,244	10,531	12,681

As of December 31, 2014, we did not have any significant water floods, pressure maintenance operations, or any other material related activities that were in process.

Description and Location of Our Core Operations

West division. In our Wilcox play, located primarily in Polk, Tyler, and Hardin Counties, Texas, we completed 15 operated gross vertical wells in 2014 with an average working interest of 92% and a success rate of 87%. Production in our overall Wilcox play (Jazz Field) increased approximately 28% in 2014 as compared to 2013. Five of the 15 wells were completed in our “Gilly” Basal Wilcox prospect bringing the total number of wells producing in that prospect to 14 at year end 2014. We averaged using two Unit drilling rigs during 2014 and currently plan to use one to two Unit drilling rigs during 2015. For 2015, we anticipate drilling approximately eight vertical wells and approximately six horizontal wells in the Wilcox play.

East division. Over the last several years, activity in our East Division has been limited due to low gas prices since this area does not generally have oil or NGLs associated with the gas.

Central division. SOHOT (Southern Oklahoma Hoxbar Oil Trend) is a new play located primarily in Grady County, Oklahoma that we first drilled in 2013. The producing horizon is named the Hoxbar which is an interval that contains several potential oil and gas sands which are generally 50 to 100 feet thick. During 2014, we focused our drilling program on two of the potential Hoxbar sands named the Marchand oil sand and the Medrano gas liquids sand. Eight new horizontal Hoxbar wells were completed during 2014. Four of the wells were completed in the Hoxbar” Marchand” zone and four were completed in the Hoxbar “Medrano” zone. Production during the fourth quarter 2014 averaged 1,410 barrels of oil per day, 1,090 barrels of NGLs per day, and 6.9 MMcf of natural gas per day which is a 437% increase over the fourth quarter 2013. During 2014, we averaged approximately two Unit drilling rigs in SOHOT. For 2015, our current plan is to average approximately one to two Unit drilling rigs.

In the Texas Panhandle District, which consists primarily of Granite Wash (GW) wells and to a lesser degree Cleveland wells, the average daily production for 2014 increased approximately 12% over 2013. We had first sales on 38 horizontal GW wells, having an average peak 30 day IP rate of approximately 4.9 MMcfe per day and an average working interest of 86%. During 2014, 12 of the 38 new wells were drilled and completed in the GW Buffalo Wallow Field and the remaining 26 wells in our legacy GW fields. For 2014, we averaged 4.7 rigs drilling in the GW with current plans to have none drilling by the end of the first quarter 2015.

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In our Mississippian play in south central Kansas, the average daily production for 2014 increased approximately 154% as compared to 2013. We had first sales on 25 operated Mississippian wells during 2014 with an average 30 day IP rate of 188 Boe per day consisting of an average of approximately 69% oil, 9% NGLs, and 22% natural gas with a 100% average working interest. We currently are shooting an 86 square mile 3-D seismic survey that is scheduled for completion around mid-year 2015. During 2014, we averaged 1.5 Unit drilling rigs in the Mississippian play. The current plan for 2015 does not include any rigs for the Mississippian play.

In the Marmaton horizontal oil play in Beaver County, Oklahoma, we had first sales on 39 horizontal wells during 2014 with an average 30 day IP rate of 303 Boe per day with an approximate average working interest of 78%. The average daily production for 2014 decreased approximately 12% as compared to 2013. During the fourth quarter 2014, we released the two Unit drilling rigs that were drilling for us in the Marmaton play. We do not anticipate drilling any new wells in the play during 2015.

Dispositions and Acquisitions. In September 2012, we sold our interest in certain Bakken properties (located in North Dakota). The proceeds, net of related expenses, were $226.6 million. In addition, we sold certain oil and natural gas assets located in Brazos and Madison Counties,Texas, for approximately $44.1 million. In August 2013, we sold additional Bakken property interests. The proceeds, net of related expenses, were $57.1 million. In addition, we had other non-core asset sales with proceeds, net of related expenses, of $21.7 million and $33.1 million for 2013 and 2014, respectively. Proceeds from these dispositions reduced the net book value of the full cost pool with no gain or loss recognized.

On September 17, 2012, we acquired certain oil and natural gas assets from Noble. After final closing adjustments, the acquisition included approximately 83,000 net acres primarily in the Granite Wash, Cleveland, and various other plays in western Oklahoma and the Texas Panhandle. The adjusted amount paid was $592.6 million.

As of the effective date of the Noble acquisition (April 1, 2012), the estimated proved reserves of the acquired properties were 44 MMBoe, The acquisition added approximately 24,000 net leasehold acres to our Granite Wash core area in the Texas Panhandle with significant potential including approximately 600 possible future horizontal drilling locations. The total acreage acquired in other plays in western Oklahoma and the Texas Panhandle was approximately 59,000 net acres and was characterized by high working interest and operatorship, 95% of which was held by production. We also received four gathering systems as part of the transaction, as well as other miscellaneous assets.

In December 2014, we determined the value of certain unproved oil and gas properties were diminished (in part or in whole) based on an impairment evaluation and our anticipated future exploration plans. That determination resulted in $73.7 million of costs associated with the unproved properties being added to the capitalized costs to be amortized. We incurred a non-cash ceiling test write-down of our oil and natural gas properties of $76.7 million pre-tax ($47.7 million net of tax). Subsequent to December 31, 2014, commodity prices have continued to decrease below December 31, 2014 levels. We anticipate that these reduced prices will require an additional write-down of the carrying value of our oil and natural gas properties for the quarter ending March 31, 2015 and potentially for subsequent quarters.

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Well and Leasehold Data. The following tables identify certain information regarding our oil and natural gas exploratory and development drilling operations:

	Year Ended December 31,					
	2014		2013		2012	
	Gross	Net	Gross	Net	Gross	Net
Wells drilled:						
Exploratory:						
Oil:						
West division	—	—	—	—	1	1.00
East division	—	—	—	—	—	—
Central division	1	0.93	—	—	1	1.00
Total oil	1	0.93	—	—	2	2.00
Natural gas:						
West division	5	4.80	2	2.00	3	2.49
East division	—	—	—	—	—	—
Central division	—	—	—	—	—	—
Total natural gas	5	4.80	2	2.00	3	2.49
Dry:						
West division	1	1.00	—	—	1	1.00
East division	—	—	—	—	—	—
Central division	—	—	—	—	—	—
Total dry	1	1.00	—	—	1	1.00
Total exploratory	7	6.73	2	2.00	6	5.49
Development:						
Oil:						
West division	4	0.37	1	0.08	29	4.10
East division	—	—	—	—	—	—
Central division	115	74.07	93	51.33	71	34.04
Total oil	119	74.44	94	51.41	100	38.14
Natural gas:						
West division	7	6.09	9	8.60	7	4.44
East division	—	—	1	—	2	0.76
Central division	49	31.91	37	26.00	55	30.45
Total natural gas	56	38.00	47	34.60	64	35.65
Dry:						
West division	1	0.80	3	1.35	1	0.80
East division	—	—	—	—	—	—
Central division	3	1.03	3	1.78	—	—
Total dry	4	1.83	6	3.13	1	0.80
Total development	179	114.27	147	89.14	165	74.59
Total wells drilled	186	121.00	149	91.14	171	80.08

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	Year Ended December 31,					
	2014 (1)		2013		2012	
	Gross	Net	Gross	Net	Gross	Net
Wells producing or capable of producing:						
Oil:						
West division	713	164.25	2,058	170.49	2,076	178.43
East division	42	1.91	42	1.91	54	3.17
Central division	997	497.10	891	426.75	807	382.34
Total oil	1,752	663.26	2,991	599.15	2,937	563.94
Natural gas:						
West division	703	326.64	1,004	326.79	1,109	330.19
East division	1,401	466.79	1,435	472.68	1,632	519.62
Central division	4,265	1,390.05	4,266	1,382.62	4,245	1,362.87
Total natural gas	6,369	2,183.48	6,705	2,182.09	6,986	2,212.68
Total	8,121	2,846.74	9,696	2,781.24	9,923	2,776.62

(1) During 2014, we had divestitures of 1,716 gross (37.31 net) wells.

As of February 13, 2015, we were drilling or participating in seven gross (4.07 net) wells started during 2015.

Cost incurred for development drilling includes $199.7 million, $136.7 million, and $123.4 million in 2014, 2013, and 2012, respectively, to develop booked proved undeveloped oil and natural gas reserves.

The following table summarizes our leasehold acreage at December 31, 2014:

	Year Ended December 31, 2014					
	Developed		Undeveloped		Total	
	Gross	Net	Gross	Net (1)	Gross	Net
West division	265,290	84,169	152,423	99,587	417,713	183,756
East division	215,075	86,427	42,342	13,628	257,417	100,055
Central division	884,774	359,079	246,427	177,352	1,131,201	536,431
Total	1,365,139	529,675	441,192	290,567	1,806,331	820,242

(1) Approximately 66% (West – 55%; East – 85%; and Central – 71%) of the net undeveloped acres are covered by leases that will expire in the years 2015—2017 unless drilling or production extends the terms of those leases. Currently, we do not have any material proved undeveloped (PUD) reserves attributable to acreage where the expiration date precedes the scheduled PUD reserve development plan.

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Price and Production Data. The following tables identify the average sales price, production volumes, and average production cost per equivalent barrel for our oil, NGLs, and natural gas production for the years indicated:

	Year Ended December 31,		
	2014	2013	2012
Average sales price per barrel of oil produced:			
Price before derivatives	$89.32	$95.18	$90.19
Effect of derivatives	0.11	(0.12)	2.41
Price including derivatives	$89.43	$95.06	$92.60
Average sales price per barrel of NGLs produced:			
Price before derivatives	$30.95	$31.79	$30.70
Effect of derivatives	—	—	0.88
Price including derivatives	$30.95	$31.79	$31.58
Average sales price per Mcf of natural gas produced:			
Price before derivatives	$4.03	$3.33	$2.53
Effect of derivatives	(0.11)	(0.01)	0.84
Price including derivatives	$3.92	$3.32	$3.37

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	Year Ended December 31,		
	2014	2013	2012
Oil production (MBbls):			
West division			
Jazz field	377	312	246
All other west division fields	256	378	825
Total west division	633	690	1,071
East division	8	16	16
Central division:			
Mendota field	407	412	497
All other central division fields	2,796	2,242	1,695
Total central division	3,203	2,654	2,192
Total oil production (MBbls)	3,844	3,360	3,279
NGLs production (MBbls):			
West division			
Jazz field	989	788	599
All other west division fields	235	205	259
Total west division	1,224	993	858
East division	6	24	23
Central division:			
Mendota field	1,117	1,050	1,128
All other central division fields	2,281	1,847	787
Total central division	3,398	2,897	1,915
Total NGLs production (MBbls)	4,628	3,914	2,796
Natural gas production (MMcf):			
West division			
Jazz field	2,066	1,471	1,174
All other west division fields	13,882	11,591	10,657
Total west division	15,948	13,062	11,831
East division	7,719	9,401	11,906
Central division:			
Mendota field	7,555	9,138	8,957
All other central division fields	27,632	25,156	16,236
Total central division	35,187	34,294	25,193
Total natural gas production (MMcf)	58,854	56,757	48,930
Total production (MBoe):			
West division			
Jazz field	3,431	2,572	2,020
All other west division fields	1,084	1,288	1,881
Total west division	4,515	3,860	3,901
East division	1,301	1,607	2,023
Central division:			
Mendota field	2,783	2,985	3,118
All other central division fields	9,682	8,282	5,188
Total central division	12,465	11,267	8,306
Total production (MBoe)	18,281	16,734	14,230
Average production cost per equivalent Bbl [1]	$7.70	$7.63	$7.00

(1) Excludes ad valorem taxes and gross production taxes.

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Our Mendota field, located in the Granite Wash play, includes 17%, 18%, and 19%, respectively of our total proved reserves in 2014, 2013, and 2012, respectively, expressed on an oil equivalent barrels basis. Before 2014 our Mendota field was the only field that accounted for more than 15% of our proved reserves. Starting in 2014 our Jazz Wilcox field, which includes Gilly, Segno, and Wildwood prospects and several smaller prospects, contained 17% of our total proved reserves in 2014, expressed on an oil equivalent barrels basis. There are no other fields besides these that accounted for more than 15% of our proved reserves.

Oil, NGLs, and Natural Gas Reserves. The following table identifies our estimated proved developed and undeveloped oil, NGLs, and natural gas reserves:

	Year Ended December 31, 2014			
	Oil (MBbls)	NGLs (MBbls)	Natural Gas (MMcf)	Total Proved Reserves (MBoe)
Proved developed:				
West division	4,280	9,675	116,531	33,377
East division	69	123	94,280	15,905
Central division	13,099	26,052	290,139	87,508
Total proved developed	17,448	35,850	500,950	136,790
Proved undeveloped:				
West division	490	871	10,751	3,153
East division	—	—	7,798	1,300
Central division	4,729	11,808	127,462	37,780
Total proved undeveloped	5,219	12,679	146,011	42,233
Total proved	22,667	48,529	646,961	179,023

Oil, NGLs, and natural gas reserves cannot be measured exactly. Estimates of oil, NGLs, and natural gas reserves require extensive judgments of reservoir engineering data and are generally less precise than other estimates made in connection with financial disclosures. We use Ryder Scott Company L.P. (Ryder Scott), independent petroleum consultants, to audit the reserves prepared by our reservoir engineers. Ryder Scott has been providing petroleum consulting services throughout the world since 1937. Their summary report is attached as Exhibit 99.1 to this Form 10-K. The wells or locations for which reserve estimates were audited were taken from reserve and income projections prepared by us as of December 31, 2014 and comprised 85% of the total proved developed discounted future net income and 83% of the total proved undeveloped discounted future net income (based on the unescalated pricing policy of the SEC).

Our Reservoir Engineering department is responsible for reserve determination for the wells in which we have an interest. Their primary objective is to estimate the wells' future reserves and future net value to us. Data is incorporated from multiple sources including geological, production engineering, marketing, production, land, and accounting departments. The engineers are responsible for reviewing this information for accuracy as it is incorporated into the reservoir engineering database. Our internal audit group reviews the controls to help provide assurance all the data has been provided. New well reserve estimates are provided to management as well as the respective operational divisions for additional scrutiny. Major reserve changes on existing wells are reviewed on a regular basis with the operational divisions to confirm correctness and accuracy. As the external audit is being completed by Ryder Scott, the reservoir department performs a final review of all properties for accuracy of forecasting.

Technical Qualifications

Ryder Scott – Mr. Fred P. Richoux is the primary technical person in charge on behalf of Ryder Scott for their audit of our reserves.

Mr. Richoux, an employee of Ryder Scott since 1978, is the President and member of the Board of Directors at Ryder Scott. He is responsible for coordinating and supervising staff and consulting engineers of the company in ongoing reservoir evaluation studies worldwide as well as other administrative functions at the Company. Before joining Ryder Scott, Mr. Richoux served in a number of engineering positions with Phillips Petroleum Company.

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Mr. Richoux earned a Bachelor of Science degree in Electrical Engineering from the University of Louisiana at Lafayette and is a registered Professional Engineer in the State of Texas and the Province of Alberta. He is also a member of the Society of Petroleum Engineers and the Society of Petroleum Evaluation Engineers.

In addition to gaining experience and competency through prior work experience, the Texas Board of Professional Engineers requires a minimum of fifteen hours of continuing education annually, including at least one hour in the area of professional ethics, which Mr. Richoux fulfills.

Based on his educational background, professional training and more than 45 years of practical experience in the estimation and evaluation of petroleum reserves, Mr. Richoux has attained the professional qualifications as a Reserves Estimator (requires appropriate degree and/or is registered as Professional Engineer and has a minimum of 3 years experience in the estimation and evaluation of reserves) and Reserves Auditor (requires appropriate degree and/or is registered as Professional Engineer and has a minimum of 10 years experience in the estimation and evaluation of reserves of which at least 5 years of such experience is being in responsible charge of the estimation and evaluation of reserves) set forth in Article III of the “Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information” promulgated by the Society of Petroleum Engineers as of February 19, 2007. For more information regarding Mr. Richoux’s geographic and job specific experience, please refer to the Ryder Scott Company website at http://www.ryderscott.com/Experience/Employees.

The Company – Responsibility for overseeing the preparation of our reserve report is shared by our reservoir engineers Trenton Mitchell and Robert Lyon.

Mr. Mitchell earned a Bachelor of Science degree in Petroleum Engineering from Texas A&M University in 1994. He has been an employee of Unit since 2002. Initially, he was the Outside Operated Engineer and since 2003 he has served in the capacity of Reservoir Engineer and in 2010 he was promoted to Manager of Reservoir Engineering. Before joining Unit, he served in a number of engineering field and technical support positions with Schlumberger Well Services in their pumping services segment (formerly Dowell Schlumberger). He obtained his Professional Engineer registration from the State of Oklahoma in 2004 and has been a member of Society of Petroleum Engineers (SPE) since 1991.

Mr. Lyon received a Bachelor of Science degree in Petroleum Engineering from the University of Tulsa in 1972 and has spent 36 of his 43 years in the industry directly involved in reserve calculation work. Included in this time were 15 years working for petroleum consulting firms Raymond F. Kravis and Associates and Southmayd and Associates performing independent reserve appraisals and audits for corporations and individuals. He joined Unit in 1996 and has shared responsibility for preparation of the company’s reserve report since that time. Mr. Lyon is a registered professional engineer in the State of Oklahoma and a member of the SPE.

As part of the continuing education requirement for maintaining their professional licenses Mr. Mitchell and Mr. Lyon have attended various seminars and forums to enhance their understanding of current standards and issues for reserves presentation. These forums have included those sponsored by various professional societies and professional service firms including Ryder Scott.

Definitions and Other. Proved oil, NGLs, and natural gas reserves, as defined in SEC Rule 4-10(a), are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible – from a given date forward, from known reservoirs and under existing economic conditions, operating methods and government regulations – before the time the contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

The area of the reservoir considered as proved includes:

- The area identified by drilling and limited by fluid contacts, if any, and
- Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geosciences and engineering data.

In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons as seen in a well penetration unless geosciences, engineering or performance data and reliable technology establishes a lower contact with reasonable certainty.

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Where direct observation from well penetrations has defined a highest known oil elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geosciences, engineering or performance data and reliable technology establish the higher contact with reasonable certainty.

Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

- Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole;
- The operation of an installed program in the reservoir or other evidence using reliable technology establishes reasonable certainty of the engineering analysis on which the project or program was based; and
- The project has been approved for development by all necessary parties and entities, including governmental entities.

Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price used is the average of the prices over the 12-month period before the ending date of the period covered by the report, and is determined as an unweighted arithmetic average of the first day of the month price for each month within the period, unless prices are defined by contractual arrangements, excluding escalations based on future conditions.

Proved undeveloped oil, NGLs, and natural gas reserves are proved reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for completion. Reserves on undrilled acreage are limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances. Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time. Under no circumstances can estimates for proved undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, or by other evidence using reliable technology establishing reasonable certainty.

Proved Undeveloped Reserves. As of December 31, 2014, we had approximately 177 gross proved undeveloped wells all of which we plan to develop within five years of initial disclosure at a net estimated cost of approximately $481.5 million. The future estimated development costs necessary to develop our proved undeveloped oil and natural gas reserves in the United States for the years 2015—2019, as disclosed in our December 31, 2014 oil and natural gas reserve report, are shown below:

Year	Number of Gross Wells Planned	Estimated Development Cost (In millions)
2015	32	$71.8
2016	73	190.3
2017	60	182.1
2018	11	32.8
2019	1	4.5
	177	$481.5

Our proved undeveloped reserves reported at December 31, 2014 did not include reserves that we did not expect to develop within five years of initial disclosure of those reserves. Below is a summary of changes to our PUD reserves during 2014:

	Oil	NGLs	Total

	(MMBbls)	(MMBbls)	Natural Gas (Bcf)	(MMBoe)
Proved undeveloped reserves, January 1, 2014	6.2	10.8	117.6	36.5
Extensions and discoveries	3.3	6.3	76.5	22.3
Converted to developed	(2.8)	(2.7)	(24.8)	(9.6)
Revisions of previous estimates	(1.4)	(1.5)	(21.8)	(6.5)
Sales of reserves	(0.1)	(0.2)	(1.4)	(0.5)
Proved undeveloped reserves, December 31, 2014	5.2	12.7	146.1	42.2

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During 2014, we converted 60 proved undeveloped wells into proved developed wells at a cost of approximately $199.7 million. The downward revision to previous estimates were due to a number of factors including the removal of PUDs that are not part of our five-year development plan due to the decline in prices causing them to be uneconomic to drill and also due to a reduction in anticipated future capital expenditures.

Our estimated proved reserves and the standardized measure of discounted future net cash flows of the proved reserves at December 31, 2014, 2013, and 2012, the changes in quantities, and standardized measure of those reserves for the three years then ended, are shown in the Supplemental Oil and Gas Disclosures included in Item 8 of this report.

Contracts. Our oil production is sold at or near our wells under purchase contracts at prevailing prices in accordance with arrangements customary in the oil industry. Our natural gas production is sold to intrastate and interstate pipelines as well as to independent marketing firms under contracts with terms generally ranging from one month to a year. Few of these contracts contain provisions for readjustment of price as most of them are market sensitive.

Customers. During 2014, sales to Valero Energy Corporation and Sunoco Logistics accounted for 24% and 14% of our oil and natural gas revenues, respectively. There was no other company that accounted for more than 10% of our oil and natural gas revenues. During 2014, our mid-stream segment purchased $80.9 million of our natural gas and NGLs production and provided gathering and transportation services of $8.7 million. Intercompany revenue from services and purchases of production between our mid-stream segment and our oil and natural gas segment has been eliminated in our consolidated financial statements. In 2013 and 2012, we eliminated intercompany revenues of $91.0 million and $73.3 million, respectively, attributable to the intercompany purchase of our production of natural gas and NGLs as well as gathering and transportation services.

CONTRACT DRILLING

General. Our contract drilling business is conducted through Unit Drilling Company and its subsidiary Unit Texas Drilling L.L.C. Through these companies we drill onshore oil and natural gas wells for our own account as well as other oil and natural gas companies. Our drilling operations are located in Oklahoma, Texas, Louisiana, Kansas, Wyoming, and North Dakota.

The following table identifies certain information concerning our contract drilling operations:

	Year Ended December 31,		
	2014	2013	2012
Number of drilling rigs available for use at year end	89.0	121.0	127.0
Average number of drilling rigs owned during year	118.8	125.4	127.4
Average number of drilling rigs utilized	75.4	65.0	73.9
Utilization rate (1)	63 %	52 %	58 %
Average revenue per day (2)	$17,318	$17,486	$19,774
Total footage drilled (feet in 1,000's)	12,551	10,578	10,551
Number of wells drilled	894	793	773

(1) Utilization rate is determined by dividing the average number of drilling rigs used by the average number of drilling rigs owned during the year.

(2) Represents the total revenues minus rental revenue from our contract drilling operations divided by the total number of days our drilling rigs were used minus the rental days during the year.

Description and Location of Our Drilling Rigs. An on-shore drilling rig is composed of major equipment components like engines, drawworks or hoists, derrick or mast, substructure, pumps to circulate the drilling fluid, blowout preventers, and drill pipe. As a result of the normal wear and tear from operating 24 hours a day, several of the major components, like engines, mud pumps, and drill pipe, must be replaced or rebuilt on a periodic basis. Other major components, like the substructure, mast, and drawworks, can be used for extended periods of time with proper maintenance. We also own additional equipment used in the operation of our drilling rigs, including top drives, skidding systems, large air compressors, trucks, and other support equipment.

The maximum depth capacities of our various drilling rigs range from 5,000 to 40,000 feet. In 2014, 83 of our 89 drilling rigs were used in drilling services.

The following table shows certain information about our drilling rigs (including their distribution) as of February 13, 2015:

Divisions	Contracted Rigs	Non-Contracted Rigs	Total Rigs	Average Rated Drilling Depth (ft)
Mid-Continent	18	13	31	18,177
Woodward	10	5	15	13,967
Panhandle	6	8	14	14,964
Gulf Coast	7	3	10	21,200
Rocky Mountain	11	9	20	19,925
Totals	52	38	90	17,700

The cyclical nature of the drilling business is best reflected in rig utilization rates. Drilling rig utilization at the beginning of 2012 had 82 rigs operating but began declining from the second quarter of 2012 and ended 2012 with 62 rigs running. Utilization remained relatively flat throughout 2013 averaging 65 rigs operating for the year. Then 2014 saw an increase of 17 rigs running - going from 65 rigs at the start of the year to 82 rigs in November. The last month of 2014 reflects the beginning of another market decline as we ended 2014 with an average of 75 rigs operating for the year. Factors contributing to the fluctuating utilization are greatly influenced by changes in commodity prices, drilling efficiencies attained by operators, improved drilling practices and more efficient drilling rigs, and, to some degree, acreage in certain plays being held by existing production thereby allowing for the deferral of the need to drill the acreage to hold it.

Mid-Continent, Woodward, and Panhandle. We have long held a strong position and market presence in the mid-continent area of Oklahoma and the Texas Panhandle. This area is commonly referred to as the Anadarko Basin, which also encompasses portions of Kansas. Historically, the Anadarko Basin has been known as a gas producing area, but it is also rich in oil and NGLs production. During the last several years operators have focused their operations in this basin on the Cana Woodford, Granite Wash, SOHOT, Cleveland, Tonkawa, Marmaton, and Mississippian horizontal plays. Three of our divisions work in the Anadarko Basin. During 2014, our Mid-Continent, Panhandle, and Woodward divisions averaged 26.5, 10.7, and 12.4 drilling rigs operating, respectively.

Gulf Coast. Our Gulf Coast division provides drilling rigs to the onshore areas of Texas and Louisiana. At the end of 2013, two drilling rigs were moved into the Permian Basin of West Texas. Also during 2014, eight additional rigs from the Gulf Coast, Mid-Continent, Woodward, and Panhandle divisions were sent to the Permian Basin for a total of ten rigs in this new market area for Unit. During 2014, the Gulf Coast division averaged 8.8 drilling rigs operating.

Rocky Mountains. Our Rocky Mountain division covers several states, including Colorado, Utah, Wyoming, Montana, and North Dakota. This vast area has produced a number of conventional and unconventional oil and gas fields. This division operated an average of 17.0 drilling rigs during 2014. We had six drilling rigs operating in the Pinedale Anticline of western Wyoming, one in northeast Wyoming, and ten drilling rigs operating in the Bakken Shale of North Dakota at the end of 2014.

At any given time the number of drilling rigs we can work depends on a number of conditions besides demand, including the availability of qualified labor and the availability of needed drilling supplies and equipment. The impact of these conditions tends to increase with increased demand for our drilling rigs. Our average utilization rate for 2014, 2013, and 2012 was 63%, 52%, and 58%, respectively.

The following table shows the average number of our drilling rigs working by quarter for the years indicated:

	2014	2013	2012
First quarter	67.9	66.3	81.5
Second quarter	73.5	65.2	76.7
Third quarter	79.1	63.5	73.4
Fourth quarter	80.9	65.0	64.0

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Drilling Rig Fleet. The following table summarizes the changes made to our drilling rig fleet in 2014. A more complete discussion of the changes follows the table:

Drilling rigs available for use at December 31, 2013	121
Drilling rigs sold	(4)
Drilling rigs removed from service [1]	(31)
Drilling rigs constructed	3
Total drilling rigs available for use at December 31, 2014	89

(1) In December 2014, we removed from service 31 drilling rigs, some older top drives, and certain drill pipe no longer marketable in the current economic environment.

Dispositions, Acquisitions, and Construction. During 2012, we placed two new build 1,500 horsepower, diesel-electric drilling rigs into service, one in Wyoming and one in North Dakota.

Also during 2012, we sold an idle 600 horsepower mechanical drilling rig to an unaffiliated third-party and had a fire on one of our drilling rigs located in the mid-continent region. The net book value of the damaged equipment was $3.2 million. All of the net book value of the damaged equipment was recovered from insurance proceeds. No personnel were injured in this incident.

During 2013, we sold four of our 2,000 horsepower electric drilling rigs and one 3,000 horsepower electric drilling rigs. All of these sales were to unaffiliated third-parties.

During the first quarter of 2014. we sold four additional idle 3,000 horsepower drilling rigs to an unaffiliated third party. The proceeds from that sale were used in our construction program for our new proprietary 1,500 horsepower, AC electric drilling rig, called the BOSS drilling rig.

During 2014, three BOSS drilling rigs were constructed and placed into service for third-party operators. Five additional BOSS drilling rigs have been contracted to be built for third-party operators and will be placed into service in 2015, the first of which began operating in January 2015.

In December 2014, we removed from service 31 drilling rigs, some older top drives, and certain drill pipe no longer marketable in the current environment. We estimated the fair value of the rigs and other assets based on the estimate market value from third-party assessments (Level 3 fair value measurement). Based on these estimates, we recorded a write-down of approximately $74.3 million, pre-tax.

Drilling Contracts. Our drilling contracts are generally obtained through competitive bidding on a well by well basis. Contract terms and payment rates vary depending on the type of contract used, the duration of the work, the equipment and services supplied, and other matters. We pay certain operating expenses, including the wages of our drilling rig personnel, maintenance expenses, and incidental drilling rig supplies and equipment. The contracts are usually subject to early termination by the customer subject to the payment of a fee. Our contracts also contain provisions regarding indemnification against certain types of claims involving injury to persons, property, and for acts of pollution. The specific terms of these indemnifications are subject to negotiation on a contract by contract basis.

The type of contract used determines our compensation. Contracts are generally one of three types: daywork; footage; or turnkey. Under a daywork contract, we provide the drilling rig with the required personnel and the operator supervises the drilling of the well. Our compensation is based on a negotiated rate to be paid for each day the drilling rig is used. Footage contracts usually require us to bear some of the drilling costs in addition to providing the drilling rig. We are paid on completion of the well at a negotiated rate for each foot drilled. Under turnkey contracts we drill the well to a specified depth for a set amount and provide most of the required equipment and services. We bear the risk of drilling the well to the contract depth and are paid when the contract provisions are completed. We may incur losses if we underestimate the costs to drill the well or if unforeseen events occur that increase our costs or result in the loss of the well. We did not have any footage or turnkey contracts in 2014, 2013, or 2012.

All of our work during the last three years was under daywork contracts. Because market demand for our drilling rigs as well as the desires of our customers determine the types of contracts we use, we cannot predict when and if a part of our drilling will be conducted under footage or turnkey contracts.

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The majority of our contracts are on a well-to-well basis, with the rest under term contracts. Term contracts range from six months to three years and the rates can either be fixed throughout the term or allow for periodic adjustments.

Customers. During 2014, QEP Resources, Inc. was our largest drilling customer accounting for approximately 19% of our total contract drilling revenues. Our work for this customer was under multiple contracts and our business was not substantially dependent on any of these individual contracts. Consequently, none of these individual contracts were considered to be material. No other third party customer accounted for 10% or more of our contract drilling revenues.

Our contract drilling segment also provides drilling services for our oil and natural gas segment. During 2014, 2013, and 2012, our contract drilling segment drilled 134, 105, and 78 wells, respectively, for our oil and natural gas segment, or 15%, 13%, and 10%, respectively, of the total wells drilled by our contract drilling segment. Depending on the timing of the drilling services performed on our properties those services may be deemed, for financial reporting purposes, to be associated with the acquisition of an ownership interest in the property. Revenues and expenses for these services are eliminated in our income statement, with any profit recognized reducing our investment in our oil and natural gas properties. The contracts for these services are issued under the similar terms and rates as the contracts entered into with unrelated third parties. By providing drilling services for the oil and natural gas segment, we eliminated revenue of $89.5 million, $64.3 million, and $49.6 million during 2014, 2013, and 2012, respectively, from our contract drilling segment and eliminated the associated operating expense of $62.4 million, $46.9 million, and $34.1 million during 2014, 2013, and 2012, respectively, yielding $27.1 million, $17.4 million, and $15.5 million during 2014, 2013, and 2012, respectively, as a reduction to the carrying value of our oil and natural gas properties.

MID-STREAM

General. Our mid-stream operations are conducted through Superior Pipeline Company, L.L.C. and its subsidiaries. Its operations consist of buying, selling, gathering, processing, and treating natural gas. It operates three natural gas treatment plants, 14 processing plants, 38 active gathering systems, and approximately 1,525 miles of pipeline. Superior and its subsidiaries operate in Oklahoma, Texas, Kansas, Pennsylvania, and West Virginia.

The following table presents certain information regarding our mid-stream segment for the years indicated:

	Year Ended December 31,		
	2014	2013	2012
Gas gathered—Mcf/day	319,348	309,554	250,290
Gas processed—Mcf/day	161,282	140,584	133,987
NGLs sold—gallons/day	733,406	543,602	542,578

Dispositions and Acquisitions. This segment did not have any significant dispositions or acquisitions during 2013 or 2014.

Included within the previously discussed acquisition of certain oil and natural gas assets from Noble were four gathering systems. These systems were transferred into our mid-stream segment. The cost for the systems was $18.7 million. Subsequently in 2013, one of these gathering systems was transferred to our oil and natural gas segment.

In December 2012, our mid-stream segment had a $1.2 million write-down of its Erick system in conjunction with the shut down of this system. In December 2014, our mid-stream segment had a $7.1 million pre-tax write-down of three of its systems, Weatherford, Billy Rose, and Spring Creek due to anticipated future cash flow and future development around these systems supporting their carrying value. The estimated future cash flows were less than the carrying value on these systems (Level 3 fair value measurement).

Contracts. Our mid-stream segment provides its customers with a full range of gathering, processing, and treating services. These services are usually provided to each customer under long-term contracts (more than one year), but we do have some short-term contracts as well. Our customer agreements include the following types of contracts:

- Fee-Based Contracts. These contracts provide for a set fee for gathering and transporting raw natural gas. Our mid-stream's revenue is a function of the volume of natural gas that is gathered or transported and is not directly dependent on the value of the natural gas. For the year ended December 31, 2014, 69% of our mid-stream segment's total volumes and 47% of its operating margins (as defined below) were under fee-based contracts.
- Percent of Proceeds Contracts (POP). These contracts provide for our mid-stream segment to retain a negotiated

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percentage of the sale proceeds from residue natural gas and NGLs it gathers and processes, with the remainder being paid to the producer. In this arrangement, Superior and the producer each own a portion of the commodity and are directly dependent on the volume and value of the commodity both of which fluctuate. For the year ended December 31, 2014, 30% of our mid-stream segment's total volumes and 49% of operating margins (as defined below) were under POP contracts.

- Percent of Index Contracts (POI). Under these contracts our mid-stream segment, as the processor, purchases raw well-head natural gas from the producer at a stipulated index price and, after processing the natural gas, sells the processed residual gas and the produced NGLs to third parties. Our mid-stream segment is subject to the economic risk (processing margin risk) that the aggregate proceeds from the sale of the processed natural gas and the NGLs could be less than the amount paid for the unprocessed natural gas. For the year ended December 31, 2014, 1% of our mid-stream segment's total volumes and 4% of operating margins (as defined below) were under POI contracts.

For each of the above contracts, operating margin is defined as total operating revenues less operating expenses and does not include depreciation and amortization, general and administrative expenses, interest expense, or income taxes.

Customers. During 2014, ONEOK Partners, L.P., Tenaska Resources, LLC, and Laclede Gas Company accounted for approximately 44%, 22%, and 10%, respectively, of our mid-stream revenues. We believe that if we lost any of these identified customers, there are other customers available to purchase our gas and NGLs. During 2014, 2013, and 2012 this segment purchased $80.9 million, $83.0 million, and $68.2 million, respectively, of our oil and natural gas segment's natural gas and NGLs production, and provided gathering and transportation services of $8.7 million, $8.0 million, and $5.1 million, respectively. Intercompany revenue from services and purchases of production between this business segment and our oil and natural gas segment has been eliminated in our consolidated financial statements.

VOLATILE NATURE OF OUR BUSINESS

The prevailing prices for oil, NGLs, and natural gas significantly affect our revenues, operating results, cash flow as well as our ability to grow our operations. Historically, oil, NGLs, and natural gas prices have been volatile and we expect them to continue to be so. For each of the periods indicated, the following table shows the highest and lowest average prices our oil and natural gas segment received for its sales of oil, NGLs, and natural gas without taking into account the effect of derivatives:

	Oil Price per Bbl		NGLs Price per Bbl		Natural Gas Price per Mcf	
Quarter	High	Low	High	Low	High	Low
2014						
Fourth	$82.30	$54.22	$29.02	$19.49	$3.96	$3.31
Third	$98.95	$90.70	$31.08	$29.32	$3.88	$3.36
Second	$102.62	$98.76	$35.45	$25.70	$4.38	$4.15
First	$98.09	$90.51	$41.62	$36.75	$5.00	$4.25
2013						
Fourth	$97.34	$91.15	$36.33	$31.92	$3.36	$3.08
Third	$104.25	$101.70	$33.14	$24.78	$3.33	$2.79
Second	$92.85	$89.97	$32.17	$28.94	$4.04	$3.73
First	$93.89	$90.80	$37.97	$33.14	$3.20	$3.04
2012						
Fourth	$87.01	$84.39	$34.82	$32.42	$3.57	$2.54
Third	$90.04	$82.69	$24.07	$18.02	$2.78	$2.19
Second	$100.63	$76.35	$34.65	$24.65	$2.34	$1.65
First	$104.32	$97.31	$39.77	$36.04	$2.80	$2.17

Prices for oil, NGLs, and natural gas are subject to wide fluctuations in response to relatively minor changes in the actual or perceived supply of and demand for oil and natural gas, market uncertainty, and a variety of additional factors that are beyond our control, including:

- political conditions in oil producing regions;

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- the ability of the members of the Organization of Petroleum Exporting Countries ("OPEC") to agree on prices and their ability or willingness to maintain production quotas;
- actions taken by foreign oil and natural gas producing nations;
- the price of foreign oil imports;
- imports and exports of liquefied natural gas;
- actions of governmental authorities;
- the domestic and foreign supply of oil, NGLs, and natural gas;
- the level of consumer demand;
- United States storage levels of oil, NGLs, and natural gas;
- weather conditions;
- domestic and foreign government regulations;
- the price, availability, and acceptance of alternative fuels;
- volatility in ethane prices causing rejection of ethane as part of the liquids processed stream; and
- worldwide economic conditions.

These factors and the volatile nature of the energy markets make it impossible to predict with any certainty the future prices of oil, NGLs, and natural gas. Prices after 2014 year-end have so far continued to decline from those existing at the end of the year. You are encouraged to read the Risk Factors discussed in Item 1A of this report for additional risks that can impact our operations.

Our contract drilling operations are dependent on the level of demand in our operating markets. Both short-term and long-term trends in oil, NGLs, and natural gas prices affect demand. Because oil, NGLs, and natural gas prices are volatile, the level of demand for our services can also be volatile.

Our mid-stream operations provide us greater flexibility in delivering our (and third parties) natural gas and NGLs from the wellhead to major natural gas and NGLs pipelines. Margins received for the delivery of these natural gas and NGLs are dependent on the price for oil, NGLs, and natural gas and the demand for natural gas and NGLs in our area of operations. If the price of NGLs falls without a corresponding decrease in the cost of natural gas, it may become uneconomical to us to extract certain NGLs. The volumes of natural gas and NGLs processed are highly dependent on the volume and Btu content of the natural gas and NGLs gathered.

It is possible that the current industry shift in drilling for oil and NGLs may at some point impact future natural gas availability as well as prices for natural gas. In addition, the increasing availability of oil and NGLs may impact the price for these products if supply was to exceed demand.

COMPETITION

All of our businesses are highly competitive and price sensitive. Competition in the contract drilling business traditionally involves factors such as demand, price, efficiency, condition of equipment, availability of labor and equipment, reputation, and customer relations.

Our oil and natural gas operations likewise encounter strong competition from other oil and natural gas companies. Many of these competitors have greater financial, technical, and other resources than we do and have more experience than we do in the exploration for and production of oil and natural gas.

Our continued drilling success and the success of other activities integral to our operations will depend, in part, on our ability to attract and retain experienced geologists, engineers, and other professionals. Competition for these professionals can be extremely intense, particularly when the industry is experiencing favorable conditions.

Our mid-stream segment competes with purchasers and gatherers of all types and sizes, including those affiliated with various producers, other major pipeline companies, as well as independent gatherers for the right to purchase natural gas and NGLs, build gathering and processing systems, and deliver the natural gas and NGLs once the gathering and processing

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systems are established. The principal elements of competition include the rates, terms, and availability of services, reputation, and the flexibility and reliability of service.

OIL AND NATURAL GAS PROGRAMS AND CONFLICTS OF INTEREST

Unit Petroleum Company serves as the general partner of 15 oil and gas limited partnerships. Two investments by third parties and 13 (the employee partnerships) were formed to allow certain of our qualified employees and our directors to participate in Unit Petroleum's oil and gas exploration and production operations. The partnerships for the third party investments were formed in 1984 and two in 1986. Effective December 31, 2014, the 1984 partnership was dissolved. Employee partnerships have been formed for each year beginning with 1984 and ending with 2011. Interests in the employee partnerships were offered to the employees of Unit and its subsidiaries whose annual base compensation was at least a specified amount and to the directors of Unit.

The employee partnerships formed in 1984 through 1999 have been combined into a single consolidated partnership. The employee partnerships each have a set annual percentage (ranging from 1% to 15%) of our interest that the partnership acquires in most of the oil and natural gas wells we drill or acquire for our own account during the year in which the partnership was formed. The total interest the participants have in our oil and natural gas wells by participating in these partnerships does not exceed one percent of our interest in the wells.

Under the terms of our partnership agreements, the general partner has broad discretionary authority to manage the business and operations of the partnership, including the authority to make decisions regarding the partnership's participation in a drilling location or a property acquisition, the partnership's expenditure of funds, and the distribution of funds to partners. Because the business activities of the limited partners and the general partner are not the same, conflicts of interest will exist and it is not possible to entirely eliminate these conflicts. Additionally, conflicts of interest may arise when we are the operator of an oil and natural gas well and also provide contract drilling services. In these cases, the drilling operations are conducted under drilling contracts containing terms and conditions comparable to those contained in our drilling contracts with non-affiliated operators. We believe we fulfill our responsibility to each contracting party and comply fully with the terms of the agreements which regulate these conflicts.

These partnerships are further described in Notes 2 and 10 to the Consolidated Financial Statements in Item 8 of this report.

EMPLOYEES

As of February 13, 2015, we had approximately 1,286 employees in our contract drilling segment, 370 employees in our oil and natural gas segment, 143 employees in our mid-stream segment, and 81 in our general corporate area. None of our employees are members of a union or labor organization nor have our operations ever been interrupted by a strike or work stoppage. We consider relations with our employees to be satisfactory.

GOVERNMENTAL REGULATIONS

Our business depends on the demand for services from the oil and natural gas exploration and development industry, and therefore our business can be affected by political developments and changes in laws and regulations that control or curtail drilling for oil and natural gas for economic, environmental, or other policy reasons.

Various state and federal regulations affect the production and sale of oil and natural gas. All states in which we conduct activities impose varying restrictions on the drilling, production, transportation, and sale of oil and natural gas.

Under the Natural Gas Act of 1938, the Federal Energy Regulatory Commission (the FERC) regulates the interstate transportation and the sale in interstate commerce for resale of natural gas. The FERC's jurisdiction over interstate natural gas sales has been substantially modified by the Natural Gas Policy Act under which the FERC continued to regulate the maximum selling prices of certain categories of gas sold in "first sales" in interstate and intrastate commerce. Effective January 1, 1993, however, the Natural Gas Wellhead Decontrol Act (the Decontrol Act) deregulated natural gas prices for all "first sales" of natural gas. Because "first sales" include typical wellhead sales by producers, all natural gas produced from our natural gas properties is sold at market prices, subject to the terms of any private contracts which may be in effect. The FERC's jurisdiction over interstate natural gas transportation is not affected by the Decontrol Act.

Our sales of natural gas will be affected by intrastate and interstate gas transportation regulation. Beginning in 1985, the FERC adopted regulatory changes that have significantly altered the transportation and marketing of natural gas. These changes are intended by the FERC to foster competition by, among other things, transforming the role of interstate pipeline companies from wholesale marketers of natural gas to the primary role of gas transporters. All natural gas marketing by the pipelines is required to divest to a marketing affiliate, which operates separately from the transporter and in direct competition with all other merchants. As a result of the various omnibus rulemaking proceedings in the late 1980s and the subsequent individual pipeline restructuring proceedings of the early to mid-1990s, interstate pipelines must provide open and nondiscriminatory transportation and transportation-related services to all producers, natural gas marketing companies, local distribution companies, industrial end users, and other customers seeking service. Through similar orders affecting intrastate pipelines that provide similar interstate services, the FERC expanded the impact of open access regulations to certain aspects of intrastate commerce.

FERC has pursued other policy initiatives that have affected natural gas marketing. Most notable are (1) the large-scale divestiture of interstate pipeline-owned gas gathering facilities to affiliated or non-affiliated companies; (2) further development of rules governing the relationship of the pipelines with their marketing affiliates; (3) the publication of standards relating to the use of electronic bulletin boards and electronic data exchange by the pipelines to make available transportation information on a timely basis and to enable transactions to occur on a purely electronic basis; (4) further review of the role of the secondary market for released pipeline capacity and its relationship to open access service in the primary market; and (5) development of policy and promulgation of orders pertaining to its authorization of market-based rates (rather than traditional cost-of-service based rates) for transportation or transportation-related services upon the pipeline’s demonstration of lack of market control in the relevant service market.

As a result of these changes, independent sellers and buyers of natural gas have gained direct access to the particular pipeline services they need and are better able to conduct business with a larger number of counter parties. We believe these changes generally have improved the access to markets for natural gas while, at the same time, substantially increasing competition in the natural gas marketplace. However, we cannot predict what new or different regulations the FERC and other regulatory agencies may adopt or what effect subsequent regulations may have on production and marketing of natural gas from our properties.

Although in the past Congress has been very active in the area of natural gas regulation as discussed above, the more recent trend has been in favor of deregulation and the promotion of competition in the natural gas industry. Thus, in addition to “first sales” deregulation, Congress also repealed incremental pricing requirements and natural gas use restraints previously applicable. There continually are legislative proposals pending in the Federal and state legislatures which, if enacted, would significantly affect the petroleum industry. At the present time, it is impossible to predict what proposals, if any, might actually be enacted by Congress or the various state legislatures and what effect, if any, these proposals might have on the production and marketing of natural gas by us. Similarly, and despite the trend toward federal deregulation of the natural gas industry, whether or to what extent that trend will continue or what the ultimate effect will be on the production and marketing of natural gas by us cannot be predicted.

Our sales of oil and natural gas liquids currently are not regulated and are at market prices. The prices received from the sale of these products are affected by the cost of transporting these products to market. Much of that transportation is through interstate common carrier pipelines. Effective as of January 1, 1995, the FERC implemented regulations generally grandfathering all previously approved interstate transportation rates and establishing an indexing system for those rates by which adjustments are made annually based on the rate of inflation, subject to certain conditions and limitations. These regulations may tend to increase the cost of transporting oil and natural gas liquids by interstate pipeline, although the annual adjustments could result in decreased rates in a given year. These regulations have generally been approved on judicial review. Every five years, the FERC will examine the relationship between the annual change in the applicable index and the actual cost changes experienced by the oil pipeline industry and make any necessary adjustment in the index to be used during the ensuing five years. We are not able to predict with certainty what effect, if any, the periodic review of the index by the FERC will have on us.

Federal, state, and local agencies also have promulgated extensive rules and regulations applicable to our oil and natural gas exploration, production, and related operations. The states we operate in require permits for drilling operations, drilling bonds, and the filing of reports concerning operations and impose other requirements relating to the exploration of oil and natural gas. Many states also have statutes or regulations addressing conservation matters including provisions for the unitization or pooling of oil and natural gas properties, the establishment of maximum rates of production from oil and natural gas wells, and the regulation of spacing, plugging and, abandonment of such wells. The statutes and regulations of some states limit the rate at which oil and natural gas is produced from our properties. The federal and state regulatory burden on the oil and natural gas industry increases our cost of doing business and affects our profitability. Because these rules and regulations are amended or reinterpreted frequently, we are unable to predict the future cost or impact of complying with those laws.

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Our operations are subject to increasingly stringent federal, state, and local laws and regulations governing protection of the environment. These laws and regulations may require acquisition of permits before certain of our operations may be commenced and may restrict the types, quantities, and concentrations of various substances that can be released into the environment. Planning and implementation of protective measures are required to prevent accidental discharges. Spills of oil, natural gas liquids, drilling fluids, and other substances may subject us to penalties and cleanup requirements. Handling, storage, and disposal of both hazardous and non-hazardous wastes are subject to regulatory requirements.

The federal Clean Water Act, as amended by the Oil Pollution Act, the federal Clean Air Act, the federal Resource Conservation and Recovery Act, and their state counterparts, are the primary vehicles for imposition of such requirements and for civil, criminal, and administrative penalties and other sanctions for violation of their requirements. In addition, the federal Comprehensive Environmental Response Compensation and Liability Act and similar state statutes impose strict liability, without regard to fault or the legality of the original conduct, on certain classes of persons who are considered responsible for the release of hazardous substances into the environment. Such liability, which may be imposed for the conduct of others and for conditions others have caused, includes the cost of remedial action as well as damages to natural resources.

On October 20, 2011, EPA announced a schedule for development of standards for disposal of wastewater produce from shale gas operations to publicly owned treatment works ("POTWs"). The regulations will be developed under EPA's Effluent Guidelines Program under the authority of the Clean Water Act. Although anticipated in 2014, EPA has not yet proposed them. Direct discharges from unconventional oil and gas extraction are subject to NPDES permit regulations (40 CFR Parts 122 through 125). Indirect discharges to POTWs are subject to the General Pretreatment Regulations (40 CFR Part 403).

The federal Endangered Species Act, referred to as the "ESA," and analogous state laws regulate a variety of activities, including oil and gas development, which could have an adverse effect on species listed as threatened or endangered under the ESA or their habitats. The designation of previously unidentified endangered or threatened species could cause oil and natural gas exploration and production operators and service companies to incur additional costs or become subject to operating delays, restrictions or bans in affected areas, which impacts could adversely reduce the amount of drilling activities in affected areas. All three of our business segments could be subject to the effect of one or more species being listed as threatened or endangered within the areas of our operations. Numerous species have been listed or proposed for protected status in areas in which we provide or could in the future undertake operations. For instance, the American Burying Beetle and the Lesser Prairie-Chicken both have habitat in some areas where we operate or provide services. The U.S. Fish and Wildlife Service ("FWS") identified the Lesser Prairie-Chicken as candidate for listing in 1998 and initiated the process to list it as "threatened" or "endangered" in November 2012. Its habitat is found in Colorado, Kansas, New Mexico, Oklahoma, and Texas, and it is listed as "threatened" by the State of Colorado. On April 10, 2014 the FWS listed the Lesser Prairie-Chicken as "threatened," effective May 12, 2014. On April 10, 2014 the FWS also finalized a final rule under section 4(d) of the ESA which "provides that all of the prohibitions under 50 CFR 17.31 and 17.32 will apply to the lesser prairie-chicken, except . . . that [actions] incidental to activities conducted by a participant enrolled in, and operating in compliance with, the Lesser Prairie-Chicken Interstate Working Group's Lesser Prairie-Chicken Range-Wide Conservation Plan (rangewide plan) will not be prohibited." The rangewide plan is administered by the Western Association of Fish and Wildlife Agencies ("WAFWA"). "The rangewide plan identifies the ecoregional population goals . . . for the four ecoregions: the Shinnery Oak Prairie Region (eastern New Mexico and southwest Texas panhandle); the Sand Sagebrush Prairie Region (southeastern Colorado, southwestern Kansas, and western Oklahoma panhandle); the Mixed Grass Prairie Region (northeastern Texas panhandle, western Oklahoma, and south central Kansas); and the Short Grass/CRP Mosaic Region (northwestern Kansas)." In turn, the FWS and the WAFWA entered into the Range-Wide Oil and Gas Candidate Conservation Agreement with Assurances ("CCAA") dated February 28, 2014. The CCAA will be administered by the WAFWA with FWS oversight and is a voluntary agreement intended to address the effects of oil and gas activities on the Lesser Prairie-Chicken and its habitat in the five states. WAFWA is to work with members of the oil and gas industry to enroll properties in the CCAA using Certificates of Inclusion (“CIs”) which are designed “to facilitate the voluntary cooperation of the oil and gas industry in providing conservation benefits” to the Lesser Prairie-Chicken. Participants will also “contribute funding [‘mitigation fees’] for conservation to offset unavoidable impacts as part of their CIs. The sage grouse and certain wildflower species, among others, are also species that have been or are being considered for protected status under the ESA and whose range can coincide with oil and natural gas production activities. The presence of protected species in areas where we provide contract drilling or mid-stream services or conduct exploration and production operations could impair our ability to timely complete or carry out those services and, consequently, adversely affect our results of operations and financial position.

Climate Regulation. Recent scientific studies have suggested that emissions of certain gases, commonly referred to as “greenhouse gases,” or GHGs, may be contributing to warming of the Earth’s atmosphere. As a result there have been a variety of regulatory developments, proposals or requirements, and legislative initiatives that have been introduced in the United States (as well as other parts of the World) that are focused on restricting the emission of carbon dioxide, methane, and other greenhouse gases.

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In 2007, the United States Supreme Court in Massachusetts, et al. v. EPA, held that carbon dioxide may be regulated as an “air pollutant” under the federal Clean Air Act if it represents a health hazard to the public. On December 7, 2009, the U.S. Environmental Protection Agency (“EPA”) responded to the Massachusetts, et al. v. EPA decision and issued a finding that the current and projected concentrations of GHGs in the atmosphere threaten the public health and welfare of current and future generations, and that certain GHGs from new motor vehicles and motor vehicle engines contribute to the atmospheric concentrations of GHG and hence to the threat of climate change. In addition, the EPA issued a final rule, effective in December 2009, requiring the reporting of GHG emissions from specified large (25,000 metric tons or more) GHG emission sources in the U.S., beginning in 2011 for emissions occurring in 2010. During 2010, the EPA proposed revisions to these reporting requirements to apply to all oil and gas production, transmission, processing, and other facilities exceeding certain emission thresholds. In September and November 2013, the EPA proposed further revisions to record keeping and reporting requirements, which have not yet been finalized. The adoption and implementation of any regulations imposing reporting obligations on, or limiting emissions of GHGs from, our equipment and operations could require us to incur additional costs to reduce emissions of GHGs associated with our operations or could adversely affect demand for the crude oil we gather, transport, store or otherwise handle in connection with our services. In addition, both President Obama and the Administrator of the EPA have repeatedly indicated their preference for comprehensive legislation to address this issue and create the framework for a clean energy economy, with the Obama Administration supporting an emission allowance system. Past proposed legislation in Congress has included an economy wide cap and trade program to reduce U.S. greenhouse gas emissions. Some states are also looking at similar types of laws and regulations.

Our oil and natural gas segment routinely applies hydraulic-fracturing techniques to many of our oil and natural gas properties, including our unconventional resource plays in the Granite Wash of Texas and Oklahoma, the Marmaton of Oklahoma, the Wilcox of Texas, and the Mississippian of Kansas. The EPA has commenced a study of the potential environmental impacts of hydraulic fracturing, including the impact on drinking water sources and public health, and a committee of the U.S. House of Representatives has been conducting an investigation of hydraulic fracturing practices. Legislation has been introduced before Congress to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the fracturing process. On November 20, 2013 the U.S. House of Representatives passed a bill, H.R. 2728, that would block the Department of Interior from regulating hydraulic fracturing in states that already have their own regulations in place; however, it is uncertain that such an act will ever be enacted and if enacted, it would likely be subject to a Presidential veto. In addition, certain states in which we operate, including Texas, Oklahoma, Kansas, Colorado, and Wyoming have adopted, and other states as well as municipalities and other local governmental entities in some states, have and others are considering adopting regulations and ordinances that could impose more stringent permitting, public disclosure of fracking fluids, waste disposal, and well construction requirements on these operations, and possibly even restrict or ban hydraulic fracturing in certain circumstances. Any new laws, regulation, or permitting requirements regarding hydraulic fracturing could lead to operational delay, or increased operating costs or third party or governmental claims, and could result in additional burdens that could serve to delay or limit the drilling services we provide to third parties whose drilling operations could be impacted by these regulations or increase our costs of compliance and doing business as well as delay the development of unconventional gas resources from shale formations which are not commercial without the use of hydraulic fracturing. Restrictions on hydraulic fracturing could also reduce the amount of oil and natural gas that we are ultimately able to produce from our reserves.

Further, after reviewing extensive comments and making a number of changes to its previously July 28, 2011 proposed rules, on April 17, 2012 the EPA issued its final rules that subject a wide range of oil and gas operations (production, processing, transmission, storage, and distribution) to regulation under the New Source Performance Standards (NSPS) and National Emission Standards for Hazardous Air Pollutants (NESHAPS) programs (with the NSPS and NESHAPS published in the Federal Register on August 16, 2012). The EPA revised the NSPS for volatile organic compounds (VOCs) from leaking components at onshore gas processing plants and the NSPS for sulfur dioxide emissions from natural gas processing plants. The EPA also established standards for certain oil and gas operations not covered by existing standards, which will regulate VOC emissions from gas wells, centrifugal and reciprocating compressors, pneumatic controllers, and storage vessels over a certain size. The EPA also made revisions to the existing leak detection and repair requirements for the oil and gas production source category and the natural gas transmission source category and established action limits reflecting most achievable control for certain previously uncontrolled emission sources. There also are additional testing and related notification, record keeping and reporting requirements. These changes were effective October 15, 2012. In July 2014 EPA proposed and on December 19, 2014 EPA finalized updates and clarifications to the rules. They focused on additional detail on requirements for handling of gas and liquids during well completions, clarify requirements for storage tanks, define low pressure wells, clarify certain requirements for leak detection at natural gas processing plants, update requirements for reciprocating compressors, and update definition of “responsible official.”

The EPA regulations also result in the first federal air standards for natural gas wells that are hydraulically fractured. Refractured gas wells that use the “green completions” will not be considered affected from a federal standpoint. The

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clarifications identify two distinct stages of the well completion, or "flowback," operation. The initial stage when it is technically feasible for a separator ("green completion" equipment) to function. The next stage is the "separation flowback stage" when gas, liquid hydrocarbons and water are separated. Wells subject to green completion must begin using green completions no later than January 1, 2015. Wells not subject to these requirements, such as exploratory wells, must flare the gas during separation.

The EPA will be designating nonattainment areas for ozone standards for outdoor quality. These areas will include those areas with significant oil and gas activities. Nonattainment areas will be required to submit state implementation plans in 2015 and to attain the standard by 2015 and 2018 for areas classified as "Marginal" and "Moderate," respectively. Areas classified as "Serious" must attain by 2021. The federal NSPS constitute a federally required minimum level of control. States have the flexibility to put their own program in place or implement existing programs as long as they are at least as protective as the federal NSPS.

Consequently, while we have been in the process of assessing and implementing the new EPA requirements as required, at this time we do not know and cannot predict with any degree of certainty what areas the EPA will designate nonattainment and what classification will be applied nor what the states may implement for such nonattainment areas which may affect our business segments and use of hydraulic fracturing practices.

We do not know and cannot predict whether there will be any further proposed legislation or regulations It is possible that such future laws, regulations, and/or ordinances could result in increasing our compliance costs or additional operating restrictions as well as those of our customers. It is also possible that such future developments could curtail the demand for fossil fuels which could adversely affect the demand for our services, which in turn could adversely affect our future results of operations. Likewise we cannot predict with any certainty whether any changes to temperature, storm intensity or precipitation patterns as a result of climate change (or otherwise) will have a material impact on our operations.

Compliance with applicable environmental requirements has not, to date, had a material effect on the cost of our operations, earnings, or competitive position. However, as noted above in connection with our discussion of the regulation of GHGs and hydraulic fracturing, compliance with amended, new or more stringent requirements of existing environmental regulations or requirements may cause us to incur additional costs or subject us to liabilities that may have a material adverse effect on our results of operations and financial condition.

FINANCIAL INFORMATION ABOUT GEOGRAPHIC AREAS

Revenues from our Canadian operations during the last three fiscal years, as well as information relating to long-lived assets attributable to those operations are immaterial. We have no other international operations.

Item 1A. Risk Factors

FORWARD-LOOKING STATEMENTS/CAUTIONARY STATEMENT AND RISK FACTORS

This report contains "forward-looking statements" – meaning, statements related to future events within the meaning of Section 27A of the Securities Act of 1933, as amended and Section 21E of the Securities Exchange Act of 1934, as amended. All statements, other than statements of historical facts, included or incorporated by reference in this document which addresses activities, events or developments which we expect or anticipate will or may occur in the future, are forward-looking statements. The words "believes," "intends," "expects," "anticipates," "projects," "estimates," "pre and similar expressions are used to identify forward-looking statements. This report modifies and supersedes documents filed by us before this report. In addition, certain information that we file with the SEC in the future will automatically update and supersede information contained in this report.

These forward-looking statements include, among others, such things as:

- the amount and nature of our future capital expenditures and how we expect to fund our capital expenditures;
- the number of wells we plan to drill or rework;
- prices for oil, NGLs, and natural gas;
- demand for oil, NGLs, and natural gas;
- our exploration and drilling prospects;

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- the estimates of our proved oil, NGLs, and natural gas reserves;
- oil, NGLs, and natural gas reserve potential;
- development and infill drilling potential;
- expansion and other development trends of the oil and natural gas industry;
- our business strategy;
- our plans to maintain or increase production of oil, NGLs, and natural gas;
- the number of gathering systems and processing plants we plan to construct or acquire;
- volumes and prices for natural gas gathered and processed;
- expansion and growth of our business and operations;
- demand for our drilling rigs and drilling rig rates;
- our belief that the final outcome of our legal proceedings will not materially affect our financial results;
- our ability to timely secure third-party services used in completing our wells;
- our ability to transport or convey our oil, NGLs, or natural gas production to established pipeline systems;
- impact of federal and state legislative and regulatory actions impacting our costs and increasing operating restrictions or delays as well as other adverse impacts on our business;
- our projected production guidelines for the year;
- our anticipated capital budgets; and
- the number of wells our oil and natural gas segment plans to drill during the year.

These statements are based on certain assumptions and analyses made by us in light of our experience and our perception of historical trends, current conditions, and expected future developments as well as other factors we believe are appropriate in the circumstances. Whether actual results and developments will conform to our expectations and predictions is subject to a number of risks and uncertainties any one or combination of which could cause our actual results to differ materially from our expectations and predictions, including:

- the risk factors discussed in this document and in the documents (if any) we incorporate by reference;
- general economic, market, or business conditions;
- the availability of and nature of (or lack of) business opportunities that we pursue;
- demand for our land drilling services;
- changes in laws or regulations;
- decreases or increases in commodity prices; and
- other factors, most of which are beyond our control.

You should not place undue reliance on any of these forward-looking statements. Except as required by law, we disclaim any current intention to update forward-looking information and to release publicly the results of any future revisions we may make to forward-looking statements to reflect events or circumstances after the date of this document to reflect the occurrence of unanticipated events.

In order to help provide you with a more thorough understanding of the possible effects of some of these influences on any forward-looking statements made by us, the following discussion outlines some (but not all) of the factors that could in the future cause our consolidated results to differ materially from those that may be presented in any forward-looking statement made by us or on our behalf.

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Demand for our contract drilling and mid-stream services is substantially dependent on the levels of expenditures by the oil and gas industry. A substantial or an extended decline in oil and gas prices could result in lower expenditures by the oil and gas industry, which could have a material adverse effect on our financial condition, results of operations and cash flows. Demand for our contract drilling and mid-stream services depends substantially on the level of expenditures by the oil and gas industry for the exploration, development and production of oil and natural gas reserves. These expenditures are generally dependent on the industry's view of future oil and natural gas prices and are sensitive to the industry's view of future economic growth and the resulting impact on demand for oil and natural gas. Declines, as well as anticipated declines, in oil and gas prices could also result in project modifications, delays or cancellations, general business disruptions, and delays in payment of, or nonpayment of, amounts that are owed to us. These effects could have a material adverse effect on our financial condition, results of operations and cash flows. The oil and gas industry has historically experienced periodic downturns, which have been characterized by diminished demand for oilfield services and downward pressure on the prices we charge. A significant downturn in the oil and gas industry could result in a reduction in demand for oilfield services and could adversely affect our financial condition, results of operations and cash flows.

Oil, NGLs, and Natural Gas Prices. In addition to the impact oil and gas prices may have on our contract drilling and mid-stream segments, the prices we receive for our oil, NGLs, and natural gas production have a direct impact on our revenues, profitability, and cash flow as well as our ability to meet our projected financial and operational goals. The prices for oil, NGLs, and natural gas are determined on a number of factors beyond our control, including:

- the demand for and supply of oil, NGLs, and natural gas;
- current weather conditions in the continental United States (which can greatly influence the demand and prices for natural gas at any given time);
- the amount and timing of liquid natural gas and liquefied petroleum gas imports and exports;
- the ability of current distribution systems in the United States to effectively meet the demand for oil, NGLs, and natural gas at any given time, particularly in times of peak demand which may result because of adverse weather conditions;
- the ability or willingness of the OPEC to set and maintain production levels for oil;
- oil and gas production levels by non-OPEC countries;
- the level of excess production capacity;
- political and economic uncertainty and geopolitical activity;
- governmental policies and subsidies;
- the costs of exploring for producing and delivering oil and gas;
- technological advances affecting energy consumption; and
- weather conditions.

Oil prices are extremely sensitive to influences domestic and foreign based on political, social or economic underpinnings, any one of which could have an immediate and significant effect on the price and supply of oil. In addition, prices of oil, NGLs, and natural gas have been at various times influenced by trading on the commodities markets. That trading, at times, has tended to increase the volatility associated with these prices resulting in large differences in prices even on a week-to-week and month-to-month basis. All of these factors, especially when coupled with the fact that much of our product prices are determined on a daily basis, can, and at times do, lead to wide fluctuations in the prices we receive.

Based on our 2014 production, a \$0.10 per Mcf change in what we receive for our natural gas production, without the effect of derivatives, would result in a corresponding \$466,000 per month (\$5.6 million annualized) change in our pre-tax operating cash flow. A \$1.00 per barrel change in our oil price, without the effect of derivatives, would have a \$308,000 per month (\$3.7 million annualized) change in our pre-tax operating cash flow and a \$1.00 per barrel change in our NGLs price, without the effect of derivatives, would have a \$368,000 per month (\$4.4 million annualized) change in our pre-tax operating cash flow.

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In order to reduce our exposure to short-term fluctuations in the price of oil, NGLs, and natural gas, we sometimes enter into derivative contracts such as swaps and collars. To date, we have derivatives in part, but not on all of our production which only provides price protection against declines in oil, NGLs, and natural gas prices on the production subject to our derivatives, but not otherwise. Should market prices for the production we have derivatives exceed the prices due under our derivative contracts, our derivative contracts then expose us to risk of financial loss and limit the benefit to us of those increases in market prices. During 2014, all of our NGLs volumes and about half of our oil and natural gas volumes were sold at market responsive prices. To help manage our cash flow and capital expenditure requirements, we had derivative contracts on approximately 69% and 56% of our 2014 average daily production for oil and natural gas, respectively. A more thorough discussion of our derivative arrangements is contained in the Management's Discussion and Analysis of Financial Condition and Results of Operations section of this report contained in Item 7.

Uncertainty of Oil, NGLs, and Natural Gas Reserves; Ceiling Test. There are many uncertainties inherent in estimating quantities of oil, NGLs, and natural gas reserves and their values, including many factors beyond our control. The oil, NGLs, and natural gas reserve information included in this report represents only an estimate of these reserves. Oil, NGLs, and natural gas reservoir engineering is a subjective and an inexact process of estimating underground accumulations of oil, NGLs, and natural gas that cannot be measured in an exact manner. Estimates of economically recoverable oil, NGLs, and natural gas reserves depend on a number of variable factors, including historical production from the area compared with production from other producing areas, and assumptions concerning:

- reservoir size;
- the effects of regulations by governmental agencies;
- future oil, NGLs, and natural gas prices;
- future operating costs;
- severance and excise taxes;
- operational risks;
- development costs; and
- workover and remedial costs.

Some or all of these assumptions may vary considerably from actual results. For these and other reasons, estimates of the economically recoverable quantities of oil, NGLs, and natural gas attributable to any particular group of properties, classifications of those oil, NGLs, and natural gas reserves based on risk of recovery, and estimates of the future net cash flows from oil, NGLs, and natural gas reserves prepared by different engineers or by the same engineers but at different times may vary substantially. Accordingly, oil, NGLs, and natural gas reserve estimates may be subject to periodic downward or upward adjustments. Actual production, revenues, and expenditures with respect to our oil, NGLs, and natural gas reserves will likely vary from estimates and those variances may be material.

The information regarding discounted future net cash flows included in this report is not necessarily the current market value of the estimated oil, NGLs, and natural gas reserves attributable to our properties. The use of full cost accounting requires us to use the unweighted arithmetic average of the commodity prices existing on the first day of each of the 12 months before the end of the reporting period to calculate discounted future revenues, unless prices were otherwise determined under contractual arrangements. Actual future prices and costs may be materially higher or lower. Actual future net cash flows are also affected, in part, by the following factors:

- the amount and timing of oil, NGLs, and natural gas production;
- supply and demand for oil, NGLs, and natural gas;
- increases or decreases in consumption; and
- changes in governmental regulations or taxation.

In addition, the 10% discount factor, required by the SEC for use in calculating discounted future net cash flows for reporting purposes, is not necessarily the most appropriate discount factor based on interest rates in effect from time to time and the risks associated with our operations or the oil and natural gas industry in general.

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We review quarterly the carrying value of our oil and natural gas properties under the full cost accounting rules of the SEC. Under these rules, capitalized costs of proved oil and natural gas properties may not exceed the present value of estimated future net revenues from those proved reserves, discounted at 10%. Application of this “ceiling test” generally requires pricing future revenue at the unescalated 12-month average price and requires a write-down for accounting purposes if we exceed the ceiling. We may be required to write-down the carrying value of our oil and natural gas properties when oil, NGLs, and natural gas prices are depressed. If a write-down is required, it would result in a charge to earnings but would not impact our cash flow from operating activities. Once incurred, a write-down is not reversible.

Debt and Bank Borrowing. We have incurred and currently expect to continue to incur substantial capital expenditures in our operations. Historically, we have funded our capital needs through a combination of internally generated cash flow and borrowings under our bank credit agreement. In 2011 and 2012, we issued $250.0 million (the 2011 Notes) and $400.0 million (the 2012 Notes), respectively, of senior subordinated notes (collectively, the Notes). We currently have, and will continue to have, a certain amount of indebtedness. At December 31, 2014, we had $166.0 million of outstanding long-term debt under our credit agreement and the amount of the Notes, net of unamortized discount, was $646.2 million.

Depending on the amount of our debt, the cash flow needed to satisfy that debt and the covenants contained in our bank credit agreement and those applicable to the Notes could:

- limit funds otherwise available for financing our capital expenditures, our drilling program or other activities or cause us to curtail these activities;
- limit our flexibility in planning for or reacting to changes in our business;
- place us at a competitive disadvantage to those of our competitors that are less indebted than we are;
- make us more vulnerable during periods of low oil, NGLs, and natural gas prices or in the event of a downturn in our business; and
- prevent us from obtaining additional financing on acceptable terms or limit amounts available under our existing or any future credit facilities.

Our ability to meet our debt obligations depends on our future performance. If the requirements of our indebtedness are not satisfied, a default could be deemed to occur and our lenders or the holders of the Notes would be entitled to accelerate the payment of the outstanding indebtedness. If that were to happen, we would not have sufficient funds available (and probably would not be able to obtain the financing required) to meet our obligations.

The amount of our existing debt, as well as our future debt, if any, is, largely, based on the costs associated with the projects we undertake at any given time and of our cash flow. Generally, our normal operating costs are those resulting from the drilling of oil and natural gas wells, the acquisition of producing properties, the costs associated with the maintenance, upgrade, or expansion of our drilling rig fleet, and the operations of our natural gas buying, selling, gathering, processing, and treating systems. To some extent, these costs, particularly the first two, are discretionary and we maintain a degree of control regarding the timing or the need to incur them. But, in some cases, unforeseen circumstances may arise, such as in the case of an unanticipated opportunity to make a large acquisition or the need to replace a costly drilling rig component due to an unexpected loss, which could force us to incur additional debt above that which we had expected or forecasted. Likewise, if our cash flow should prove to be insufficient to cover our current cash requirements we would need to increase our debt either through bank borrowings or otherwise.

RISK FACTORS

Many other factors could adversely affect our business. The following discussion describes the material risks currently known to us. However, additional risks that we do not know about or that we currently view as immaterial may also impair our business or adversely affect the value of our securities. You should carefully consider the risks described below together with the other information contained in, or incorporated by reference into, this report.

If demand for oil, NGLs, and natural gas is reduced, our ability to market as well as produce our oil, NGLs, and natural gas may be negatively affected.

Historically, oil, NGLs, and natural gas prices have been extremely volatile, with significant increases and significant price drops being experienced from time to time. In the future, various factors beyond our control will have a significant effect

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on oil, NGLs, and natural gas prices. Such factors include, among other things, the domestic and foreign supply of oil, NGLs, and natural gas, the price of foreign imports, the levels of consumer demand, the price and availability of alternative fuels, the availability of pipeline capacity, and changes in existing and proposed federal regulation and price controls.

The oil, NGLs, and natural gas markets are also unsettled due to a number of factors. Production from oil and natural gas wells in some geographic areas of the United States has been curtailed for considerable periods of time due to a lack of market demand and transportation and storage capacity. It is possible, however, that some of our wells may in the future be shut-in or that oil, NGLs, and natural gas will be sold on terms less favorable than might otherwise be obtained should demand for oil, NGLs, and natural gas decrease. Competition for available markets has been vigorous and there remains great uncertainty about prices that purchasers will pay. Oil, NGLs, and natural gas surpluses could result in our inability to market oil, NGLs, and natural gas profitably, causing us to curtail production and/or receive lower prices for our oil, NGls, and natural gas, situations which would adversely affect us.

Disruptions in the financial markets could affect our ability to obtain financing or refinance existing indebtedness on reasonable terms and may have other adverse effects.

Commercial-credit market disruptions may result in tight credit markets in the United States. Liquidity in the global-credit markets can be severely contracted by market disruptions making terms for certain financings less attractive, and in certain cases, result in the unavailability of certain types of financing. As a result of credit-market turmoil, we may not be able to obtain debt financing, or refinance existing indebtedness on favorable terms, which could affect operations and financial performance.

Oil, NGLs, and natural gas prices are volatile, and low prices have negatively affected our financial results and could do so in the future.

Our revenues, operating results, cash flow, and future rate of growth depend substantially on prevailing prices for oil, NGLs, and natural gas. Historically, oil, NGLs, and natural gas prices and markets have been volatile, and they are likely to continue to be volatile in the future. Any decline in prices in the future would have a negative impact on our future financial results.

Prices for oil, NGLs, and natural gas are subject to wide fluctuations in response to relatively minor changes in the actual or perceived supply of and demand for oil, NGLs, and natural gas, market uncertainty, and a variety of additional factors that are beyond our control. These factors include:

- political conditions in oil producing regions;
- the ability of the members of the OPEC to agree on prices and their ability to maintain production quotas;
- actions taken by foreign oil and natural gas companies;
- the price of foreign oil imports;
- imports and exports of liquefied natural gas;
- actions of governmental authorities;
- the domestic and foreign supply of oil, NGLs, and natural gas;
- the level of consumer demand;
- United States storage levels of oil, NGLs, and natural gas;
- weather conditions;
- domestic and foreign government regulations;
- the price, availability, and acceptance of alternative fuels;
- volatility in ethane prices causing rejection of ethane as part of the liquids processed stream; and
- worldwide economic conditions.

These factors and the volatile nature of the energy markets make it impossible to predict with any certainty the future prices of oil, NGLs, and natural gas.

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Our contract drilling operations depend on levels of activity in the oil, NGLs, and natural gas exploration and production industry.

Our contract drilling operations depend on the level of activity in oil, NGLs, and natural gas exploration and production in our operating markets. Both short-term and long-term trends in oil, NGLs, and natural gas prices affect the level of that activity. Because oil, NGLs, and natural gas prices are volatile, the level of exploration and production activity can also be volatile. Any decrease from current oil, NGLs, and natural gas prices would further depress the level of exploration and production activity. This, in turn, would likely result in further declines in the demand for our drilling services and would have an adverse effect on our contract drilling revenues, cash flows, and profitability. As a result, the future demand for our drilling services is uncertain.

The industries in which we operate are highly competitive, and many of our competitors have greater resources than we do.

The drilling industry in which we operate is generally very competitive. Most drilling contracts are awarded on the basis of competitive bids, which may result in intense price competition. Some of our competitors in the contract drilling industry have greater financial and human resources than we do. These resources may enable them to better withstand periods of low drilling rig utilization, to compete more effectively on the basis of price and technology, to build new drilling rigs or acquire existing drilling rigs, and to provide drilling rigs more quickly than we do in periods of high drilling rig utilization.

The oil and natural gas industry is also highly competitive. We compete in the areas of property acquisitions and oil and natural gas exploration, development, production, and marketing with major oil companies, other independent oil and natural gas concerns, and individual producers and operators. In addition, we must compete with major and independent oil and natural gas concerns in recruiting and retaining qualified employees. Many of our competitors in the oil and natural gas industry have substantially greater resources than we do.

The midstream industry is also highly competitive. We compete in areas of gathering, processing, transporting, and treating natural gas with other midstream companies. We are continually competing with larger midstream companies for acquisitions and construction projects. Many of our competitors have greater financial resources, human resources, and larger geographic presence than we do currently.

Continued growth through acquisitions is not assured.

In the past, we have experienced growth in each of our segments, in part, through mergers and acquisitions. The contract land drilling industry, the exploration and development industry, as well as the gas gathering and processing industry, have experienced significant consolidation over the past several years, and there can be no assurance that acquisition opportunities will continue to be available. Additionally, we are likely to continue to face intense competition from other companies for available acquisition opportunities.

There can be no assurance that we will:

- be able to identify suitable acquisition opportunities;
- have sufficient capital resources to complete additional acquisitions;
- successfully integrate acquired operations and assets;
- effectively manage the growth and increased size;
- maintain the crews and market share to operate any future drilling rigs we may acquire; or
- successfully improve our financial condition, results of operations, business or prospects in any material manner as a result of any completed acquisition.

We may incur substantial indebtedness to finance future acquisitions and also may issue debt instruments, equity securities, or convertible securities in connection with any acquisitions. Debt service requirements could represent a significant burden on our results of operations and financial condition and the issuance of additional equity would be dilutive to existing shareholders. Also, continued growth could strain our management, operations, employees, and other resources.

Successful acquisitions, particularly those of oil and natural gas companies or of oil and natural gas properties, require an assessment of a number of factors, many of which are beyond our control. These factors include recoverable reserves,

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exploration potential, future oil, NGLs, and natural gas prices, operating costs, and potential environmental and other liabilities. Such assessments are inexact and their accuracy is inherently uncertain.

Our operations have significant capital requirements, and our indebtedness could have important consequences.

We have experienced and may continue to experience substantial capital needs for our operations. We have $646.2 million of indebtedness outstanding (net of unamortized discount) under the senior subordinated notes we have issued to date and in addition, have the right to borrow up to $500.0 million under our credit agreement. As of February 13, 2015, we had $201.5 million outstanding borrowings under our credit agreement. Our level of indebtedness, the cash flow needed to satisfy our indebtedness, and the covenants governing our indebtedness could:

- limit funds available for financing capital expenditures, our drilling program or other activities or cause us to curtail these activities;
- limit our flexibility in planning for, or reacting to changes in, our business;
- place us at a competitive disadvantage to some of our competitors that are less leveraged than we are;
- make us more vulnerable during periods of low oil, NGLs, and natural gas prices or in the event of a downturn in our business; and
- prevent us from obtaining additional financing on acceptable terms or limit amounts available under our existing or any future credit facilities.

Our ability to meet our debt service and other contractual and contingent obligations will depend on our future performance. In addition, lower oil, NGLs, and natural gas prices could result in future reductions in the amount available for borrowing under our credit agreement, reducing our liquidity, and even triggering mandatory loan repayments.

The instruments governing our indebtedness contain various covenants limiting the conduct of our business.

The indentures governing our senior subordinated notes and our credit agreement contain various restrictive covenants that limit the conduct of our business. In particular, these agreements will place certain limits on our ability to, among other things:

- incur additional indebtedness, guarantee obligations or issue disqualified capital stock;
- pay dividends or distributions on our capital stock or redeem, repurchase or retire our capital stock;
- make investments or other restricted payments;
- grant liens on assets;
- enter into transactions with stockholders or affiliates;
- sell assets;
- issue or sell capital stock of certain subsidiaries; and
- merge or consolidate.

In addition, our credit agreement also requires us to maintain a minimum current ratio and a maximum leverage ratio.

If we fail to comply with the restrictions in the indentures governing our senior subordinated notes, our credit agreement or any other subsequent financing agreements, a default may allow the creditors, if the agreements so provide, to accelerate the related indebtedness as well as any other indebtedness to which a cross-acceleration or cross-default provision applies. If that occurs, we may not be able to make all of the required payments or borrow sufficient funds to refinance that debt. Even if new financing were available at that time, it may not be on terms acceptable to us. In addition, lenders may be able to terminate any commitments they had made to make available further funds.

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Our future performance depends on our ability to find or acquire additional oil, NGLs, and natural gas reserves that are economically recoverable.

In general, production from oil and natural gas properties declines as reserves are depleted, with the rate of decline depending on reservoir characteristics. Unless we successfully replace the reserves that we produce, our reserves will decline, resulting eventually in a decrease in oil, NGLs, and natural gas production and lower revenues and cash flow from operations. Historically, we have succeeded in increasing reserves after taking production into account through exploration and development. We have conducted these activities on our existing oil and natural gas properties as well as on newly acquired properties. We may not be able to continue to replace reserves from these activities at acceptable costs. Lower prices of oil, NGLs, and natural gas may further limit the kinds of reserves that can economically be developed. Lower prices also decrease our cash flow and may cause us to decrease capital expenditures.

We are continually identifying and evaluating opportunities to acquire oil and natural gas properties, including acquisitions that would be significantly larger than those consummated to date by us. We cannot assure you that we will successfully consummate any acquisition, that we will be able to acquire producing oil and natural gas properties that contain economically recoverable reserves or that any acquisition will be profitably integrated into our operations.

The competition for producing oil and natural gas properties is intense. This competition could mean that to acquire properties we will have to pay higher prices and accept greater ownership risks than we have in the past.

Our exploration and production and mid-stream operations involve a high degree of business and financial risk which could adversely affect us.

Exploration and development involve numerous risks that may result in dry holes, the failure to produce oil, NGLs, and natural gas in commercial quantities and the inability to fully produce discovered reserves. The cost of drilling, completing, and operating wells is substantial and uncertain. Numerous factors beyond our control may cause the curtailment, delay, or cancellation of drilling operations, including:

- unexpected drilling conditions;
- pressure or irregularities in formations;
- capacity of pipeline systems;
- equipment failures or accidents;
- adverse weather conditions;
- compliance with governmental requirements; and
- shortages or delays in the availability of drilling rigs or delivery crews and the delivery of equipment.

Exploratory drilling is a speculative activity. Although we may disclose our overall drilling success rate, those rates may decline. Although we may discuss drilling prospects that we have identified or budgeted for, we may ultimately not lease or drill these prospects within the expected time frame, or at all. Lack of drilling success will have an adverse effect on our future results of operations and financial condition.

Our mid-stream operations involve numerous risks, both financial and operational. The cost of developing gathering systems and processing plants is substantial and our ability to recoup these costs is uncertain. Our operations may be curtailed, delayed, or canceled as a result of many things beyond our control, including:

- unexpected changes in the deliverability of natural gas reserves from the wells connected to the gathering systems;
- availability of competing pipelines in the area;
- capacity of pipeline systems;
- equipment failures or accidents;
- adverse weather conditions;
- compliance with governmental requirements;

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- delays in the development of other producing properties within the gathering system's area of operation; and
- demand for natural gas and its constituents.

Many of the wells from which we gather and process natural gas are operated by other parties. As a result, we have little control over the operations of those wells which can act to increase our risk. Operators of those wells may act in ways that are not in our best interests.

Competition for experienced technical personnel may negatively impact our operations or financial results.

Our continued oil and natural gas segment and mid-stream segment success and the success of other activities integral to our operations will depend, in part, on our ability to attract and retain experienced geologists, engineers, and other professionals. Competition for these professionals can be extremely intense, particularly when the industry is experiencing favorable conditions.

Our derivative arrangements might limit the benefit of increases in oil, NGLs, and natural gas prices.

In order to reduce our exposure to short-term fluctuations in the price of oil, NGLs, and natural gas, we sometimes enter into derivative contracts. These derivative contracts apply to only a portion of our production and provide only partial price protection against declines in oil, NGLs, and natural gas prices. These derivative contracts may expose us to risk of financial loss and limit the benefit to us of increases in prices.

Estimates of our reserves are uncertain and may prove to be inaccurate.

There are numerous uncertainties inherent in estimating quantities of proved reserves and their values, including many factors beyond our control. The reserve data represents only estimates. Reservoir engineering is a subjective and inexact process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact manner. Estimates of economically recoverable oil, NGLs, and natural gas reserves depend on a number of variable factors, including historical production from the area compared with production from other producing areas, and assumptions concerning:

- the effects of regulations by governmental agencies;
- future oil, NGLs, and natural gas prices;
- future operating costs;
- severance and excise taxes;
- development costs; and
- workover and remedial costs.

Some or all of these assumptions may vary considerably from actual results. For these reasons, estimates of the economically recoverable quantities of oil, NGLs, and natural gas attributable to any particular group of properties, classifications of those reserves based on risk of recovery, and estimates of the future net cash flows from reserves prepared by different engineers or by the same engineers but at different times may vary substantially. Accordingly, reserve estimates may be subject to downward or upward adjustment. Actual production, revenues and expenditures with respect to our reserves will likely vary from estimates, and those variances may be material.

The information regarding discounted future net cash flows should not be considered as the current market value of the estimated oil, NGLs, and natural gas reserves attributable to our properties. As required by the SEC, the estimated discounted future net cash flows from proved reserves are based on prices on the first day of the month for each month within the 12-month period before the end of the reporting period and costs as of the date of the estimate, while actual future prices and costs may be materially higher or lower. Actual future net cash flows also will be affected by the following factors:

- the amount and timing of actual production;
- supply and demand for oil, NGLs, and natural gas;
- increases or decreases in consumption; and
- changes in governmental regulations or taxation.

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In addition, the 10% per year discount factor, which is required by the SEC to be used in calculating discounted future net cash flows for reporting purposes, is not necessarily the most appropriate discount factor based on interest rates in effect from time to time and risks associated with our operations or the oil and natural gas industry in general.

If oil, NGLs, and natural gas prices decrease or are unusually volatile, we may be required to take write-downs of our oil and natural gas properties, the carrying value of our drilling rigs or our natural gas gathering and processing systems.

We review quarterly the carrying value of our oil and natural gas properties under the full cost accounting rules of the SEC. Under these rules, capitalized costs of proved oil and natural gas properties may not exceed the present value of estimated future net revenues from proved reserves, discounted at 10% per year. Application of the ceiling test generally requires pricing future revenue at the unweighted arithmetic average of the price on the first day of month for each month within the 12-month period prior to the end of the reporting period, unless prices were defined by contractual arrangements, and requires a write-down for accounting purposes if the ceiling is exceeded. We may be required to write-down the carrying value of our oil and natural gas properties when oil, NGLs, and natural gas prices are depressed. If a write-down is required, it would result in a charge to earnings, but would not impact cash flow from operating activities. Once incurred, a write-down of oil and natural gas properties is not reversible at a later date. Because our ceiling tests use a rolling 12-month look back average price it is possible that a write down during a reporting period will not remove the need for us to take additional write downs in one or more succeeding periods. This would be the case when months with higher commodity prices roll off the 12-month period and are replaced with more recent months having lower commodity prices.

Our drilling equipment, transportation equipment, gas gathering and processing systems, and other property and equipment are carried at cost. We are required to periodically test to see if these values, including associated goodwill and other intangible assets, have been impaired whenever events or changes in circumstances suggest the carrying amount may not be recoverable. If any of these assets are determined to be impaired, the loss is measured as the amount by which the carrying amount of the asset exceeds its fair value. An estimate of fair value is based on the best information available, including prices for similar assets. Changes in these estimates could cause us to reduce the carrying value of property, equipment, and related intangible assets. Once these values have been reduced, they are not reversible.

Our operations present inherent risks of loss that, if not insured or indemnified against, could adversely affect our results of operations.

Our contract drilling operations are subject to many hazards inherent in the drilling industry, including blowouts, cratering, explosions, fires, loss of well control, loss of hole, damaged or lost drilling equipment, and damage or loss from inclement weather. Our exploration and production and mid-stream operations are subject to these and similar risks. Any of these events could result in personal injury or death, damage to or destruction of equipment and facilities, suspension of operations, environmental damage, and damage to the property of others. Generally, drilling contracts provide for the division of responsibilities between a drilling company and its customer, and we seek to obtain indemnification from our drilling customers by contract for some of these risks. To the extent that we are unable to transfer these risks to drilling customers by contract or indemnification agreements (or to the extent we assume obligations of indemnity or assume liability for certain risks under our drilling contracts), we seek protection from some of these risks through insurance. However, some risks are not covered by insurance and we cannot assure you that the insurance we do have or the indemnification agreements we have entered into will adequately protect us against liability from all of the consequences of the hazards described above. The occurrence of an event not fully insured or indemnified against, or the failure of a customer to meet its indemnification obligations, could result in substantial losses. In addition, we cannot assure you that insurance will be available to cover any or all of these risks. Even if available, the insurance might not be adequate to cover all of our losses, or we might decide against obtaining that insurance because of high premiums or other costs.

In addition, we are not the operator of many of our wells. As a result, our operating risks for those wells and our ability to influence the operations for those wells are less subject to our control. Operators of those wells may act in ways that are not in our best interests.

Governmental and environmental regulations could adversely affect our business.

Our business is subject to federal, state, and local laws and regulations on taxation, the exploration for and development, production, and marketing of oil and natural gas, and safety matters. Many laws and regulations require drilling permits and govern the spacing of wells, rates of production, prevention of waste, unitization and pooling of properties, and other matters. These laws and regulations have increased the costs of planning, designing, drilling, installing, operating, and abandoning our

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oil and natural gas wells and other facilities. In addition, these laws and regulations, and any others that are passed by the jurisdictions where we have production, could limit the total number of wells drilled or the allowable production from successful wells, which could limit our revenues.

We are (or could become) subject to complex environmental laws and regulations adopted by the various jurisdictions where we own or operate. We could incur liability to governments or third parties for discharges of oil, natural gas or other pollutants into the air, soil or water, including responsibility for remedial costs. We could potentially discharge these materials into the environment in any number of ways including the following:

- from a well or drilling equipment at a drill site;
- from gathering systems, pipelines, transportation facilities, and storage tanks;
- damage to oil and natural gas wells resulting from accidents during normal operations; and
- blowouts, cratering, and explosions.

Because the requirements imposed by laws and regulations are frequently changed, we cannot assure you that laws and regulations enacted in the future, including changes to existing laws and regulations, will not adversely affect our business. The current Congress and White House administration may impose or change laws and regulations that will adversely affect our business. With the trend toward stricter standards, greater regulation, and more extensive permit requirements, our risks related to environmental matters and our environmental expenditures could increase in the future. In addition, because we acquire interests in properties that have been operated in the past by others, we may be liable for environmental damage caused by the former operators, which liability could be material.

Any future implementation of price controls on oil, NGLs, and natural gas would affect our operations.

Certain groups have asserted efforts to have the United States Congress impose some form of price controls on either oil, natural gas, or both. There is no way at this time to know what result these efforts will have nor, if implemented, their effect on our operations. However, it is possible that these efforts, if successful, would serve to limit the amount that we might be able to get for our future oil, NGLs, and natural gas production. Any future limits on the price of oil, NGLs, and natural gas could also result in adversely affecting the demand for our drilling services.

Our shareholders' rights plan and provisions of Delaware law and our by-laws and charter could discourage change in control transactions and prevent shareholders from receiving a premium on their investment.

Our by-laws and charter provide for a classified board of directors with staggered terms and authorizes the board of directors to set the terms of preferred stock. In addition, our charter and Delaware law contain provisions that impose restrictions on business combinations with interested parties. We have also adopted a shareholders' rights plan. Because of our shareholders' rights plan and these provisions of our by-laws, charter, and Delaware law, persons considering unsolicited tender offers or other unilateral takeover proposals may be more likely to negotiate with our board of directors rather than pursue non-negotiated takeover attempts. As a result, these provisions may make it more difficult for our shareholders to benefit from transactions that are opposed by an incumbent board of directors.

New technologies may cause our current exploration and drilling methods to become obsolete, resulting in an adverse effect on our production.

Our industry is subject to rapid and significant advancements in technology, including the introduction of new products and services using new technologies. As competitors use or develop new technologies, we may be placed at a competitive disadvantage, and competitive pressures may force us to implement new technologies at a substantial cost. In addition, competitors may have greater financial, technical, and personnel resources that allow them to enjoy technological advantages and may in the future allow them to implement new technologies before we can. We cannot be certain that we will be able to implement technologies on a timely basis or at a cost that is acceptable to us. One or more of the technologies that we currently use or that we may implement in the future may become obsolete or may not work as we expected and we may be adversely affected.

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We may be affected by climate change and market or regulatory responses to climate change.

Climate change, including the impact of potential global warming regulations, could have a material adverse effect on our results of operations, financial condition, and liquidity. Restrictions, caps, taxes, or other controls on emissions of greenhouse gasses, including diesel exhaust, could significantly increase our operating costs. Restrictions on emissions could also affect our customers that (a) use commodities that we carry to produce energy, (b) use significant amounts of energy in producing or delivering the commodities we carry, or (c) manufacture or produce goods that consume significant amounts of energy or burn fossil fuels, including chemical producers, farmers and food producers, and automakers and other manufacturers. Significant cost increases, government regulation, or changes of consumer preferences for goods or services relating to alternative sources of energy or emissions reductions could materially affect the markets for the commodities associated with our business, which in turn could have a material adverse effect on our results of operations, financial condition, and liquidity. Government incentives encouraging the use of alternative sources of energy could also affect certain of our customers and the markets for certain of the commodities associated with our business in an unpredictable manner that could alter our business activities. Finally, we could face increased costs related to defending and resolving legal claims and other litigation related to climate change and the alleged impact of our operations on climate change. Any of these factors, individually or in operation with one or more of the other factors, or other unforeseen impacts of climate change could reduce the amount of business activity we conduct and have a material adverse effect on our results of operations, financial condition, and liquidity.

The results of our operations depend on our ability to transport oil, NGLs, and gas production to key markets.

The marketability of our oil, NGLs, and natural gas production depends in part on the availability, proximity, and capacity of pipeline systems, refineries, and other transportation sources. The unavailability of or lack of available capacity on these systems and facilities could result in the shut-in of producing wells or the delay or discontinuance of development plans for properties. Federal and state regulation of oil, NGLs, and natural gas production and transportation, tax and energy policies, changes in supply and demand, pipeline pressures, damage to or destruction of pipelines, and general economic conditions could adversely affect our ability to produce, gather and, transport oil, NGLs, and natural gas.

The loss of one or a number of our larger customers could have a material adverse effect on our financial condition and results of operations.

During 2014, QEP Resources, Inc. was our largest drilling customer accounting for approximately 19% of our total contract drilling revenues. No other third party customer accounted for 10% or more of our contract drilling revenues. Any of our customers may choose not to use our services and the loss of one or a number of our larger customers could have a material adverse effect on our financial condition and results of operations.

Shortages of completion equipment and services could delay or otherwise adversely affect our oil and natural gas segment’s operations.

In the past several years, the increase in horizontal drilling activity in certain areas has, at times, resulted in shortages in the availability of third party equipment and services required for the completion of wells drilled by our oil and natural gas segment. As a result, we have experienced delays in completing some of our wells. Although we have taken steps to try to reduce the delays associated with these services, we anticipate that any shortages in availability of these services could, at times, delay, restrict, or curtail part of our exploration and development operations, which could in turn harm our results.

Our mid-stream segment depends on certain natural gas producers and pipeline operators for a significant portion of its supply of natural gas and NGLs. The loss of any of these producers could result in a decline in our volumes and revenues.

We rely on certain natural gas producers for a significant portion of our natural gas and NGLs supply. While some of these producers are subject to long-term contracts, we may be unable to negotiate extensions or replacements of these contracts on favorable terms, if at all. The loss of all or even a portion of the natural gas volumes supplied by these producers, as a result of competition or otherwise, could have a material adverse effect on our mid-stream segment unless we were able to acquire comparable volumes from other sources.

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The counterparties to our commodity derivative contracts may not be able to perform their obligations to us, which could materially affect our cash flows and results of operations.

To reduce our exposure to adverse fluctuations in the prices of oil and natural gas, we currently, and may in the future, enter into commodity derivative contracts for a significant portion of our forecasted oil, NGLs, and natural gas production. The extent of our commodity price exposure is related largely to the effectiveness and scope of our derivative activities, as well as to the ability of counterparties under our commodity derivative contracts to satisfy their obligations to us. If one or more of our counterparties is unable or unwilling to make required payments to us under our commodity derivative contracts, it could have a material adverse effect on our financial condition and results of operations.

Reliance on management.

We depend greatly on the efforts of our executive officers and other key employees to manage our operations. The loss or unavailability of any of our executive officers or other key employees could have a material adverse effect on our business.

We are subject to various claims and litigation that could ultimately be resolved against us requiring material future cash payments and/or future material charges against our operating income and materially impairing our financial position.

The nature of our business makes us highly susceptible to claims and litigation. We are subject to various existing legal claims and lawsuits, which could have a material adverse effect on our consolidated financial position, results of operations, or cash flows. Any claims or litigation, even if fully indemnified or insured, could negatively affect our reputation among our customers and the public, and make it more difficult for us to compete effectively or obtain adequate insurance in the future.

Derivative regulations included in current financial reform legislation could impede our ability to manage business and financial risks by restricting our use of derivative instruments as hedges against fluctuating commodity prices and interest rates.

In July 2010, the Dodd-Frank Wall Street Reform and Consumer Protection Act (the Act) was passed by Congress and signed into law. The Act contains significant derivative regulations, including a requirement that certain transactions be cleared on exchanges and a requirement to post cash collateral (commonly referred to as “margin”) for such transactions. The Act provides for a potential exception from these clearing and cash collateral requirements for commercial end-users and it includes a number of defined terms that will be used in determining how this exception applies to particular derivative transactions and the parties to those transactions.

We use crude oil and natural gas derivative instruments with respect to a portion of our expected production in order to reduce commodity price uncertainty and enhance the predictability of cash flows relating to the marketing of our crude oil and natural gas. As commodity prices increase, our derivative liability positions increase; however, none of our current derivative contracts require the posting of margin or similar cash collateral when there are changes in the underlying commodity prices that are referred to in these contracts.

Depending on the rules and definitions adopted by the CFTC, we could be required to post collateral with our dealer counterparties for our commodities derivative transactions. Such a requirement could have a significant impact on our business by reducing our ability to execute derivative transactions to reduce commodity price uncertainty and to protect cash flows. Requirements to post collateral would cause significant liquidity issues by reducing our ability to use cash for investment or other corporate purposes, or would require us to increase our level of debt. In addition, a requirement for our counterparties to post collateral would likely result in additional costs being passed on to us, thereby decreasing the effectiveness of our derivative contracts and our profitability.

Proposed federal and state legislative and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays.

Hydraulic-fracturing is an essential and common practice in the oil and gas industry used to stimulate production of oil, natural gas, and associated liquids from dense subsurface rock formations. Our oil and natural gas segment routinely apply hydraulic-fracturing techniques to many of our oil and natural gas properties, including our unconventional resource plays in the Granite Wash of Texas and Oklahoma, the Marmaton of Oklahoma, the Wilcox of Texas, and the Mississippian of Kansas. Hydraulic-fracturing involves using water, sand, and certain chemicals to fracture the hydrocarbon-bearing rock formation to allow the flow of hydrocarbons into the wellbore. The process is typically regulated by state oil and natural gas commissions;

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however, the EPA has asserted federal regulatory authority over certain hydraulic-fracturing activities involving diesel under the Safe Drinking Water Act and has begun the process of drafting guidance documents related to this newly asserted regulatory authority. In addition, legislation has been introduced before Congress, called the Fracturing Responsibility and Awareness of Chemicals Act, to provide for federal regulation of hydraulic-fracturing and to require disclosure of the chemicals used in the hydraulic-fracturing process.

Certain states in which we operate, including Texas, Oklahoma, Kansas, Colorado, and Wyoming, have adopted, and other states are considering adopting, regulations that could impose more stringent permitting, public disclosure of fracking fluids, waste disposal, and well construction requirements on hydraulic-fracturing operations or otherwise seek to ban fracturing activities altogether. For example, Texas adopted a law in June 2011 requiring disclosure to the Railroad Commission of Texas (RCT) and the public of certain information regarding the components used in the hydraulic-fracturing process. In addition to state laws, local land use restrictions, such as city ordinances, may restrict or prohibit the performance of well drilling in general and/or hydraulic fracturing in particular. In the event state, local, or municipal legal restrictions are adopted in areas where we are currently conducting, or in the future plan to conduct operations, we may incur additional costs to comply with such requirements that may be significant in nature, experience delays or curtailment in the pursuit of exploration, development, or production activities, and perhaps even be precluded from the drilling and/or completion of wells.

There are certain governmental reviews either underway or being proposed that focus on environmental aspects of hydraulic-fracturing practices. The White House Council on Environmental Quality is coordinating a review of hydraulic-fracturing practices, and a committee of the United States House of Representatives has conducted an investigation of hydraulic-fracturing practices. Furthermore, a number of federal agencies are analyzing, or have been requested to review, a variety of environmental issues associated with hydraulic fracturing. The EPA has commenced a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater. In addition, the U.S. Department of Energy is conducting an investigation into practices the agency could recommend to better protect the environment from drilling using hydraulic-fracturing completion methods.

Additionally, certain members of the Congress have previously called upon the U.S. Government Accountability Office to investigate how hydraulic fracturing might adversely affect water resources, the U.S. Securities and Exchange Commission to investigate the natural gas industry and any possible misleading of investors or the public regarding the economic feasibility of pursuing natural gas deposits in shales by means of hydraulic fracturing, and the U.S. Energy Information Administration to provide a better understanding of that agency's estimates regarding natural gas reserves, including reserves from shale formations, as well as uncertainties associated with those estimates. These ongoing or proposed studies, depending on their course and results obtained, could spur initiatives to further regulate hydraulic fracturing under the Safe Drinking Water Act or other regulatory processes.

Further, after reviewing extensive comments and making a number of changes to its previously July 28, 2011 proposed rules, on April 17, 2012 the EPA issued its final rules that subject a wide range of oil and gas operations (production, processing, transmission, storage, and distribution) to regulation under the New Source Performance Standards (NSPS) and National Emission Standards for Hazardous Air Pollutants (NESHAPS) programs (with the NSPS and NESHAPS published in the Federal Register on August 16, 2012). The EPA revised the NSPS for volatile organic compounds (VOCs) from leaking components at onshore gas processing plants and the NSPS for sulfur dioxide emissions from natural gas processing plants. The EPA also established standards for certain oil and gas operations not covered by existing standards, which will regulate VOC emissions from gas wells, centrifugal and reciprocating compressors, pneumatic controllers, and storage vessels over a certain size. The EPA also made revisions to the existing leak detection and repair requirements for the oil and gas production source category and the natural gas transmission source category and established action limits reflecting most achievable control for certain previously uncontrolled emission sources. There also are additional testing and related notification, record keeping and reporting requirements. These changes were effective October 15, 2012. In July 2014 EPA proposed and on

December 19, 2014 EPA finalized updates and clarifications to the rules. They focused on additional detail on requirements for handling of gas and liquids during well completions, clarify requirements for storage tanks, define low pressure wells, clarify certain requirements for leak detection at natural gas processing plants, update requirements for reciprocating compressors, and update definition of “responsible official.”

The EPA regulations also result in the first federal air standards for natural gas wells that are hydraulically fractured. The clarifications identify two distinct stages of the well completion, or “flowback,” operation. The initial stage when it is technically feasible for a separator (“green completion” equipment) to function. The next stage is the “separation flowback stage” when gas, liquid hydrocarbons and water are separated. Wells subject to green completion must begin using green

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completions no later than January 1, 2015. Wells not subject to these requirements, such as exploratory wells, must flare the gas during separation.

Increased regulation and attention given to the hydraulic fracturing process could lead to greater opposition, including litigation, to oil and gas production activities using hydraulic fracturing techniques. Additional legislation or regulation could also lead to operational delays or increased operating costs in the production of oil, natural gas, and associated liquids including from the development of shale plays, or could make it more difficult to perform hydraulic fracturing. The adoption of additional federal, state or local laws or the implementation of regulations regarding hydraulic fracturing could potentially cause a decrease in the completion of new oil and gas wells, increased compliance costs and time, which could adversely affect our financial position, results of operations, and cash flows.

On October 20, 2011, EPA announced a schedule for development of standards for disposal of wastewater produced from shale gas operations to publicly owned treatment works (POTWs). The regulations will be developed under EPA's Effluent Guidelines Program under the authority of the Clean Water Act. Although anticipated in 2014, EPA has not yet proposed them. Direct discharges from unconventional oil and gas extraction are subject to NPDES permit regulations (40 CFR Parts 122 through 125). Indirect discharges to POTWs are subject to the General Pretreatment Regulations (40 CFR Part 403).

Our ability to produce crude oil, natural gas, and associated liquids economically and in commercial quantities could be impaired if we are unable to acquire adequate supplies of water for our drilling operations and/or completions or are unable to dispose of or recycle the water we use at a reasonable cost and in accordance with applicable environmental rules.

To our knowledge, there have been no citations, suits, or contamination of potable drinking water arising from our fracturing operations. We do not have insurance policies in effect that are intended to provide coverage for losses solely related to hydraulic fracturing operations; however, it is possible that our general liability and excess liability insurance policies might cover third-party claims related to hydraulic fracturing operations and associated legal expenses depending on the specific nature of the claims, the timing of the claims, as well as the specific terms of such policies.

Uncertainty regarding increased seismic activity in Oklahoma.

We conduct oil and natural gas exploration, development and drilling activities in Oklahoma and elsewhere. In recent years, Oklahoma has experienced a significant increase in earthquakes and other seismic activity. Some parties believe that there is a correlation between certain oil and gas activities and the increased occurrence of earthquakes. The extent of this correlation, if any, is the subject of studies by both state and federal agencies the results of which remain uncertain. We cannot state at this time what if any impact this seismic activity may have on us or our industry in the future.

The hydraulic fracturing process on which we depend to produce commercial quantities of crude oil, natural gas, and associated NGLs from many reservoirs requires the use and disposal of significant quantities of water.

Our inability to secure sufficient amounts of water, or to dispose of or recycle the water used in our oil and natural gas segment operations, could adversely impact our operations. Moreover, the imposition of new environmental initiatives and regulations could include restrictions on our ability to conduct certain operations such as hydraulic fracturing or disposal of wastes, including, but not limited to, produced water, drilling fluids, and other wastes associated with the exploration, development or production of oil and natural gas.

Compliance with environmental regulations and permit requirements governing the withdrawal, storage and, use of surface water or groundwater necessary for hydraulic fracturing of wells may increase our operating costs and cause delays, interruptions, or termination of our operations, the extent of which cannot be predicted, all of which could have an adverse effect on our operations and financial condition.

We may decide not to drill some of the prospects we have identified, and locations that we do drill may not yield oil, NGLs, and natural gas in commercially viable quantities.

Our oil and natural gas segment's prospective drilling locations are in various stages of evaluation, ranging from a prospect that is ready to drill to a prospect that will require additional geological and engineering analysis. Based on a variety of factors, including future oil, NGLs, natural gas prices, the generation of additional seismic or geological information, and other factors, we may decide not to drill one or more of these prospects. As a result, we may not be able to increase or maintain our reserves or production, which in turn could have an adverse effect on our business, financial position, and results of operations.

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In addition, the SEC's reserve reporting rules include a general requirement that, subject to limited exceptions, proved undeveloped reserves may only be booked if they relate to wells scheduled to be drilled within five years of the date of booking. At December 31, 2014, we had 177 proved undeveloped drilling locations. To the extent that we do not drill these locations within five years of initial booking, they may not continue to qualify for classification as proved reserves, and we may be required to reclassify such reserves as unproved reserves. The reclassification of those reserves could also have a negative effect on the borrowing base under our credit facility.

The cost of drilling, completing, and operating a well is often uncertain, and cost factors can adversely affect the economics of a well. Our efforts will be uneconomic if we drill dry holes or wells that are productive but do not produce enough oil, NGLs, and natural gas to be commercially viable after drilling, operating, and other costs.

The borrowing base under our credit agreement is determined semi-annually at the discretion of the lenders and is based in a large part on the prices for oil, NGLs, and natural gas.

Significant declines in oil, NGLs, and natural gas prices may result in a decrease in our borrowing base. The lenders can unilaterally adjust the borrowing base and therefore the borrowings permitted to be outstanding under our credit agreement. If outstanding borrowings are in excess of the borrowing base, we must (a) repay the loan in excess of the borrowing base, (b) dedicate additional properties to the borrowing base, or (c) begin monthly principal payments in accordance with our credit agreement.

Potential listing of species as “endangered” under the federal Endangered Species Act could result in increased costs and new operating restrictions or delays on our operations and that of our customers, which could adversely affect our operations and financial results.

The federal Endangered Species Act, referred to as the “ESA,” and analogous state laws regulate a variety of activities, including oil and gas development, which could have an adverse effect on species listed as threatened or endangered under the ESA or their habitats. The designation of previously unidentified endangered or threatened species could cause oil and natural gas exploration and production operators and service companies to incur additional costs or become subject to operating delays, restrictions or bans in affected areas, which impacts could adversely reduce the amount of drilling activities in affected areas. All three of our business segments could be subject to the effect of one or more species being listed as threatened or endangered within the areas of our operations. Numerous species have been listed or proposed for protected status in areas in which we provide or could in the future undertake operations. For instance, the American Burying Beetle and the Lesser Prairie-Chicken both have habitat in some areas where we operate or provide services. The FWS initiated the process to list the Lesser Prairie-Chicken as threatened in November 2012. On April 10, 2014 the FWS listed the Lesser Prairie-Chicken as “threatened,” effective May 12, 2014. On April 10, 2014 the FWS also finalized a final rule under section 4(d) of the ESA which “provides that all of the prohibitions under 50 CFR 17.31 and 17.32 will apply to the lesser prairie-chicken, except . . . that [actions] incidental to activities conducted by a participant enrolled in, and operating in compliance with, the Lesser Prairie-Chicken Interstate Working Group’s Lesser Prairie-Chicken Range-Wide Conservation Plan (rangewide plan) will not be prohibited.” The rangewide plan is administered by the Western Association of Fish and Wildlife Agencies (“WAFWA”). “The rangewide plan identifies the ecoregional population goals . . . for the four ecoregions: the Shinnery Oak Prairie Region (eastern New Mexico and southwest Texas panhandle); the Sand Sagebrush Prairie Region (southeastern Colorado, southwestern Kansas, and western Oklahoma panhandle); the Mixed Grass Prairie Region (northeastern Texas panhandle, western Oklahoma, and south central Kansas); and the Short Grass/CRP Mosaic Region (northwestern Kansas).” In turn, the FWS and the WAFWA entered into the Range-Wide Oil and Gas Candidate Conservation Agreement with Assurances (“CCAA”) dated February 28, 2014. The CCAA will be administered by the WAFWA with FWS oversight and is a voluntary agreement intended to address the effects of oil and gas activities on the Lesser Prairie-Chicken and its habitat in the five states. WAFWA is to work with members of the oil and gas industry to enroll properties in the CCAA using Certificates of Inclusion (“CIs”) which are designed “to facilitate the voluntary cooperation of the oil and gas industry in providing conservation benefits" to the Lesser Prairie-Chicken. Participants will also "contribute funding ['mitigation fees'] for conservation to offset unavoidable impacts as part of their CIs. The sage grouse and certain wildflower species, among others, are also species that have been or are being considered for protected status under the ESA and whose range can coincide with oil and natural gas production activities. The presence of protected species in areas where we provide contract drilling or mid-stream services or conduct exploration and production operations could impair our ability to timely complete or carry out those services and, consequently, adversely affect our results of operations and financial position.

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Our new drilling rig program to design and build new proprietary BOSS drilling rigs is subject to risks, including delays and cost overruns, and may not meet our expectations.

We have launched a new drilling rig program to design and build new proprietary 1,500 horsepower AC electric drilling rigs, which we refer to as BOSS drilling rigs. We anticipate that this new drilling rig will position us to more effectively meet the demands of our existing customers, result in additional new-build contract opportunities and allow us to compete for the work of new customers. The construction of new BOSS drilling rigs is subject to the risks of delays or cost overruns inherent in any large construction project as a result of numerous possible factors, including the following:

- shortages of equipment, materials or skilled labor;
- work stoppages and labor disputes;
- unscheduled delays in the delivery of ordered materials and equipment;
- unanticipated increases in the cost of equipment, labor and raw materials used in construction of our rigs, particularly steel;
- weather interferences;
- difficulties in obtaining necessary permits or in meeting permit conditions;
- unforeseen design and engineering problems;
- failure or delay in obtaining acceptance of the rig from our customer; and
- failure or delay of third party equipment vendors or service providers.

As we design and build new BOSS drilling rigs, there can be no assurance that we will:

- obtain additional new-build contract opportunities; or
- successfully improve our financial condition, results of operations or prospects as a result of the new rigs.

Cyber attacks targeting systems and infrastructure used by the oil and gas industry may adversely impact our operations.

Our business has become increasingly dependent on digital technologies to conduct certain exploration, development and production activities. We depend on digital technology to estimate quantities of natural gas, oil and NGL reserves, process and record financial and operating data, analyze seismic and drilling information, and communicate with our employees and third-party partners. Although we utilize various procedures and controls to mitigate our exposure to such risk, cyber attacks are evolving and unpredictable. These attacks could include, but are not limited to, malicious software, attempts to gain unauthorized access to data, other electronic security breaches that could lead to disruptions in critical systems, the unauthorized release of protected information and the corruption or loss of data. The occurrence of such an attack could lead to financial losses and have a negative impact on our results of operations. We are not aware that any such breaches have occurred to date.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

The information called for by this item was consolidated with and disclosed in connection with Item 1 above.

Item 3. Legal Proceedings

Panola Independent School District No. 4, et al. v. Unit Petroleum Company, No. CJ-07-215, District Court of Latimer County, Oklahoma.

Panola Independent School District No. 4, Michael Kilpatrick, Gwen Grego, Carla Lessel, Thelma Christine Pate, Juanita Golightly, Melody Culberson, and Charlotte Abernathy are the Plaintiffs in this case and are royalty owners in oil and gas drilling and spacing units for which the company's exploration segment distributes royalty. The Plaintiffs' central allegation is

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that the company's exploration segment has underpaid royalty obligations by deducting post-production costs or marketing related fees. Plaintiffs sought to pursue the case as a class action on behalf of persons who receive royalty from us for our Oklahoma production. We have asserted several defenses including that the deductions are permitted under Oklahoma law. We have also asserted that the case should not be tried as a class action due to the materially different circumstances that determine what, if any, deductions are taken for each lease. On December 16, 2009, the trial court entered its order certifying the class. On May 11, 2012 the court of civil appeals reversed the trial court's order certifying the class. The Plaintiffs petitioned the supreme court for certiorari and on October 8, 2012, the Plaintiff's petition was denied. On January 22, 2013, the Plaintiffs filed a second request to certify a class of royalty owners that was slightly smaller than their first attempt. Since then, the Plaintiffs have further amended their proposed class to just include royalty owners entitled to royalties under certain leases located in Latimer, Le Flore, and Pittsburg Counties, Oklahoma. In July 2014, a second class certification hearing was held where, in addition to the defenses described above, we argued that the amended class definition is still deficient under the court of civil appeals opinion reversing the initial class certification. Closing arguments were held on December 2, 2014. There is no timetable for when the court will issue its ruling. The merits of Plaintiffs' claims will remain stayed while class certification issues are pending.

Item 4. Mine Safety Disclosures

Not applicable.

PART II

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

Our common stock trades on the New York Stock Exchange under the symbol "UNT." The following table identifies the high and low sales prices per share of our common stock for the periods indicated:

	2014		2013	
Quarter	High	Low	High	Low
First	$65.63	$48.47	$49.68	$43.75
Second	$68.88	$61.40	$47.45	$40.51
Third	$70.36	$57.85	$47.49	$42.50
Fourth	$59.68	$28.24	$52.81	$46.34

On February 13, 2015, the closing sale price of our common stock, as reported by the NYSE, was $33.26 per share. On that date, there were approximately 887 holders of record of our common stock.

We have never declared any cash dividends on our common stock. Any future determination by our board of directors to pay dividends on our common stock will be made only after considering our financial condition, results of operations, capital requirements, and other relevant factors. Additionally, our bank credit agreement and the Notes prohibit the payment of cash dividends on our common stock under certain circumstances. For further information regarding our bank credit agreement and the Notes agreement's impact on our ability to pay dividends see "Our Credit Agreement and Senior Subordinated Notes" under Item 7 of this report.

Performance Graph. The following graph and related information shall not be deemed "soliciting material" or be deemed to be "filed" with the SEC, nor shall such information be incorporated by reference into any future filing, except to the extent that we specifically incorporate it by reference into such filing.

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Set forth below is a line graph comparing our cumulative total shareholder return on our common stock with the cumulative total return of the S&P 500 Stock Index, S&P 600 Oil and Gas Exploration & Production and our peer group which includes Helmerich & Payne, Inc., Patterson – UTI Energy Inc., and Pioneer Energy Services Corp. The graph below assumes an investment of $100 at the beginning of the period. The shareholder return set forth below is not necessarily indicative of future performance.

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Item 6. Selected Financial Data

The following table shows selected consolidated financial data. The data should be read in conjunction with Item 7 "Management's Discussion and Analysis of Financial Condition and Results of Operations," for a review of 2014, 2013, and 2012 activity.

	As of and for the Year Ended December 31,				
	2014	2013	2012	2011	2010
	(In thousands except per share amounts)				
Revenues[1]	$1,572,944	$1,351,850	$1,315,123	$1,207,503	$870,671
Net income	$136,276 [3]	$184,746	$23,176 [2]	$195,867	$146,484
Net income per common share:					
Basic	$2.80	$3.83	$0.48	$4.11	$3.10
Diluted	$2.78	$3.80	$0.48	$4.08	$3.09
Total assets	$4,473,728	$4,022,390	$3,761,120	$3,256,720	$2,669,240
Long-term debt [4]	$812,163	$645,696	$716,359	$300,000	$163,000
Other long-term liabilities	$148,785	$158,331	$167,545	$113,830	$92,389
Cash dividends per common share	$—	$—	$—	$—	$—

(1) During the third quarter of 2012, we made the decision to prospectively use mark-to-market accounting for our economic hedges. Previously, we reported all gains (losses) in oil and natural gas revenues and now we reflect gains (losses) on non-designated hedges and the ineffectiveness from cash flow hedges along with other revenue items in other income (expense) below income from operations. Prior year amounts have been reclassified to conform to current year presentation.

(2) In June 2012 and December 2012, due to low 12-month average commodity prices, we incurred non-cash ceiling test write-downs of our oil and natural gas properties of $115.9 million pre-tax ($72.1 million net of tax) and $167.7 million pre-tax ($104.4 million net of tax), respectively.

(3) In December 2014, we incurred a non-cash ceiling test write-down of our oil and natural gas properties of $76.7 million pre-tax ($47.7 million net of tax), a non-cash write-down associated with the removal of 31 drilling rigs from our fleet along with certain other equipment and drill pipe of $74.3 million pre-tax ($46.3 million net of tax), and a non-cash write-down associated with a reduction in the carrying value of three midstream segment systems of $7.1 million pre-tax ($4.4 million net of tax).

(4) Long-term debt is net of unamortized discount.

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

Please read the following discussion of our financial condition and results of operations in conjunction with the consolidated financial statements and related notes included in Item 8 of this report.

General

We operate, manage, and analyze our results of operations through our three principal business segments:

- Oil and Natural Gas – carried out by our subsidiary Unit Petroleum Company. This segment explores, develops, acquires, and produces oil and natural gas properties for our own account.
- Contract Drilling – carried out by our subsidiary Unit Drilling Company and its subsidiaries. This segment contracts to drill onshore oil and natural gas wells for others and for our own account.
- Mid-Stream – carried out by our subsidiary Superior Pipeline Company, L.L.C. and its subsidiaries. This segment buys, sells, gathers, processes, and treats natural gas for third parties and for our own account.

Business Outlook

As discussed in other parts of this report, the success of our business and each of our three main operating segments depend, on a large part, on the prices we receive for our oil and natural gas production and the demand for oil and natural gas as well as for our drilling rigs which, in turn, influences the amounts we can charge for the use of those drilling rigs. While our operations are located within the United States, events outside the United States can also impact us and our industry.

During recent months, both within the United States and the world, deteriorating commodity prices have brought about significant and immediate changes affecting our industry and us. The recent decline in commodity prices is causing us (and other oil and gas companies) to reduce our level of drilling activity and spending. When drilling activity and spending decline for any sustained period of time the rates for and the number of our drilling rigs working also tend to decline. In addition, lower commodity prices for any sustained period of time could impact the liquidity condition of some of our industry partners and customers, which, in turn, might limit their ability to meet their financial obligations to us.

How long the current depressed prices for oil and natural gas products continues is uncertain at this time. As noted elsewhere in this report, commodity prices are subject to a number of factors most of which are beyond our control.

The impact on our business and financial results as a consequence of the recent reduction in oil and NGLs (and to a lesser extent natural gas) prices is uncertain in the long term, but in the short term, it has had a number of consequences for us, including the following:

- In December 2014, we determined the value of certain unproved oil and gas properties were diminished (in part or in whole) based on an impairment evaluation and our anticipated future exploration plans. That determination resulted in $73.7 million of costs associated with the unproved properties being added to the capitalized costs to be amortized.
- We incurred a non-cash ceiling test write-down of our oil and natural gas properties of $76.7 million pre-tax ($47.7 million net of tax). Subsequent to December 31, 2014, commodity prices have continued to decrease below December 31, 2014 levels. We anticipate that these reduced prices will require an additional write-down of the carrying value of our oil and natural gas properties for the quarter ending March 31, 2015 and potentially for subsequent quarters.
- We have reduced the number of gross wells we plan to drill in 2015 by approximately 62% from the number of gross wells drilled in 2014. This reduction is driven not only by reduced commodity prices but also because the costs to drill the wells have tended to remain relatively high in comparison to current commodity prices.
-

In December 2014, we removed from service 31 drilling rigs, some older top drives, and certain drill pipe no longer marketable in the current environment. We estimated the fair value of the rigs and other assets based on the estimate market value from third-party assessments (Level 3 fair value measurement). Based on these estimates, we recorded a write-down of approximately $74.3 million pre-tax.

- Several of our drilling rig customers have significantly reduced their drilling budgets for 2015, resulting in a significant reduction in the average utilization of our drilling rig fleet. At December 31, 2014, we had 75 rigs operating, at February 13, 2015, this number was 50. We currently expect further reductions into 2015.

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- In December 2014, our mid-stream segment had a $7.1 million pre-tax write-down of three of its systems, Weatherford, Billy Rose, and Spring Creek due to anticipated future cash flow and future development around these systems supporting their carrying value. The estimated future cash flows were less than the carrying value on these systems (Level 3 fair value measurement).
- Due to the decline in NGLs prices during 2014, in the second half of the year we operated our processing facilities in full ethane rejection mode which reduced the amount of liquids sold during this time period. As long as NGLs prices continue to be at or below these levels, we expect to continue operating in full ethane rejection mode. Our mid-stream segment did not experience a significant reduction in processed volumes in 2014, but as the low prices continue we expect further reductions in drilling activity around our systems which will eventually effect our ability to connect new wells and resulting in lower processed volumes in the future.

We have reduced our total 2015 capital budget for all three of our business segments by approximately 52% as compared to 2014, excluding acquisitions and ARO liability. Our budget is designed to keep our capital expenditures substantially within our anticipated cash flow.

Our 2015 current capital expenditures budget is based on realized prices for the year of $53.73 per barrel of oil, $17.03 per barrel of NGLs, and $3.18 per Mcf of natural gas. Our budget is subject to possible periodic adjustments for various reasons including changes in commodity prices and industry conditions. Funding for the budget will come primarily from our cash flow and, if necessary, borrowings under our credit agreement.

Executive Summary

Oil and Natural Gas

Fourth quarter 2014 production from our oil and natural gas segment was 4,868,000 barrels of oil equivalent (Boe), a 6% increase over the third quarter of 2014 and a 10% increase over the fourth quarter of 2013. These increases came mostly from production associated with new wells. Oil and NGLs production during the fourth quarter of 2014 was 47% of our total production compared to 46% of our total production during the fourth quarter of 2013.

Fourth quarter 2014 oil and natural gas revenues decreased 13% from the third quarter of 2014 and decreased 5% from the fourth quarter of 2013. These deceases were primarily due to lower oil and NGLs prices.

Our NGLs and oil prices for the fourth quarter of 2014 decreased 16% and 11%, respectively, compared to the third quarter of 2014 while our natural gas prices increased 1%. Our NGLs and oil prices decreased 26% and 14%, respectively compared to the fourth quarter of 2013 while natural gas prices increased 16%.

Direct profit (oil and natural gas revenues less oil and natural gas operating expense) decreased 21% from the third quarter of 2014 and 13% from the fourth quarter of 2013. The decreases were primarily attributable to decreased oil and NGLs prices and from higher saltwater disposal expense.

Operating cost per Boe produced for the fourth quarter of 2014 increased 5% and 7% over the third quarter of 2014 and the fourth quarter of 2013, respectively. The increases were primarily due to higher saltwater disposal expenses and higher lease operating expenses (LOE). The increase in LOE was mitigated in part by lower gross production tax resulting from lower oil and NGLs prices (not under derivative contracts) and from credits received.

For 2014, we had derivative contracts on approximately 69% of our average daily oil production and approximately 56% of our average natural gas production. These derivatives were intended to help manage our cash flow and capital expenditure requirements.

We have a derivative contract on 1,000 Bbls per day of oil production for 2015. We have derivative contracts on 70,000 Mmbtu per day of natural gas production in the first quarter 2015, 100,000 Mmbtu per day of natural gas production in the second quarter 2015, 70,000 Mmbtu per day of natural gas production, and 40,000 Mmbtu per day of natural gas production in the third and fourth quarters 2015, respectively. The contract for the oil production is a swap contract for 1,000 Bbls per day. The swap transaction was done at a comparable average NYMEX price of \$95.00. The contracts for the natural gas production in the first quarter are swaps covering 40,000 Mmbtu per day and collars for 30,000 Mmbtu per day. The first quarter swap transactions were done at a comparable average NYMEX price of \$3.98. The first quarter collar transactions were done at a

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comparable average NYMEX floor price of $4.20 and ceiling price of $5.03. The contracts for the natural gas production in the second quarter are swaps for 70,000 Mmbtu per day and collars for 30,000 Mmbtu per day. The second quarter swap transactions were done at a comparable average NYMEX price of $3.60. The second quarter collar transactions were done at a comparable average NYMEX floor price of $2.92 and ceiling price of $3.26. The contracts for the natural gas production in the third quarter are swaps for 40,000 Mmbtu per day and collars for 30,000 Mmbtu per day. The third quarter swap transactions were done at a comparable average NYMEX price of $3.98. The third quarter collar transactions were done at a comparable average NYMEX floor price of $2.58 and ceiling price of $3.04. The contracts for the natural gas production in the fourth quarter are swaps for 40,000 Mmbtu per day. The fourth quarter swap transactions were done at a comparable average NYMEX price of $3.98.

During 2014, we participated in the drilling of 186 wells (121.00 net wells). For 2015, we plan to participate in the drilling of approximately 70 wells. Our 2015 production guidance is approximately 18.6 to 19.0 MMBoe, an increase of 2% to 4% over 2014, although actual results will continue to be subject to many factors. This segment’s capital budget for 2015 is $308.5 million, a 60% decrease from 2014, excluding acquisitions and ARO liability.

Contract Drilling

The average number of drilling rigs we operated for 2014 was 75.4 compared to 65.0 in 2013. Late in the fourth quarter of 2014, the number of our drilling rigs operating started to decline and has continued to decline and at February 13, 2015, we had 50 drilling rigs operating. We anticipate further reductions through the first quarter of 2015 and potentially for subsequent quarters.

Dayrates for the fourth quarter of 2014 averaged $20,488, a 2% and 4% increase over the third quarter of 2014 and the fourth quarter of 2013, respectively. The increases were primarily due to the higher rates for the new BOSS rigs that went into service.

Direct profit (contract drilling revenue less contract drilling operating expense) for the fourth quarter of 2014 increased 6% and 33% over the third quarter of 2014 and the fourth quarter of 2013, respectively. For both comparative periods, we had more drilling rigs operating with higher dayrates.

Operating cost per day for the fourth quarter of 2014 increased 14% over the third quarter of 2014 and 7% over the fourth quarter of 2013. The increases were primarily due to increases in direct expense for both comparative periods and indirect rig expenses and workers' compensation related costs in the fourth quarter of 2014 versus the third quarter of 2013.

Almost all of our working drilling rigs in 2014 have been drilling horizontal or directional wells. With the recent low commodity prices, our customers have drastically reduced their drilling budgets. As a result, we are experiencing reduced rig utilization. Commodity prices in the various basins in which we operate ultimately affect the demand and mix of the type of drilling rigs used by our customers. Unit’s rig fleet is comprised of rigs capable to meet our customers’ demands whether it be for oil, natural gas, or NGLs and whether it be for shallow, deep, vertical, or horizontal type drilling. Current and future demand for drilling rigs will have an impact on dayrates. The future demand for and the availability of drilling rigs to meet that demand will have an impact on our future dayrates.

As of December 31, 2014, we had 30 term drilling contracts with original terms ranging from six months to three years. Twenty-six of these contracts are up for renewal in 2015, (ten in the first quarter, eight in the second quarter, seven in the third quarter, and one in the fourth quarter) and four are up for renewal in 2016. Term contracts may contain a fixed rate for the duration of the contract or provide for rate adjustments within a specific range from the existing rate. As of February 13, 2015, four expired and were not renewed and two of these term drilling contracts have been terminated early.

During the first quarter of 2014, four idle 3,000 horsepower drilling rigs were sold to an unaffiliated third party. The proceeds from the sale were used in our construction program for our new proprietary 1,500 horsepower, AC electric drilling rig, called the BOSS drilling rig. This new drilling rig design is positioning us to more effectively meet the demands of our existing customers as well as allowing us to compete for the work of new customers.

During 2014, three BOSS drilling rigs were constructed and placed into service for third-party operators.

In December 2014, we removed from service 31 drilling rigs, some older top drives, and certain drill pipe no longer marketable under the current environment. We estimated the fair value of the rigs and other assets based on the estimate market value from third-party assessments (Level 3 fair value measurement). Based on these estimates, we recorded a write-down of approximately $74.3 million pre-tax. This reduction to our fleet brought our total number of drilling rigs at year end to 89.

Five additional BOSS drilling rigs have been contracted to be built for third-party operators and will be placed into service in 2015, the first of which began operating in January 2015. Some of the long lead time components for three additional BOSS drilling rigs have also been ordered. Our anticipated 2015 capital expenditures for this segment are $99.7 million, a 44% decrease from 2014.

Mid-Stream

Fourth quarter 2014 liquids sold per day decreased 11% from the third quarter of 2014 and increased 5% over the fourth quarter of 2013. The decrease in liquids sold from the third quarter was due to operating in ethane rejection mode. The increase over prior year was due to increased purchased volume from connecting new wells to our systems. For the fourth quarter of 2014, gas processed per day decreased 3% from the third quarter of 2014 and increased 10% over the fourth quarter of 2013. The decrease from the third quarter was due to declining volumes on several systems. The increase over prior year was due to upgrading several of our existing processing facilities and adding processing plants along with connecting new wells. For the fourth quarter of 2014, gas gathered per day increased 2% over the third quarter of 2014 and increased 5% over the fourth quarter of 2013. These increases were primarily from well connects throughout 2014.

NGLs prices in the fourth quarter of 2014 decreased 24% and 36% from the prices received in the third quarter of 2014 and the fourth quarter of 2013, respectively. Because certain of the contracts used by our mid-stream segment for NGLs transactions are percent of proceeds (POP) contracts – under which we receive a share of the proceeds from the sale of the NGLs – our revenues from those POP contracts fluctuate based on NGLs prices.

Direct profit (mid-stream revenues less mid-stream operating expense) for the fourth quarter of 2014 decreased 25% from the third quarter of 2014 and decreased 18% from the fourth quarter of 2013. The decreases were primarily due to lower NGLs and condensate prices. Total operating cost for our this segment for the fourth quarter of 2014 decreased 13% from the third quarter of 2014 and decreased 4% from the fourth quarter of 2013 due primarily to the lower cost of gas purchased.

At our Hemphill County, Texas facility, we operate four processing plants with a total processing capacity of 135 MMcf per day. During the year we completed the construction of a nine-mile trunkline and related compression facilities allowing us to connect our Buffalo Wallow gathering system to our Hemphill processing facility.

At our Cashion facility located in central Oklahoma, our total processing capacity is currently 45 MMcf per day. During December 2014, we connected 33 new wells to this system.

At our Perkins facility, our total processing capacity has increased from 20 MMcf per day to 27 MMcf per day due to several projects that are being completed. These projects consist of processing plant upgrades along with projects to improve recoveries at this facility. We connected 33 new wells to this system in 2014.

In the Mississippian play in north central Oklahoma, we continue to add wells and increase volumes on our Bellmon facility. Sixty new wells were connected to this system during 2014. Our current processing capacity is approximately 90 MMcf per day.

In the Appalachian region, we continue to expand our Pittsburgh Mills gathering system. We are completing the construction of a project which extends our gathering system into Butler County, Pennsylvania. This project consists of a seven-mile trunkline along with related compressor station and provides us an additional outlet for our gas. This project is expected to be completed in the first quarter of 2015.

Also in the Appalachian area, we recently began construction of our Snow Show Gathering System, a new fee-based gathering system in Centre County, Pennsylvania. This system will consist of approximately seven miles of 16” and 24” pipeline and a related compressor station. All environmental and regulatory activities have been completed and we are in the process of clearing right of way. Construction of the pipeline and compressor station will begin in the second quarter of 2015 with an expected completion date in the third quarter of 2015.

Anticipated 2015 capital expenditures for this segment are $68.4 million, a 34% increase over 2014, excluding acquisitions and capital leases.

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Critical Accounting Policies and Estimates

Summary

In this section, we identify those critical accounting policies we follow in preparing our financial statements and related disclosures. Many of these policies require us to make difficult, subjective, and complex judgments in the course of making estimates of matters that are inherently imprecise. Some accounting policies involve judgments and uncertainties to such an extent that there is reasonable likelihood that materially different amounts could have been reported under different conditions, or if different assumptions had been used. We evaluate our estimates and assumptions on a regular basis. We base our estimates on historical experience and various other assumptions that we believe are reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities that are not readily apparent from other sources. Actual results may differ from these estimates and assumptions used in preparation of our financial statements. In the following discussion we will attempt to explain the nature of these estimates, assumptions and judgments, as well as the likelihood that materially different amounts would be reported in our financial statements under different conditions or using different assumptions.

The following table lists the critical accounting policies, identifies the estimates and assumptions that can have a significant impact on the application of these accounting policies, and the financial statement accounts that are affected by these estimates and assumptions.

Accounting Policies	Estimates or Assumptions	Accounts Affected
Full cost method of accounting for oil, NGLs, and natural gas properties	• Oil, NGLs, and natural gas reserves, estimates, and related present value of future net revenues • Valuation of unproved properties • Estimates of future development costs	• Oil and natural gas properties • Accumulated depletion, depreciation and amortization • Provision for depletion, depreciation and amortization • Impairment of oil and natural gas properties • Long-term debt and interest expense
Accounting for ARO for oil, NGLs, and natural gas properties	• Cost estimates related to the plugging and abandonment of wells • Timing of cost incurred	• Oil and natural gas properties • Accumulated depletion, depreciation and amortization • Provision for depletion, depreciation and amortization • Current and non-current liabilities • Operating expense
Accounting for impairment of long-lived assets	• Forecast of undiscounted estimated future net operating cash flows	• Drilling and mid-stream property and equipment • Accumulated depletion, depreciation and amortization • Provision for depletion, depreciation and amortization • Other intangible assets
Goodwill	• Forecast of discounted estimated future net operating cash flows • Terminal value	• Goodwill

	• Weighted average cost of capital	
Accounting for value of stock compensation awards	• Estimates of stock volatility • Estimates of expected life of awards granted • Estimates of rates of forfeitures	• Oil and natural gas properties • Shareholder's equity • Operating expenses • General and administrative expenses
Accounting for derivative instruments and hedging	• Hedges measured for effectiveness and ineffectiveness • Non-qualifying and qualifying derivatives measured at fair value	• Current and non-current derivative assets and liabilities • Other comprehensive income as a component of equity • Oil and natural gas revenue • Gain (loss) on derivatives not designated as hedges and hedge ineffectiveness, net

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Significant Estimates and Assumptions

Full Cost Method of Accounting for Oil, NGLs, and Natural Gas Properties. The determination of our oil, NGLs, and natural gas reserves is a subjective process. It entails estimating underground accumulations of oil, NGLs, and natural gas that cannot be measured in an exact manner. The degree of accuracy of these estimates depends on a number of factors, including, the quality and availability of geological and engineering data, the precision of the interpretations of that data, and individual judgments. Each year, we hire an independent petroleum engineering firm to audit our internal evaluation of our reserves. The audit of our reserve wells or locations as of December 31, 2014 covered those that we projected to comprise 85% of the total proved developed discounted future net income and 83% of the total proved undeveloped discounted future net income based on the unescalated pricing policy of the SEC. Included in Part I, Item 1 of this report are the qualifications of our independent petroleum engineering firm and our employees responsible for the preparation of our reserve reports.

As a general rule, the accuracy of estimating oil, NGLs, and natural gas reserves varies with the reserve classification and the related accumulation of available data, as shown in the following table:

Type of Reserves	Nature of Available Data	Degree of Accuracy
Proved undeveloped	Data from offsetting wells, seismic data	Less accurate
Proved developed non-producing	The above as well as logs, core samples, well tests, pressure data	More accurate
Proved developed producing	The above as well as production history, pressure data over time	Most accurate

Assumptions of future oil, NGLs, and natural gas prices and operating and capital costs also play a significant role in estimating these reserves as well as the estimated present value of the cash flows to be received from the future production of those reserves. Volumes of recoverable reserves are influenced by the assumed prices and costs due to the economic limit (that point when the projected costs and expenses of producing recoverable oil, NGLs, and natural gas reserves is greater than the projected revenues from the oil, NGLs, and natural gas reserves). But more significantly, the estimated present value of the future cash flows from our oil, NGLs, and natural gas reserves is sensitive to prices and costs, and may vary materially based on different assumptions. Companies, like ours, using full cost accounting use the unweighted arithmetic average of the commodity prices existing on the first day of each of the 12 months before the end of the reporting period to calculate discounted future revenues, unless prices were otherwise determined under contractual arrangements.

We compute DD&A on a units-of-production method. Each quarter, we use the following formulas to compute the provision for DD&A for our producing properties:

- DD&A Rate = Unamortized Cost / End of Period Reserves Adjusted for Current Period Production
- Provision for DD&A = DD&A Rate x Current Period Production

Oil, NGLs, and natural gas reserve estimates have a significant impact on our DD&A rate. If future reserve estimates for a property or group of properties are revised downward, the DD&A rate will increase as a result of the revision. Alternatively, if reserve estimates are revised upward, the DD&A rate will decrease. Based on our 2014 production level of 18.3 MMBoe, a decrease in the amount of our 2014 oil, NGLs, and natural gas reserves by 5% would increase our DD&A rate by $0.78 per Boe and would decrease pre-tax income by $14.3 million annually. Conversely, an increase in our 2014 oil, NGLs, and natural gas reserves by 5% would decrease our DD&A rate by $0.72 per Boe and would increase pre-tax income by $13.2 million annually.

The DD&A expense on our oil and natural gas properties is calculated each quarter using period end reserve quantities adjusted for current period production.

We account for our oil and natural gas exploration and development activities using the full cost method of accounting. Under this method, we capitalize all costs incurred in the acquisition, exploration, and development of oil and natural gas properties. At the end of each quarter, the net capitalized costs of our oil and natural gas properties are limited to that amount which is the lower of unamortized costs or a ceiling. The ceiling is defined as the sum of the present value (using a 10% discount rate) of the estimated future net revenues from our proved reserves (based on the unescalated 12-month average price on our oil, NGLs, and natural gas adjusted for any cash flow hedges), plus the cost of properties not being amortized, plus the

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lower of the cost or estimated fair value of unproved properties included in the costs being amortized, less related income taxes. If the net capitalized costs of our oil and natural gas properties exceed the ceiling, we are required to write-down the excess amount. A ceiling test write-down is a non-cash charge to earnings. If required, it reduces earnings and impacts shareholders' equity in the period of occurrence and results in lower DD&A expense in future periods. Once incurred, a write-down cannot be reversed.

The risk that we will be required to write-down the carrying value of our oil and natural gas properties increases when the prices for oil, NGLs, and natural gas are depressed or if we have large downward revisions in our estimated proved oil, NGLs, and natural gas reserves. Application of these rules during periods of relatively low prices, even if temporary, increases the chance of a ceiling test write-down. Based on applying 12-month 2014 average unescalated prices of $94.99 per barrel of oil, $45.25 per barrel of NGLs, and $4.36 per Mcf of natural gas (then adjusted for price differentials) over the estimated life of each of our oil and natural gas properties, the unamortized cost of our oil and natural gas properties exceeded the ceiling of our proved oil, NGLs, and natural gas reserves in the fourth quarter of 2014. We incurred a non-cash ceiling test write-down of our oil and natural gas properties of $76.7 million pre-tax ($47.7 million net of tax) due to the inclusion of the impaired value of certain unproved properties and a reduction of the 12-month average commodity prices during the quarter. Subsequent to December 31, 2014, commodity prices have continued to decrease below December 31, 2014 levels. We anticipate that these reduced prices will require an additional write-down of the carrying value of our oil and natural gas properties for the quarter ending March 31, 2015 and potentially for subsequent quarters.

Derivative instruments qualifying as cash flow hedges are included in the computation of limitation on capitalized costs. All of our cash flow hedges expired as of December 31, 2013 and no longer effect this computation. Our oil and natural gas derivatives are discussed in Note 13 of the Notes to our Consolidated Financial Statements.

We use the sales method for recording natural gas sales. This method allows for the recognition of revenue, which may be more or less than our share of pro-rata production from certain wells. Our policy is to expense our pro-rata share of lease operating costs from all wells as incurred. The expenses relating to the wells in which we have a production imbalance are not material.

Costs Withheld from Amortization. Costs associated with unproved properties are excluded from our amortization base until we have evaluated the properties. The costs associated with unevaluated leasehold acreage and related seismic data, wells currently drilling and capitalized interest are initially excluded from our amortization base. Leasehold costs are either transferred to our amortization base with the costs of drilling a well on the lease or are assessed at least annually for possible impairment or reduction in value. Leasehold costs are transferred to our amortization base to the extent a reduction in value has occurred.

Our decision to withhold costs from amortization and the timing of the transfer of those costs into the amortization base involve a significant amount of judgment and may be subject to changes over time based on several factors, including our drilling plans, availability of capital, project economics and results of drilling on adjacent acreage. In December 2014, we determined the value of certain unproved oil and gas properties were diminished (in part or in whole) based on an impairment evaluation and our anticipated future exploration plans. That determination resulted in $73.7 million of costs associated with the unproved properties being added to the capitalized costs to be amortized. We incurred a non-cash ceiling test write-down. At December 31, 2014, we had a total of approximately $485.6 million of costs excluded from the amortization base of our full cost pool.

Accounting for ARO for Oil, NGLs, and Natural Gas Properties. We record the fair value of liabilities associated with the retirement of assets having a long life. In our case, when the reserves in each of our oil or gas wells deplete or otherwise become uneconomical, we are required to incur costs to plug and abandon the wells. These costs are recorded in the period in which the liability is incurred (at the time the wells are drilled or acquired). We do not have any assets restricted for the purpose of settling these ARO liabilities. Our engineering staff uses historical experience to determine the estimated plugging costs taking into account the type of well (either oil or natural gas), the depth of the well and physical location of the well to determine the estimated plugging costs.

Accounting for Impairment of Long-Lived Assets. Drilling equipment, transportation equipment, gas gathering and processing systems, and other property and equipment are carried at cost less accumulated depreciation. Renewals and enhancements are capitalized while repairs and maintenance are expensed. We review the carrying amounts of long-lived assets for potential impairment annually, typically during the fourth quarter, or when events occur or changes in circumstances suggest that these carrying amounts may not be recoverable. Changes that could prompt such an assessment may include equipment obsolescence, changes in the market demand for a specific asset, changes in commodity prices, periods of relatively low rig utilization, declining revenue per day, declining cash margin per day, or overall changes in general market conditions. Assets are determined to be impaired if a forecast of undiscounted estimated future net operating cash flows directly related to the asset, including disposal value if any, is less than the carrying amount of the asset. If any asset is determined to be impaired, the loss is measured as the amount by which the carrying amount of the asset exceeds its fair value. The estimate of fair value is based on the best information available, including prices for similar assets. Changes in these estimates could cause us to reduce the carrying value of property and equipment. Asset impairment evaluations are, by nature, highly subjective. They involve expectations about future cash flows generated by our assets and reflect management's assumptions and judgments regarding future industry conditions and their effect on future utilization levels, dayrates, and costs. The use of different estimates and assumptions could result in materially different carrying values of our assets.

On a periodic basis, we evaluate our fleet of drilling rigs for marketability based on the condition of inactive rigs, expenditures that would be necessary to bring them to working condition and the expected demand for drilling services by rig type. The components comprising inactive rigs are evaluated, and those components with continuing utility to the Company's other marketed rigs are transferred to other rigs or to its yards to be used as spare equipment. The remaining components of these rigs are retired. In December 2014, we removed from service 31 drilling rigs, some older top drives, and certain drill pipe no longer marketable in the current environment. We estimated the fair value of the rigs and other assets based on the estimate market value from third-party assessments (Level 3 fair value measurement). Based on these estimates, we recorded a write-down of approximately $74.3 million pre-tax.

In December 2014, our mid-stream segment had a $7.1 million pre-tax write-down of three of its systems, Weatherford, Billy Rose, and Spring Creek due to anticipated future cash flow and future development around these systems supporting their carrying value. The estimated future cash flows were less than the carrying value on these systems (Level 3 fair value measurement). In December 2012, our mid-stream segment had a $1.2 million write-down of its Erick system. There was no volume from the wells connected to this system, the compressor and related surface equipment have been removed from this location and there is no future activity anticipated from this gathering system. No significant impairment was recorded at December 31, 2013.

Goodwill. Goodwill represents the excess of the cost of acquisitions over the fair value of the net assets acquired. Goodwill is not amortized, but an impairment test is performed at least annually to determine whether the fair value has decreased and is performed additionally when events indicate an impairment may have occurred. For purposes of impairment testing, goodwill is evaluated at the reporting unit level. Our goodwill is all related to our contract drilling segment, and accordingly, the impairment test is generally based on the estimated discounted future net cash flows of our drilling segment, utilizing discount rates and other factors in determining the fair value of our drilling segment. Inputs in our estimated discounted future net cash flows include rig utilization, day rates, gross margin percentages, and terminal value (these are all considered level 3 inputs). No goodwill impairment was recorded at December 31, 2014, 2013, or 2012.

Turnkey and Footage Drilling Contracts. Because our contract drilling operations do not bear the risk of completion of a well being drilled under a "daywork" contract, we recognize revenues and expense generated under "daywork" contracts as the services are performed. Under "footage" and "turnkey" contracts we bear the risk of completion of the well, so revenues and expenses are recognized when the well is substantially completed. Substantial completion is determined when the well bore reaches the depth specified in the contract. The entire amount of a loss, if any, is recorded when the loss can be reasonably determined, however, any profit is recorded only at the time the well is finished. The costs of drilling contracts uncompleted at the end of the reporting period (which includes expenses incurred to date on "footage" or "turnkey" contracts) are included in other current assets. We did not drill any wells under turnkey or footage contracts in 2014, 2013, or 2012.

Accounting for Value of Stock Compensation Awards. To account for stock-based compensation, compensation cost is measured at the grant date based on the fair value of an award and is recognized over the service period, which is usually the vesting period. We elected to use the modified prospective method, which requires compensation expense to be recorded for all unvested stock options and other equity-based compensation beginning in the first quarter of adoption. The determination of the fair value of an award requires significant estimates and subjective judgments regarding, among other things, the appropriate option pricing model, the expected life of the award and performance vesting criteria assumptions. As there are inherent uncertainties related to these factors and our judgment in applying them to the fair value determinations, there is risk that the recorded stock compensation may not accurately reflect the amount ultimately earned by the employee.

Accounting for Derivative Instruments and Hedging. For our economic hedges that we did not apply cash flow accounting to, any changes in their fair value occurring before their maturity (i.e., temporary fluctuations in value) are reported

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in gain (loss) on derivatives not designated as hedges and hedge ineffectiveness, net in our Consolidated Statements of Income. The commodity derivative instruments we had under cash flow accounting expired as of December 2013. Previous changes in the fair value of derivatives designated as cash flow hedges, to the extent they were effective in offsetting cash flows attributable to the hedged risk, were recorded in OCI until the hedged item was recognized into earnings. When the hedged item was recognized into earnings, it was reported in oil and natural gas revenues. Any change in fair value resulting from ineffectiveness was recognized in gain (loss) on derivatives not designated as hedges and hedge ineffectiveness, net.

New Accounting Standards

Presentation of Financial Statements-Going Concern: Disclosure of Uncertainties about an Entity's Ability to Continue as a Going Concern. The FASB has issued ASU 2014-15. This is intended to define management's responsibility to evaluate whether there is substantial doubt about an organization's ability to continue as a going concern and to provide related footnote disclosures. For each reporting period, management will be required to evaluate whether there are conditions or events that raise substantial doubt about a company's ability to continue as a going concern within one year from the date financial statements are issued. The amendments are effective for annual periods ending after December 15, 2016, and interim periods within annual periods beginning after December 15, 2016. Early application is permitted for annual or interim reporting periods for which the financial statements have not previously been issued.

Compensation - Stock Compensation: Accounting for Share-Based Payments When the Terms of an Award Provide that a Performance Target Could Be Achieved after the Requisite Service Period. The FASB has issued ASU 2014-12, the amendments in the ASU require that a performance target that affects vesting and that could be achieved after the requisite service period be treated as a performance condition. A reporting entity should apply existing guidance in Topic 718, Compensation – Stock Compensation, as it relates to awards with performance conditions that affect vesting to account for such awards. The performance target should not be reflected in estimating the grant-date fair value of the award. Compensation cost should be recognized in the period in which it becomes probable that the performance target will be achieved and should represent the compensation cost attributable to the period(s) for which the requisite service has already been rendered. If the performance target becomes probable of being achieved before the end of the requisite service period, the remaining unrecognized compensation cost should be recognized prospectively over the remaining requisite service period. The total amount of compensation cost recognized during and after the requisite service period should reflect the number of awards that are expected to vest and should be adjusted to reflect those awards that ultimately vest. The requisite service period ends when the employee can cease rendering service and still be eligible to vest in the award if the performance target is achieved.The amendments in this ASU are effective for annual periods and interim periods within those annual periods beginning after December 15, 2015. Earlier adoption is permitted. We do not have any stock compensation awards with these conditions at this time.

Revenue from Contracts with Customers. The FASB has issued ASU 2014-09. This affects any entity using U.S. GAAP that either enters into contracts with customers to transfer goods or services or enters into contracts for the transfer of nonfinancial assets unless those contracts are within the scope of other standards (e.g., insurance contracts or lease contracts). The core principle of the guidance is that an entity should recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. The amendments in this ASU are effective for annual reporting periods beginning after December 15, 2016, including interim periods within that reporting period. Early application is not permitted. We are in the process of evaluating the impact it will have on our financial statements.

Presentation of Financial Statements and Property, Plant, and Equipment: Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity. The FASB has issued ASU 2014-08, the amendments in this update change the criteria for reporting discontinued operations while enhancing disclosures in this area. It also addresses sources of confusion and inconsistent application related to financial reporting of discontinued operations guidance in U.S. GAAP. Under the new guidance, only disposals representing a strategic shift that would have a major effect on the organization's operations and financial results should be presented as discontinued operations. In addition, it requires expanded disclosures about discontinued operations that will provide financial statement users with more information about the assets, liabilities, income, and expenses of discontinued operations. It also requires disclosure of pre-tax income attributable to a disposal of a significant part of an organization that does not qualify for discontinued operations reporting. The updates are effective for fiscal years, and interim periods within those years, beginning after December 15, 2014. Early adoption is permitted. We currently do not have any discontinued operations or disposals of components of an entity.

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Financial Condition and Liquidity

Summary.

Our financial condition and liquidity primarily depends on the cash flow from our operations and borrowings under our credit agreement. The principal factors determining the amount of our cash flow are:

- the quantity of natural gas, oil, and NGLs we produce;
- the prices we receive for our natural gas, oil, and NGLs production;
- the demand for and the dayrates we receive for our drilling rigs; and
- the fees and margins we obtain from our natural gas gathering and processing contracts.

We currently believe we have sufficient cash flow and liquidity to meet our obligations for the next twelve months. Our ability to meet our debt covenants (under our credit agreement as well as our Indenture) and our capacity to incur additional indebtedness will depend on our future performance, which in turn will be affected by financial, business, economic, regulatory, and other factors. For example, lower oil, natural gas, and NGLs prices could result in a redetermination of the borrowing base under our credit agreement to a lower level and therefore reduce or limit our ability to incur indebtedness. As a result, we monitor our liquidity and capital resources, endeavor to anticipate potential covenant compliance issues and work with the lenders under our credit agreement to address those issues, if any, ahead of time.

As part of our plan to manage liquidity risks, we have lowered our capital expenditures budget, focused our drilling program on our highest return plays, and continue to explore opportunities to divest non-core assets and properties.

The following is a summary of certain financial information for the years ended December 31:

	2014	2013	2012
	(In thousands)		
Net cash provided by operating activities	$708,993	$674,331	$690,911
Net cash used in investing activities	(920,597)	(579,180)	(1,079,042)
Net cash provided by (used in) financing activities	194,060	(77,532)	388,270
Net increase (decrease) in cash and cash equivalents	$(17,544)	$17,619	$139

Cash flows from Operating Activities

Our operating cash flow is primarily influenced by the prices we receive for our oil, NGLs, and natural gas production, the quantity of oil, NGL, and natural gas we produce, settlements of derivative contracts, third-party demand for our drilling rigs and mid-stream services, and the rates we are able to charge for those services. Our cash flows from operating activities are also impacted by changes in working capital.

Net cash provided by operating activities during 2014 increased by $34.7 million over 2013 due primarily to adjustments for depreciation and impairment and to a lesser extent from changes in operating assets and liabilities related to the timing of cash receipts and disbursements offset partially by lower net income and adjustments for gains on derivatives.

Cash flows from Investing Activities

We dedicate and expect to continue to dedicate a substantial portion of our capital expenditure program toward the exploration for and production of oil, NGLs, and natural gas. Theses capital expenditures are necessary to offset inherent declines in production, which is typical in the capital-intensive oil and natural gas industry.

Cash flows used in investing activities increased by $341.4 million in 2014 compared to 2013. The change was due primarily to an increase in capital expenditures partially offset by the proceeds received from the disposition of assets. See additional information on capital expenditures below under Capital Requirements.

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Cash Flows from Financing Activities

Cash flows provided by financing activities increased by $271.6 million in 2014 compared to 2013. This increase was primarily due to our borrowings under our credit agreement as well as an increase in our book overdrafts (which are checks that have been issued but not presented to our bank for payment before the end of the period).

At December 31, 2014, we had unrestricted cash totaling $1.0 million and had borrowed $166.0 million of the $500.0 million we currently have available under our credit agreement. Our credit agreement is used primarily for working capital and capital expenditures.

The following is a summary of certain financial information as of December 31, and for the years ended December 31:

	2014	2013	2012
	(In thousands except percentages)		
Working capital	$(51,680)	$(31,542)	$(11,495)
Long-term debt (1)	$812,163	$645,696	$716,359
Shareholders’ equity	$2,332,394 (2)	$2,173,392	$1,974,301 (2)
Ratio of long-term debt to total capitalization	26% (2)	23%	27% (2)
Net income	$136,276 (2)	$184,746	$23,176 (2)

(1) Long-term debt is net of unamortized discount.

(2) In 2014 and 2012, we incurred non-cash ceiling test write-downs of our oil and natural gas properties of $76.7 million and $283.6 million pre-tax ($47.7 million and $176.5 million, net of tax), respectively. Also in December 2014, we incurred a non-cash write-down associated with the removal of 31 drilling rigs from our fleet along with certain other equipment and drill pipe of $74.3 million pre-tax ($46.3 million net of tax) and a non-cash write-down associated with a reduction in the carrying value of three midstream segment systems of $7.1 million pre-tax ($4.4 million net of tax). The write-downs impacted our shareholders’ equity, ratio of long-term debt to total capitalization, and net income for years 2014 and 2012. There was no impact on our compliance with the covenants contained in our credit agreement.

The following table summarizes certain operating information for the years ended December 31:

	2014	2013	2012
Oil and Natural Gas:			
Oil production (MBbls)	3,844	3,360	3,279
Natural gas liquids production (MBbls)	4,628	3,914	2,796
Natural gas production (MMcf)	58,854	56,757	48,930
Average oil price per barrel received	$89.43	$95.06	$92.60
Average oil price per barrel received excluding derivatives	$89.32	$95.18	$90.19
Average NGLs price per barrel received	$30.95	$31.79	$31.58
Average NGLs price per barrel received excluding derivatives	$30.95	$31.79	$30.70
Average natural gas price per mcf received	$3.92	$3.32	$3.37
Average natural gas price per mcf received excluding derivatives	$4.03	$3.33	$2.53
Contract Drilling:			
Average number of our drilling rigs in use during the period	75.4	65.0	73.9
Total number of drilling rigs available for use at the end of the period	89	121	127
Average dayrate	$20,043	$19,646	$19,949
Mid-Stream:			
Gas gathered—Mcf/day	319,348	309,554	250,290
Gas processed—Mcf/day	161,282	140,584	133,987
Gas liquids sold—gallons/day	733,406	543,602	542,578

Number of natural gas gathering systems	38	38	39
Number of processing plants	14	15	14

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Working Capital

Typically, our working capital balance fluctuates, in part, because of the timing of our trade accounts receivable and accounts payable and the fluctuation in current assets and liabilities associated with the mark to market value of our derivative activity. We had negative working capital of $51.7 million, $31.5 million, and $11.5 million as of December 31, 2014, 2013, and 2012, respectively. This is primarily from the timing of our accounts payable associated with our capital expenditures. Our credit agreement is used primarily for working capital and capital expenditures. At December 31, 2014, we had borrowed $166.0 million of the $500.0 million currently available to us under our credit agreement. The effect of our derivatives increased working capital by $31.1 million as of December 31, 2014, and decreased working capital by $5.0 million as of December 31, 2013, and increased working capital by $9.6 million as of December 31, 2012.

Oil and Natural Gas Operations

Any significant change in oil, NGLs, or natural gas prices has a material effect on our revenues, cash flow, and the value of our oil, NGLs, and natural gas reserves. Generally, prices and demand for domestic natural gas are influenced by weather conditions, supply imbalances, and by worldwide oil price levels. Domestic oil prices are primarily influenced by world oil market developments. All of these factors are beyond our control and we cannot predict nor measure their future influence on the prices we will receive.

Based on our 2014 production, a $0.10 per Mcf change in what we are paid for our natural gas production, without the effect of derivatives, would result in a corresponding $466,000 per month ($5.6 million annualized) change in our pre-tax operating cash flow. Our 2014 average natural gas price was $3.92 compared to an average natural gas price of $3.32 for 2013 and $3.37 for 2012. A $1.00 per barrel change in our oil price, without the effect of derivatives, would have a $308,000 per month ($3.7 million annualized) change in our pre-tax operating cash flow and a $1.00 per barrel change in our NGLs prices, without the effect of derivatives, would have a $368,000 per month ($4.4 million annualized) change in our pre-tax operating cash flow based on our production in 2014. Our 2014 average oil price per barrel was $89.43 compared with an average oil price of $95.06 in 2013 and $92.60 in 2012, and our 2014 average NGLs price per barrel was $30.95 compared with an average NGLs price of $31.79 in 2013 and $31.58 in 2012.

Because commodity prices have an effect on the value of our oil, NGLs, and natural gas reserves, declines in those prices can result in a decline in the carrying value of our oil and natural gas properties. Price declines can also adversely affect the semi-annual determination of the amount available for us to borrow under our credit agreement since that determination is based mainly on the value of our oil, NGLs, and natural gas reserves. A reduction could limit our ability to carry out our planned capital projects. Subsequent to December 31, 2014, commodity prices have continued to decrease and should commodity prices remain below December 31, 2014 levels, we anticipate an additional write-down of the carrying value of our oil and natural gas properties will be required for the quarter ending March 31, 2015 and potentially for subsequent quarters.

Our natural gas production is sold to intrastate and interstate pipelines, to independent marketing firms and gatherers under contracts with terms generally ranging anywhere from one month to five years. Our oil production is sold to independent marketing firms generally under six month contracts.

Contract Drilling Operations

Many factors influence the number of drilling rigs we are working at any given time as well as the costs and revenues associated with that work. These factors include the demand for drilling rigs in our areas of operation, competition from other drilling contractors, the prevailing prices for oil, NGLs, and natural gas, availability and cost of labor to run our drilling rigs, and our ability to supply the equipment needed. Several of our drilling rig customers have significantly reduced their drilling budgets for 2015, resulting in a significant reduction in the utilization of our drilling rig fleet. At December 31, 2014, we had 75 rigs operating, and at February 13, 2015, this number has been reduced to 50 rigs operating. We currently expect further reductions into 2015.

We increased compensation for rig personnel in our Oklahoma, Texas, Louisiana, and Kansas operations during the third quarter of 2014 to remain competitive in attracting and retaining rig crew personnel in a growing drilling market. Now that the market conditions have changed and our rig utilization has decreased dramatically, we do not anticipate any further increases.

Almost all of our working drilling rigs in 2014 have been drilling horizontal or directional wells. With the recent low commodity prices, our customers have drastically reduced their drilling budgets. As a result, we are experiencing reduced rig

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utilization. Commodity prices in the various basins in which we operate ultimately affect the demand and mix of the type of drilling rigs used by our customers. Unit’s rig fleet is comprised of rigs capable to meet our customers’ demands whether it be for oil, natural gas, or NGLs and whether it be for shallow, deep, vertical, or horizontal type drilling. Current and future demand for drilling rigs will have an impact on dayrates. The future demand for and the availability of drilling rigs to meet that demand will have an impact on our future dayrates. For 2014, our average dayrate was $20,043 per day compared to $19,646 and $19,949 per day for 2013 and 2012, respectively. Our average number of drilling rigs used in 2014 was 75.4 (63%) compared with 65.0 (52%) and 73.9 (58%) in 2013 and 2012, respectively. Based on the average utilization of our drilling rigs during 2014, a $100 per day change in dayrates has a $7,500 per day ($2.8 million annualized) change in our pre-tax operating cash flow.

Our contract drilling segment provides drilling services for our exploration and production segment. Some of the drilling services we perform on our properties are, depending on the timing of those services, deemed to be associated with the acquisition of an ownership interest in the property. In those cases, revenues and expenses for those services are eliminated in our income statement, with any profit recognized as a reduction in our investment in our oil and natural gas properties. The contracts for these services are issued under the same conditions and rates as the contracts entered into with unrelated third parties. We eliminated revenue of $89.5 million, $64.3 million, and $49.6 million for 2014, 2013, and 2012, respectively, from our contract drilling segment and eliminated the associated operating expense of $62.4 million, $46.9 million, and $34.1 million during 2014, 2013, and 2012, respectively, yielding $27.1 million, $17.4 million, and $15.5 million during 2014, 2013, and 2012, respectively, as a reduction to the carrying value of our oil and natural gas properties.

Mid-Stream Operations

This segment is engaged primarily in the buying, selling, gathering, processing, and treating of natural gas. It operates three natural gas treatment plants, 14 processing plants, 38 gathering systems, and approximately 1,525 miles of pipeline. Its operations are located in Oklahoma, Texas, Kansas, Pennsylvania, and West Virginia. This segment enhances our ability to gather and market not only our own natural gas and NGLs but also that owned by third parties and serves as a mechanism through which we can construct or acquire existing natural gas gathering and processing facilities. During 2014, 2013, and 2012 this segment purchased $80.9 million, $83.0 million, and $68.2 million, respectively, of our oil and natural gas segment's natural gas and NGLs production, and provided gathering and transportation services of $8.7 million, $8.0 million, and $5.1 million, respectively. Intercompany revenue from services and purchases of production between this business segment and our oil and natural gas segment has been eliminated in our consolidated financial statements.

Our mid-stream segment gathered an average of 319,348 Mcf per day in 2014 compared to 309,554 Mcf per day in 2013 and 250,290 Mcf per day in 2012. It processed an average of 161,282 Mcf per day in 2014 compared to 140,584 Mcf per day in 2013 and 133,987 Mcf per day in 2012, and sold NGLs of 733,406 gallons per day in 2014 compared to 543,602 gallons per day in 2013 and 542,578 gallons per day in 2012. Gas gathering volumes per day in 2014 increased primarily from new wells connected to our systems throughout 2014 along with the addition of new systems and the expansion of existing systems. Volumes processed and NGLs sold both increased primarily due to the addition of new wells connected, recent upgrades to several existing processing facilities, and the addition of new processing facilities.

Due to the decline in NGLs prices during 2014, in the second half of the year we operated our processing facilities in full ethane rejection mode which reduced the amount of liquids sold during this time period. As long as NGLs prices continue at or below these levels,we expect to continue operating in full ethane rejection mode. Our mid-stream segment did not experience a significant reduction in processed volumes in 2014 but as low prices continue we expect further reductions in drilling activity around our systems which will eventually effect our ability to connect new wells resulting in lower processed volumes in the future.

Our Credit Agreement and Senior Subordinated Notes

Credit Agreement. Under our Senior Credit Agreement (credit agreement), the amount we can borrow is the lesser of the amount we elect (from time to time) as the commitment amount or the value of the borrowing base as determined by the lenders, but in either event not to exceed the maximum credit agreement amount of $900.0 million. Our current commitment amount is $500.0 million. Our current borrowing base is $900.0 million. We are charged a commitment fee ranging from 0.375 to 0.50 of 1% on the amount available but not borrowed. The fee varies based on the amount borrowed as a percentage of the amount of the total borrowing base. The credit agreement matures as of September 13, 2016. In connection with the most recent amendment of the credit agreement, we paid $1.5 million in origination, agency, syndication, and other related fees. We are amortizing these fees over the life of the credit agreement.

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The current lenders under our credit agreement and their respective participation interests are as follows:

Lender	Participation Interest	
BOK (BOKF, NA, dba Bank of Oklahoma)	17	%
BBVA Compass Bank	17	%
Bank of Montreal	15	%
Bank of America, N.A.	15	%
Comerica Bank	8	%
Crédit Agricole Corporate and Investment Bank, London Branch	8	%
Wells Fargo Bank, National Association	8	%
Canadian Imperial Bank of Commerce	8	%
The Bank of Nova Scotia	4	%
	100	%

The amount of the borrowing base–which is subject to redetermination by the lenders on April 1st and October 1st of each year, is based primarily on a percentage of the discounted future value of our oil and natural gas reserves. There was no change to the borrowing base with the October 2014 redetermination. With the recent decline in commodity prices, we anticipate our lenders may reduce our borrowing base at the next scheduled redetermination. We do not anticipate any reduction at the next borrowing base redetermination will result in the borrowing base being below our current elected commitment amount of $500.0 million. We or the lenders may request a onetime special redetermination of the borrowing base between each scheduled redetermination. In addition, we may request a redetermination following the completion of an acquisition that meets the requirements set forth in the credit agreement.

At our election, any part of the outstanding debt under the credit agreement may be fixed at a London Interbank Offered Rate (LIBOR). LIBOR interest is computed as the sum of the LIBOR base for the applicable term plus 1.75% to 2.50% depending on the level of debt as a percentage of the borrowing base and is payable at the end of each term, or every 90 days, whichever is less. Borrowings not under LIBOR bear interest at the prime rate specified in the credit agreement that in any event cannot be less than LIBOR plus 1.00%. Interest is payable at the end of each month and the principal may be repaid in whole or in part at anytime, without a premium or penalty. At December 31, 2014 and February 13, 2015, we had $166.0 million and $201.5 million, respectively, outstanding borrowings under our credit agreement.

We can use borrowings for financing general working capital requirements for (a) exploration, development, production and acquisition of oil and gas properties, (b) acquisitions and operation of mid-stream assets, (c) issuance of standby letters of credit, (d) contract drilling services, and (e) general corporate purposes.

The credit agreement prohibits, among other things:

- the payment of dividends (other than stock dividends) during any fiscal year in excess of 30% of our consolidated net income for the preceding fiscal year;
- the incurrence of additional debt with certain limited exceptions; and
- the creation or existence of mortgages or liens, other than those in the ordinary course of business, on any of our properties, except in favor of our lenders.

The credit agreement also requires that we have at the end of each quarter:

- a current ratio (as defined in the credit agreement) of not less than 1 to 1; and
- a leverage ratio of funded debt to consolidated EBITDA (as defined in the credit agreement) for the most recently ended rolling four fiscal quarters of no greater than 4 to 1.

As of December 31, 2014, we were in compliance with the covenants contained in the credit agreement.

6.625% Senior Subordinated Notes. We have issued and outstanding an aggregate principal amount of $650.0 million, 6.625% senior subordinated notes (the Notes). The interest is payable semi-annually (in arrears) on May 15 and November 15 of each year, and the Notes will mature on May 15, 2021. In connection with the issuance of the Notes, we incurred $14.7 million of fees that are being amortized as debt issuance cost over the life of the Notes.

The Notes are subject to an Indenture dated as of May 18, 2011, between us and Wilmington Trust, National Association (successor to Wilmington Trust FSB), as Trustee (the Trustee), as supplemented by the First Supplemental Indenture dated as of May 18, 2011, between us, the Guarantors, and the Trustee, and as further supplemented by that the Second Supplemental Indenture dated as of January 7, 2013, between us, the Guarantors and the Trustee (as supplemented, the 2011 Indenture), establishing the terms and providing for the issuance of the Notes. The Guarantors are all of our direct and indirect subsidiaries. The discussion of the Notes in this report is qualified by and subject to the actual terms of the 2011 Indenture.

Unit, as the parent company, has no independent assets or operations. The guarantees by the Guarantors of the Notes (registered under registration statements) are full and unconditional, joint and several, subject to certain automatic customary releases, are subject to certain restrictions on the sale, disposition, or transfer of the capital stock or substantially all of the assets of a subsidiary guarantor, and other conditions and terms set out in the Indenture. Any of our subsidiaries that are not Guarantors are minor. There are no significant restrictions on our ability to receive funds from our subsidiaries through dividends, loans, advances or otherwise.

At any time before May 15, 2016, we may redeem the Notes, in whole or in part, at a redemption price equal to 100% of the principal amount plus a “make whole” premium, plus accrued and unpaid interest, if any, to the redemption date. On and after May 15, 2016, we may redeem all or, from time to time, a part of the Notes at certain redemption prices, plus accrued and unpaid interest. If a “change of control” occurs, subject to certain conditions, we must offer to repurchase from each holder all or any part of that holder’s Notes at a purchase price in cash equal to 101% of the principal amount of the Notes plus accrued and unpaid interest, if any, to the date of purchase. The 2011 Indenture contains customary events of default. The 2011 Indenture also contains covenants that, among other things, limit our ability and the ability of certain of our subsidiaries to incur or guarantee additional indebtedness; pay dividends on our capital stock or redeem capital stock or subordinated indebtedness; transfer or sell assets; make investments; incur liens; enter into transactions with our affiliates; and merge or consolidate with other companies. We were in compliance with all covenants of the Notes as of December 31, 2014.

Capital Requirements

Oil and Natural Gas Dispositions, Acquisitions, and Capital Expenditures. Most of our capital expenditures for this segment are discretionary and directed toward future growth. Any decision to increase our oil, NGLs, and natural gas reserves through acquisitions or through drilling depends on the prevailing or expected market conditions, potential return on investment, future drilling potential, and opportunities to obtain financing under the circumstances involved, all of which provide us with a large degree of flexibility in deciding when and if to incur these costs. We completed drilling 186 gross wells (121.0 net wells) in 2014 compared to 149 gross wells (91.14 net wells) in 2013, and 171 gross wells (80.08 net wells) in 2012. Our 2014 total capital expenditures for our oil and natural gas segment, excluding a $37.7 million reduction in the ARO liability and $5.7 million in acquisitions, totaled $772.2 million compared to 2013 capital expenditures of $549.2 million (excluding a $18.0 million ARO liability), and 2012 capital expenditures of $521.2 million (excluding a $45.1 million ARO liability and $579.0 million for acquisitions).

For all of 2015, we plan to participate in drilling approximately 70 wells and estimate our total capital expenditures (excluding any possible acquisitions) for our oil and natural gas segment will be approximately $308.5 million. Whether we are able to drill all of those wells is dependent on a number of factors, many of which are beyond our control and include the availability of drilling rigs, availability of pressure pumping services, prices for oil, NGLs, and natural gas, demand for oil, NGLs, and natural gas, the cost to drill wells, the weather, and the efforts of outside industry partners.

On September 17, 2012, we closed on the acquisition of certain oil and natural gas assets from Noble Energy, Inc. (Noble). After final closing adjustments, the acquisition included approximately 83,000 net acres primarily in the Granite Wash, Cleveland, and various other plays in western Oklahoma and the Texas Panhandle. The adjusted amount paid was $592.6 million.

Also in September 2012, we sold our interest in certain Bakken properties. The proceeds, net of related expenses were $226.6 million. In addition, we sold certain oil and natural gas assets located in Brazos and Madison Counties, Texas, for approximately $44.1 million. In August 2013, we sold additional Bakken property interests. The proceeds, net of related

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expenses, were $57.1 million. In addition, we had other non-core asset sales with proceeds, net of related expenses, of $21.7 million for 2013. Proceeds from these dispositions reduced the net book value of the full cost pool with no gain or loss recognized. We sold non-core oil and natural gas assets, net of related expenses, for $33.1 million during 2014. Proceeds from those dispositions reduced the net book value of our full cost pool with no gain or loss recognized.

Contract Drilling Dispositions, Acquisitions, and Capital Expenditures. During 2012, we placed two new build 1,500 horsepower, diesel-electric drilling rigs into service, one in Wyoming and one in North Dakota.

Also during 2012, we sold an idle 600 horsepower mechanical drilling rig to an unaffiliated third party and had a fire on one of our drilling rigs located in the mid-continent region. The net book value of the damaged equipment was $3.2 million. All of the net book value of the damaged equipment was recovered from insurance proceeds. No personnel were injured in this incident.

During 2013, we sold four of our 2,000 horsepower electric drilling rigs and one 3,000 horsepower electric drilling rigs. All of these sales were to unaffiliated third parties.

During the first quarter of 2014. we sold four additional idle 3,000 horsepower drilling rigs to an unaffiliated third party. The proceeds from that sale were used in our construction program for our new proprietary 1,500 horsepower, AC electric drilling rig, called the BOSS drilling rig.

During 2014, three BOSS drilling rigs were constructed and placed into service for third-party operators. In December 2014, we removed from service 31 drilling rigs, some older top drives, and certain drill pipe no longer marketable in the current environment. We estimated the fair value of the rigs and other assets based on the estimate market value from third-party assessments (Level 3 fair value measurement). Based on these estimates, we recorded a write-down of approximately $74.3 million, pre-tax. This reduction to our fleet brought our total number of drilling rigs at year end to 89.

Five additional BOSS drilling rigs have been contracted to be built for third-party operators and will be placed into service in 2015, the first of which began operating in January 2015. The long lead time components for three additional BOSS drilling rigs have also been ordered.

Our anticipated 2015 capital expenditures for this segment are $99.7 million. We have spent $176.7 million for capital expenditures during 2014 compared to $64.3 million in 2013, and $77.5 million in 2012.

Mid-Stream Dispositions, Acquisitions, and Capital Expenditures. At our Hemphill County, Texas facility, we operate four processing plants with a total processing capacity of 135 MMcf per day. During the year we completed the construction of a nine-mile trunkline and related compression facilities allowing us to connect our Buffalo Wallow gathering system to our Hemphill processing facility.

At our Cashion facility located in central Oklahoma, our total processing capacity is currently 45 MMcf per day. During December 2014, we connected 33 new wells to this system.

At our Perkins facility, our total processing capacity has increased from 20 MMcf per day to 27 MMcf per day due to several projects that are being completed. These projects consist of processing plant upgrades along with projects to improve recoveries at this facility. We connected 33 new wells to this system in 2014.

In the Mississippian play in north central Oklahoma, we continue to add wells and increase volumes on our Bellmon facility. Sixty new wells were connected to this system during 2014. Our current processing capacity is approximately 90 MMcf per day.

In the Appalachian region, we continue to expand our Pittsburgh Mills gathering system. We are completing the construction of a project which extends our gathering system into Butler County, Pennsylvania. This project consists of a seven-mile trunkline along with related compressor station and provides us an additional outlet for our gas. This project is expected to be completed in the first quarter of 2015.

Also in the Appalachian area, we recently began construction of our Snow Show Gathering System, a new fee-based gathering system in Centre County, Pennsylvania. This system will consist of approximately seven miles of 16” and 24” pipeline and a related compressor station. All environmental and regulatory activities have been completed and we are in the

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process of clearing right of way. Construction of the pipeline and compressor station will begin in the second quarter of 2015 with an expected completion date in the third quarter of 2015.

During 2014, our mid-stream segment incurred $51.1 million in capital expenditures, excluding $28.2 million for capital leases, as compared to $96.1 million in 2013, and $183.2 million ($18.7 million on four gathering systems acquired in the Noble acquisition) in 2012, including acquisitions. For 2015, our estimated capital expenditures (excluding acquisitions) are $68.4 million. At December 31, 2014, we had committed to purchase a gas accounting system for $0.2 million within the next twelve months.

Contractual Commitments

At December 31, 2014, we had the following contractual obligations:

	Payments Due by Period				
	Total	Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years
	(In thousands)				
Long-term debt (1)	$1,264,440	$47,820	$421,505	$86,125	$708,990
Operating leases (2)	9,802	6,837	2,904	61	—
Capital lease interest and maintenance (3)	15,066	2,785	5,147	4,545	2,589
Drill pipe, drilling components, and equipment purchases (4)	26,092	22,265	3,827	—	—
Enterprise Resource Planning software obligations (5)	1,911	1,425	486	—	—
Gas accounting system (6)	161	161	—	—	—
Total contractual obligations	$1,317,472	$81,293	$433,869	$90,731	$711,579

(1) See previous discussion in MD&A regarding our long-term debt. This obligation is presented in accordance with the terms of the Notes and credit agreement and includes interest calculated using our December 31, 2014 interest rates of 6.625% for the Notes and 2.9% for the credit agreement.

(2) We lease office space or yards in Edmond, Oklahoma City, and Tulsa, Oklahoma; Houston, Texas; Englewood, Colorado; Pinedale, Wyoming; and Pittsburgh, Pennsylvania under the terms of operating leases expiring through July 2019. Additionally, we have several equipment leases and lease space on short-term commitments to stack excess drilling rig equipment and production inventory.

(3) Maintenance and interest payments are included in our capital lease agreements. The capital leases are discounted using annual rates of 4.0%. Total maintenance and interest remaining are $11.4 million and $3.7 million, respectively.

(4) We have committed to purchase approximately $26.1 million of new drilling rig components, drill pipe, and related equipment over the next two years.

(5) We have committed to pay $1.4 million for Enterprise Resource Planning software and $0.5 million for maintenance for one year following implementation.

(6) We have committed to pay $0.2 million for a gas accounting system over the next twelve months.

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At December 31, 2014, we also had the following commitments and contingencies that could create, increase or accelerate our liabilities:

	Estimated Amount of Commitment Expiration Per Period				
Other Commitments	Total Accrued	Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years
	(In thousands)				
Deferred compensation plan [1]	$4,055	Unknown	Unknown	Unknown	Unknown
Separation benefit plans [2]	$11,276	$504	Unknown	Unknown	Unknown
ARO liability [3]	$100,567	$3,204	$35,874	$5,840	$55,649
Gas balancing liability [4]	$3,623	Unknown	Unknown	Unknown	Unknown
Repurchase obligations [5]	$—	Unknown	Unknown	Unknown	Unknown
Workers' compensation liability[6]	$17,997	$7,901	$2,832	$1,202	$6,062
Capital lease obligations [7]	$25,876	$3,410	$7,242	$7,845	$7,379
Other	$410	Unknown	$410	Unknown	Unknown

(1) We provide a salary deferral plan which allows participants to defer the recognition of salary for income tax purposes until actual distribution of benefits, which occurs at either termination of employment, death or certain defined unforeseeable emergency hardships. We recognize payroll expense and record a liability, included in other long-term liabilities in our Consolidated Balance Sheets, at the time of deferral.

(2) Effective January 1, 1997, we adopted a separation benefit plan ("Separation Plan"). The Separation Plan allows eligible employees whose employment with us is involuntarily terminated or, in the case of an employee who has completed 20 years of service, voluntarily or involuntarily terminated, to receive benefits equivalent to four weeks salary for every whole year of service completed with the company up to a maximum of 104 weeks. To receive payments the recipient must waive certain claims against us in exchange for receiving the separation benefits. On October 28, 1997, we adopted a Separation Benefit Plan for Senior Management ("Senior Plan"). The Senior Plan provides certain officers and key executives of the company with benefits generally equivalent to the Separation Plan. The Compensation Committee of the Board of Directors has absolute discretion in the selection of the individuals covered in this plan. On May 5, 2004 we also adopted the Special Separation Benefit Plan ("Special Plan"). This plan is identical to the Separation Benefit Plan with the exception that the benefits under the plan vest on the earliest of a participant's reaching the age of 65 or serving 20 years with the company. On December 31, 2008, all these plans were amended to bring the plans into compliance with Section 409A of the Internal Revenue Code of 1986, as amended.

(3) When a well is drilled or acquired, under ASC 410 "Accounting for Asset Retirement Obligations," we record the fair value of liabilities associated with the retirement of long-lived assets (mainly plugging and abandonment costs for our depleted wells).

(4) We have recorded a liability for those properties we believe do not have sufficient oil, NGLs, and natural gas reserves to allow the under-produced owners to recover their under-production from future production volumes.

(5) We formed The Unit 1984 Oil and Gas Limited Partnership and the 1986 Energy Income Limited Partnership along with private limited partnerships (the "Partnerships") with certain qualified employees, officers and directors from 1984 through 2011, with a subsidiary of ours serving as general partner. Effective December 31, 2014, The Unit 1984 Oil and Gas Limited Partnership dissolved. The Partnerships were formed for the purpose of conducting oil and natural gas acquisition, drilling and development operations and serving as co-general partner with us in any additional limited partnerships formed during that year. The Partnerships participated on a proportionate basis with us in most drilling operations and most producing property acquisitions commenced by us for our own account during the period from the formation of the Partnership through December 31 of that year. These partnership agreements require, on the election of a limited partner, that we repurchase the limited partner's interest at amounts to be determined by appraisal in the future. Repurchases in any one year are limited to 20% of the units outstanding. We made repurchases of $45,000, $16,000, and $56,000 in 2014, 2013, and 2012, respectively.

(6) We have recorded a liability for future estimated payments related to workers' compensation claims primarily associated with our contract drilling segment.
(7) This amount includes commitments under capital lease arrangements for compressors in our mid-stream segment.

Derivative Activities

Periodically we enter into derivative transactions locking in the prices to be received for a portion of our oil, NGLs, and natural gas production. In August 2012, we determined–on a prospective basis–that we would no longer elect to use cash flow hedge accounting for our economic hedges. All of our previous cash flow hedges expired as of December 31, 2013. Any change in fair value on all commodity derivatives we have entered into are now reflected in the income statement and not in accumulated other comprehensive income.

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Commodity Derivatives. Our commodity derivatives is intended to reduce our exposure to price volatility and manage price risks. Our decision on the type and quantity of our production and the price(s) of our derivative(s) is based, in part, on our view of current and future market conditions. As of December 31, 2014, based on our fourth quarter 2014 average daily production, the approximated percentages of our production under derivative contracts are as follows:

	Mark-to-Market			
	Q1 2015	Q2 2015	Q3 2015	Q4 2015
Daily oil production	9 %	9 %	9 %	9 %
Daily natural gas production	42 %	24 %	24 %	24 %

With respect to the commodities subject to derivative contracts, those contracts serve to limit the risk of adverse downward price movements. However, they also limit increases in future revenues that would otherwise result from price movements above the contracted prices.

The use of derivative transactions carries with it the risk that the counterparties may not be able to meet their financial obligations under the transactions. Based on our evaluation at December 31, 2014, we believe the risk of non-performance by our counterparties is not material. At December 31, 2014, the fair values of the net assets we had with each of the counterparties to our commodity derivative transactions are as follows:

	December 31, 2014
	(In millions)
Bank of Montreal	$27.8
Scotiabank	3.3
Total assets	$31.1

If a legal right of set-off exists, we net the value of the derivative arrangements we have with the same counterparty in our Consolidated Balance Sheets. At December 31, 2014, we recorded the fair value of our commodity derivatives on our balance sheet as current derivative assets of $31.1 million. At December 31, 2013, we recorded the fair value of our commodity derivatives on our balance sheet as current derivative assets of $0.5 million and current derivative liabilities of $5.6 million.

For our economic hedges that we did not apply cash flow accounting to, any changes in their fair value occurring before their maturity (i.e., temporary fluctuations in value) are reported in gain (loss) on derivatives not designated as hedges and hedge ineffectiveness, net in our Consolidated Statements of Income. The commodity derivative instruments we had under cash flow accounting expired as of December 2013. Previous changes in the fair value of derivatives designated as cash flow hedges, to the extent they were effective in offsetting cash flows attributable to the hedged risk, were recorded in OCI until the hedged item was recognized into earnings. When the hedged item was recognized into earnings, it was reported in oil and natural gas revenues. Any change in fair value resulting from ineffectiveness was recognized in gain (loss) on derivatives not designated as hedges and hedge ineffectiveness, net.

These gains (losses) are as follows at December 31:

	2014	2013	2012
	(In thousands)		
Gain (loss) on derivatives not designated as hedges and hedge ineffectiveness, net			
Gain (loss) on derivatives not designated as hedges, included are amounts settled during the period of ($6,038), ($1,764), and $0, respectively	$30,147	$(8,184)	$1,373
Gain (loss) on ineffectiveness of cash flow hedges	—	(190)	(2,616)
	$30,147	$(8,374)	$(1,243)

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Stock and Incentive Compensation

During 2014, we granted awards covering 468,890 shares of restricted stock. These awards were granted as retention incentive awards. These stock awards had an estimated fair value as of the grant date of $24.1 million. Compensation expense will be recognized over the awards' three year vesting period. During 2014, we recognized $9.1 million in additional compensation expense and capitalized $1.9 million for these awards. During 2013, we granted awards covering 474,677 shares of restricted stock. These awards were granted as retention incentive awards and are being recognized over the awards' three year vesting period. During 2012, we granted awards covering 401,051 shares of restricted stock. These awards were granted as retention incentive awards and are being recognized over their two and three year vesting periods. No SAR awards were made during 2014, 2013, or 2012.

During 2014, we recognized compensation expense of $17.4 million for our restricted stock grants and capitalized $3.7 million of compensation cost for oil and natural gas properties.

Insurance

We are self-insured for certain losses relating to workers' compensation, control of well, and employee medical benefits. Insured policies for other coverages contain deductibles or retentions per occurrence that range from zero to $1.5 million. We have purchased stop-loss coverage in order to limit, to the extent feasible, per occurrence and aggregate exposure to certain types of claims. However, there is no assurance that the insurance coverages we have will adequately protect us against liability from all potential consequences. We have elected to use an ERISA governed occupational injury benefit plan to cover our drilling segment employees in Texas in lieu of covering them under Texas Workers' Compensation. If insurance coverage becomes more expensive, we may choose to self-insure, decrease our limits, raise our deductibles or any combination of these rather than pay higher premiums.

Oil and Natural Gas Limited Partnerships and Other Entity Relationships.

We are the general partner of 15 oil and natural gas partnerships which were formed privately or publicly. Each partnership's revenues and costs are shared under formulas set out in that partnership's agreement. The partnerships repay us for contract drilling, well supervision and general and administrative expense. Related party transactions for contract drilling and well supervision fees are the related party's share of such costs. These costs are billed on the same basis as billings to unrelated third parties for similar services. General and administrative reimbursements consist of direct general and administrative expense incurred on the related party's behalf as well as indirect expenses assigned to the related parties. Allocations are based on the related party's level of activity and are considered by us to be reasonable. During 2014, 2013, and 2012, the total we received for all of these fees was $0.5 million, $0.5 million, and $0.7 million, respectively. Our proportionate share of assets, liabilities, and net income relating to the oil and natural gas partnerships is included in our consolidated financial statements.

Effects of Inflation

The effect of inflation in the oil and natural gas industry is primarily driven by the prices for oil, NGLs, and natural gas. Increases in these prices increase the demand for our contract drilling rigs and services. This increase in demand in turn affects the dayrates we can obtain for our contract drilling services. During periods of higher demand for our drilling rigs we have experienced increases in labor costs as well as the costs of services to support our drilling rigs. Historically, during this same period, when oil, NGLs, and natural gas prices did decline, labor rates did not come back down to the levels existing before the increases. If commodity prices increase substantially for a long period, shortages in support equipment (such as drill pipe, third party services, and qualified labor) can result in additional increases in our material and labor costs. Increases in dayrates for drilling rigs also increase the cost of our oil and natural gas properties. How inflation will affect us in the future will depend on increases, if any, realized in our drilling rig rates, the prices we receive for our oil, NGLs, and natural gas, and the rates we receive for gathering and processing natural gas.

Off-Balance Sheet Arrangements

We do not currently utilize any off-balance sheet arrangements with unconsolidated entities to enhance liquidity and capital resource positions, or for any other purpose. However, as is customary in the oil and gas industry, we are subject to various contractual commitments.

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Results of Operations

2014 versus 2013

	2014	2013	Percent Change [1]
	(In thousands unless otherwise specified)		
Total operating revenue	$1,572,944	$1,351,850	16 %
Net income	$136,276	$184,746	(26)%
Oil and Natural Gas:			
Revenue	$740,079	$649,718	14 %
Operating costs excluding depreciation, depletion, amortization, and impairment	$187,916	$184,001	2 %
Depreciation, depletion, and amortization	$276,088	$226,498	22 %
Impairment of oil and gas properties	$76,683	$—	NM
Average oil price received (Bbl)	$89.43	$95.06	(6)%
Average NGL price received (Bbl)	$30.95	$31.79	(3)%
Average natural gas price received (Mcf)	$3.92	$3.32	18 %
Oil production (Bbl)	3,844,000	3,360,000	14 %
NGLs production (Bbl)	4,628,000	3,914,000	18 %
Natural gas production (Mcf)	58,854,000	56,757,000	4 %
Depreciation, depletion, and amortization rate (Boe)	$14.82	$13.32	11 %
Contract Drilling:			
Revenue	$476,517	$414,778	15 %
Operating costs excluding depreciation and impairment	$274,933	$247,280	11 %
Depreciation and impairment	$159,688	$71,194	124 %
Percentage of revenue from daywork contracts	100 %	100 %	
Average number of drilling rigs in use	75.4	65.0	16 %
Average dayrate on daywork contracts	$20,043	$19,646	2 %
Mid-Stream:			
Revenue	$356,348	$287,354	24 %
Operating costs excluding depreciation, amortization, and impairment	$306,831	$243,406	26 %
Depreciation, amortization, and impairment	$47,502	$33,191	43 %
Gas gathered—Mcf/day	319,348	309,554	3 %
Gas processed—Mcf/day	161,282	140,584	15 %
Gas liquids sold—gallons/day	733,406	543,602	35 %
Corporate and other:			
General and administrative expense	$42,023	$38,323	10 %
Gain on disposition of assets	$8,953	$17,076	(48)%
Other income (expense):			
Interest expense, net	$(17,371)	$(15,015)	16 %

Gain (loss) on derivatives not designated as hedges and hedge ineffectiveness, net	$30,147	$(8,374)	NM
Other	$(70)	$(175)	(60)%
Income tax expense	$86,663	$116,723	(26)%
Average interest rate	6.5%	6.4%	2%
Average long-term debt outstanding	$674,832	$686,656	(2)%

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(1) NM – A percentage calculation is not meaningful due to a zero-value denominator or a percentage change greater than 200.

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Oil and Natural Gas

Oil and natural gas revenues increased $90.4 million or 14% in 2014 as compared to 2013 primarily due to a 9% increase in equivalent production volumes. Oil production increased 14%, NGLs production increased 18%, and natural gas production increased 4%. Average oil prices between the comparative years decreased 6% to $89.43 per barrel and NGLs prices decreased 3% to $30.95 per barrel while prices for natural gas increased 18% to $3.92 per Mcf.

Oil and natural gas operating costs increased $3.9 million or 2% between the comparative years of 2014 and 2013 due to increased lease operating costs, higher saltwater disposal expenses, and increased general and administrative expense partially offset by lower gross production tax due to tax credits.

Depreciation, depletion, and amortization ("DD&A") increased $49.6 million or 22% primarily due to an 9% increase in equivalent production and an 11% increase in our DD&A rate. The increase in our DD&A rate in 2014 compared to 2013 resulted primarily from increased capitalized cost on new wells drilled between periods. Our DD&A expense on our oil and natural gas properties is calculated each quarter utilizing period end reserve quantities adjusted for current period production.

In December 2014, we determined the value of certain unproved oil and gas properties were diminished (in part or in whole) based on an impairment evaluation and our anticipated future exploration plans. That determination resulted in $73.7 million of costs associated with the unproved properties being added to the capitalized costs to be amortized. We incurred a non-cash ceiling test write-down of our oil and natural gas properties of $76.7 million pre-tax ($47.7 million net of tax). Subsequent to December 31, 2014, commodity prices have continued to decrease below December 31, 2014 levels. We anticipate that these reduced prices will require an additional write-down of the carrying value of our oil and natural gas properties for the quarter ending March 31, 2015 and potentially for subsequent quarters. We did not have any ceiling test write-downs during 2013.

Contract Drilling

Drilling revenues increased $61.7 million or 15% in 2014 as compared to 2013. The increase was due primarily to a 16% increase in the average number of drilling rigs in use and a 2% increase in the average dayrate. Average drilling rig utilization increased from 65.0 drilling rigs in 2013 to 75.4 drilling rigs in 2014.

Drilling operating costs increased $27.7 million or 11% in 2014 compared to 2013. The increase was due primarily to higher direct and indirect expenses due to higher utilization. Contract drilling depreciation and impairment increased $88.5 million or 124% due primarily to the write-down of 31 drilling rigs and other assets and to a lesser extent the increase in utilization.

In December 2014, we removed from service 31 drilling rigs, some older top drives, and certain drill pipe no longer marketable in the current environment. We estimated the fair value of the rigs and other assets based on the estimate market value from third-party assessments (Level 3 fair value measurement). Based on these estimates, we recorded a write-down of approximately $74.3 million pre-tax.

Several of our drilling rig customers have significantly reduced their drilling budgets for 2015, resulting in a significant reduction in the average utilization of our drilling fleet mix. At December 31, 2014, we had 75 rigs operating, at February 13, 2015, this number has been reduced to 50 rigs operating. We currently expect further reductions into 2015.

Mid-Stream

Our mid-stream revenues increased $69.0 million or 24% in 2014 as compared to 2013. The average price for natural gas sold increased 15%. Gas processing volumes per day increased 15% between the comparative years and NGLs sold per day increased 35% between the comparative periods. The increase in volumes processed per day is primarily attributable to the volumes added from new wells connected to existing systems and increased capacity of processing facilities. Gas gathering volumes per day increased 3% primarily from new well connections.

Operating costs increased $63.4 million or 26% in 2014 compared to 2013 primarily due to an 8% increase in prices paid for natural gas purchased. Depreciation, amortization, and impairment increased $14.3 million or 43% primarily due to the write-down of three systems and additional assets placed into service throughout 2013.

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In December 2014, our mid-stream segment had a $7.1 million pre-tax write-down of three of its systems, Weatherford, Billy Rose, and Spring Creek due to anticipated future cash flow and future development around these systems supporting their carrying value. The estimated future cash flows were less than the carrying value on these systems (Level 3 fair value measurement).

Due to the decline in NGLs prices during 2014, in the second half of the year we operated our processing facilities in full ethane rejection mode which reduced the amount of liquids sold during this time period. As long as NGLs prices continue at or below these levels,we expect to continue operating in full ethane rejection mode. Our mid-stream segment did not experience a significant reduction in processed volumes in 2014 but as low prices continue we expect further reductions in drilling activity around our systems which will eventually effect our ability to connect new wells resulting in lower processed volumes in the future.

General and Administrative

General and administrative expenses increased $3.7 million or 10% in 2014 compared to 2013. The increase was primarily due to increases in employee costs.

Gain on Disposition of Assets

Gain on disposition of assets decreased $8.1 million in 2014 compared to 2013 primarily due to the sale of fewer rigs.

Other Income (Expense)

Interest expense, net of capitalized interest, increased $2.4 million between the comparative years of 2014 and 2013. We capitalized interest based on the net book value associated with unproved properties not being amortized, the construction of additional drilling rigs, and the construction of gas gathering systems. Capitalized interest for 2014 was $32.2 million compared to $33.7 million in 2013, and was netted against our gross interest of $49.6 million and $48.7 million for 2014 and 2013, respectively. Our average interest rate increased from 6.4% to 6.5% and our average debt outstanding was $11.8 million lower in 2014 as compared to 2013 primarily due to the reduction of outstanding borrowings under our credit agreement over the comparative periods.

Gain (loss) on derivatives not designated as hedges and hedge ineffectiveness, net increased from a loss of $8.4 million in 2013 to a gain of $30.1 million in 2014 primarily due to fluctuations in forward prices used to estimate the fair value in mark-to-market accounting.

Income Tax Expense

Income tax expense decreased $30.1 million in 2014 compared to 2013 primarily due to decreased income due to the impairments in all three segments during 2014. Our effective tax rate was 38.9% for 2014 and 38.7% for 2013. This increase is primarily due to the effect of permanent differences as they relate to the decline in pre-tax income. Current income tax expense was $9.4 million in 2014 compared to a current income tax expense of $16.0 million for 2013. This decrease is also primarily due to decreased income. We paid $15.9 million in income taxes during 2014.

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2013 versus 2012

	2013	2012	Percent Change [1]
	(In thousands unless otherwise specified)		
Total operating revenue	$1,351,850	$1,315,123	3 %
Net income	$184,746	$23,176	NM
Oil and Natural Gas:			
Revenue	$649,718	$567,944	14 %
Operating costs excluding depreciation, depletion, amortization, and impairment	$184,001	$150,212	22 %
Depreciation, depletion, and amortization	$226,498	$211,347	7 %
Impairment of oil and natural gas properties	$—	$283,606	NM
Average oil price received (Bbl)	$95.06	$92.60	3 %
Average NGLs price received (Bbl)	$31.79	$31.58	1 %
Average natural gas price received (Mcf)	$3.32	$3.37	(1)%
Oil production (Bbl)	3,360,000	3,279,000	2 %
NGLs production (Bbl)	3,914,000	2,796,000	40 %
Natural gas production (Mcf)	56,757,000	48,930,000	16 %
Depreciation, depletion, and amortization rate (Boe)	$13.32	$14.70	(9)%
Contract Drilling:			
Revenue	$414,778	$529,719	(22)%
Operating costs excluding depreciation	$247,280	$289,524	(15)%
Depreciation	$71,194	$81,007	(12)%
Percentage of revenue from daywork contracts	100 %	100 %	
Average number of drilling rigs in use	65.0	73.9	(12)%
Average dayrate on daywork contracts	$19,646	$19,949	(2)%
Mid-Stream:			
Revenue	$287,354	$217,460	32 %
Operating costs excluding depreciation and amortization	$243,406	$187,292	30 %
Depreciation, amortization, and impairment	$33,191	$24,388	36 %
Gas gathered—Mcf/day	309,554	250,290	24 %
Gas processed—Mcf/day	140,584	133,987	5 %
Gas liquids sold—gallons/day	543,602	542,578	— %
Corporate and other:			
General and administrative expense	$38,323	$33,086	16 %
Gain (loss) on disposition of assets	$(17,076)	$(253)	NM
Other income (expense): [2]			
Interest expense, net	$(15,015)	$(14,137)	(6)%
Loss on derivatives not designated as hedges and hedge ineffectiveness, net	$(8,374)	$(1,243)	NM
Other	$(175)	$(132)	33 %

Income tax expense	$116,723	$16,226	NM
Average interest rate	6.4 %	6.1 %	5 %
Average long-term debt outstanding	$686,656	$495,830	38 %

(1) NM – A percentage calculation is not meaningful due to a zero-value denominator or a percentage change greater than 200.

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Oil and Natural Gas

Oil and natural gas revenues increased $81.8 million or 14% in 2013 as compared to 2012 primarily due to an 18% increase in equivalent production volumes. This production increase was the result of 2012 acquisitions and new wells completed in oil and NGLs rich prospects that were brought online. Oil production increased 2%, NGLs production increased 40%, and natural gas production increased 16%. Average oil prices between the comparative years increased 3% to $95.06 per barrel and NGLs prices increased 1% to $31.79 per barrel while prices for natural gas decreased 1% to $3.32 per Mcf, respectively.

Oil and natural gas operating costs increased $33.8 million or 22% between the comparative years of 2013 and 2012 due to increased well servicing costs, higher saltwater disposal expenses, and increased general and administrative expense.

DD&A increased $15.2 million or 7% primarily due to an 18% increase in equivalent production offset by a 9% decrease in our DD&A rate. The decrease in our DD&A rate resulted primarily from a reduction to the full cost pool from proceeds associated with the divestitures completed during 2013 and the non-cash ceiling test write-down of $167.7 million pre-tax ($104.4 million, net of tax) that occurred during the fourth quarter of 2012. Our DD&A expense on our oil and natural gas properties is calculated each quarter using period end reserve quantities adjusted for current period production.

We did not have any ceiling test write-downs during 2013. During the second quarter of 2012, we recorded a non-cash ceiling test write-down of $115.9 million pre-tax ($72.1 million, net of tax). During the fourth quarter of 2012, we recorded a non-cash ceiling test write-down of $167.7 million pre-tax ($104.4 million, net of tax).

Contract Drilling

Drilling revenues decreased $114.9 million or 22% in 2013 as compared to 2012. The decrease was due primarily to a 12% decrease in the average number of drilling rigs in use and a 2% decrease in the average dayrate. Average drilling rig utilization decreased from 73.9 drilling rigs in 2012 to 65.0 drilling rigs in 2013. During 2012, we had eight drilling contracts that were terminated early by the operator. The early termination fees associated with these contracts included in revenues was approximately $22.6 million compared to $1.9 million for the termination of one long-term drilling contract in 2013.

Drilling operating costs decreased $42.2 million or 15% in 2013 compared to 2013. The decrease was due primarily to operating fewer rigs as per day direct cost increased $79 and indirect cost increased $0.6 million due to increased ad valorem tax. Contract drilling depreciation decreased $9.8 million or 12% also due primarily to the decrease in utilization.

Mid-Stream

Our mid-stream revenues increased $69.9 million or 32% in 2013 as compared to 2012. The average price for natural gas sold increased 37%. Gas processing volumes per day increased 5% between the comparative years and NGLs sold per day essentially unchanged between the comparative periods. The increase in volumes processed per day is primarily attributable to the volumes added from new wells connected to existing systems and increased capacity of processing facilities. NGLs sold volumes per day remained constant as an increase in volumes processed and upgrades to several of our processing facilities was offset from decreases due to one of our customers completing construction of their own processing plant and moving their volumes off our system during the second half of 2012. Gas gathering volumes per day increased 24% primarily from new well connections.

Operating costs increased $56.1 million or 30% in 2013 compared to 2012 primarily due to a 25% increase in prices paid for natural gas purchased. Depreciation, amortization, and impairment increased $8.8 million or 36% primarily due to additional assets placed into service throughout 2013.

General and Administrative

General and administrative expenses increased $5.2 million or 16% in 2013 compared to 2012. The increase was primarily due to increases in employee costs.

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Gain on Disposition of Assets

Gain on disposition of assets increased $16.8 million in 2013 compared to 2012 primarily due to the sale of five drilling rigs.

Other Income (Expense)

Interest expense, net of capitalized interest, increased $0.9 million between the comparative years of 2013 and 2012. We capitalized interest based on the net book value associated with unproved properties not being amortized, the construction of additional drilling rigs, and the construction of gas gathering systems. Capitalized interest for 2013 was $33.7 million compared to $18.9 million in 2012, and was netted against our gross interest of $48.7 million and $33.0 million for 2013 and 2012, respectively. Our average interest rate increased from 6.1% to 6.4% and our average debt outstanding was $190.8 million higher in 2013 as compared to 2012 due to the issuance of $400.0 million of senior subordinated notes during the third quarter of 2012 to partially fund the Noble acquisition in the oil and natural gas segment.

Loss on derivatives not designated as hedges and hedge ineffectiveness, net increased from $1.2 million in 2012 to $8.4 million in 2013 primarily due to fluctuations in forward prices used to estimate the fair value in mark-to-market accounting.

Income Tax Expense

Income tax expense increased $100.5 million in 2013 compared to 2012 primarily due to decreased income. Our effective tax rate was 38.7% for 2013 and 41.2% for 2012. This decrease is primarily due to the effect of permanent differences as they relate to the rise in pre-tax income. Current income tax expense was $16.0 million in 2013 compared to a current income tax expense of $0.7 million for 2012. This increase is also primarily due to increased income. We paid $9.1 million in income taxes during 2013.

Item 7A. Quantitative and Qualitative Disclosures about Market Risk

Our operations are exposed to market risks primarily as a result of changes in the prices for natural gas and oil and interest rates.

Commodity Price Risk. Our major market risk exposure is in the prices we receive for our oil, NGLs, and natural gas production. Those prices are primarily driven by the prevailing worldwide price for crude oil and market prices applicable to our natural gas production. Historically, these prices have fluctuated and we expect they will continue to do so. The price of oil, NGLs, and natural gas also affects both the demand for our drilling rigs and the amount we can charge for the use of our drilling rigs. Based on our 2014 production, a $0.10 per Mcf change in what we are paid for our natural gas production would result in a corresponding $466,000 per month ($5.6 million annualized) change in our pre-tax cash flow. A $1.00 per barrel change in our oil price would have a $308,000 per month ($3.7 million annualized) change in our pre-tax operating cash flow and a $1.00 per barrel change in our NGLs prices would have a $368,000 per month ($4.4 million annualized) change in our pre-tax cash flow.

We use derivative transactions to manage the risk associated with price volatility. Our decision on the type and quantity of our production and the price(s) of our derivative(s) is based, in part, on our view of current and future market conditions. The transactions we use include financial price swaps under which we will receive a fixed price for our production and pay a variable market price to the contract counterparty. We do not hold or issue derivative instruments for speculative trading purposes.

At December 31, 2014, the following non-designated hedges were outstanding:

Term	Commodity	Contracted Volume	Weighted Average Fixed Price for Swaps	Contracted Market
Jan’15 – Dec’15	Natural gas – swap	40,000 MMBtu/day	$3.98	IF – NYMEX (HH)
Jan’15 – Mar’15	Natural gas – collar	30,000 MMBtu/day	$4.20-$5.03	IF – NYMEX (HH)
Jan’15 – Dec'15	Crude oil – swap	1,000 Bbl/day	$95.00	WTI – NYMEX

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Subsequent to December 31, 2014, the following non-designated hedges were entered into:

Term	Commodity	Contracted Volume	Weighted Average Fixed Price for Swaps	Contracted Market
Apr’15 – Jun'15	Natural gas – swap	30,000 MMBtu/day	$3.10	IF – NYMEX (HH)
Apr’15 – Jun'15	Natural gas – collar	30,000 MMBtu/day	$2.92-$3.26	IF – NYMEX (HH)
Jul’15 – Sep'15	Natural gas – collar	30,000 MMBtu/day	$2.58-$3.04	IF – NYMEX (HH)

Interest Rate Risk. Our interest rate exposure relates to our long-term debt under our credit agreement and the Notes. The credit agreement, at our election bears interest at variable rates based on the Prime Rate or the LIBOR Rate. At our election, borrowings under our credit agreement may be fixed at the LIBOR Rate for periods of up to 180 days. Based on our average outstanding long-term debt subject to a variable rate in 2014, a 1% increase in the floating rate would reduce our annual pre-tax cash flow by approximately $0.2 million. Under our Notes, we pay a fixed rate of interest of 6.625% per year (payable semi-annually in arrears on May 15 and November 15 of each year).

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Item 8. Financial Statements and Supplementary Data

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Unit Corporation and Subsidiaries

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Management's Report on Internal Control over Financial Reporting

Management of the company is responsible for establishing and maintaining adequate internal control over financial reporting. Internal control over financial reporting is defined in Rules 13a-15(f) or 15d-15(f) promulgated under the Securities Exchange Act of 1934 as a process designed by, or under the supervision of, the company's principal executive and principal financial officers and effected by the company's board of directors, management and other personnel, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles and includes those policies and procedures that:

- Pertain to the maintenance of records that in reasonable detail accurately and fairly reflect the transactions and dispositions of the assets of the company;
- Provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and
- Provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate. Internal control over financial reporting cannot provide absolute assurance of achieving financial reporting objectives because of its inherent limitations. Internal control over financial reporting is a process that involves human diligence and compliance and is subject to lapses in judgment and breakdowns resulting from human failures. Internal control over financial reporting also can be circumvented by collusion or improper management override. Because of such limitations, there is a risk that material misstatements may not be prevented or detected on a timely basis by internal control over financial reporting. However, these inherent limitations are known features of the financial reporting process. Therefore, it is possible to design into the process safeguards to reduce, though not eliminate, this risk.

The company's management assessed the effectiveness of the company's internal control over financial reporting as of December 31, 2014. In making this assessment, the company's management used the criteria set forth in Internal Control—Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on their assessment, the company's management concluded that, as of December 31, 2014, the company's internal control over financial reporting was effective based on those criteria.

The effectiveness of the company's internal control over financial reporting as of December 31, 2014, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears herein.

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Report of Independent Registered Public Accounting Firm

To Board of Directors and Shareholders of Unit Corporation:

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of income, comprehensive income, changes in shareholders' equity, and cash flows present fairly, in all material respects, the financial position of Unit Corporation and its subsidiaries at December 31, 2014 and 2013, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2014, in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the index appearing under Item 15(a)(2), presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2014, based on criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements and financial statement schedule, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express opinions on these financial statements, on the financial statement schedule and on the Company's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

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

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

/s/ PricewaterhouseCoopers LLP

Tulsa, Oklahoma

February 24, 2015

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UNIT CORPORATION AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

	As of December 31, 2014	2013
	(In thousands except share and par value amounts)	
ASSETS		
Current assets:		
Cash and cash equivalents	$1,049	$18,593
Accounts receivable (less allowance for doubtful accounts of $5,039 and $5,342 at December 31, 2014 and 2013, respectively)	189,812	139,788
Materials and supplies	5,590	10,998
Current derivative asset (Note 13)	31,139	515
Current deferred tax asset (Note 8)	11,527	13,585
Assets held for sale (Note 3)	—	15,621
Prepaid expenses and other	13,374	12,931
Total current assets	252,491	212,031
Property and equipment:		
Oil and natural gas properties, on the full cost method:		
Proved properties	4,990,753	4,235,712
Unproved properties not being amortized	485,568	545,588
Drilling equipment	1,620,692	1,477,093
Gas gathering and processing equipment	628,689	549,422
Saltwater disposal systems	56,702	44,579
Transportation equipment	40,693	39,666
Other	57,706	42,856
	7,880,803	6,934,916
Less accumulated depreciation, depletion, amortization, and impairment	3,747,412	3,212,225
Net property and equipment	4,133,391	3,722,691
Debt issuance cost	10,255	11,844
Goodwill (Note 2)	62,808	62,808
Other assets	14,783	13,016
Total assets	$4,473,728	$4,022,390

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UNIT CORPORATION AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS - (Continued)

	As of December 31, 2014	2013
	(In thousands except share and par value amounts)	
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$218,500	$154,062
Accrued liabilities (Note 5)	70,171	64,363
Income taxes payable	481	7,474
Current derivative liabilities (Note 13)	—	5,561
Current portion of other long-term liabilities (Note 6)	15,019	12,113
Total current liabilities	304,171	243,573
Long-term debt (Note 6)	812,163	645,696
Other long-term liabilities (Note 6)	148,785	158,331
Deferred income taxes (Note 8)	876,215	801,398
Commitments and contingencies (Note 16)	—	—
Shareholders' equity:		
Preferred stock, $1.00 par value, 5,000,000 shares authorized, none issued	—	—
Common stock, $0.20 par value, 175,000,000 shares authorized, 49,593,812 and 49,107,004 shares issued as of December 31, 2014 and 2013, respectively	9,732	9,659
Capital in excess of par value	468,123	445,470
Retained earnings	1,854,539	1,718,263
Total shareholders' equity	2,332,394	2,173,392
Total liabilities and shareholders' equity	$4,473,728	$4,022,390

The accompanying notes are an integral part of the consolidated financial statements.

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UNIT CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF INCOME

	Year Ended December 31, 2014	2013	2012
	(In thousands except per share amounts)		
Revenues:			
Oil and natural gas	$740,079	$649,718	$567,944
Contract drilling	476,517	414,778	529,719
Gas gathering and processing	356,348	287,354	217,460
Total revenues	1,572,944	1,351,850	1,315,123
Expenses:			
Oil and natural gas:			
Operating costs	187,916	184,001	150,212
Depreciation, depletion, and amortization	276,088	226,498	211,347
Impairment of oil and natural gas properties (Note 2)	76,683	—	283,606
Contract drilling:			
Operating costs	274,933	247,280	289,524
Depreciation and impairment (Note 2)	159,688	71,194	81,007
Gas gathering and processing:			
Operating costs	306,831	243,406	187,292
Depreciation, amortization, and impairment (Note 2)	47,502	33,191	24,388
General and administrative	42,023	38,323	33,086
Gain on disposition of assets	(8,953)	(17,076)	(253)
Total expenses	1,362,711	1,026,817	1,260,209
Income from operations	210,233	325,033	54,914
Other income (expense):			
Interest, net	(17,371)	(15,015)	(14,137)
Gain (loss) on derivatives not designated as hedges and hedge ineffectiveness, net	30,147	(8,374)	(1,243)
Other	(70)	(175)	(132)
Total other expense	12,706	(23,564)	(15,512)
Income before income taxes	222,939	301,469	39,402
Income tax expense:			
Current	9,378	15,991	696
Deferred	77,285	100,732	15,530
Total income taxes	86,663	116,723	16,226
Net income	$136,276	$184,746	$23,176
Net income per common share:			
Basic	$2.80	$3.83	$0.48
Diluted	$2.78	$3.80	$0.48

The accompanying notes are an integral part of the consolidated financial statements.

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UNIT CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	For Years ended December 31,		
	2014	2013	2012
	(In thousands)		
Net income	$136,276	$184,746	$23,176
Other comprehensive income (loss), net of taxes:			
Change in value of derivative instruments used as cash flow hedges, net of tax of $0, ($4,717), and $12,094	—	(7,349)	18,635
Reclassification - derivative settlements, net of tax of $0, ($249), and ($20,171)	—	(354)	(31,682)
Ineffective portion of derivatives, net of tax of $0, $74, and $1,008	—	116	1,608
Comprehensive income	$136,276	$177,159	$11,737

The accompanying notes are an integral part of the consolidated financial statements.

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UNIT CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY
Year Ended December 31, 2012, 2013, and 2014

	Common Stock	Capital In Excess of Par Value	Accumulated Other Comprehensive Income	Retained Earnings	Total
	(In thousands except share amounts)				
Balances, January 1, 2012	$9,541	$408,109	$19,026	$1,510,341	$1,947,017
Comprehensive income:					
Net income	—	—	—	23,176	23,176
Other comprehensive loss (net of tax ($7,069))	—	—	(11,439)	—	(11,439)
Total comprehensive income					11,737
Activity in employee compensation plans (430,506 shares)	53	15,494	—	—	15,547
Balances, December 31, 2012	9,594	423,603	7,587	1,533,517	1,974,301
Comprehensive income (loss):					
Net income	—	—	—	184,746	184,746
Other comprehensive loss (net of tax ($4,892))	—	—	(7,587)	—	(7,587)
Total comprehensive income					177,159
Activity in employee compensation plans (525,056 shares)	65	21,867	—	—	21,932
Balances, December 31, 2013	9,659	445,470	—	1,718,263	2,173,392
Net income	—	—	—	136,276	136,276
Activity in employee compensation plans (486,808 shares)	73	22,653	—	—	22,726
Balances, December 31, 2014	$9,732	$468,123	$—	$1,854,539	$2,332,394

The accompanying notes are an integral part of the consolidated financial statements.

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UNIT CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2014	2013	2012
	(In thousands)		
OPERATING ACTIVITIES:			
Net income	$136,276	$184,746	$23,176
Adjustments to reconcile net income to net cash provided (used) by operating activities:			
Depreciation, depletion, and amortization	404,943	333,907	319,021
Impairment of properties (Note 2)	158,069	—	283,606
(Gain) loss on derivatives	(30,147)	7,771	(50,610)
Cash (payments) receipts on derivatives settled	(6,038)	(1,161)	51,853
Gain on disposition of assets	(8,953)	(17,076)	(253)
Deferred tax expense	77,285	100,732	15,530
Employee stock compensation plans	24,320	21,317	16,956
Bad debt expense	3,562	—	90
ARO liability accretion	4,599	5,450	4,615
Other, net	1,068	2,250	781
Changes in operating assets and liabilities increasing (decreasing) cash:			
Accounts receivable	(60,800)	2,967	13,994
Materials and supplies	2,602	(2,435)	(361)
Prepaid expenses and other	(444)	1,813	(3,466)
Accounts payable	4,715	15,715	10,187
Accrued liabilities	(1,297)	17,198	6,911
Contract advances	(767)	1,137	(1,119)
Net cash provided by operating activities	708,993	674,331	690,911
INVESTING ACTIVITIES:			
Capital expenditures	(981,374)	(703,984)	(762,381)
Producing property and other acquisitions	(5,723)	—	(598,485)
Proceeds from disposition of property and equipment	66,197	120,910	281,824
Other	303	3,894	—
Net cash used in investing activities	(920,597)	(579,180)	(1,079,042)
FINANCING ACTIVITIES:			
Borrowings under line of credit	725,800	222,500	735,300
Payments under line of credit	(559,800)	(293,600)	(714,200)
Proceeds from issuance of senior subordinated notes, net of debt issuance costs and discount	—	—	386,274
Payments on capitalized leases	(2,392)	—	—
Proceeds from exercise of stock options	1,083	574	215
Tax benefit from stock options	1,614	8	121
Increase (decrease) in book overdrafts (Note 2)	27,755	(7,014)	(19,440)
Net cash provided by (used in) financing activities	194,060	(77,532)	388,270
Net increase (decrease) in cash and cash equivalents	(17,544)	17,619	139
Cash and cash equivalents, beginning of year	18,593	974	835
Cash and cash equivalents, end of year	$1,049	$18,593	$974
Supplemental disclosure of cash flow information:			
Cash paid during the year for:			
Interest paid (net of capitalized)	$13,620	$12,485	$14,880

Income taxes	$15,898	$9,100	$5,116
Changes in accounts payable and accrued liabilities related to purchases of property, plant, and equipment	$(31,968)	$(6,550)	$(4,753)
Non-cash (additions) reductions to oil and natural gas properties related to asset retirement obligations	$37,689	$17,952	$(45,097)
Non-cash additions to property, plant, and equipment acquired under capital leases	$(28,202)	$—	$—

The accompanying notes are an integral part of the consolidated financial statements.

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UNIT CORPORATION AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1 – ORGANIZATION

Unless the context clearly indicates otherwise, references in this report to "Unit", "Company", "we", "our", "us", or like terms refer to Unit Corporation and its subsidiaries.

We are primarily engaged in the exploration, development, acquisition, and production of oil and natural gas properties, the land contract drilling of natural gas and oil wells, and the buying, selling, gathering, processing, and treating of natural gas. Our operations are located principally in the United States and are organized in the following three reporting segments: (1) Oil and Natural Gas, (2) Contract Drilling, and (3) Mid-Stream.

Oil and Natural Gas. Carried out by our subsidiary, Unit Petroleum Company, we explore, develop, acquire, and produce oil and natural gas properties for our own account. Our producing oil and natural gas properties, unproved properties, and related assets are located mainly in Oklahoma and Texas, and to a lesser extent, in Arkansas, Colorado, Kansas, Louisiana, Mississippi, Montana, New Mexico, North Dakota, and Wyoming.

Historically, our contract drilling segment experienced more demand for natural gas drilling as opposed to drilling for oil and NGLs. With the current natural gas market, operators have been focusing on drilling for oil and NGLs.

Contract Drilling. Carried out by our subsidiary, Unit Drilling Company and its subsidiary Unit Texas Drilling, L.L.C., we drill onshore oil and natural gas wells for our own account as well as for a wide range of other oil and natural gas companies. Our drilling operations are mainly located in Oklahoma, Texas, Louisiana, Kansas, Wyoming, and North Dakota.

Mid-Stream. Carried out by our subsidiary, Superior Pipeline Company, L.L.C. and its subsidiaries, we buy, sell, gather, transport, process, and treat natural gas for our own account and for third parties. Mid-stream operations are performed in Oklahoma, Texas, Kansas, Pennsylvania, and West Virginia.

NOTE 2 – SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Principles of Consolidation. The consolidated financial statements include the accounts of Unit Corporation and its subsidiaries. Our investment in limited partnerships is accounted for on the proportionate consolidation method, whereby our share of the partnerships' assets, liabilities, revenues, and expenses are included in the appropriate classification in the accompanying consolidated financial statements.

Certain amounts in the accompanying consolidated financial statements for prior periods have been reclassified to conform to current year presentation. Certain financial statement captions were expanded or combined with no impact to consolidated net income or shareholders' equity.

Accounting Estimates. The preparation of financial statements in conformity with generally accepted accounting principles (GAAP) 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.

Drilling Contracts. We recognize revenues and expenses generated from "daywork" drilling contracts as the services are performed, since we do not bear the risk of completion of the well. Under "footage" and "turnkey" contracts, we bear the risk of completion of the well; therefore, revenues and expenses are recognized when the well is substantially completed. Under this method, substantial completion is determined when the well bore reaches the negotiated depth as stated in the contract. The entire amount of a loss, if any, is recorded when the loss is determinable. The costs of uncompleted drilling contracts include expenses incurred to date on “footage” or “turnkey” contracts, which are still in process at the end of the period, and are included in other current assets. Typically, any one of these three types of contracts can be used for the drilling of one well which can take from 20 to 90 days. At December 31, 2014, all of our contracts were daywork contracts of which 30 were multi-well and had durations which ranged from six months to three years, 26 of which expire in 2015 and four expiring in 2016. These longer term contracts may contain a fixed rate for the duration of the contract or provide for the periodic renegotiation of the rate within a specific range from the existing rate.

Cash Equivalents and Book Overdrafts. We include as cash equivalents all investments with maturities at date of purchase of three months or less which are readily convertible into known amounts of cash. Book overdrafts are checks that have been issued before the end of the period, but not presented to our bank for payment before the end of the period. At December 31, 2014, book overdrafts were $27.8 million. There were no book overdrafts at December 31, 2013.

Accounts Receivable. Accounts receivable are carried on a gross basis, with no discounting, less an allowance for doubtful accounts. We estimate the allowance for doubtful accounts based on existing economic conditions, the financial condition of our customers, and the amount and age of past due accounts. Receivables are considered past due if full payment is not received by the contractual due date. Past due accounts are generally written off against the allowance for doubtful accounts only after all collection attempts have been unsuccessful.

Financial Instruments and Concentrations of Credit Risk and Non-performance Risk. Financial instruments, which potentially subject us to concentrations of credit risk, consist primarily of trade receivables with a variety of oil and natural gas companies. We do not generally require collateral related to receivables. Our credit risk is considered to be limited due to the large number of customers comprising our customer base. Below are the third-party customers that accounted for more than 10% of our segment's revenues:

	2014		2013		2012	
Oil and Natural Gas:						
Valero Energy Corporation	24	%	25	%	26	%
Sunoco Partners Marketing	14	%	8	%	8	%
Drilling:						
QEP Resources, Inc.	19	%	18	%	15	%
Whiting Petroleum Corp. (formerly Kodiak Oil and Gas Corp.)	9	%	10	%	10	%
Mid-Stream:						
ONEOK Partners, L.P.	44	%	57	%	54	%
Tenaska Resources, LLC	22	%	16	%	7	%
Laclede Gas Company	10	%	2	%	—	%
Gavilon, LLC	—	%	—	%	10	%

We had a concentration of cash of $18.4 million and $52.1 million at December 31, 2014 and 2013, respectively with one bank.

The use of derivative transactions also involves the risk that the counterparties will be unable to meet the financial terms of the transactions. We considered this non-performance risk with regard to our counterparties and our own non-performance risk in our derivative valuation at December 31, 2014 and determined there was no material risk at that time. At December 31, 2014, the fair values of the net assets (liabilities) we had with each of the counterparties with respect to all of our commodity derivative transactions are listed in the table below:

	December 31, 2014
	(In millions)
Bank of Montreal	$27.8
Scotiabank	3.3
Total assets	$31.1

Property and Equipment. Drilling equipment, transportation equipment, gas gathering and processing systems, and other property and equipment are carried at cost less accumulated depreciation. Renewals and enhancements are capitalized while repairs and maintenance are expensed. Depreciation of drilling equipment is recorded using the units-of-production method based on estimated useful lives starting at 15 years , including a minimum provision of 20% of the active rate when the equipment is idle. We use the composite method of depreciation for drill pipe and collars and calculate the depreciation by footage actually drilled compared to total estimated remaining footage. Depreciation of other property and equipment is computed using the straight-line method over the estimated useful lives of the assets ranging from 3 to 15 years.

We review the carrying amounts of long-lived assets for potential impairment annually, typically during the fourth quarter, or when events occur or changes in circumstances suggest that these carrying amounts may not be recoverable. Changes that could prompt such an assessment may include equipment obsolescence, changes in the market demand for a specific asset, changes in commodity prices, periods of relatively low rig utilization, declining revenue per day, declining cash margin per day, or overall changes in general market conditions. Assets are determined to be impaired if a forecast of undiscounted estimated future net operating cash flows directly related to the asset, including disposal value if any, is less than the carrying amount of the asset. If any asset is determined to be impaired, the loss is measured as the amount by which the carrying amount of the asset exceeds its fair value. The estimate of fair value is based on the best information available, including prices for similar assets. Changes in these estimates could cause us to reduce the carrying value of property and equipment. Asset impairment evaluations are, by nature, highly subjective. They involve expectations about future cash flows generated by our assets and reflect management's assumptions and judgments regarding future industry conditions and their effect on future utilization levels, dayrates, and costs. The use of different estimates and assumptions could result in materially different carrying values of our assets.

On a periodic basis, we evaluate our fleet of drilling rigs for marketability based on the condition of inactive rigs, expenditures that would be necessary to bring them to working condition and the expected demand for drilling services by rig type. The components comprising inactive rigs are evaluated, and those components with continuing utility to the Company's other marketed rigs are transferred to other rigs or to its yards to be used as spare equipment. The remaining components of these rigs are retired. In December 2014, we removed from service 31 drilling rigs, some older top drives, and certain drill pipe no longer marketable in the current economic environment. We estimated the fair value of the rigs and other assets based on the estimate market value from third-party assessments (Level 3 fair value measurement). Based on these estimates, we recorded a write-down of approximately $74.3 million, pre-tax. When property and equipment components are disposed of, the cost and the related accumulated depreciation are removed from the accounts and any resulting gain or loss is generally reflected in operations. For dispositions of drill pipe and drill collars, an average cost for the appropriate feet of drill pipe and drill collars is removed from the asset account and charged to accumulated depreciation and proceeds, if any, are credited to accumulated depreciation.

In December 2014, our mid-stream segment had a $7.1 million, pre-tax write-down of three of its systems, Weatherford, Billy Rose, and Spring Creek due to anticipated future cash flow and future development around these systems supporting their carrying value. The estimated future cash flows were less than the carrying value on these systems (Level 3 fair value measurement). In December 2012, our mid-stream segment had a $1.2 million write-down of its Erick system. There was no volume from the wells connected to this system, the compressor and related surface equipment have been removed from this location and there is no future activity anticipated from this gathering system. No significant impairments were recorded in 2013.

We record an asset and a liability equal to the present value of the expected future ARO associated with our oil and gas properties. The ARO asset is depreciated in a manner consistent with the depreciation of the underlying physical asset. We measure changes in the liability due to passage of time by accreting an interest charge. This amount is recognized as an increase in the carrying amount of the liability and as a corresponding accretion expense.

Capitalized Interest. During 2014, 2013, and 2012, interest of approximately $32.2 million, $33.7 million, and $18.9 million, respectively, was capitalized based on the net book value associated with unproved properties not being amortized, the construction of additional drilling rigs, and the construction of gas gathering systems. Interest is being capitalized using a weighted average interest rate based on our outstanding borrowings.

Goodwill. Goodwill represents the excess of the cost of acquisitions over the fair value of the net assets acquired. Goodwill is not amortized, but an impairment test is performed at least annually to determine whether the fair value has decreased and is performed additionally when events indicate an impairment may have occurred. For purposes of impairment testing, goodwill is evaluated at the reporting unit level. Our goodwill is all related to our contract drilling segment, and accordingly, the impairment test is generally based on the estimated discounted future net cash flows of our drilling segment, utilizing discount rates and other factors in determining the fair value of our drilling segment. Inputs in our estimated discounted future net cash flows include rig utilization, day rates, gross margin percentages, and terminal value (these are all considered level 3 inputs). No goodwill impairment was recorded for the years ended December 31, 2014, 2013, or 2012. There were no additions to goodwill in 2014, 2013, or 2012. Goodwill of $3.1 million is deductible for tax purposes.

Intangible Assets. Intangible assets are capitalized and amortized over the estimated period benefited. Such amounts are reviewed for possible impairment whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. No intangible asset impairment was recorded for the years ended December 31, 2014, 2013, or 2012. Amortization of $0.7 million and $1.2 million was recorded in 2013 and 2012, respectively. Accumulated amortization for 2013 and 2012 was $18.0 million and $17.3 million, respectively. Our intangible assets became fully amortized in 2013, so no amortization was recorded in 2014.

Oil and Natural Gas Operations. We account for our oil and natural gas exploration and development activities using the full cost method of accounting prescribed by the SEC. Accordingly, all productive and non-productive costs incurred in connection with the acquisition, exploration and development of our oil, NGLs, and natural gas reserves, including directly related overhead costs and related asset retirement costs, are capitalized and amortized on a units-of-production method based on proved oil and natural gas reserves. Directly related overhead costs of $23.7 million, $21.5 million, and $17.6 million were capitalized in 2014, 2013, and 2012, respectively. Independent petroleum engineers annually audit our internal evaluation of our reserves. The average rates used for depreciation, depletion, and amortization (DD&A) were $14.82, $13.32, and $14.70 per Boe in 2014, 2013, and 2012, respectively. The calculation of DD&A includes estimated future expenditures to be incurred in developing proved reserves and estimated dismantlement and abandonment costs, net of estimated salvage values. Our unproved properties totaling $485.6 million are excluded from the DD&A calculation.

No gains or losses are recognized on the sale, conveyance, or other disposition of oil and natural gas properties unless a significant reserve amount to our total reserves is involved.

Revenue from the sale of oil and natural gas is recognized when title passes, net of royalties.

Under the full cost rules, at the end of each quarter, we review the carrying value of our oil and natural gas properties. The full cost ceiling is based principally on the estimated future discounted net cash flows from our oil and natural gas properties discounted at 10%. We use the unweighted arithmetic average of the commodity prices existing on the first day of each of the 12 months before the end of the reporting period to calculate discounted future revenues, unless prices were otherwise determined under contractual arrangements. In the event the unamortized cost of oil and natural gas properties being amortized exceeds the full cost ceiling, as defined by the SEC, the excess is charged to expense in the period during which such excess occurs. Once incurred, a write-down of oil and natural gas properties is not reversible.

For the quarter ended June 30, 2012, the 12-month average commodity prices, including the discounted value of our cash flow hedges, decreased significantly, resulting in a non-cash ceiling test write-down of $115.9 million pre-tax ($72.1 million, net of tax). Our qualifying cash flow hedges used in the ceiling test determination at June 30, 2012, consisted of swaps and collars, covering production of 2.9 MMBoe in 2012 and 4.5 MMBoe in 2013. The effect of those hedges on the June 30, 2012 ceiling test was a $32.5 million pre-tax increase in the discounted net cash flows of our oil and natural gas properties.

For the quarter ended December 31, 2012, the 12-month average commodity prices, including the discounted value of our cash flow hedges, decreased further, resulting in an additional non-cash ceiling test write-down of $167.7 million pre-tax ($104.4 million, net of tax). Our qualifying cash flow hedges used in the ceiling test determination at December 31, 2012, consisted of swaps and collars covering 6.9 MMBoe in 2013. The effect of those hedges on the December 31, 2012 ceiling test was a $29.8 million pre-tax increase in the discounted net cash flows of our oil and natural gas properties. Our oil and natural gas derivatives are discussed in Note 13 of the Notes to our Consolidated Financial Statements.

In December 2014, we determined the value of certain unproved oil and gas properties were diminished (in part or in whole) based on an impairment evaluation and our anticipated future exploration plans. That determination resulted in $73.7 million of costs associated with the unproved properties being added to the capitalized costs to be amortized. We incurred a non-cash ceiling test write-down of our oil and natural gas properties of $76.7 million pre-tax ($47.7 million net of tax). Subsequent to December 31, 2014, commodity prices have continued to decrease below December 31, 2014 levels. We anticipate that these reduced prices will require an additional write-down of the carrying value of our oil and natural gas properties for the quarter ending March 31, 2015 and potentially subsequent quarters.

Our contract drilling segment provides drilling services for our exploration and production segment. Depending on their timing some of the drilling services performed on our properties are also deemed to be associated with the acquisition of an ownership interest in the property. Revenues and expenses for such services are eliminated in our income statement, with any profit recognized as a reduction in our investment in our oil and natural gas properties. The contracts for these services are issued under the same conditions and rates as the contracts entered into with unrelated third parties. We eliminated revenue of $89.5 million, $64.3 million, and $49.6 million for 2014, 2013, and 2012, respectively from our contract drilling segment and eliminated the associated operating expense of $62.4 million, $46.9 million, and $34.1 million during 2014, 2013, and 2012, respectively, yielding $27.1 million, $17.4 million, and $15.5 million during 2014, 2013, and 2012, respectively, as a reduction to the carrying value of our oil and natural gas properties.

Gas Gathering and Processing Revenue. Our gathering and processing segment recognizes revenue from the gathering and processing of natural gas and NGLs in the period the service is provided based on contractual terms.

Insurance. We are self-insured for certain losses relating to workers' compensation, control of well and employee medical benefits. Insured policies for other coverage contain deductibles or retentions per occurrence that range from zero to $1.5 million. We have purchased stop-loss coverage in order to limit, to the extent feasible, per occurrence and aggregate exposure to certain types of claims. However, there is no assurance that the insurance coverage will adequately protect us against liability from all potential consequences. We have elected to use an ERISA governed occupational injury benefit plan to cover all Texas drilling operations in lieu of covering them under Texas Workers' Compensation. If insurance coverage becomes more expensive, we may choose to self-insure, decrease our limits, raise our deductibles or any combination of these rather than pay higher premiums.

Derivative Activities. All derivatives are recognized on the balance sheet and measured at fair value. For our economic hedges that we did not apply cash flow accounting to, any changes in their fair value occurring before their maturity (i.e., temporary fluctuations in value) are reported in gain (loss) on derivatives not designated as hedges and hedge ineffectiveness, net in our Consolidated Statements of Income. The commodity derivative instruments we had under cash flow accounting expired as of December 2013. Previous changes in the fair value of derivatives designated as cash flow hedges, to the extent they were effective in offsetting cash flows attributable to the hedged risk, were recorded in OCI until the hedged item was recognized into earnings. When the hedged item was recognized into earnings, it was reported in oil and natural gas revenues. Any change in fair value resulting from ineffectiveness was recognized in gain (loss) on derivatives not designated as hedges and hedge ineffectiveness, net. In August 2012, we determined on a prospective basis, to enter into economic hedges without electing cash flow hedge accounting.

We do not engage in derivative transactions for speculative purposes. We document our risk management strategy, and for the cash flow hedges, we tested the hedge effectiveness at the inception of and during the term of each hedge.

Limited Partnerships. Unit Petroleum Company is a general partner in 15 oil and natural gas limited partnerships sold privately and publicly. Some of our officers, directors, and employees own the interests in most of these partnerships. We share in each partnership's revenues and costs in accordance with formulas set out in each of the limited partnership agreement. The partnerships also reimburse us for certain administrative costs incurred on behalf of the partnerships.

Income Taxes. Measurement of current and deferred income tax liabilities and assets is based on provisions of enacted tax law; the effects of future changes in tax laws or rates are not included in the measurement. Valuation allowances are established where necessary to reduce deferred tax assets to the amount expected to be realized. Income tax expense is the tax payable for the year and the change during that year in deferred tax assets and liabilities.

The accounting for uncertainty in income taxes prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a return. Guidance is also provided on de-recognition, classification, interest and penalties, accounting in interim periods, disclosure, and transition. We have $0.4 million of unrecognized tax benefits.

Natural Gas Balancing. We use the sales method for recording natural gas sales. This method allows for recognition of revenue, which may be more or less than its share of pro-rata production from certain wells. We estimate our

December 31, 2014 balancing position to be approximately 5.1 Bcf on under-produced properties and approximately 4.4 Bcf on over-produced properties. We have recorded a receivable of $2.0 million on certain wells where we estimate that insufficient reserves are available for us to recover the under-production from future production volumes. We have also recorded a liability of $3.6 million on certain properties where we believe there are insufficient reserves available to allow the under-produced owners to recover their under-production from future production volumes. Our policy is to expense the pro-rata share of lease operating costs from all wells as incurred. Such expenses relating to the balancing position on wells in which we have imbalances are not material.

Employee and Director Stock Based Compensation. We recognize in our financial statements the cost of employee services received in exchange for awards of equity instruments based on the grant date fair value of those awards. The amount of our equity compensation cost relating to employees directly involved in exploration activities of our oil and natural gas segment is capitalized to our oil and natural gas properties. Amounts not capitalized to our oil and natural gas properties are recognized in general and administrative expense and operating costs of our business segments. We utilize the Black-Scholes option pricing model to measure the fair value of stock options and stock appreciation rights (SARs). The value of our restricted stock grants is based on the closing stock price on the date of the grants.

Impact of Financial Accounting Pronouncements.

Presentation of Financial Statements-Going Concern: Disclosure of Uncertainties about an Entity's Ability to Continue as a Going Concern. The FASB has issued ASU 2014-15. This is intended to define management's responsibility to evaluate whether there is substantial doubt about an organization's ability to continue as a going concern and to provide related footnote disclosures. For each reporting period, management will be required to evaluate whether there are conditions or events that raise substantial doubt about a company's ability to continue as a going concern within one year from the date financial statements are issued. The amendments are effective for annual periods ending after December 15, 2016, and interim periods within annual periods beginning after December 15, 2016. Early application is permitted for annual or interim reporting periods for which the financial statements have not previously been issued.

Compensation - Stock Compensation: Accounting for Share-Based Payments When the Terms of an Award Provide that a Performance Target Could Be Achieved after the Requisite Service Period. The FASB has issued ASU 2014-12, the amendments in the ASU require that a performance target that affects vesting and that could be achieved after the requisite service period be treated as a performance condition. A reporting entity should apply existing guidance in Topic 718, Compensation – Stock Compensation, as it relates to awards with performance conditions that affect vesting to account for such awards. The performance target should not be reflected in estimating the grant-date fair value of the award. Compensation cost should be recognized in the period in which it becomes probable that the performance target will be achieved and should represent the compensation cost attributable to the period(s) for which the requisite service has already been rendered. If the performance target becomes probable of being achieved before the end of the requisite service period, the remaining unrecognized compensation cost should be recognized prospectively over the remaining requisite service period. The total amount of compensation cost recognized during and after the requisite service period should reflect the number of awards that are expected to vest and should be adjusted to reflect those awards that ultimately vest. The requisite service period ends when the employee can cease rendering service and still be eligible to vest in the award if the performance target is achieved.The amendments in this ASU are effective for annual periods and interim periods within those annual periods beginning after December 15, 2015. Earlier adoption is permitted. We do not have any stock compensation awards with these conditions at this time.

Revenue from Contracts with Customers. The FASB has issued ASU 2014-09. This affects any entity using U.S. GAAP that either enters into contracts with customers to transfer goods or services or enters into contracts for the transfer of nonfinancial assets unless those contracts are within the scope of other standards (e.g., insurance contracts or lease contracts). The core principle of the guidance is that an entity should recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. The amendments in this ASU are effective for annual reporting periods beginning after December 15, 2016, including interim periods within that reporting period. Early application is not permitted. We are in the process of evaluating the impact it will have on our financial statements.

Presentation of Financial Statements and Property, Plant, and Equipment: Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity. The FASB has issued ASU 2014-08, the amendments in this update change the criteria for reporting discontinued operations while enhancing disclosures in this area. It also addresses sources of confusion and inconsistent application related to financial reporting of discontinued operations guidance in U.S. GAAP. Under the new guidance, only disposals representing a strategic shift that would have a major effect on the organization's operations and financial results should be presented as discontinued operations. In addition, it requires expanded disclosures about discontinued operations that will provide financial statement users with more information about the assets, liabilities, income, and expenses of discontinued operations. It also requires disclosure of pre-tax income attributable to a disposal of a significant part of an organization that does not qualify for discontinued operations reporting. The updates are effective for fiscal years, and interim periods within those years, beginning after December 15, 2014. Early adoption is permitted. We currently do not have any discontinued operations or disposals of components of an entity.

NOTE 3 – ACQUISITIONS AND DIVESTITURES

On September 17, 2012, we closed on the acquisition of certain oil and natural gas assets from Noble Energy, Inc. (Noble). After final closing adjustments, the acquisition included approximately 83,000 net acres primarily in the Granite Wash, Cleveland, and various other plays in western Oklahoma and the Texas Panhandle. The adjusted amount paid was $592.6 million.

As of the effective date of the Noble acquisition (April 1, 2012), the estimated proved reserves of the acquired properties were 44 million barrels of oil equivalent (MMBoe). The acquisition added approximately 24,000 net acres to our Granite Wash core area in the Texas Panhandle with significant resource potential including approximately 600 horizontal drilling locations. The total acreage acquired in other plays in western Oklahoma and the Texas Panhandle was approximately 59,000 net acres and is characterized by high working interest and operatorship, 95% of which was held by production. We also received four gathering systems as part of the transaction and other miscellaneous assets.

The Noble acquisition was accounted for using the acquisition method under ASC 805, Business Combinations, which required that the acquired assets and liabilities be recorded at their fair values as of the acquisition date. The following table summarizes the adjusted purchase price and the estimated values of assets acquired and liabilities assumed. It was based on information available to us at the time these consolidated financial statements were prepared and we believe these estimates are reasonable(in thousands):

Adjusted Purchase Price	
Total consideration given	$592,627
Adjusted Allocation of Purchase Price	
Oil and natural gas properties included in the full cost pool:	
Proved oil and natural gas properties	$260,799
Unproved oil and natural gas properties	353,343
Total oil and natural gas properties included in the full cost pool [1]	614,142
Gas gathering and processing equipment and other	25,163
Asset retirement obligation	(46,678)
Fair value of net assets acquired	$592,627

(1) We used a discounted cash flow model and made market assumptions as to future commodity prices, projections of estimated quantities of oil and natural gas reserves, expectations for timing and amount of future development and operating costs, projections of future rates of production, expected recovery rates, and risk adjusted discount rates.

Pro Forma Financial Information

The following unaudited pro forma financial information is presented to reflect the operations of the acquired assets as if the acquisition had been completed on January 1, 2012. The unaudited pro forma financial information was derived from the historical accounting records of the seller adjusted for estimated transaction costs, depreciation, depletion and amortization, ceiling test impact, general and administrative expenses, capitalized interest, and interest on the $400.0 million of Notes issued along with additional borrowings under our credit agreement to finance the acquisition. The unaudited pro forma financial information does not purport to be indicative of results of operations that would have occurred had the transaction occurred on the basis assumed above, nor is such information indicative of our expected future results of operations. The pro forma results of operations do not include any cost savings or other synergies that resulted, or may result, from the acquisition or any estimated costs that will be incurred to integrate these assets. Future results may vary significantly from the results reflected in this pro forma financial information because of future events and transactions, as well as other factors.

	Twelve months ended December 31, 2012 (In thousands, except per share amounts)
Pro forma:	
Revenues	$1,376,393
Net income	$83,940
Net income per common share:	
Basic	$1.75
Diluted	$1.74

From September 17, 2012, the date of the acquisition, through December 31, 2012, the portion of our revenues that were attributable to Noble were $21.4 million with a net loss of $0.8 million.

2012 Divestitures

In September 2012, we sold our interest in certain Bakken properties. The proceeds, net of related expenses were $226.6 million. In addition, we sold certain oil and natural gas assets located in Brazos and Madison Counties, Texas, for approximately $44.1 million. Proceeds from these dispositions reduced the net book value of the full cost pool with no gain or loss recognized.

2012 Other

In conjunction with the acquisition and divestitures completed in the third quarter 2012, we took the necessary steps to secure like-kind exchange tax treatment for the transactions under Section 1031 of the Internal Revenue Code.

2013 Divestitures and Assets Held for Sale

In August 2013, we sold additional Bakken property interests. The proceeds, net of related expenses, were $57.1 million. In addition, we had other non-core asset sales with proceeds, net of related expenses, of $21.7 million for 2013. Proceeds from these dispositions reduced the net book value of the full cost pool with no gain or loss recognized.

During 2013, we sold five 2,000-3,000 horsepower drilling rigs to unaffiliated third-parties for a gain of $16.5 million. Four of our idle drilling rigs were classified as assets held for sale at December 31, 2013.

2014 Divestitures

The four drilling rigs classified as assets held for sale at December 31, 2013 were sold to an unaffiliated third party in the first quarter of 2014. The proceeds of this sale, less costs to sell, exceeded the $16.3 million net book value of the drilling rigs, both in the aggregate and for each drilling rig, resulting in a gain of $9.6 million.

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We sold non-core oil and natural gas assets, net of related expenses, for $33.1 million during 2014. Proceeds from those dispositions reduced the net book value of our full cost pool with no gain or loss recognized.

NOTE 4 – EARNINGS PER SHARE

The following data shows the amounts used in computing earnings per share:

	Income (Numerator)	Weighted Shares (Denominator)	Per-Share Amount
	(In thousands except per share amounts)		
For the year ended December 31, 2014:			
Basic earnings per common share	$136,276	48,611	$2.80
Effect of dilutive stock options, restricted stock, and SARs	—	472	(0.02)
Diluted earnings per common share	$136,276	49,083	$2.78
For the year ended December 31, 2013:			
Basic earnings per common share	$184,746	48,218	$3.83
Effect of dilutive stock options, restricted stock, and SARs	—	354	(0.03)
Diluted earnings per common share	$184,746	48,572	$3.80
For the year ended December 31, 2012:			
Basic earnings per common share	$23,176	47,909	$0.48
Effect of dilutive stock options, restricted stock, and SARs	—	245	—
Diluted earnings per common share	$23,176	48,154	$0.48

The following options and their average exercise prices were not included in the computation of diluted earnings per share because the option exercise prices were greater than the average market price of our common stock for the years ended December 31:

	2014	2013	2012
Options and SARs	73,500	149,665	250,901
Average exercise price	$64.43	$58.41	$52.72

NOTE 5 – ACCRUED LIABILITIES

Accrued liabilities consisted of the following as of December 31:

	2014	2013
	(In thousands)	
Employee costs	$31,451	$27,633
Lease operating expenses	20,709	16,073
Interest payable	6,654	6,504
Taxes	3,284	2,313
Deposits on assets held for sale	—	3,750
Derivative settlements	—	416
Other	8,073	7,674
Total accrued liabilities	$70,171	$64,363

NOTE 6 – LONG-TERM DEBT AND OTHER LONG-TERM LIABILITIES

Long-Term Debt

Long-term debt consisted of the following as of December 31:

	2014	2013
	(In thousands)	
Credit agreement with an average interest rates of 2.9% at December 31, 2014	$166,000	$—
6.625% senior subordinated notes due 2021, net of unamortized discount of $3.8 million and $4.3 million at December 31, 2014 and 2013, respectively	646,163	645,696
Total long-term debt	$812,163	$645,696

Credit Agreement. Under our Senior Credit Agreement (credit agreement), the amount we can borrow is the lesser of the amount we elect (from time to time) as the commitment amount or the value of the borrowing base as determined by the lenders, but in either event not to exceed the maximum credit agreement amount of $900.0 million. Our current commitment amount is $500.0 million. Our current borrowing base is $900.0 million. We are charged a commitment fee ranging from 0.375 to 0.50 of 1% on the amount available but not borrowed. The fee varies based on the amount borrowed as a percentage of the amount of the total borrowing base. The credit agreement matures as of September 13, 2016. In connection with the most recent amendment of the credit agreement, we paid $1.5 million in origination, agency, syndication, and other related fees. We are amortizing these fees over the life of the credit agreement.

The amount of the borrowing base–which is subject to redetermination by the lenders on April 1st and October 1st of each year, is based primarily on a percentage of the discounted future value of our oil and natural gas reserves. There was no change to the borrowing base with the October 2014 redetermination. We or the lenders may request a onetime special redetermination of the borrowing base between each scheduled redetermination. In addition, we may request a redetermination following the completion of an acquisition that meets the requirements set forth in the credit agreement.

At our election, any part of the outstanding debt under the credit agreement may be fixed at a London Interbank Offered Rate (LIBOR). LIBOR interest is computed as the sum of the LIBOR base for the applicable term plus 1.75% to 2.50% depending on the level of debt as a percentage of the borrowing base and is payable at the end of each term, or every 90 days, whichever is less. Borrowings not under LIBOR bear interest at the prime rate specified in the credit agreement that in any event cannot be less than LIBOR plus 1.00%. Interest is payable at the end of each month and the principal may be repaid in whole or in part at anytime, without a premium or penalty. At December 31, 2014, we had $166.0 million outstanding borrowings under our credit agreement.

We can use borrowings for financing general working capital requirements for (a) exploration, development, production and acquisition of oil and gas properties, (b) acquisitions and operation of mid-stream assets, (c) issuance of standby letters of credit, (d) contract drilling services, and (e) general corporate purposes.

The credit agreement prohibits, among other things:

- the payment of dividends (other than stock dividends) during any fiscal year in excess of 30% of our consolidated net income for the preceding fiscal year;
- the incurrence of additional debt with certain limited exceptions; and
- the creation or existence of mortgages or liens, other than those in the ordinary course of business, on any of our properties, except in favor of our lenders.

The credit agreement also requires that we have at the end of each quarter:

- a current ratio (as defined in the credit agreement) of not less than 1 to 1; and
- a leverage ratio of funded debt to consolidated EBITDA (as defined in the credit agreement) for the most recently ended rolling four fiscal quarters of no greater than 4 to 1.

As of December 31, 2014, we were in compliance with the covenants contained in the credit agreement.

6.625% Senior Subordinated Notes. We have issued and outstanding an aggregate principal amount of $650.0 million, 6.625% senior subordinated notes (the Notes). The interest is payable semi-annually (in arrears) on May 15 and November 15 of each year, and the Notes will mature on May 15, 2021. In connection with the issuance of the Notes, we incurred $14.7 million of fees that are being amortized as debt issuance cost over the life of the Notes.

The Notes are subject to an Indenture dated as of May 18, 2011, between us and Wilmington Trust, National Association (successor to Wilmington Trust FSB), as Trustee (the Trustee), as supplemented by the First Supplemental Indenture dated as of May 18, 2011, between us, the Guarantors, and the Trustee, and as further supplemented by that the Second Supplemental Indenture dated as of January 7, 2013, between us, the Guarantors and the Trustee (as supplemented, the 2011 Indenture), establishing the terms and providing for the issuance of the Notes. The Guarantors are all of our direct and indirect subsidiaries. The discussion of the Notes in this report is qualified by and subject to the actual terms of the 2011 Indenture.

Unit, as the parent company, has no independent assets or operations. The guarantees by the Guarantors of the Notes (registered under registration statements) are full and unconditional, joint and several, subject to certain automatic customary releases, are subject to certain restrictions on the sale, disposition, or transfer of the capital stock or substantially all of the assets of a subsidiary guarantor, and other conditions and terms set out in the Indenture. Any of our subsidiaries that are not Guarantors are minor. There are no significant restrictions on our ability to receive funds from our subsidiaries through dividends, loans, advances or otherwise.

At any time before May 15, 2016, we may redeem the Notes, in whole or in part, at a redemption price equal to 100% of the principal amount plus a "make whole" premium, plus accrued and unpaid interest, if any, to the redemption date. On and after May 15, 2016, we may redeem all or, from time to time, a part of the Notes at certain redemption prices, plus accrued and unpaid interest. If a "change of control" occurs, subject to certain conditions, we must offer to repurchase from each holder all or any part of that holder's Notes at a purchase price in cash equal to 101% of the principal amount of the Notes plus accrued and unpaid interest, if any, to the date of purchase. The 2011 Indenture contains customary events of default. The 2011 Indenture also contains covenants that, among other things, limit our ability and the ability of certain of our subsidiaries to incur or guarantee additional indebtedness; pay dividends on our capital stock or redeem capital stock or subordinated indebtedness; transfer or sell assets; make investments; incur liens; enter into transactions with our affiliates; and merge or consolidate with other companies. We were in compliance with all covenants of the Notes as of December 31, 2014.

Other Long-Term Liabilities

Other long-term liabilities consisted of the following as of December 31:

	2014	2013
	(In thousands)	
ARO liability	$100,567	$133,657
Capital lease obligations	25,876	—
Workers' compensation	17,997	20,041
Separation benefit plans	11,276	9,382
Gas balancing liability	3,623	3,775
Deferred compensation plan	4,055	3,589
Other	410	—
	163,804	170,444
Less current portion	15,019	12,113
Total other long-term liabilities	$148,785	$158,331

Estimated annual principal payments under the terms of debt and other long-term liabilities from 2015 through 2019 are $15.0 million, $204.0 million, $8.4 million, $7.2 million, and $7.6 million, respectively.

Capital Leases

During 2014, our mid-stream segment entered into capital lease agreements for twenty compressors with initial terms of seven years. The underlying assets are included in gas gathering and processing equipment. The current portion of our capital lease obligations of $3.4 million is included in current portion of other long-term liabilities and the non-current portion of $22.5 million is included in other long-term liabilities in the accompanying Consolidated Balance Sheets as of December 31, 2014. These capital leases are discounted using annual rates of 4.0%. Total maintenance and interest remaining related to these leases are $11.4 million and $3.7 million, respectively at December 31, 2014. Annual payments, net of maintenance and interest, average $3.9 million annually through 2021. At the end of the term, our mid-stream segment has the option to purchase the assets at 10% of the fair market value of the assets at that time.

Future payments required under the capital leases at December 31, 2014 are as follows:

Ending December 31,	Amount (In thousands)
2015	$6,195
2016	6,195
2017	6,195
2018	6,195
2019	6,195
2020 and thereafter	9,967
Total future payments	40,942
Less payments related to:	
Maintenance	11,395
Interest	3,671
Present value of future minimum payments	$25,876

NOTE 7 – ASSET RETIREMENT OBLIGATIONS

We are required to record the estimated fair value of the liabilities relating to the future retirement of our long-lived assets (AROs). Our oil and natural gas wells are plugged and abandoned when the oil and natural gas reserves in those wells are depleted or the wells are no longer able to produce. The plugging and abandonment liability for a well is recorded in the period in which the obligation is incurred (at the time the well is drilled or acquired). None of our assets are restricted for purposes of settling these AROs. All of our AROs relate to plugging costs associated with our oil and gas wells.

The following table shows certain information about our AROs for the periods indicated:

	2014	2013
	(In thousands)	
ARO liability, January 1:	$133,657	$146,159
Accretion of discount	4,599	5,450
Liability incurred	6,246	4,857
Liability settled	(4,490)	(4,751)
Liability sold	(1,206)	(2,622)
Revision of estimates [1]	(38,239)	(15,436)
ARO liability, December 31:	100,567	133,657
Less current portion	3,204	2,954
Total long-term ARO liability	$97,363	$130,703

(1) Plugging liability estimates were revised in both 2014 and 2013 for updates in the cost of services used to plug wells over the preceding year. We had various upward and downward adjustments as well as changes in estimated timing of cash flows.

NOTE 8 – INCOME TAXES

A reconciliation of income tax expense, computed by applying the federal statutory rate to pre-tax income to our effective income tax expense is as follows:

	2014	2013	2012
	(In thousands)		
Income tax expense computed by applying the statutory rate	$78,029	$105,514	$13,791
State income tax, net of federal benefit	6,131	8,290	1,084
Statutory depletion and other	2,503	2,919	1,351
Income tax expense	$86,663	$116,723	$16,226

For the periods indicated, the total provision for income taxes consisted of the following:

	2014	2013	2012
	(In thousands)		
Current taxes:			
Federal	$8,594	$15,845	$2,084
State	784	146	(1,388)
	9,378	15,991	696
Deferred taxes:			
Federal	68,360	87,839	13,768
State	8,925	12,893	1,762
	77,285	100,732	15,530
Total provision	$86,663	$116,723	$16,226

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Deferred tax assets and liabilities are comprised of the following at December 31:

	2014	2013
	(In thousands)	
Deferred tax assets:		
Allowance for losses and nondeductible accruals	$55,231	$77,285
Net operating loss carryforward	54,901	61,055
Alternative minimum tax and research and development tax credit carryforward	25,991	17,258
	136,123	155,598
Deferred tax liability:		
Depreciation, depletion, amortization, and impairment	(1,000,811)	(943,411)
Net deferred tax liability	(864,688)	(787,813)
Current deferred tax asset	11,527	13,585
Non-current—deferred tax liability	$(876,215)	$(801,398)

Realization of the deferred tax assets are dependent on generating sufficient future taxable income. Although realization is not assured, management believes it is more likely than not that the deferred tax asset will be realized. The amount of the deferred tax asset considered realizable, however, could be reduced in the near-term if estimates of future taxable income are reduced. At December 31, 2014, we have federal net operating loss carryforwards of approximately $128.0 million which expire from 2020 to 2034.

We file income tax returns in the U.S. federal jurisdiction and various states. We are no longer subject to U.S. federal or state income tax examinations by tax authorities for years before 2011. We are currently under examination by the state of Texas for the 2011-2013 return years but have not been made aware of any adjustments that would be material to our financial statements. During 2014, we recognized a tax benefit relating to a research and development tax credit carryforward in conjunction with our BOSS drilling rig activities. Due to the nature and subjectivity surrounding the research and development credit and historical challenges by the IRS against companies who claim the credit, it is our belief that the full amount of the credit may not be eventually allowed by the IRS once we are no longer in an AMT tax paying position. A reconciliation of the beginning and ending amount of unrecognized tax benefits is as follows:

	2014	2013	2012
	(In thousands)		
Balance at January 1:	$—	$—	$—
Additions based on tax positions related to current year	410	—	—
Additions for tax positions of prior years	—	—	—
Reductions for tax positions of prior years	—	—	—
Settlements	—	—	—
Balance at December 31:	$410	$—	$—

At December 31, 2014, there was $0.4 million of unrecognized tax benefits that if recognized would affect the annual effective tax rate. We did not have any unrecognized tax benefits in 2013 or 2012.

NOTE 9 – EMPLOYEE BENEFIT PLANS

Under our 401(k) Employee Thrift Plan, employees who meet specified service requirements may contribute a percentage of their total compensation, up to a specified maximum, to the plan. We may match each employee’s contribution, up to a specified maximum, in full or on a partial basis. We made discretionary contributions under the plan of 120,333, 111,995, and 95,598 shares of common stock and recognized expense of $5.2 million, $6.0 million, and $5.5 million in 2014, 2013, and 2012, respectively.

We provide a salary deferral plan (Deferral Plan) which allows participants to defer the recognition of salary for income tax purposes until actual distribution of benefits which occurs at either termination of employment, death or certain defined unforeseeable emergency hardships. The liability recorded under the Deferral Plan at December 31, 2014 and 2013 was $4.1 million and $3.6 million, respectively. We recognized payroll expense and recorded a liability at the time of deferral.

Effective January 1, 1997, we adopted a separation benefit plan (Separation Plan). The Separation Plan allows eligible employees whose employment is involuntarily terminated or, in the case of an employee who has completed 20 years of service, voluntarily or involuntarily terminated, to receive benefits equivalent to four weeks salary for every whole year of service completed up to a maximum of 104 weeks. To receive payments, the recipient must waive any claims against us in exchange for receiving the separation benefits. On October 28, 1997, we adopted a Separation Benefit Plan for Senior Management (Senior Plan). The Senior Plan provides certain officers and key executives of Unit with benefits generally equivalent to the Separation Plan. The Compensation Committee of the Board of Directors has absolute discretion in the selection of the individuals covered in this plan. On May 5, 2004 we also adopted the Special Separation Benefit Plan (Special Plan). This plan is identical to the Separation Benefit Plan with the exception that the benefits under the plan vest on the earliest of a participant’s reaching the age of 65 or serving 20 years with the company.

On December 31, 2008, we amended all three Plans to be in compliance with Section 409A of the Internal Revenue Code of 1986, as amended. The key amendments to the Plans address, among other things, when distributions may be made, the timing of payments, and the circumstances under which employees become eligible to receive benefits. None of the amendments materially increase the benefits, grants or awards issuable under the Plans. We recognized expense of $2.7 million, $2.4 million, and $2.2 million in 2014, 2013, and 2012, respectively, for benefits associated with anticipated payments from these separation plans.

We have entered into key employee change of control contracts with three of our current executive officers. These severance contracts have an initial three-year term that is automatically extended for one year on each anniversary, unless a notice not to extend is given by us. If a change of control of the company, as defined in the contracts, occurs during the term of the severance contract, then the contract becomes operative for a fixed three-year period. The severance contracts generally provide that the executive’s terms and conditions for employment (including position, work location, compensation, and benefits) will not be adversely changed during the three-year period after a change of control. If the executive’s employment is terminated (other than for cause, death, or disability), the executive terminates for good reason during such three-year period, or the executive terminates employment for any reason during the 30-day period following the first anniversary of the change of control, and on certain terminations prior to a change of control or in connection with or in anticipation of a change of control, the executive is generally entitled to receive, in addition to certain other benefits, any earned but unpaid compensation; up to 2.9 times the executive's base salary plus annual bonus (based on historic annual bonus); and the company matching contributions that would have been made had the executive continued to participate in the company's 401(k) plan for up to an additional three years.

The severance contract provides that the executive is entitled to receive a payment in an amount sufficient to make the executive whole for any excise tax on excess parachute payments imposed under Section 4999 of the Code. As a condition to receipt of these severance benefits, the executive must remain in the employ of the company prior to change of control and render services commensurate with his position.

NOTE 10 – TRANSACTIONS WITH RELATED PARTIES

Unit Petroleum Company serves as the general partner of 15 oil and gas limited partnerships. Two investments by third parties and 13 (the employee partnerships) were formed to allow certain of our qualified employees and our directors to participate in Unit Petroleum's oil and gas exploration and production operations. The partnerships for the third party investments were formed in 1984 and two in 1986. Effective December 31, 2014, the 1984 partnership was dissolved. Employee partnerships have been formed for each year beginning with 1984 and ending with 2011. Interests in the employee partnerships were offered to the employees of Unit and its subsidiaries whose annual base compensation was at least a specified amount and to the directors of Unit.

The employee partnerships formed in 1984 through 1990 were consolidated into a single consolidating partnership in 1993 and the employee partnerships formed in 1991 through 1999 were also consolidated into the consolidating partnership in 2002. The consolidation of the 1991 through the 1999 employee partnerships was done by the general partners under the authority contained in the respective partnership agreements and did not involve any vote, consent or approval by the limited partners. The employee partnerships have each had a set percentage (ranging from 1% to 15%) of our interest in most of the oil and natural gas wells we drill or acquire for our own account during the particular year for which the partnership was formed. The total interest the employees have in our oil and natural gas wells by participating in these partnerships does not exceed one percent.

Amounts received in the years ended December 31, from both public and private Partnerships for which Unit is a general partner are as follows:

	2014	2013	2012
	(In thousands)		
Contract drilling	$4	$16	$246
Well supervision and other fees	435	470	434
General and administrative expense reimbursement	39	36	39

Related party transactions for contract drilling and well supervision fees are the related party's share of such costs. These costs are billed to related parties on the same basis as billings to unrelated parties for such services. General and administrative reimbursements are both direct general and administrative expense incurred on the related party's behalf and indirect expenses allocated to the related parties. Such allocations are based on the related party's level of activity and are considered by management to be reasonable.

The Chairman of our Board, John Nikkel is a 6.5% owner of Toklan Oil and Gas Company (Toklan), an oil and gas exploration and production company located in Tulsa, Oklahoma. Mr. Nikkel's son, Robert Nikkel is Toklan's President, and he owns approximately 35.3% of the company. In the ordinary course of business, there were two wells drilled for Toklan during 2014, with no activity in 2013 or 2012. Under its usual standard dayrate contract terms available generally to all similarly-situated customers at that time and in the same general drilling area, the Company received payments from Toklan of approximately $1.1 million in 2014 and had an accounts receivable balance of $0.4 million at December 31, 2014. The Company also paid royalties in 2014, in the ordinary course of business, of approximately $0.2 million to Toklan. There were no amounts to disclose for 2013 or 2012.

One of our directors, G. Bailey Peyton IV, also serves as the President and a significant investor in Upland Resources, L.L.C., a small independent oil and natural gas exploration company, and as Manager of Peyton Royalties, LP, a family-

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controlled limited partnership that owns royalty rights in wells in the Texas and Oklahoma Panhandles. In the ordinary course of business, there were no wells drilled for Upland Resources, L.L.C. during 2014 or 2013 and the Company drilled three wells during 2012, under its usual standard dayrate contracts, in which Upland Resources, L.L.C. was a participant, for which the Company received payments of approximately $1.6 million from Upland Resources, L.L.C. The Company also paid royalties, primarily due to its status as successor in interest to prior transactions and as operator of the wells involved and, in some cases, as lessee, with respect to certain wells in which Mr. Peyton, members of Mr. Peyton's family, and Peyton Royalties, LP have an interest. Such payments totaled approximately $1.3 million, $1.4 million, and $1.2 million during 2014, 2013, and 2012, respectively.

Our Audit Committee and the board, in accordance with our related party transaction policy, have determined that these arrangements are in the best interest of the Company.

NOTE 11 – SHAREHOLDER RIGHTS PLAN

We maintain a Shareholder Rights Plan (the Plan) designed to deter coercive or unfair takeover tactics, to prevent a person or group from gaining control of us without offering fair value to all our shareholders and to deter other abusive takeover tactics, which are not in the best interest of shareholders.

Under the terms of the Plan, each share of common stock is accompanied by one right, which given certain acquisition and business combination criteria, entitles the shareholder to purchase from us one one-hundredth of a newly issued share of Series A Participating Cumulative Preferred Stock at a price subject to adjustment by us or to purchase from an acquiring company certain shares of its common stock or the surviving company’s common stock at 50% of its value.

The rights become exercisable 10 days after we learn that an acquiring person (as defined in the Plan) has acquired 15% or more of the outstanding common stock of Unit or 10 business days after the commencement of a tender offer, which would result in a person owning 15% or more of our shares. We can redeem the rights for $0.01 per right at any date before the earlier of (i) the close of business on the 10th day following the time we learn that a person has become an acquiring person or (ii) May 19, 2015 (the “Expiration Date”). The rights will expire on the Expiration Date, unless redeemed earlier by Unit.

NOTE 12 – STOCK-BASED COMPENSATION

For restricted stock awards and stock options, we had:

	2014	2013	2012
	(In millions)		
Recognized stock compensation expense	$17.4	$16.1	$11.4
Capitalized stock compensation cost for our oil and natural gas properties	3.7	3.5	2.7
Tax benefit on stock based compensation	6.7	6.2	4.5

The remaining unrecognized compensation cost related to unvested awards at December 31, 2014 is approximately $17.4 million of which $2.7 million is anticipated to be capitalized. The weighted average period of time over which this cost will be recognized is 0.8 of a year.

At our annual meeting of stockholders held on May 2, 2012, our stockholders approved the Unit Corporation Stock and Incentive Compensation Plan Amended and Restated May 2, 2012 (the amended plan). The amended plan allows us to grant stock-based and cash-based compensation to our employees (including employees of subsidiaries) as well as non-employee directors. The amended plan succeeds the Non-employee Directors' 2000 Stock Option Plan (the option plan), with 2011 being the last year options were granted under the option plan.

The amended plan allows for the issuance of 3.3 million shares of common stock with 2.0 million shares being the maximum number of shares that can be issued as “incentive stock options.” Awards under this plan may be granted in any one or a combination of the following:

- incentive stock options under Section 422 of the Internal Revenue Code;
- non-qualified stock options;

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- performance shares;
- performance units;
- restricted stock;
- restricted stock units;
- stock appreciation rights;
- cash based awards; and
- other stock-based awards.

This plan also contains various limits as to the amount of awards that can be given to an employee in any fiscal year. All awards are generally subject to the minimum vesting periods, as determined by our Compensation Committee and included in the award agreement.

Expected volatilities are based on the historical volatility of our stock. We use historical data to estimate option exercise and termination rates within the model and aggregate groups that have similar historical exercise behavior for valuation purposes. To date, we have not paid dividends on our stock. The risk free interest rate is computed from the United States Treasury Strips rate using the term over which it is anticipated the grant will be exercised.

SARs

Activity pertaining to SARs granted under the Unit Corporation Stock and Incentive Compensation Plan is as follows:

	Number of Shares	Weighted Average Price
Outstanding at January 1, 2012	145,901	$46.59
Granted	—	—
Exercised	—	—
Forfeited	—	—
Outstanding at December 31, 2012	145,901	46.59
Granted	—	—
Exercised	—	—
Forfeited	—	—
Outstanding at December 31, 2013	145,901	46.59
Granted	—	—
Exercised	(14,131)	46.50
Forfeited	—	—
Outstanding at December 31, 2014	131,770	$46.60

There were no SARs granted or vested during 2014, 2013, or 2012.

Exercise Prices	Outstanding and exercisable SARs at December 31, 2014		
	Number of Shares	Weighted Average Remaining Contractual Life	Weighted Average Exercise Price
$44.31	91,255	3.0 years	$44.31
$51.76	40,515	1.9 years	$51.76

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The intrinsic value of SARs exercised in 2014 was $0.2 million. No cash is received from SARs exercised. The SARs expire after 10 years from the date of the grant. There was no aggregate intrinsic value on the 131,770 shares outstanding at December 31, 2014. The remaining weighted average contractual term is 2.6 years.

Restricted Stock

Activity pertaining to restricted stock awards granted under the amended plan is as follows:

Employees	Number of Shares	Weighted Average Price
Nonvested at January 1, 2012	447,961	$47.44
Granted	376,445	47.37
Vested	(220,788)	45.66
Forfeited	(14,091)	45.37
Nonvested at December 31, 2012	589,527	48.11
Granted	453,549	48.20
Vested	(248,003)	46.46
Forfeited	(18,330)	47.85
Nonvested at December 31, 2013	776,743	48.70
Granted	455,122	53.72
Vested	(304,804)	49.68
Forfeited	(26,775)	51.92
Nonvested at December 31, 2014	900,286	$50.81

Non-Employee Directors	Number of Shares	Weighted Average Price
Nonvested at January 1, 2012	—	$—
Granted	24,606	40.23
Vested	—	—
Forfeited	—	—
Nonvested at December 31, 2012	24,606	$40.23
Granted	21,128	41.65
Vested	(10,030)	40.23
Forfeited	—	—
Nonvested at December 31, 2013	35,704	$41.07
Granted	13,768	63.91
Vested	(14,336)	40.93
Forfeited	—	—
Nonvested at December 31, 2014	35,136	$50.08

The restricted stock awards vest in periods ranging from 2 to 3 years, except for a portion of those granted to certain executive officers. As to those executive officers, 40% of the shares granted, or 71,674 shares in 2014, and 30% of the shares granted, or 57,405 shares in 2013, and 46,441 shares in 2012 (the performance shares), will cliff vest in the first half of 2017, 2016, and 2015, respectively. The actual number of performance shares that vest in 2015, 2016, and 2017 will be based on the company's achievement of certain stock performance measures at the end of the term, and will range from 0% to 150% of the restricted shares granted as performance shares. Based on the selected performance criteria, the participants are estimated to receive the targeted amount (or approximately 100%) of the performance based shares.

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The fair value of the restricted stock granted in 2014, 2013, and 2012 at the grant date was $24.1 million, $21.3 million, and $16.9 million, respectively. The aggregate intrinsic value of the 319,140 shares of restricted stock that vested in 2014 on their vesting date was $20.2 million. The aggregate intrinsic value of the 935,422 shares of restricted stock outstanding subject to vesting at December 31, 2014 was $31.9 million with a weighted average remaining life of 0.7 of a year.

Employee Stock Option Plan

The Stock Option Plan, provided the granting of options for up to 2,700,000 shares of common stock to officers and employees. The option plan permitted the issuance of qualified or nonqualified stock options. Options granted typically became exercisable at the rate of 20% per year one year after being granted and expire after 10 years from the original grant date. The exercise price for options granted under this plan was the fair market value of the common stock on the date of the grant. In 2006, as a result of the approval of the adoption of the Unit Corporation Stock and Incentive Compensation Plan, no further awards were made under this plan.

Activity pertaining to the Stock Option Plan is as follows:

	Number of Shares	Weighted Average Exercise Price
Outstanding at January 1, 2012	138,980	$31.39
Granted	—	—
Exercised	(18,850)	20.38
Forfeited	(2,100)	37.83
Outstanding at December 31, 2012	118,030	33.03
Granted	—	—
Exercised	(48,110)	26.09
Forfeited	(1,000)	37.83
Outstanding at December 31, 2013	68,920	37.81
Granted	—	—
Exercised	(21,490)	37.83
Forfeited	(37,930)	37.83
Outstanding at December 31, 2014	9,500	$37.69

There were no shares that vested in 2014, 2013, or 2012. The intrinsic value of options exercised in 2014 was $0.4 million. Total cash received from the options exercised in 2014 was $0.4 million.

	Outstanding and Exercisable Options at December 31, 2014		
Exercise Price	Number of Shares	Weighted Average Remaining Contractual Life	Weighted Average Exercise Price
$37.69	9,500	0.4 years	$37.69

There was no aggregate intrinsic value on the 9,500 shares outstanding subject to options at December 31, 2014. The remaining weighted average contractual term is 0.4 of a year.

Non-Employee Directors' Stock Option Plan

Under the Unit Corporation 2000 Non-Employee Directors' Stock Option Plan, on the first business day following each annual meeting of shareholders, each person who was then a member of our Board of Directors and who was not then an employee of the company or any of its subsidiaries was granted an option to purchase 3,500 shares of common stock. The option price for each stock option was the fair market value of the common stock on the date the stock options were granted.

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The term of each option is 10 years and cannot be increased and no stock options were to be exercised during the first six months of its term except in case of death. As mentioned above, on May 2, 2012, our stockholders approved the amended plan which succeeds this plan, and no further awards were made under the non-employee director option plan.

Activity pertaining to the Directors’ Plan is as follows:

	Number of Shares	Weighted Average Exercise Price
Outstanding at January 1, 2012	199,500	$48.37
Granted	—	—
Exercised	(7,000)	20.28
Forfeited	—	—
Outstanding at December 31, 2012	192,500	49.39
Granted	—	—
Exercised	(17,500)	32.53
Forfeited	(3,500)	20.46
Outstanding at December 31, 2013	171,500	51.70
Granted	—	—
Exercised	(21,000)	33.94
Forfeited	—	—
Outstanding at December 31, 2014	150,500	$54.18

The intrinsic value of the 21,000 options exercised in 2014 was $0.6 million. Total cash received from options exercised in 2014 was $0.7 million.

	Outstanding and Exercisable Options at December 31, 2014		
Weighted Average Exercise Price	Number of Shares	Weighted Average Remaining Contractual Life	Weighted Average Exercise Price
$31.30 - $41.21	45,500	4.2 years	$37.88
$53.81 - $73.26	105,000	3.5 years	$61.24

The aggregate intrinsic value of the shares outstanding subject to options at December 31, 2014 was less than $0.1 million with a weighted average remaining contractual term of 3.7 years.

NOTE 13 – DERIVATIVES

Commodity Derivatives

We have entered into various types of derivative transactions covering some of our projected natural gas, NGLs, and oil production. These transactions are intended to reduce our exposure to market price volatility by setting the price(s) we will receive for that production. Our decisions on the price(s), type, and quantity of our production subject to a derivative contract is based, in part, on our view of current and future market conditions. As of December 31, 2014, our derivative transactions consisted of the following types of hedges:

- Swaps. We receive or pay a fixed price for the commodity and pay or receive a floating market price to the counterparty. The fixed-price payment and the floating-price payment are netted, resulting in a net amount due to or from the counterparty.

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- Collars. A collar contains a fixed floor price (put) and a ceiling price (call). If the market price exceeds the call strike price or falls below the put strike price, we receive the fixed price and pay the market price. If the market price is between the call and the put strike price, no payments are due from either party.

We have documented policies and procedures to monitor and control the use of derivative instruments. We do not engage in derivative transactions for speculative purposes. In August 2012, we determined–on a prospective basis–that we would no longer elect to use cash flow hedge accounting for our economic hedges. As a result, the change in fair value, on all commodity derivatives entered into after that determination, is reflected in the income statement and not in accumulated other comprehensive income (OCI). As of December 31, 2013, all cash flow hedges had expired.

At December 31, 2014, the following non-designated hedges were outstanding:

Term	Commodity	Contracted Volume	Weighted Average Fixed Price for Swaps	Contracted Market
Jan’15 – Dec’15	Natural gas – swap	40,000 MMBtu/day	$3.98	IF – NYMEX (HH)
Jan’15 – Mar’15	Natural gas – collar	30,000 MMBtu/day	$4.20-$5.03	IF – NYMEX (HH)
Jan’15 – Dec'15	Crude oil – swap	1,000 Bbl/day	$95.00	WTI – NYMEX

Subsequent to December 31, 2014, the following non-designated hedges were entered into:

Term	Commodity	Contracted Volume	Weighted Average Fixed Price for Swaps	Contracted Market
Apr’15 – Jun'15	Natural gas – swap	30,000 MMBtu/day	$3.10	IF – NYMEX (HH)
Apr’15 – Jun'15	Natural gas – collar	30,000 MMBtu/day	$2.92-$3.26	IF – NYMEX (HH)
Jul’15 – Sep'15	Natural gas – collar	30,000 MMBtu/day	$2.58-$3.04	IF – NYMEX (HH)

The following tables present the fair values and locations of the derivative transactions recorded in our Consolidated Balance Sheets at December 31:

	Balance Sheet Location	Derivative Assets Fair Value 2014	2013
		(In thousands)	
Commodity derivatives:			
Current	Current derivative assets	$31,139	$515
Long-term	Non-current derivative assets	—	—
Total derivative assets		$31,139	$515

	Balance Sheet Location	Derivative Liabilities Fair Value 2014	2013
		(In thousands)	
Commodity derivatives:			
Current	Current derivative liabilities	$—	$5,561
Long-term	Non-current derivative liabilities	—	—
Total derivative liabilities		$—	$5,561

If a legal right of set-off exists, we net the value of the derivative transactions we have with the same counterparty in our Consolidated Balance Sheets.

For hedges designated under cash flow accounting, we recognized in OCI the effective portion of any changes in fair value and reclassified the recognized gains (losses) on the sales to oil and natural gas revenue as the underlying transactions

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were settled. Because our cash flow hedges expired as of December 31, 2013, we had no balance in accumulated OCI at December 31, 2014 or 2013.

For our economic hedges that we elected not to apply cash flow accounting to, any changes in their fair value occurring before their maturity (i.e., temporary fluctuations in value) are reported in gain (loss) on derivatives not designated as hedges and hedge ineffectiveness, net in our Consolidated Statements of Income. Changes in the fair value of derivatives that were designated as cash flow hedges, to the extent they were effective in offsetting cash flows attributable to the hedged risk, were recorded in OCI until the hedged item was recognized into earnings. When the hedged item was recognized into earnings, it was reported in oil and natural gas revenues. Any change in fair value that resulted from ineffectiveness was recognized in gain (loss) on derivatives not designated as hedges and hedge ineffectiveness, net.

Effect of derivative instruments on the Consolidated Statements of Income (cash flow hedges) for the year ended December 31:

Derivative Instrument	Location of Gain or (Loss) Reclassified from Accumulated OCI into Income & Location of Gain or (Loss) Recognized in Income	Amount of Gain or (Loss) Reclassified from Accumulated OCI into Income (1)		Amount of Gain or (Loss) Recognized in Income (2)	
		2014	2013	2014	2013
		(In thousands)			
Commodity derivatives	Oil and natural gas revenue (1)	$—	$603	$—	$—
Commodity derivatives	Gain (loss) on derivatives not designated as hedges and hedge ineffectiveness, net (2)	—	—	—	(190)
	Total	$—	$603	$—	$(190)

(1) Effective portion of gain (loss).
(2) Ineffective portion of gain (loss).

Effect of Derivative Instruments on the Consolidated Statements of Income (derivatives not designated as hedging instruments) for the year ended December 31:

Derivatives Not Designated as Hedging Instruments	Location of Gain or (Loss) Recognized in Income on Derivative	Amount of Gain or (Loss) Recognized in Income on Derivative	
		2014	2013
		(In thousands)	
Commodity derivatives	Gain (loss) on derivatives not designated as hedges and hedge ineffectiveness, net (1)	$30,147	$(8,184)
Total		$30,147	$(8,184)

(1) Amount settled during the period is a loss of $6,038 and $1,764, respectively.

NOTE 14 – FAIR VALUE MEASUREMENTS

Fair value is defined as the amount that would be received from the sale of an asset or paid for the transfer of a liability in an orderly transaction between market participants (in either case, an exit price). To estimate an exit price, a three-level hierarchy is used prioritizing the valuation techniques used to measure fair value into three levels with the highest priority given to Level 1 and the lowest priority given to Level 3. The levels are summarized as follows:

- Level 1—unadjusted quoted prices in active markets for identical assets and liabilities.
- Level 2—significant observable pricing inputs other than quoted prices included within level 1 that are either directly or indirectly observable as of the reporting date. Essentially, inputs (variables used in the pricing models) that are derived principally from or corroborated by observable market data.
- Level 3—generally unobservable inputs which are developed based on the best information available and may include our own internal data.

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The inputs available to us determine the valuation technique we use to measure the fair values of our financial instruments.

The following tables set forth our recurring fair value measurements:

	December 31, 2014			
	Level 2	Level 3	Effect of Netting	Total
	(In thousands)			
Financial assets (liabilities):				
Commodity derivatives:				
Assets	$27,784	$3,355	$—	$31,139
Liabilities	—	—	—	—
	$27,784	$3,355	$—	$31,139

	December 31, 2013			
	Level 2	Level 3	Effect of Netting	Total
	(In thousands)			
Financial assets (liabilities):				
Commodity derivatives:				
Assets	$1,978	$20	$(1,483)	$515
Liabilities	(4,429)	(2,615)	1,483	(5,561)
	$(2,451)	$(2,595)	$—	$(5,046)

All of our counterparties are subject to master netting arrangements. If a legal right of set-off exists, we net the value of the derivative transactions we have with the same counterparty. We are not required to post any cash collateral with our counterparties and no collateral has been posted as of December 31, 2014.

The following methods and assumptions were used to estimate the fair values of the assets and liabilities in the table above.

Level 2 Fair Value Measurements

Commodity Derivatives. We measure the fair values of our crude oil and natural gas swaps using estimated internal discounted cash flow calculations based on the NYMEX futures index.

Level 3 Fair Value Measurements

Commodity Derivatives. The fair values of our natural gas and crude oil collars are estimated using internal discounted cash flow calculations based on forward price curves, quotes obtained from brokers for contracts with similar terms, or quotes obtained from counterparties to the agreements.

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The following tables are reconciliations of our level 3 fair value measurements:

	Net Derivatives For the Year Ended, December 31, 2014 (In thousands)	December 31, 2013
Beginning of period	$(2,595)	$(595)
Total gains or losses:		
Included in earnings [1]	6,108	(2,637)
Included in other comprehensive income (loss)	—	—
Settlements	(158)	637
End of period	$3,355	$(2,595)
Total gains (losses) for the period included in earnings attributable to the change in unrealized loss relating to assets still held at end of period	$5,950	$(2,000)

(1) Commodity sales collars are reported in the consolidated statements of income in oil and gas revenues (for cash flow hedges), and gain (loss) on derivatives not designated as hedges and hedge ineffectiveness, net, respectively.

The following table provides quantitative information about our Level 3 unobservable inputs at December 31, 2014:

Commodity [1]	Fair Value (In thousands)	Valuation Technique	Unobservable Input	Range
Natural gas collar	$3,355	Discounted cash flow	Forward commodity price curve	$0.00 - $1.32

(1) The commodity contracts detailed in this category include non-exchange-traded natural gas collars that are valued based on NYMEX. The forward pricing range represents the low and high price expected to be received within the settlement period.

Based on our valuation at December 31, 2014, we determined that the non-performance risk with regard to our counterparties was immaterial.

Fair Value of Other Financial Instruments

The following disclosure of the estimated fair value of financial instruments is made in accordance with accounting guidance for financial instruments. We have determined the estimated fair values by using available market information and valuation methodologies. Considerable judgment is required in interpreting market data to develop the estimates of fair value. The use of different market assumptions or valuation methodologies may have a material effect on the estimated fair value amounts.

At December 31, 2014, the carrying values on the consolidated balance sheets for cash and cash equivalents (classified as Level 1), accounts receivable, accounts payable, other current assets, and current liabilities approximate their fair value because of their short term nature.

Based on the borrowing rates currently available to us for credit agreement debt with similar terms and maturities and also considering the risk of our non-performance, long-term debt under our credit agreement at December 31, 2014 approximates its fair value. This debt would be classified as Level 2.

The carrying amounts of long-term debt, net of unamortized discount, associated with the Notes reported in the Consolidated Balance Sheets at December 31, 2014 and December 31, 2013 were $646.2 million and $645.7 million, respectively. We estimate the fair value of these Notes using quoted marked prices at December 31, 2014 and December 31, 2013 were $605.5 million and $688.2 million, respectively. These Notes would be classified as Level 2.

NOTE 15 – ACCUMULATED OTHER COMPREHENSIVE INCOME

Changes in accumulated other comprehensive income (loss) by component, net of tax, are as follows:

	Net Gains (Losses) on Cash Flow Hedges		
	2014	2013	2012
	(In thousands)		
Balance at January 1:	$—	$7,587	$19,026
Other comprehensive income before reclassification	—	(7,349)	18,635
Amounts reclassified from accumulated other comprehensive income	—	(238)	(30,074)
New current-period other comprehensive income	—	(7,587)	(11,439)
Balance at December 31:	$—	$—	$7,587

Amounts reclassified from accumulated other comprehensive income (loss) into the Consolidated Statements of Income for the year ended December 31:

	2014	2013	2012	Affected Line Item in the Statement Where Net Income is Presented
	(In thousands)			
Net gains (loss) on cash flow hedges				
Commodity derivatives	$—	$603	$51,853	Oil and natural gas revenues
Commodity derivatives	—	(190)	(2,616)	Gain (loss) on derivatives not designated as hedges and hedge ineffectiveness, net
	—	413	49,237	Total before tax
	—	(175)	(19,163)	Tax expense
Total reclassification for the period	$—	$238	$30,074	Net of tax

NOTE 16 – COMMITMENTS AND CONTINGENCIES

We lease office space or yards in Edmond, Oklahoma City, and Tulsa, Oklahoma; Houston, Texas; Englewood, Colorado; Pinedale, Wyoming; and Pittsburgh, Pennsylvania under the terms of operating leases expiring through July 2019. Additionally, we have several compressor rentals, equipment leases, and lease space on short-term commitments to stack excess drilling rig equipment and production inventory. Future minimum rental payments under the terms of the leases are approximately $6.8 million, $2.7 million, $0.2 million, and less than $0.1 million in 2015 through 2018, respectively. Total rent expense incurred was $13.6 million, $16.9 million, and $14.0 million in 2014, 2013, and 2012, respectively.

During 2014, our mid-stream segment entered into capital lease agreements for twenty compressors with initial terms of seven years. Future capital lease payments under the terms are approximately $6.2 million each year through 2019 and approximately $10.0 million thereafter. Total maintenance and interest remaining related to these leases are $11.4 million and $3.7 million, respectively at December 31, 2014. Annual payments, net of maintenance and interest, average $3.9 million annually through 2021. At the end of the term, our mid-stream segment has the option to purchase the assets at 10% of the fair market value of the assets at that time.

The Unit 1984 Oil and Gas Limited Partnership and the 1986 Energy Income Limited Partnership agreements along with the employee oil and gas limited partnerships require, on the election of a limited partner, that we repurchase the limited partner’s interest at amounts to be determined by appraisal in the future. These repurchases in any one year are limited to 20% of the units outstanding. We made repurchases of $45,000, $16,000, $56,000 in 2014, 2013, and 2012, respectively. Effective December 31, 2014, the Unit 1984 Oil and Gas Limited Partnership was dissolved.

We manage our exposure to environmental liabilities on properties to be acquired by identifying existing problems and assessing the potential liability. We also conduct periodic reviews, on a company-wide basis, to identify changes in our environmental risk profile. These reviews evaluate whether there is a probable liability, its amount, and the likelihood that the liability will be incurred. The amount of any potential liability is determined by considering, among other matters, incremental direct costs of any likely remediation and the proportionate cost of employees who are expected to devote a significant amount of time directly to any possible remediation effort. As it relates to evaluations of purchased properties, depending on the extent of an identified environmental problem, we may exclude a property from the acquisition, require the seller to remediate the property to our satisfaction, or agree to assume liability for the remediation of the property.

We have not historically experienced any environmental liability while being a contract driller since the greatest portion of risk is borne by the operator. Any liabilities we have incurred have been small and have been resolved while the drilling rig is on the location and the cost has been included in the direct cost of drilling the well.

For 2015 and 2016, we have committed to purchase approximately $22.3 million and $3.8 million, respectively, of new drilling rig components, drill pipe, drill collars, and related equipment. We have also committed to paying $1.4 million for Enterprise Resource Planning software over the next year and then $0.5 million for maintenance one year following implementation. Also over the next twelve months, we have $0.2 million remaining towards a gas accounting system.

We are subject to various legal proceedings arising in the ordinary course of our various businesses none of which, in our opinion, will result in judgments which would have a material adverse effect on our financial position, operating results or cash flows.

NOTE 17 – INDUSTRY SEGMENT INFORMATION

We have three main business segments offering different products and services:

- Oil and natural gas,
- Contract drilling, and
- Mid-stream

The oil and natural gas segment is engaged in the development, acquisition, and production of oil, NGLs, and natural gas properties. The contract drilling segment is engaged in the land contract drilling of oil and natural gas wells and the mid-stream segment is engaged in the buying, selling, gathering, processing, and treating of natural gas and NGLs.

We evaluate each segment’s performance based on its operating income, which is defined as operating revenues less operating expenses and depreciation, depletion, amortization, and impairment. Our oil and natural gas production outside the United States is not significant.

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UNIT CORPORATION AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

The following table provides certain information about the operations of each of our segments:

	2014		2013		2012	
	(In thousands)					
Revenues:						
Oil and natural gas	$740,079		$649,718		$567,944	
Contract drilling	566,012		479,091		579,368	
Elimination of inter-segment revenue	(89,495	)	(64,313	)	(49,649	)
Contract drilling net of inter-segment revenue	476,517		414,778		529,719	
Gas gathering and processing	445,934		378,397		290,773	
Elimination of inter-segment revenue	(89,586	)	(91,043	)	(73,313	)
Gas gathering and processing net of inter-segment revenue	356,348		287,354		217,460	
Total revenues	$1,572,944		$1,351,850		$1,315,123	
Operating income:						
Oil and natural gas	$199,392	(5)	$239,219		$(77,221	) (5)
Contract drilling	41,896	(6)	96,304		159,188	
Gas gathering and processing	2,015	(7)	10,757		5,780	(7)
Total operating income (1)	243,303		346,280		87,747	
General and administrative	(42,023	)	(38,323	)	(33,086	)
Gain on disposition of assets	8,953		17,076		253	
Interest expense, net	(17,371	)	(15,015	)	(14,137	)
Gain (loss) on derivatives not designated as hedges and hedge ineffectiveness, net	30,147		(8,374	)	(1,243	)
Other	(70	)	(175	)	(132	)
Income before income taxes	$222,939		$301,469		$39,402	
Identifiable assets:						
Oil and natural gas	$2,856,833		$2,441,792		$2,214,029	
Contract drilling	1,059,980		1,042,661		1,079,736	
Gas gathering and processing	500,255		473,717		413,708	
Total identifiable assets (2)	4,417,068		3,958,170		3,707,473	
Corporate assets	56,660		64,220		53,647	
Total assets	$4,473,728		$4,022,390		$3,761,120	
Capital expenditures:						
Oil and natural gas (3)	$740,262		$531,233		$1,145,337	
Contract drilling	176,683		64,325		77,520	
Gas gathering and processing	79,268	(4)	96,085		183,162	
Other (3)	17,067		4,483		11,083	
Total capital expenditures	$1,013,280		$696,126		$1,417,102	
Depreciation, depletion, amortization, and impairment:						
Oil and natural gas						
Depreciation, depletion, and amortization	$276,088		$226,498		$211,347	
Impairment of oil and natural gas properties	76,683	(5)	—		283,606	(5)
Contract drilling	159,688	(6)	71,194		81,007	
Gas gathering and processing	47,502	(7)	33,191		24,388	(7)
Other	3,051		3,024		2,279	

Total depreciation, depletion, amortization, and impairment	$563,012	$333,907	$602,627

(1) Operating income is total operating revenues less operating expenses, depreciation, depletion, amortization, and impairment and does not include general corporate expenses, (gain) loss on disposition of assets, gain (loss) on non-designated hedges and hedge ineffectiveness, interest expense, other income (loss), or income taxes.

(2) Identifiable assets are those used in Unit's operations in each industry segment. Corporate assets are principally cash and cash equivalents, short-term investments, corporate leasehold improvements, furniture and equipment.

(3) In 2013, we reclassified salt water disposal capital expenditures out of other and into oil and natural gas of $17.0 million for 2012.
(4) In 2014, we entered into capital leases for $28.2 million.
(5) In 2014 and 2012, we incurred non-cash ceiling test write-downs of our oil and natural gas properties of $76.7 million and $283.6 million pre-tax ($47.7 million and $176.5 million, net of tax), respectively.
(6) Depreciation, depletion, amortization, and impairment for contract drilling includes a $74.3 million pre-tax write-down for 31 drilling rigs, some older top drives, and certain drill pipe removed from service.
(7) Depreciation, depletion, amortization, and impairment for gas gathering and processing for 2014 includes a $7.1 million pre-tax write-down for three of our systems, Weatherford, Billy Rose, and Spring Creek and for 2012 includes a $1.2 million write-down of our Erick system.

NOTE 18 – SELECTED QUARTERLY FINANCIAL INFORMATION

Summarized unaudited quarterly financial information is as follows:

	Three Months Ended			
	March 31	June 30	September 30	December 31
	(In thousands except per share amounts)			
2014				
Revenues	$387,988	$405,431	$400,974	$378,551
Gross profit (loss)	$115,143	$113,973	$103,983	$(89,796) [1]
Net income (loss)	$56,945	$54,360	$67,522	$(42,551)
Net income (loss) per common share:				
Basic	$1.17	$1.12	$1.39	$(0.88)
Diluted	$1.17	$1.11	$1.37	$(0.88) [2]
2013				
Revenues	$318,532	$340,421	$333,776	$359,121
Gross profit	$83,683	$90,823	$79,082	$92,692 [1]
Net income	$40,206	$59,007	$34,232	$51,301
Net income per common share:				
Basic	$0.84	$1.22	$0.71	$1.06
Diluted	$0.83	$1.22	$0.70	$1.05

(1) Gross profit excludes general and administrative expense, interest expense, (gain) loss on disposition of assets, gain (loss) on non-designated hedges and hedge ineffectiveness, income taxes, and other income (loss).
(2) Due to the effect of the loss in the fourth quarter, the diluted earnings per share for the year's four quarters does not equal annual earnings per share.

SUPPLEMENTAL OIL AND GAS DISCLOSURES
(UNAUDITED)

Our oil and gas operations are substantially located in the United States. The capitalized costs at year-end and costs incurred during the year were as follows:

	2014	2013	2012
	(In thousands)		
Capitalized costs:			
Proved properties	$4,990,753	$4,235,712	$3,822,381
Unproved properties	485,568	545,588	521,659
	5,476,321	4,781,300	4,344,040
Accumulated depreciation, depletion, amortization, and impairment	(2,786,678)	(2,439,458)	(2,216,787)
Net capitalized costs	$2,689,643	$2,341,842	$2,127,253
Cost incurred:			
Unproved properties acquired	$76,041	$76,304	$420,467
Proved properties acquired	5,723	—	225,669
Exploration	68,811	33,373	46,467
Development	615,252	424,314	390,649
Asset retirement obligation	(37,687)	(17,951)	45,097
Total costs incurred	$728,140	$516,040	$1,128,349

The following table shows a summary of the oil and natural gas property costs not being amortized at December 31, 2014, by the year in which such costs were incurred:

	2014	2013	2012	2011 and Prior	Total
	(In thousands)				
Unproved properties acquired and wells in progress	$102,930	$64,795	$310,891	$6,952	$485,568

Unproved properties not subject to amortization relates to properties which are not individually significant and consist primarily of lease acquisition costs. The evaluation process associated with these properties has not been completed and therefore, the company is unable to estimate when these costs will be included in the amortization calculation.

The results of operations for producing activities are as follows:

	2014	2013	2012
	(In thousands)		
Revenues	$723,566	$633,792	$557,003
Production costs	(165,315)	(162,822)	(131,389)
Depreciation, depletion, amortization, and impairment	(347,220)	(222,672)	(492,475)
	211,031	248,298	(66,861)
Income tax (expense) benefit	(82,028)	(96,091)	27,533
Results of operations for producing activities (excluding corporate overhead and financing costs)	$129,003	$152,207	$(39,328)

Estimated quantities of proved developed oil, NGLs, and natural gas reserves and changes in net quantities of proved developed and undeveloped oil, NGLs, and natural gas reserves were as follows:

	Oil Bbls	NGLs Bbls	Natural Gas Mcf
	(In thousands)		
2014			
Proved developed and undeveloped reserves:			
Beginning of year	21,765	41,205	581,784
Revision of previous estimates [1]	(3,174)	(2,266)	(32,790)
Extensions and discoveries	5,327	10,850	113,541
Infill reserves in existing proved fields	2,775	3,577	47,189
Purchases of minerals in place	236	88	368
Production	(3,844)	(4,629)	(58,854)
Sales	(418)	(296)	(4,277)
End of year	22,667	48,529	646,961
Proved developed reserves:			
Beginning of year	15,594	30,437	464,234
End of year	17,448	35,850	500,950
Proved undeveloped reserves:			
Beginning of year	6,171	10,768	117,550
End of year	5,219	12,679	146,011
2013			
Proved developed and undeveloped reserves:			
Beginning of year	21,998	35,166	555,647
Revision of previous estimates [1]	(2,113)	836	2,421
Extensions and discoveries	4,678	7,273	68,611
Infill reserves in existing proved fields	2,299	1,945	21,573
Purchases of minerals in place	—	—	11
Production	(3,360)	(3,914)	(56,757)
Sales	(1,737)	(101)	(9,722)
End of year	21,765	41,205	581,784
Proved developed reserves:			
Beginning of year	16,441	25,657	452,844
End of year	15,594	30,437	464,234
Proved undeveloped reserves:			
Beginning of year	5,557	9,509	102,803
End of year	6,171	10,768	117,550
2012			
Proved developed and undeveloped reserves:			
Beginning of year	20,255	22,087	442,135
Revision of previous estimates [1]	(1,747)	(2,682)	(55,110)
Extensions and discoveries	5,014	4,819	54,761
Infill reserves in existing proved fields	4,196	3,018	25,057
Purchases of minerals in place	2,830	11,098	141,494
Production	(3,279)	(2,796)	(48,930)
Sales	(5,271)	(378)	(3,760)
End of year	21,998	35,166	555,647
Proved developed reserves:			
Beginning of year	15,618	16,649	372,311
End of year	16,441	25,657	452,844

Proved undeveloped reserves:			
Beginning of year	4,637	5,438	69,824
End of year	5,557	9,509	102,803

(1) Natural gas revisions of previous estimates decreased primarily due to a decline in natural gas prices.

Estimates of oil, NGLs, and natural gas reserves require extensive judgments of reservoir engineering data. Assigning monetary values to such estimates does not reduce the subjectivity and changing nature of such reserve estimates. Indeed the uncertainties inherent in the disclosure are compounded by applying additional estimates of the rates and timing of production and the costs that will be incurred in developing and producing the reserves. The information set forth in this report is, therefore, subjective and, since judgments are involved, may not be comparable to estimates submitted by other oil and natural gas producers. In addition, since prices and costs do not remain static, and no price or cost escalations or de-escalations have been considered, the results are not necessarily indicative of the estimated fair market value of estimated proved reserves, nor of estimated future cash flows.

The standardized measure of discounted future net cash flows (SMOG) was calculated using 12-month average prices and year-end costs and statutory tax rates, adjusted for permanent differences that relate to existing proved oil, NGLs, and natural gas reserves. SMOG as of December 31 is as follows:

	2014	2013	2012
	(In thousands)		
Future cash flows	$6,398,236	$5,573,119	$4,522,351
Future production costs	(2,069,636)	(1,734,985)	(1,405,773)
Future development costs	(560,102)	(571,170)	(431,673)
Future income tax expenses	(1,228,533)	(1,044,608)	(762,519)
Future net cash flows	2,539,965	2,222,356	1,922,386
10% annual discount for estimated timing of cash flows	(1,104,221)	(996,380)	(842,430)
Standardized measure of discounted future net cash flows relating to proved oil, NGLs, and natural gas reserves	$1,435,744	$1,225,976	$1,079,956

The principal sources of changes in the standardized measure of discounted future net cash flows were as follows:

	2014	2013	2012
	(In thousands)		
Sales and transfers of oil and natural gas produced, net of production costs	$(558,252)	$(470,970)	$(425,626)
Net changes in prices and production costs	(33,259)	188,826	(321,099)
Revisions in quantity estimates and changes in production timing	(135,125)	(10,650)	(148,648)
Extensions, discoveries, and improved recovery, less related costs	635,752	426,377	432,058
Changes in estimated future development costs	96,339	26,629	51,587
Previously estimated cost incurred during the period	164,430	96,457	104,377
Purchases of minerals in place	8,395	9	283,774
Sales of minerals in place	(19,135)	(43,435)	(112,359)
Accretion of discount	179,190	147,579	157,842
Net change in income taxes	(98,119)	(170,091)	94,678
Other—net	(30,448)	(44,711)	(124,537)
Net change	209,768	146,020	(7,953)
Beginning of year	1,225,976	1,079,956	1,087,909
End of year	$1,435,744	$1,225,976	$1,079,956

Certain information concerning the assumptions used in computing SMOG and their inherent limitations are discussed below. We believe this information is essential for a proper understanding and assessment of the data presented.

The assumptions used to compute SMOG do not necessarily reflect our expectations of actual revenues to be derived from those reserves nor their present worth. Assigning monetary values to the reserve quantity estimation process does not reduce the subjective and ever-changing nature of reserve estimates. Additional subjectivity occurs when determining present values because the rate of producing the reserves must be estimated. In addition to difficulty inherent in predicting the future, variations from the expected production rate could result from factors outside of our control, such as unintentional delays in development, environmental concerns or changes in prices or regulatory controls. Also, the reserve valuation assumes that all

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reserves will be disposed of by production. However, other factors such as the sale of reserves in place could affect the amount of cash eventually realized.

The December 31, 2014, future cash flows were computed by applying the unescalated 12-month average prices of $94.99 per barrel for oil, $45.25 per barrel for NGLs, and $4.36 per Mcf for natural gas (then adjusted for price differentials) relating to proved reserves and to the year-end quantities of those reserves. Future price changes are considered only to the extent provided by contractual arrangements in existence at year-end.

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

Future income tax expenses are computed by applying the appropriate year-end statutory tax rates to the future pretax net cash flows relating to proved oil, NGLs, and natural gas reserves less the tax basis of our properties. The future income tax expenses also give effect to permanent differences and tax credits and allowances relating to our proved oil, NGLs, and natural gas reserves.

Care should be exercised in the use and interpretation of the above data. As production occurs over the next several years, the results shown may be significantly different as changes in production performance, petroleum prices and costs are likely to occur.

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

None.

Item 9A. Controls and Procedures

(a) Evaluation of Disclosure Controls and Procedures

The company maintains “disclosure controls and procedures,” as that term is defined in Rule 13a-15(e) and Rule 15d-15(e) under the Securities Exchange Act of 1934 (the Exchange Act), that are designed to ensure that information required to be disclosed in reports the company files or submits under the Exchange Act is recorded, processed, summarized, and reported within the time periods specified in SEC rules and forms, and that such information is collected and communicated to management, including our Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure. In designing and evaluating its disclosure controls and procedures, our management recognized that no matter how well conceived and operated, disclosure controls and procedures can provide only reasonable, not absolute, assurance that the objectives of the disclosure controls and procedures are met. Our disclosure controls and procedures have been designed to meet, and our management believes that they meet, reasonable assurance standards. Based on their evaluation as of the end of the period covered by this Annual Report on Form 10-K, our Chief Executive Officer and Chief Financial Officer have concluded that, subject to the limitations noted above, the company’s disclosure controls and procedures were effective.

(b) 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 Exchange Act Rule 13a-15(f). Our management, including our Chief Executive Officer and Chief Financial Officer, conducted an evaluation of the effectiveness of our internal control over financial reporting based on the Internal Control—Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on the results of this evaluation, our management concluded that our internal control over financial reporting was effective as of December 31, 2014.

The effectiveness of the company's internal control over financial reporting as of December 31, 2014, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears herein.

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(c) Changes in Internal Control Over Financial Reporting

During the last quarter, there were no changes in our internal control over financial reporting that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Item 9B. Other Information

None.

PART III

Item 10. Directors, Executive Officers, and Corporate Governance

In accordance with Instruction G(3) of Form 10-K, the information required by this item is incorporated in this report by reference to the Proxy Statement, except for the information regarding our executive officers which is presented below. The Proxy Statement will be filed before our annual shareholders' meeting scheduled to be held on May 6, 2015.

Our Code of Ethics and Business Conduct applies to all directors, officers, and employees, including our Chief Executive Officer, our Chief Financial Officer, and our Controller. You can find our Code of Ethics and Business Conduct on our internet website, www.unitcorp.com. We will post any amendments to the Code of Ethics and Business Conduct, and any waivers that are required to be disclosed by the rules of either the SEC or the NYSE, on our internet website.

Because our common stock is listed on the NYSE, our Chief Executive Officer was required to make, and he has made, an annual certification to the NYSE stating that he was not aware of any violation of our corporate governance listing standards of the NYSE. Our Chief Executive Officer made his annual certification to that effect to the NYSE as of May 23, 2014. In addition, we have filed, as exhibits to this Annual Report on Form 10-K, the certifications of our Chief Executive Officer and Chief Financial Officer required under Section 302 of the Sarbanes-Oxley Act of 2002 to be filed with the SEC regarding the quality of our public disclosure.

Executive Officers

The table below and accompanying text sets forth certain information as of February 13, 2015 concerning each of our executive officers as well as certain officers of our subsidiaries. There were no arrangements or understandings between any of the officers and any other person(s) under which the officers were elected.

NAME	AGE	POSITION HELD
Larry D. Pinkston	60	Chief Executive Officer since April 1, 2005, Director since January 15, 2004, President since August 1, 2003, Chief Operating Officer since February 24, 2004, Vice President and Chief Financial Officer from May 1989 to February 24, 2004
Mark E. Schell	57	Senior Vice President since December 2002, General Counsel and Corporate Secretary since January 1987
David T. Merrill	54	Senior Vice President since May 2, 2012, Chief Financial Officer and Treasurer since February 24, 2004, Vice President of Finance from August 2003 to February 24, 2004
Brad J. Guidry	59	Executive Vice President, Unit Petroleum Company since March 1, 2005
John Cromling	67	Executive Vice President, Unit Drilling Company since April 15, 2005
Robert Parks	60	Manager and President, Superior Pipeline Company, L.L.C. since June 1996

Mr. Pinkston joined the company in December 1981. He had served as Corporate Budget Director and Assistant Controller before being appointed Controller in February, 1985. In December, 1986 he was elected Treasurer of the company and was elected to the position of Vice President and Chief Financial Officer in May, 1989. In August, 2003, he was elected to the position of President. He was elected a director of the company by the Board in January, 2004. In February, 2004, in addition to his position as President, he was elected to the office of Chief Operating Officer. In April 2005, he also began serving as Chief Executive Officer. Mr. Pinkston holds the offices of President, Chief Executive Officer, and Chief Operating Officer. He holds a Bachelor of Science Degree in Accounting from East Central University of Oklahoma.

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Mr. Schell joined the company in January 1987, as its Secretary and General Counsel. In 2003, he was promoted to Senior Vice President. From 1979 until joining Unit Corporation, Mr. Schell was Counsel, Vice President, and a member of the Board of Directors of C & S Exploration Inc. He received a Bachelor of Science degree in Political Science from Arizona State University and his Juris Doctorate degree from the University of Tulsa College of Law. He is a member of the Oklahoma Bar Association as well as the Association of Corporate Counsel. Mr. Schell is a director of the Oklahoma Independent Petroleum Association and is Chairman of its legal committee. In addition, he is the Chairman and a director of the Oklahoma Injury Benefit Coalition, an Oklahoma non-profit association advocating for alternatives to Oklahoma's current Workers' Compensation system. He is also a member of the State Chamber of Oklahoma board of directors and serves on the board of advisors for the Greater Oklahoma City Chamber.

Mr. Merrill joined the company in August 2003 and served as its Vice President of Finance until February 2004 when he was elected to the position of Chief Financial Officer and Treasurer. In May 2012, he was promoted to Senior Vice President. From May 1999 through August 2003, Mr. Merrill served as Senior Vice President, Finance with TV Guide Networks, Inc. From July 1996 through May 1999 he was a Senior Manager with Deloitte & Touche LLP. From July 1994 through July 1996 he was Director of Financial Reporting and Special Projects for MAPCO, Inc. He began his career as an auditor with Deloitte, Haskins & Sells in 1983. Mr. Merrill received a Bachelor of Business Administration Degree in Accounting from the University of Oklahoma and is a Certified Public Accountant.

Mr. Guidry joined Unit Petroleum Company in August 1988 as a Staff Geologist. In 1991, he was promoted to Geologic Manager overseeing the Geologic Operations of the company. In January 2003, he was promoted to Vice President of the West division. In March 2005, Mr. Guidry was promoted to Senior Vice President of Exploration for Unit Petroleum Company. From 1979 to 1988, he was employed as a Division Geologist for Reading and Bates Petroleum Co. From 1978 to 1979, he worked with ANR Resources in Houston. He began his career as an open hole well logging engineer with Dresser Atlas Oilfield Services. Mr. Guidry graduated from Louisiana State University with a Bachelor of Science degree in Geology.

Mr. Cromling joined Unit Drilling Company in 1997 as a Vice-President and Division Manager. In April 2005, he was promoted to the position of Executive Vice-President of Drilling for Unit Drilling Company. In 1980, he formed Cromling Drilling Company which managed and operated drilling rigs until 1987. From 1987 to 1997, Cromling Drilling Company provided engineering consulting services and generated and drilled oil and natural gas prospects. Prior to this, he was employed by Big Chief Drilling for 11 years and served as Vice-President. Mr. Cromling graduated from the University of Oklahoma with a degree in Petroleum Engineering.

Mr. Parks founded Superior Pipeline Company, L.L.C. in 1996. When Superior was acquired by the company in July 2004, he continued with Superior as one of its managers and as its President. From April 1992 through April 1996 Mr. Parks served as Vice-President—Gathering and Processing for Cimarron Gas Companies. From December 1986 through March 1992, he served as Vice-President—Business Development for American Central Gas Companies. Mr. Parks began his career as an engineer with Cities Service Company in 1978. He received a Bachelor of Science degree in Chemical Engineering from Rice University and his M.B.A. from the University of Texas at Austin.

Item 11. Executive Compensation

In accordance with Instruction G(3) of Form 10-K, the information required by this Item is incorporated into this report by reference to the Proxy Statement (see Item 10 above).

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

The following table provides information for all equity compensation plans as of the fiscal year ended December 31, 2014, under which our equity securities were authorized for issuance:

Plan Category	Number of Securities to be Issued Upon Exercise of Outstanding Options, Warrants and Rights (a)	Weighted Average Exercise Price of Outstanding Options, Warrants and Rights (b)	Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plans (Excluding Securities Reflected in Column (a)) (c)
Equity compensation plans approved by security holders (1)	160,000 (2)	$53.20	1,287,534 (3)
Equity compensation plans not approved by security holders	—	—	—
Total	160,000	$53.20	1,287,534

(1) Shares awarded under all above plans may be newly issued, from our treasury or acquired in the open market.
(2) This number includes the following:
9,500 stock options outstanding under the company's Amended and Restated Stock Option Plan.
150,500 stock options outstanding under the Non-Employee Directors' Stock Option Plan.
(3) This number reflects the shares available for issuance under the Unit Corporation Stock and Incentive Compensation Plan Amended and Restated May 2, 2012 (the amended plan). The amended plan allows us to grant stock-based compensation to our employees and non-employee directors. The previous balance of 230,000 shares that were available for issuance under the Non-Employee Directors' Stock Option Plan were transferred to the amended plan on May 2, 2012. No more than 2,000,000 of the shares available under the amended plan may be issued as "incentive stock options" and all of the shares available under this plan may be issued as restricted stock. In addition, shares related to grants that are forfeited, terminated, canceled, expire unexercised, or settled in such manner that all or some of the shares are not issued to a participant shall immediately become available for issuance.

In accordance with Instruction G(3) of Form 10-K, the information required by this Item is incorporated into this report by reference to the Proxy Statement (see Item 10 above).

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

In accordance with Instruction G(3) of Form 10-K, the information required by this Item is incorporated into this report by reference to the Proxy Statement (see Item 10 above).

Item 14. Principal Accounting Fees and Services

In accordance with Instruction G(3) of Form 10-K, the information required by this Item is incorporated into this report by reference to the Proxy Statement (see Item 10 above).

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PART IV

Item 15. Exhibits, Financial Statement Schedules

(a) Financial Statements, Schedules and Exhibits:

1. Financial Statements:

Included in Part II of this report:

Report of Independent Registered Public Accounting Firm
Consolidated Balance Sheets as of December 31, 2014 and 2013
Consolidated Statements of Income for the years ended December 31, 2014, 2013, and 2012
Consolidated Statements of Comprehensive Income for the Years Ended December 31, 2014, 2013, and 2012
Consolidated Statements of Changes in Shareholders' Equity for the years ended December 31, 2012, 2013, and 2014
Consolidated Statements of Cash Flows for the years ended December 31, 2014, 2013, and 2012
Notes to Consolidated Financial Statements

2. Financial Statement Schedules:

Included in Part IV of this report for the years ended December 31, 2014, 2013, and 2012:

Schedule II—Valuation and Qualifying Accounts and Reserves

Other schedules are omitted because of the absence of conditions under which they are required or because the required information is included in the consolidated financial statements or notes thereto.

3. Exhibits:

The exhibit numbers in the following list correspond to the numbers assigned such exhibits in the Exhibit Table of Item 601 of Regulation S-K.

3.1	Restated Certificate of Incorporation of Unit Corporation (filed as Exhibit 3.1 to Unit's Form 8-K, dated June 29, 2000, which is incorporated herein by reference).
3.1.2	Certificate of Amendment of Amended and Restated Certificate of Incorporation of the Company (filed as Exhibit 3.1 to Unit's Form 8-K, dated May 9, 2006 which is incorporated herein by reference).
3.2	By-Laws of Unit Corporation as amended and restated June 17, 2014 (filed as Exhibit 3.2 to Unit's Form 8-K, dated June 23, 2014 which is incorporated herein by reference).
4.1	Form of Common Stock Certificate (filed as Exhibit 4.1 to Unit's Form S-3 (File No. 333-83551), which is incorporated herein by reference).
4.2	Rights Agreement as amended and restated on May 18, 2005 (filed as Exhibit 4.1 to Unit's Form 8-K dated May 18, 2005, which is incorporated herein by reference).
4.3	Amendment to Rights Agreement dated March 24, 2009 (filed as Exhibit 4.1 to Unit's Form 8-K dated March 23, 2009, which is incorporated herein by reference).

4.4	Standstill Agreement dated March 24, 2009, by and between us and the George Kaiser Foundation (filed as Exhibit 4.2 to Unit's Form 8-K dated March 23, 2009, which is incorporated herein by reference).
4.5	Indenture dated as of May 18, 2011, by and between the Company and Wilmington Trust FSB, as trustee (filed as Exhibit 4.1 to Unit's Form 8-K dated May 18, 2011, which is incorporated herein by reference).
4.6	First Supplemental Indenture (including form of note) dated as of May 18, 2011, by and among the Company, as issuer, the Subsidiary Guarantors (as defined therein), as guarantors and Wilmington Trust FSB as trustee (filed as Exhibit 4.1 to Unit's Form 8-K dated May 18, 2011, which is incorporated herein by reference).

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4.7	Registration Rights Agreement dated July 24, 2012, among Unit Corporation, certain of its wholly-owned subsidiaries party thereto, as guarantors, and Merrill Lynch, Pierce, Fenner & Smith Incorporated, as the representative of the several initial purchasers (filed as Exhibit 4.3 to Unit’s Form 8-K dated July 24, 2012, which is incorporated herein by reference).
10.1.1	Third Amended and Restated Security Agreement effective November 1, 2005 (filed as Exhibit 10.2 to Unit’s Form 8-K dated November 4, 2005, which is incorporated herein by reference).
10.1.2*	Form of Unit Corporation Restricted Stock Bonus Agreement (filed as Exhibit 10.1 to Unit’s Form 8-K dated December 13, 2005, which is incorporated herein by reference).
10.1.3*	Unit Corporation Stock and Incentive Compensation Plan Amended and Restated May 2, 2012 (filed as Exhibit 10 to Unit’s Form 8-K dated May 2, 2012, which is incorporated herein by reference).
10.1.4	Amended and Restated Key Employee Change of Control Contract dated August 19, 2008 (filed as Exhibit 10.1 to Unit’s Form 8-K dated August 25, 2008, which is incorporated herein by reference).
10.1.5	Senior Credit Agreement dated September 13, 2011 by and among the Company and the subsidiaries named therein (as borrowers), BOKF, NA DBA Bank of Oklahoma, as Administrative Agent, and the institutions named therein (as lenders) (filed as Exhibit 10.1 to Unit’s Form 8-K dated September 13, 2011, which is incorporated herein by reference).
10.1.6	Gas Purchase Agreement dated November 21, 2011 by and between Superior Pipeline Company, L.L.C. and Sullivan and Company, L.L.C. (filed as Exhibit 10.1 to Unit’s Form 8-K dated November 21, 2011, which is incorporated herein by reference).
10.1.7	First Amendment and Consent, dated September 5, 2012, to the Senior Credit Agreement by and among the Company and the subsidiaries named therein (as borrowers), BOKF, NA DBA Bank of Oklahoma, as Administrative Agent, and the institutions named therein (as lenders) (filed as exhibit 10.1 to Unit's Form 8-K dated September 5, 2012, which is incorporated herein by reference).
10.2.1	Unit 1979 Oil and Gas Program Agreement of Limited Partnership (filed as Exhibit I to Unit Drilling and Exploration Company’s Registration Statement on Form S-1 as S.E.C. File No. 2-66347, which is incorporated herein by reference).
10.2.3*	Unit’s Amended and Restated Stock Option Plan (filed as an Exhibit to Unit’s Registration Statement on Form S-8 as S.E.C. File No’s. 33-19652, 33-44103, 33-64323 and 333-39584 which is incorporated herein by reference).
10.2.4*	Unit Corporation Non-Employee Directors’ Stock Option Plan (filed as an Exhibit to Form S-8 as S.E.C. File No. 33-49724 and File No. 333-166605, which are incorporated herein by reference).
10.2.5*	Unit Corporation Employees’ Thrift Plan (filed as an Exhibit to Form S-8 as S.E.C. File No. 33-53542, which is incorporated herein by reference).
10.2.6	Unit Consolidated Employee Oil and Gas Limited Partnership Agreement (filed as an Exhibit to Unit’s Annual Report under cover of Form 10-K for the year ended December 31, 1993, which is incorporated herein by reference).

10.2.7*	Unit Corporation Salary Deferral Plan (filed as an Exhibit to Unit's Annual Report under cover of Form 10-K for the year ended December 31, 1993, which is incorporated herein by reference).
10.2.8*	Unit Corporation Separation Benefit Plan for Senior Management as amended (filed as an Exhibit 10.1 to Unit's Form 8-K dated December 20, 2004).
10.2.9*	Unit Corporation Special Separation Benefit Plan as amended (filed as Exhibit 10.3 to Unit's Form 8-K dated December 20, 2004).
10.2.10	Unit 2000 Employee Oil and Gas Limited Partnership Agreement of Limited Partnership (filed as an Exhibit to Unit's Annual Report under the cover of Form 10-K for the year ended December 31, 1999).
10.2.11*	Unit Corporation 2000 Non-Employee Directors' Stock Option Plan (filed as an Exhibit to Form S-8 as S.E.C. File No. 333-38166, which is incorporated herein by reference).
10.2.12	Unit 2001 Employee Oil and Gas Limited Partnership Agreement of Limited Partnership (filed as an Exhibit to Unit's Annual Report under the cover of Form 10-K for the year ended December 31, 2000).
10.2.13	Unit 2002 Employee Oil and Gas Limited Partnership Agreement of Limited Partnership (filed as an Exhibit to Unit's Annual Report under cover of Form 10-K for the year ended December 31, 2001).

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10.2.14	Unit 2003 Employee Oil and Gas Limited Partnership Agreement of Limited Partnership (filed as an Exhibit to Unit’s Annual Report under cover of Form 10-K for the year ended December 31, 2002).
10.2.15	Unit 2004 Employee Oil and Gas Limited Partnership Agreement of Limited Partnership (filed as an Exhibit to Unit’s Annual Report under cover of Form 10-K for the year ended December 31, 2003).
10.2.16	Unit 2005 Employee Oil and Gas Limited Partnership Agreement of Limited Partnership (filed as an Exhibit to Unit’s Annual Report under cover of Form 10-K for the year ended December 31, 2004).
10.2.17*	Form of Indemnification Agreement entered into between the Company and its executive officers and directors (filed as Exhibit 10.1 to Unit’s Form 8-K dated February 22, 2005, which is incorporated herein by reference).
10.2.18	Unit 2006 Employee Oil and Gas Limited Partnership Agreement of Limited Partnership (filed as an Exhibit to Unit’s Annual Report under cover of Form 10-K for the year ended December 31, 2005).
10.2.19	Unit 2007 Employee Oil and Gas Limited Partnership Agreement of Limited Partnership (filed as an Exhibit to Unit’s Annual Report under cover of Form 10-K for the year ended December 31, 2006).
10.2.20*	Separation Benefit Plan as amended August 21, 2007 (filed as an Exhibit to Unit’s Form 10-Q for the quarter ended September 30, 2007).
10.2.21	Unit 2008 Employee Oil and Gas Limited Partnership Agreement of Limited Partnership (filed as an Exhibit to Unit’s Annual Report under cover of Form 10-K for the year ended December 31, 2007).
10.2.22*	Annual Bonus Performance Plan entered into October 21, 2008 (filed as Exhibit 10.1 to Unit’s Form 8-K dated October 23, 2008, which is incorporated herein by reference).
10.2.23*	Separation Benefit Plan as amended October 21, 2008 (filed as Exhibit 10.2 to Unit’s Form 8-K dated October 23, 2008, which is incorporated herein by reference).
10.2.24*	Separation Benefit Plan as amended December 31, 2008 (filed as Exhibit 10.1 to Unit’s Form 8-K dated January 6, 2009, which is incorporated herein by reference).
10.2.25*	Special Separation Benefit Plan as amended December 31, 2008 (filed as Exhibit 10.2 to Unit’s Form 8-K dated January 6, 2009, which is incorporated herein by reference).
10.2.26*	Separation Benefit Plan for Senior Management as amended December 31, 2008 (filed as Exhibit 10.3 to Unit’s Form 8-K dated January 6, 2009, which is incorporated herein by reference).
10.2.27	Unit 2009 Employee Oil and Gas Limited Partnership Agreement of Limited Partnership (filed as an Exhibit to Unit’s Annual Report under cover of Form 10-K for the year ended December 31, 2008).
10.2.28*	Unit Corporation 2000 Non-Employee Directors’ Stock Option Plan as Amended and Restated August 25, 2004 (as amended on May 29, 2009 and filed as Exhibit 10.1 to Unit’s Form 8-K dated May 29, 2009, which is incorporated herein by reference).
10.2.29	Unit 2010 Employee Oil and Gas Limited Partnership Agreement of Limited Partnership (filed as an Exhibit to Unit’s Annual Report under cover of Form 10-K for the year ended December 31, 2009).

10.2.30	Unit 2011 Employee Oil and Gas Limited Partnership Agreement of Limited Partnership (filed as an Exhibit to Unit's Annual Report under cover of Form 10-K for the year ended December 31, 2010).
12	Computation Ratio of Earnings to Fixed Charges
21	Subsidiaries of the Registrant (filed herein).
23.1	Consent of Independent Registered Public Accounting Firm, PricewaterhouseCoopers LLP (filed herein).
23.2	Consent of Ryder Scott Company, L.P. (filed herein).
31.1	Certification of Chief Executive Officer under Rule 13a - 14(a) of the Exchange Act (filed herein).
31.2	Certification of Chief Financial Officer under Rule 13a - 14(a) of the Exchange Act (filed herein).
32	Certification of Chief Executive Officer and Chief Financial Officer under Rule 13a-14(a) of the Exchange Act and 18 U.S.C. Section 1350, as adopted under Section 906 of the Sarbanes-Oxley Act of 2002 (filed herein).
99.1	Ryder Scott Company, L.P. Summary Report (filed herein).
101.INS	XBRL Instance Document.

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101.SCH	XBRL Taxonomy Extension Schema Document.
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document.
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document.
101.LAB	XBRL Taxonomy Extension Labels Linkbase Document.
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document.

* Indicates a management contract or compensatory plan identified under the requirements of Item 15 of Form 10-K.

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Schedule II
UNIT CORPORATION AND SUBSIDIARIES
VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

Allowance for Doubtful Accounts:

Description	Balance at Beginning of Period	Additions Charged to Costs & Expenses	Deductions & Net Write-Offs	Balance at End of Period
	(In thousands)			
Year ended December 31, 2014	$5,342	$3,562	$(3,865)	$5,039
Year ended December 31, 2013	$5,343	$—	$(1)	$5,342
Year ended December 31, 2012	$5,343	$90	$(90)	$5,343

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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.

	UNIT CORPORATION
DATE: February 24, 2015 By:	/s/ LARRY D. PINKSTON LARRY D. PINKSTON President and Chief Executive Officer (Principal Executive Officer)

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 on the 24th day of February, 2015.

Name	Title
/s/ JOHN G. NIKKEL John G. Nikkel	Chairman of the Board and Director
/s/ LARRY D. PINKSTON Larry D. Pinkston	President and Chief Executive Officer, Chief Operating Officer and Director (Principal Executive Officer)
/s/ DAVID T. MERRILL David T. Merrill	Senior Vice President, Chief Financial Officer and Treasurer (Principal Financial Officer)
/s/ DON A. HAYES Don A. Hayes	Vice President, Controller (Principal Accounting Officer)
/s/ J. MICHAEL ADCOCK J. Michael Adcock	Director
/s/ GARY CHRISTOPHER Gary Christopher	Director
/s/ STEVEN B. HILDEBRAND Steven B. Hildebrand	Director
/s/ WILLIAM B. MORGAN William B. Morgan	Director
/s/ LARRY C. PAYNE Larry C. Payne	Director
/s/ G. BAILEY PEYTON IV G. Bailey Peyton IV	Director
/s/ ROBERT SULLIVAN, JR. Robert Sullivan, Jr.	Director

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EXHIBIT INDEX

Exhibit No.	Description
12	Computation Ratio of Earnings to Fixed Charges
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