UNIT CORP
Form 10-K
February 25, 2014
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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, 2013
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, 2013, 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, 2013) held by non-affiliates was approximately $1,080,689,810
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 14, 2014
Common Stock, $0.20 par value per share	49,232,860 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 7, 2014. The Proxy Statement shall be filed within 120 days after the end of the fiscal year to which this report relates.	Part III

Exhibit Index—See Page 119

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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, 2013

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 and, as appropriate, one or more of Unit Corporation and 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 14, 2014:

Completed gross wells in which we own an interest	9,842
Number of drilling rigs we own	117

Number of natural gas treatment plants we own	3
Number of processing plants we own	15
Number of natural gas gathering systems we own	38

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2013 SEGMENT OPERATIONS HIGHLIGHTS

Oil and Natural Gas

- Attained net proved oil, NGLs, and natural gas reserves of 159.9 million barrels of oil equivalents (MMBoe), a 7% increase over 2012 reserves.
- Increased net proved oil and NGLs reserves by 10% over 2012.
- Total production of 16.7 MMBoe or an 18% increase over 2012.
- Participated in the drilling of 149 wells.
- Sold non-core assets with proceeds of $78.8 million for the year.

Contract Drilling

- Sold five 2,000-3,000 horsepower electric drilling rigs to unaffiliated third-parties.
- Launched our new drilling program to design and build new proprietary 1,500 horsepower AC electric drilling rigs, called the BOSS drilling rig. The first BOSS drilling rig is expected to be completed and put into service for our oil and natural gas segment during the first quarter of 2014.
- Moved two rigs into the Permian Basin of West Texas.

Mid-Stream

- Gas gathered increased from 250,290 Mcf per day in 2012 to 309,554 Mcf per day in 2013, a 24% increase.
- Gas processed increased from 133,987 Mcf per day in 2012 to 140,584 Mcf per day in 2013, a 5% increase.
- Added 155 miles of pipeline (approximately a 12% increase) and connected 150 new wells to our various gathering systems.
- Completed construction of a new gathering and processing facility in south central Kansas, known as the Reno system, and the related installation of two gas processing plants which provide 25 MMcf per day total processing capacity.
- Completed the installation of a 30 MMcf per day plant at our Bellmon facility increasing our total processing capacity to 55 MMcf per day.
- Purchased a new 60 MMcf per day gas processing plant for our Bellmon system and began installation of this plant which was completed in February 2014.
- Completed the installation and upgrade of the Dove Creek processing plant at our Perkins facility increasing our processing capacity by 8 MMcf per day.
- Completed construction of a new gathering system in north-central Pennsylvania, known as the Brookfield system.
- Increased the contract mix as a percent of volume for fee-based contracts to 62% in 2013 from 39% in 2012.

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, Pennsylvania, 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, 2013:

Our Divisions/Area	Number of Gross Wells	Number of Net Wells	Number of Gross Wells in Process	Number of Net Wells in Process	2013 Average Net Daily Production		
					Natural Gas (Mcf)	Oil (Bbls)	NGLs (Bbls)
West division	3,119	515.39	2	0.75	35,787	1,889	2,720
East division	1,484	475.59	5	0.03	25,755	45	66
Central division	5,238	1,840.83	14	9.63	93,956	7,273	7,937
Total	9,841	2,831.81	21	10.41	155,498	9,207	10,723

As of December 31, 2013, we did not have any significant water floods, pressure maintenance operations, or any other material operations 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 operated and completed eight gross wells in 2013 with an average working interest of 100% and a success rate of 88%. Five of the eight wells were completed in our “Gilly” Basal Wilcox field bringing the total number of wells completed in that field to ten at year end 2013. Production for 2013 increased 21% as compared to 2012. Our first horizontal Wilcox well was completed in the fourth quarter of 2013 at an initial daily rate of approximately 4.4 MMcf per day and 73 barrels of condensate per day from approximately 1,500 feet of Basal Wilcox lateral. There are currently two Unit rigs drilling in our Wilcox play with plans to add a third rig in the second half of the year, which should result in approximately 10 to 12 gross vertical wells and two to four horizontal wells at an approximate net cost of $112 million for 2014.

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. In our Mississippian play in south central Kansas, the average daily production for 2013 increased approximately 218% as compared to 2012. We had first sales on eight Mississippian wells during 2013 with an average 30 day IP rate of 222 Boe per day consisting of an average of approximately 53% oil, 11% NGLs, and 36% natural gas with a 100% average working interest. The last four wells completed in the fourth quarter of 2013 had a significantly higher liquids cut consisting of approximately 79% oil, 6% NGLs, and 15% natural gas with an average 30 day IP rate of approximately 231 Boe per day. Two potential enhancements we may make to wells drilled in the play during 2014 are drilling extended lateral wells and testing different fracture stimulation designs. We have leased approximately 143,000 net acres in the play and are currently running two Unit drilling rigs and expect to spend approximately $111 million in 2014.

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In the Marmaton horizontal oil play in Beaver County, Oklahoma, we had first sales on 41 horizontal wells during 2013 with an average 30 day IP rate of 371 Boe per day with an approximate average working interest of 75%. The average daily production for 2013 increased approximately 25% as compared to 2012. A decision from the Oklahoma Legislature to allow drilling extended lateral wells in the play is anticipated by May 2014. Two additional potential horizontal targets in the play are scheduled to be tested in 2014. We have leases on approximately 119,000 net acres and have two Unit rigs drilling in the play with current plans to spend approximately $70 million.

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 2013 increased approximately 28% over 2012. We had first sales on 23 horizontal GW wells, having an average peak 30 day IP rate of 5.2 MMcfe per day and an average working interest of 85%. We also had first sales on three Cleveland wells with an average peak 30 day rate of 3.9 MMcfe per day at an average working interest of 80%. We recently completed drilling operations on three separate well pads located in different sections of the Buffalo Wallow GW field. Each pad has three wells resulting in nine total wells that will target five different GW sand intervals. Six of the wells have been fracture stimulated and the remaining three wells are scheduled to be fracture stimulated in the first quarter 2014. We plan to monitor production from these three pads for approximately 90 days prior to resuming pad drilling in the field. We plan to run three to five drilling Unit rigs in the GW play and one Unit rig in the Cleveland play for 2014 with plans to spend approximately $174 million.

Dispositions and Acquisitions. There were no material dispositions during 2011. 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 for 2013. Proceeds from these dispositions reduced the net book value of the full cost pool with no gain or loss recognized.

On July 20, 2011, we acquired certain producing properties from an unaffiliated seller for approximately $12.3 million in cash, after post-closing adjustments, consisting of 30 operated wells and 59 non-operated well interests located in Beaver, Harper, and Ellis Counties, Oklahoma and Lipscomb County, Texas. The purchase price allocation was $8.4 million for proved properties and $3.9 million for acreage. The acquisition also included in excess of 12,000 net acres held by production available for future development.

On August 31, 2011, we acquired certain producing oil and gas properties for $30.5 million in cash from an unaffiliated seller. Included in the acquisition were more than 500 wells located principally in the Oklahoma Arkoma Woodford and Hartshorne Coal plays along with other properties located throughout Oklahoma and Texas. The acquisition also included approximately 55,000 net acres of which 96% was held by production.

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.

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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,					
	2013		2012		2011	
	Gross	Net	Gross	Net	Gross	Net
Wells drilled:						
Exploratory:						
Oil:						
West division	—	—	1	1.00	—	—
East division	—	—	—	—	—	—
Central division	—	—	1	1.00	—	—
Total oil	—	—	2	2.00	—	—
Natural gas:						
West division	2	2.00	3	2.49	5	4.13
East division	—	—	—	—	—	—
Central division	—	—	—	—	—	—
Total natural gas	2	2.00	3	2.49	5	4.13
Dry:						
West division	—	—	1	1.00	7	6.50
East division	—	—	—	—	—	—
Central division	—	—	—	—	—	—
Total dry	—	—	1	1.00	7	6.50
Total exploratory	2	2.00	6	5.49	12	10.63
Development:						
Oil:						
West division	1	0.08	29	4.10	21	4.57
East division	—	—	—	—	—	—
Central division	93	51.33	71	34.04	56	32.81
Total oil	94	51.41	100	38.14	77	37.38
Natural gas:						
West division	9	8.60	7	4.44	9	6.26
East division	1	—	2	0.76	9	4.65
Central division	37	26.00	55	30.45	44	18.32
Total natural gas	47	34.60	64	35.65	62	29.23
Dry:						
West division	3	1.35	1	0.80	3	2.03
East division	—	—	—	—	1	1.00
Central division	3	1.78	—	—	5	2.15
Total dry	6	3.13	1	0.80	9	5.18
Total development	147	89.14	165	74.59	148	71.79
Total wells drilled	149	91.14	171	80.08	160	82.42

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	Year Ended December 31,					
	2013		2012		2011	
	Gross	Net	Gross	Net	Gross	Net
Wells producing or capable of producing:						
Oil:						
West division	2,058	170.49	2,076	178.43	2,074	183.50
East division	42	1.91	54	3.17	54	3.17
Central division	891	426.75	807	382.34	631	273.31
Total oil	2,991	599.15	2,937	563.94	2,759	459.98
Natural gas:						
West division	1,004	326.79	1,109	330.19	1,182	335.90
East division	1,435	472.68	1,632	519.62	1,636	522.15
Central division	4,266	1,382.62	4,245	1,362.87	3,097	683.08
Total natural gas	6,705	2,182.09	6,986	2,212.68	5,915	1,541.13
Total	9,696	2,781.24	9,923	2,776.62	8,674	2,001.11

As of February 14, 2014, we are currently drilling or participating in 13 gross (9.66 net) wells started during 2014.

Cost incurred for development drilling includes $136.7 million, $123.4 million, and $111.4 million in 2013, 2012, and 2011, respectively, to develop booked proved undeveloped oil and natural gas reserves.

The following table summarizes our leasehold acreage at December 31, 2013:

	Year Ended December 31, 2013					
	Developed		Undeveloped		Total	
	Gross	Net	Gross	Net [(1)]	Gross	Net
West division	282,448	94,918	166,432	112,403	448,880	207,321
East division	225,054	87,908	57,707	17,811	282,761	105,719
Central division	857,022	334,472	300,560	236,567	1,157,582	571,039
Total	1,364,524	517,298	524,699	366,781	1,889,223	884,079

(1) Approximately 90% (West – 83%; East – 48%; and Central – 97%) of the net undeveloped acres are covered by leases that will expire in the years 2014—2016 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,		
	2013	2012	2011
Average sales price per barrel of oil produced:			
Price before hedging	$95.18	$90.19	$93.49
Effect of hedging	(0.12)	2.41	(6.31)
Price including hedging	$95.06	$92.60	$87.18
Average sales price per barrel of NGLs produced:			
Price before hedging	$31.79	$30.70	$44.44
Effect of hedging	—	0.88	(0.80)
Price including hedging	$31.79	$31.58	$43.64
Average sales price per Mcf of natural gas produced:			
Price before hedging	$3.33	$2.53	$3.78
Effect of hedging	(0.01)	0.84	0.48
Price including hedging	$3.32	$3.37	$4.26

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	Year Ended December 31,		
	2013	2012	2011
Oil production (MBbls):			
West division	690	1,071	893
East division	16	16	12
Central division:			
Mendota field	412	497	262
All other central division fields	2,242	1,695	1,344
Total central division	2,654	2,192	1,606
Total oil production (MBbls)	3,360	3,279	2,511
NGLs production (MBbls):			
West division	993	858	798
East division	24	23	5
Central division:			
Mendota field	1,050	1,128	691
All other central division fields	1,847	787	745
Total central division	2,897	1,915	1,436
Total NGLs production (MBbls)	3,914	2,796	2,239
Natural gas production (MMcf):			
West division	13,062	11,831	11,774
East division	9,401	11,906	12,768
Central division:			
Mendota field	9,138	8,957	4,887
All other central division fields	25,156	16,236	14,675
Total central division	34,294	25,193	19,562
Total natural gas production (MMcf)	56,757	48,930	44,104
Total production (MBoe):			
West division	3,860	3,901	3,653
East division	1,607	2,023	2,145
Central division:			
Mendota field	2,985	3,118	1,768
All other central division fields	8,282	5,188	4,535
Total central division	11,267	8,306	6,303
Total production (MBoe)	16,734	14,230	12,101
Average production cost per equivalent Bbl (1)	$7.63	$7.00	$6.90

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

Our Mendota field, located in the Granite Wash play, includes 18%, 19%, and 22%, respectively of our total proved reserves in 2013, 2012, and 2011, respectively, expressed on an oil equivalent barrels basis, and is the only field that is greater than 15% of our proved reserves.

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

	Oil (MBbls)	NGLs (MBbls)	Natural Gas (MMcf)	Total Proved Reserves (MBoe)
Proved developed:				
West division	3,244	5,981	79,760	22,518
East division	38	28	97,891	16,381
Central division	12,312	24,428	286,583	84,504
Total proved developed	15,594	30,437	464,234	123,403
Proved undeveloped:				
West division	325	599	8,121	2,278
East division	—	—	9,428	1,571
Central division	5,846	10,169	100,001	32,682
Total proved undeveloped	6,171	10,768	117,550	36,531
Total proved	21,765	41,205	581,784	159,934

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 for over seventy years. 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, 2013 and comprised 84% of the total proved developed discounted future net income and 91% 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.

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.

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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 34 of his 41 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.

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.

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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 is the average price during the 12-month period before the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first day of 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, 2013, we had approximately 180 gross proved undeveloped wells all of which we plan to develop within five years of initial disclosure at a net estimated cost of approximately $508.3 million. The future estimated development costs necessary to develop our proved undeveloped oil and natural gas reserves in the United States for the years 2014—2017, as disclosed in our December 31, 2013 oil and natural gas reserve report, are $238.3 million, $185.4 million, $25.1 million, and $59.5 million, respectively. Our proved undeveloped reserves reported at December 31, 2013 did not include reserves that we did not expect to develop within five years of initial disclosure of those reserves. During 2013, we added new PUD reserves through extensions and discoveries representing 4.1 MMBls of oil, 5.0 MMBls of NGLs, and 52.7 Bcf of natural gas. We converted 47 proved undeveloped wells into proved developed wells at a cost of approximately $136.7 million. The proved undeveloped reserves that were converted to proved developed reserves during 2013, represented 1.8 MMBls of oil, 2.6 MMBls of NGLs, and 21.6 Bcf of natural gas. There were no other material changes to the PUD reserves.

Our estimated proved reserves and the standardized measure of discounted future net cash flows of the proved reserves at December 31, 2013, 2012, and 2011, 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 2013, sales to Valero Energy Corporation accounted for 25% of our oil and natural gas revenues. There was no other company that accounted for more than 10% of our oil and natural gas revenues. During 2013, our mid-stream segment purchased $83.0 million of our natural gas and NGLs production and provided gathering and transportation services of $8.0 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 2012 and 2011, we eliminated intercompany revenues of $73.3 million and $76.1 million, respectively, attributable to the intercompany purchase of our production of natural gas and NGLs as well as gathering and transportation services.

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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, Colorado, Utah, Montana, and North Dakota.

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

	Year Ended December 31,		
	2013	2012	2011
Number of drilling rigs owned at year end	121.0	127.0	127.0
Average number of drilling rigs owned during year	125.4	127.4	123.7
Average number of drilling rigs utilized	65.0	73.9	76.1
Utilization rate (1)	52 %	58 %	61 %
Average revenue per day (2)	$17,486	$19,774	$17,520
Total footage drilled (feet in 1,000's)	10,578	10,551	9,749
Number of wells drilled	793	773	742

(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 2013, 78 of our 121 drilling rigs were used in drilling services.

The following table shows certain information about our drilling rigs (including their distribution) as of February 14, 2014:

Divisions	Contracted Rigs	Non-Contracted Rigs	Total Rigs	Average Rated Drilling Depth (ft)
Mid-Continent	23	6	29	17,879
Woodward	12	4	16	13,719
Panhandle	9	17	26	12,885
Gulf Coast	8	6	14	17,929
Rocky Mountain	15	17	32	17,188
Totals	67	50	117	16,017

Drilling rig utilization steadily increased throughout 2011 and through the first quarter of 2012. It began declining from the second quarter of 2012 and throughout the remainder of 2012 with utilization remaining relatively flat throughout 2013. Factors contributing to the fluctuating utilization include drilling efficiencies attained by operators, more acreage in certain

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plays being held by production, and weakness in commodity prices. Our active drilling rig count at the start of 2011 was 72 drilling rigs. It decreased to 62 rigs at the end of 2012 and finished out 2013 at 65.

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 NGL production. During the last several years operators have focused their operations in this basin on the Cana Woodford, Granite Wash, Marmaton, and Mississippian horizontal plays. Three of our divisions work in this basin. During 2013, our Mid-Continent, Panhandle, and Woodward divisions averaged 22.0, 9.5, and 10.3 drilling rigs operating, respectively.

Gulf Coast – Our Gulf Coast division provides drilling rigs to the onshore areas of Louisiana, Texas Gulf Coast, East Texas, South Texas. Recently two drilling rigs were moved into the Permian Basin of West Texas. During 2013, this division averaged 6.7 drilling rigs operating. Within this division, our largest drilling rig, Rig 201, a 4,000 horsepower rig rated to drill to 40,000 feet, drilled an ultra-deep exploration well for a major oil company in south Louisiana, establishing the record for the deepest onshore well in the state of Louisiana.

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 16.5 drilling rigs during 2013. We had six drilling rigs operating in the Pinedale Anticline of western Wyoming and ten drilling rigs operating in the Bakken Shale of North Dakota at the end of 2013.

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 2011, 2012, and 2013 was 61%, 58%, and 52%, respectively.

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

	2013	2012	2011
First quarter	66.3	81.5	70.0
Second quarter	65.2	76.7	73.1
Third quarter	63.5	73.4	78.9
Fourth quarter	65.0	64.0	82.1

Drilling Rig Fleet. The following table summarizes the changes made to our drilling rig fleet in 2013. A more complete discussion of the changes follows the table:

Drilling rigs owned at December 31, 2012	127	
Drilling rigs sold	(5	)
Drilling rigs removed from service	(1	)
Drilling rigs purchased	—	
Drilling rigs constructed	—	
Total drilling rigs owned at December 31, 2013	121	

Dispositions, Acquisitions, and Construction. During 2011, we were awarded two new build drilling rig contracts for 1,500 horsepower, diesel-electric drilling rigs. One was placed into service during the fourth quarter of 2011 and the other was placed in service during the first quarter of 2012, both in Wyoming.

During the first quarter of 2012, we sold an idle 600 horsepower mechanical drilling rig to an unaffiliated third-party. In the second quarter we placed a new 1,500 horsepower, diesel-electric drilling rig to work in North Dakota under a three year contract.

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During the third quarter of 2012, we 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.
In the second quarter of 2013, we sold one of our 2,000 horsepower electric drilling rigs. During the third and fourth quarters of 2013, we sold three additional 2,000 horsepower and one 3,000 horsepower electric drilling rigs. All of these sales were to unaffiliated third-parties. Four additional idle 3,000 horsepower drilling rigs were sold to an unaffiliated third party in the first quarter of 2014 all of which were classified as assets held for sale at December 31, 2013. The proceeds from these various sales will be used in our new drilling rig program we launched to design and build a new proprietary 1,500 horsepower, AC electric drilling rig, called the BOSS rig. We anticipate the BOSS drilling rig will position us to more effectively meet the demands of our existing customers as well as allowing us to compete for the work of new customers.

The first BOSS drilling rig will be operational the first quarter of 2014 and will work initially for our oil and natural gas segment. Two additional BOSS drilling rigs are contracted to third party operators and are anticipated to be placed into service in the second and third quarters of 2014.

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. Additional compensation may be acquired for special risks and unusual conditions. 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. We did not have any footage or turnkey contracts in 2013, 2012, or 2011.

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. 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.

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 2013, QEP Resources, Inc. and Kodiak Oil and Gas Corp. were our largest drilling customers accounting for approximately 18% and 10%, respectively, of our total contract drilling revenues. Our work for these customers 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 2013, 2012, and 2011, our contract drilling segment drilled 105, 78, and 81 wells, respectively, or 13%, 10%, and 11%, respectively, of the total wells drilled for our oil and natural gas 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 $64.3 million, $49.6 million, and $52.2 million during 2013, 2012, and 2011, respectively, from our contract drilling segment and eliminated the associated operating expense of $46.9 million, $34.1 million, and $32.6

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million during 2013, 2012, and 2011, respectively, yielding \$17.4 million, \$15.5 million, and \$19.6 million during 2013, 2012, and 2011, 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, 15 processing plants, 38 active gathering systems, and approximately 1,500 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,		
	2013	2012	2011
Gas gathered—Mcf/day	309,554	250,290	188,569
Gas processed—Mcf/day	140,584	133,987	92,940
NGLs sold—gallons/day	543,602	542,578	412,064

Dispositions and Acquisitions. This segment did not have any significant dispositions or acquisitions during 2011 or 2013.

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.

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, 2013, 62% of our mid-stream segment's total volumes and 37% 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 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, 2013, 36% of our mid-stream segment's total volumes and 59% 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, 2013, 2% 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 2013, ONEOK, Inc. and Tenaska Resources, LLC accounted for approximately 50% and 16%, respectively, of our mid-stream revenues. We believe that if we lost one or both of these identified customers, there are other

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customers available to purchase our gas and NGLs. During 2013, 2012, and 2011 this segment purchased $83.0 million, $68.2 million, and $71.5 million, respectively, of our oil and natural gas segment's natural gas and NGLs production, and provided gathering and transportation services of $8.0 million, $5.1 million, and $4.6 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 our hedging activity:

	Oil Price per Bbl		NGLs Price per Bbl		Natural Gas Price per Mcf	
Quarter	High	Low	High	Low	High	Low
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						