Unit Corporation Reports 2015 Fourth Quarter & Year End Results

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Unit Corporation (NYSE: UNT) today reported its financial and operational results for the fourth quarter and year end 2015. Operational highlights for the year include:

- Achieved year over year production growth of 9%
- Successful development of the company's horizontal well program in its Wilcox play
- Placed into service five new BOSS drilling rigs
- Achieved the best safety performance in the history of the company
- Gas gathered and gas processed volumes per day increased 11% and 13%, respectively, over 2014
- Completed the expansion of the Pittsburgh Mills pipeline in Butler County, Pennsylvania, and completed construction of the new fee-based Snow Shoe gathering system in Centre County, Pennsylvania

FOURTH QUARTER 2015 FINANCIAL RESULTS

Adjusted net loss (which excludes the effect of non-cash commodity derivatives and the effect of the non-cash write-downs) was $6.6 million, or $0.14 per share (see Non-GAAP Financial Measures below). Low commodity prices continued to significantly affect Unit's financial results. Because of lower commodity prices, Unit incurred during the quarter a pre-tax non-cash ceiling test write-down of $458.3 million in the carrying value of its oil and natural gas properties and $27.0 million in the carrying value of three of its gas gathering systems. Although these write-downs were non-cash items, they resulted in Unit recording a net loss of $309.3 million, or $6.29 per share, compared to a net loss of $42.6 million, or $0.88 per share, for the fourth quarter of 2014. Total revenues were $172.3 million (44% oil and natural gas, 29% contract drilling, and 27% mid-stream), compared to $378.6 million (43% oil and natural gas, 36% contract drilling, and 21% mid-stream) for the fourth quarter of 2014. Adjusted EBITDA was $73.5 million, or $1.49 per diluted share (see Non-GAAP Financial Measures below).

YEAR END 2015 FINANCIAL RESULTS

Adjusted net loss (which excludes the effect of non-cash commodity derivatives and the effects of the non-cash write-downs) was $7.2 million, or $0.15 per share (see Non-GAAP Financial Measures below). For the full year, Unit recorded pre-tax non-cash ceiling test write-downs of $1.6 billion in the carrying value of its oil and natural gas properties, $8.3 million in the carrying value of certain drilling rigs and other assets removed from service, and $27.0 million for the gas gathering systems discussed above. Because of these write-downs, Unit recorded a net loss of $1.0 billion, or $21.12 per share, compared to net income of $136.3 million, or $2.78 per diluted share, for 2014. Total revenues were $854.2 million (45% oil and natural gas, 31% contract drilling, and 24% mid-stream), compared to $1.6 billion (47% oil and natural gas, 30% contract drilling, and 23% mid-stream) for 2014. Adjusted EBITDA for the year was $384.6 million, or $7.80 per diluted share (see Non-GAAP Financial Measures below).

Larry Pinkston, Unit's Chief Executive Officer and President, said: "Without question 2015 has been a very challenging year, and 2016 is not starting off any better. We have been through many of these cycles and have survived to see the benefit of a return to better times. We intend to do so again. In response to the current conditions, we have taken several actions. First, in the normal course of our operations we have continued to carry out our program of selling certain non-core exploration and production assets. Early in 2016, we completed various non-core asset sales with total proceeds of approximately $37.4 million. We will continue to market non-core assets as opportunities arise. Second, we have carried out several reductions in our workforce, including both corporate and field staff. Third, in our drilling segment, we are reorganizing our drilling divisions from five to two. Fourth, we continue to manage our outstanding borrowings under our credit agreement. At December 31, 2015, our bank borrowings totaled $281.0 million, while currently our borrowings are $267.7 million. Last, our 2016 budget shifts much of our exploration segment budget to the latter part of the year to provide us time to assess future commodity price movements before we expend those funds."

OIL AND NATURAL GAS SEGMENT INFORMATION

Total production for 2015 was 20.0 million barrels of oil equivalent (MMBoe), a 9% increase over 2014. For the quarter, total equivalent production was 4.8 MMBoe, a decrease of 2% from the fourth quarter of 2014 and a 6% decrease from the third quarter of 2015. Liquids (oil and NGLs) production represented 44% of total equivalent production for the quarter. Oil production for the quarter was 8,562 barrels per day, a decrease of 25% from the fourth quarter of 2014 and a decrease of 17% from the third quarter of 2015. NGLs production for the quarter was 14,346 barrels per day, an increase of 5% over the fourth quarter of 2014 and a 1% decrease from the third quarter of 2015. Natural gas production for the quarter was 172,783 thousand cubic feet (Mcf) per day, an increase of 3% over the fourth quarter of 2014 and a decrease of 4% from the third quarter of 2015.

Unit's average realized per barrel equivalent price for the quarter was $18.54, a decrease of 48% from the fourth quarter of 2014 and a 10% decrease from the third quarter of 2015. Unit's average natural gas price for the quarter was $2.24 per Mcf, a decrease of 40% from the fourth quarter of 2014 and a decrease of 16% from the third quarter of 2015. Unit's average oil price for the quarter was $48.23 per barrel, a decrease of 41% from the fourth quarter of 2014 and a decrease of 5% from the third quarter of 2015. Unit's average NGLs price for the quarter was $11.05 per barrel, a 56% decrease from the fourth quarter of 2014 and an increase of 26% over the third quarter of 2015. All prices in this paragraph include the effects of derivative contracts.

Three Unit drilling rigs are operating for this segment. One is operating in the Southern Oklahoma Hoxbar Oil Trend (SOHOT), one is drilling in the Wilcox play, in Southeast Texas, and one is drilling in the Granite Wash Buffalo Wallow field in the Texas Panhandle. The current plan is to keep these three Unit drilling rigs operating during the first quarter, at which time all three rigs will be released. The budget for this segment contemplates that the rigs may be put back into service during the year depending on commodity prices.

In the Wilcox play, production for the fourth quarter averaged 88 million cubic feet equivalent (MMcfe) per day (11% oil, 31% NGLs), which is a 25% increase over the fourth quarter of 2014, and a 7% increase over the third quarter 2015. Two new vertical Wilcox wells were completed during the quarter, bringing the total for 2015 to 15 wells (three horizontal) with a 100% completion success rate. Production from Unit's three horizontal Wilcox wells completed in the first half of 2015 continues to be encouraging. The Parker 5H (75% working interest) is averaging approximately 13.9 MMcfe per day (3,457' lateral) with 5,300 pounds of flowing tubing pressure after 330 days on line. The Epstein 7H (100% working interest) is averaging approximately 10.8 MMcfe per day (4,364' lateral) with 2,700 pounds of flowing tubing pressure after 240 days on line. The BP America 2H (100% working interest) is averaging approximately 1.6 MMcfe per day (1,413' lateral) with 700 pounds of flowing tubing pressure after 390 days on line. Three additional horizontal Wilcox wells completed drilling operations during the fourth quarter and early 2016. All three wells have been fracture stimulated and are in the early stages of flow back. Two of the wells are in the Gilly Field with lateral lengths of 5,484 feet and 5,654 feet. The other well is in a nearby field and has a lateral length of 5,861 feet. The average total well cost for these three wells decreased 61% to $1,110 per lateral foot as compared to an average cost of $2,839 per lateral foot for the first three wells discussed above. The significant well cost reduction is attributed to lower service costs and drilling and completion efficiencies. Unit is drilling another horizontal Wilcox well that is scheduled for completion in April.

In the SOHOT area, production for the quarter averaged 44 MMcfe per day (28% oil, 21% NGLs) which is a 117% increase over the fourth quarter 2014, and a 6% increase over the third quarter 2015. Three horizontal operated Hoxbar wells were completed during the quarter with two wells in the Marchand bench and one well in the Medrano bench. The two Marchand completions targeted a previously untested "Marchand Shale" interval to evaluate the potential of this interval in connection with an acquisition opportunity Unit was then reviewing in the SOHOT area. Although both shale wells are productive, the initial production rates are lower than the Marchand sand wells and appear uneconomic at current oil prices. Unit's Marchand well inventory of approximately 60 gross operated and non-operated locations does not include any shale interval locations. Drilling and completion cost for Marchand wells continue to trend lower. The current AFE for a 4,500' Marchand sand well is approximately $4.9 million, which is a decrease of approximately 30% as compared to 2014 AFE's of $7.0 million. During the first quarter of 2016, Unit completed two new Marchand sand wells that are in the early stages of flow back. A third well has been drilled and is scheduled to be fracture stimulated in mid-March. A fourth well is drilling and will be completed in April.

Pinkston said: "With a significantly reduced capital budget, our exploration and production segment was able to exceed our annual production growth guidance of 6%-8% year over year with growth of 9% for 2015. Our 2015 capital expenditures for the segment were 64% lower than 2014. During 2015, we reduced our operating expense by 12% year over year (27% during the second half of 2015 compared to the second half of 2014.) We will continue to make adjustments as the current pricing cycle dictates."

The following table illustrates this segment's comparative production, realized prices, and operating profit for the periods indicated:

	Three Months Ended			Three Months Ended			Twelve Months Ended		
	Dec 31, 2015	Dec 31, 2014	Change	Dec 31, 2015	Sept 30, 2015	Change	Dec 31, 2015	Dec 31, 2014	Change
Oil and NGLs Production, MBbl	2,108	2,296	(8)%	2,108	2,289	(8)%	9,057	8,472	7%
Natural Gas Production, Bcf	15.9	15.4	3%	15.9	16.6	(4)%	65.5	58.9	11%
Production, MBoe	4,757	4,868	(2)%	4,757	5,053	(6)%	19,982	18,281	9%
Production, MBoe/day	51.7	52.9	(2)%	51.7	54.9	(6)%	54.7	50.1	9%
Avg. Realized Natural Gas Price, Mcf (1)	$ 2.24	$ 3.72	(40)%	$ 2.24	$ 2.66	(16)%	$ 2.63	$ 3.92	(33)%
Avg. Realized NGL Price, Bbl (1)	$ 11.05	$ 25.28	(56)%	$ 11.05	$ 8.74	26%	$ 10.12	$ 30.95	(67)%
Avg. Realized Oil Price, Bbl (1)	$ 48.23	$ 81.34	(41)%	$ 48.23	$ 50.87	(5)%	$ 50.79	$ 89.43	(43)%
Realized Price / Boe (1)	$ 18.54	$ 35.73	(48)%	$ 18.54	$ 20.61	(10)%	$ 20.92	$ 39.25	(47)%
Operating Profit Before Depreciation, Depletion, Amortization & Impairment (MM) (2)	$ 39.7	$ 111.0	(64)%	$ 39.7	$ 57.9	(32)%	$ 219.7	$ 552.2	(60)%

(1) Realized price includes oil, NGLs, natural gas, and associated derivatives.

(2) Operating profit before depreciation is calculated by taking operating revenues for this segment less operating expenses excluding depreciation, depletion, amortization, and impairment.

Pinkston said: "We endeavor to go into each year with 50% - 70% of our anticipated production volumes hedged. For 2016, we have achieved that objective on our anticipated natural gas production. We currently have not achieved that objective for our crude oil production, but we intend to add to that position as circumstances allow."

The following table summarizes this segment's outstanding derivative contracts.

Crude						
Period	Structure	Volume Bbl/Day	Weighted Average Fixed Price	Weighted Average Floor Price	Weighted Average Subfloor Price	Weighted Average Ceiling Price
Jan'16 - Dec'16	3-Way Collar	700		$46.50	$35.00	$57.00
Jan'16 - Jun'16	Collar	2,150		$46.36		$55.62
Jul'16 - Dec'16	3-Way Collar (1)	700		$47.50	$35.00	$63.50
Jul'16 - Dec'16	Collar	1,450		$47.50		$56.40
Jan'17 - Dec'17	3-Way Collar	750		$50.00	$37.50	$63.90

Natural Gas						
Period	Structure	Volume MMBtu/Day	Weighted Average Fixed Price	Weighted Average Floor Price	Weighted Average Subfloor Price	Weighted Average Ceiling Price
Jan'16 - Dec'16	Swap	35,000	$2.625			
Feb'16 - Dec'16	Swap	10,000	$2.495			
Jan'16 - Dec'16	3-Way Collar	13,500		$2.70	$2.20	$3.26
Jan'16 - Dec'16	Collar	42,000		$2.40		$2.88
Jan'17 - Dec'17	Swap	10,000	$2.795			
Jan'17 - Dec'17	3-Way Collar	15,000		$2.50	$2.00	$3.32

(1) Unit pays its counterparty a premium, which can be and is being deferred until settlement.

YEAR END 2015 ESTIMATED PROVED RESERVES

The PV-10 value of Unit's estimated year-end 2015 proved reserves decreased 67% from 2014 to $690.7 million. Unit's estimated year-end 2015 proved oil and natural gas reserves were 135.2 MMBoe, or 811.4 billion cubic feet of natural gas equivalents (Bcfe), as compared with 179.0 MMBoe, or 1.1 trillion cubic feet of natural gas equivalents (Tcfe), at year-end 2014, a 24% decrease. Estimated reserves were 12% oil, 28% NGLs, and 60% natural gas. During 2015, Unit sold 0.2 MMBoe of non-core oil and natural gas reserves.

The following details the changes to Unit's proved oil, NGLs, and natural gas reserves during 2015:

	Oil (MMbls)	NGLs (MMbls)	Natural Gas (Bcf)	Proved Reserves (MMBoe)
Proved Reserves, at December 31, 2014	22.7	48.5	647.0	179.0
Revisions of previous estimates	(4.0)	(9.3)	(139.5)	(36.6)
Extensions, discoveries, and other additions	1.9	3.8	43.6	13.0
Purchases of minerals in place	-	-	-	-
Production	(3.8)	(5.3)	(65.5)	(20.0)
Sales	(0.1)	-	(0.7)	(0.2)
Proved Reserves, at December 31, 2015	16.7	37.7	484.9	135.2

Estimated 2015 year-end proved reserves included proved developed reserves of 115 MMBoe, or 692 Bcfe, (13% oil, 27% NGLs, and 60% natural gas) and proved undeveloped reserves of 20 MMBoe, or 120 Bcfe, (10% oil, 33% NGLs, and 57% natural gas). Overall, 85% of Unit's estimated proved reserves are proved developed.

The present value of the estimated future net cash flows from the 2015 estimated proved reserves (before income taxes and using a 10% discount rate (PV-10)), is approximately $690.7 million. The present value was determined using the required SEC's pricing methodology. The aggregate price used for all future reserves was $50.28 per barrel of oil, $19.47 per barrel of NGLs, and $2.59 per Mcf of natural gas (then adjusted for price differentials). Unit's 2015 year-end proved reserves were independently audited by Ryder Scott Company, L.P. Their audit covered properties which accounted for 81% of the discounted future net cash flow (PV-10). See below for the reconciliation of PV-10 to the standardized measure of discounted future net cash flows as defined by GAAP.

Pinkston said: "The reduced commodity prices for oil (47%), NGLs (57%), and natural gas (41%) used to calculate our reserves as compared to year end 2014 had a substantial impact on our reserves. Reserve revisions were primarily due to pricing. Our proved undeveloped reserves have decreased to 15% of total proved reserves at the end of 2015 as compared to 24% at the end of the prior year. Although current pricing has rendered a number of our oil and natural gas properties uneconomic, the reserves remain in place to be developed in a more favorable pricing environment."

CONTRACT DRILLING SEGMENT INFORMATION

The average number of drilling rigs used in the quarter was 27.2, a decrease of 66% from the fourth quarter of 2014, and a decrease of 13% from the third quarter of 2015. Per day drilling rig rates for the quarter averaged $18,604, a decrease of 9% from the fourth quarter of 2014 and a 1% decrease from the third quarter of 2015. Average per day operating margin for the quarter was $7,258 (before elimination of intercompany drilling rig profit and bad debt expense of $0.3 million). This compares to $8,834 (before elimination of intercompany drilling rig profit and bad debt expense of $8.7 million) for the fourth quarter of 2014, a decrease of 18%, or $1,576. As compared to $10,368 (before elimination of intercompany drilling rig profit and bad debt expense of $0.2 million) for the third quarter of 2015, fourth quarter 2015 operating margin decreased 30% or $3,110, principally due to lower early termination fees (in each case regarding eliminating intercompany drilling rig profit and bad debt expense - see Non-GAAP Financial Measures below). Average operating margins for the quarter included early termination fees of approximately $3.3 million, or $1,327 per day, from the cancellation of certain long-term contracts, compared to early termination fees of $0.2 million, or $27 per day, during the fourth quarter of 2014 and $11.4 million, or $3,958 per day, for the third quarter of 2015.

Pinkston said: "During the first half of 2015, we completed the construction of five BOSS drilling rigs that were contracted and placed into service, bringing our total BOSS drilling rig count to eight. With the decline in commodity prices, drilling rig demand also declined throughout the year. During the fourth quarter, we were notified of a customer's intent to terminate early the contract on one of our BOSS drilling rigs, which was subsequently laid down in January of 2016. Currently, we have seven of our eight BOSS drilling rigs under contract. Our current drilling rig fleet totals 94 drilling rigs, of which 20 are working under contract. Long-term contracts (contracts with original terms ranging from six months to two years in length) are in place for nine of our drilling rigs. Of the nine long-term contracts, two are up for renewal during the first quarter of 2016, three during the third quarter, and four in 2017. Unit has focused on safety performance for many years to keep our employees safe and to provide an efficient operation. In 2015, we achieved our best safety performance in the company's history. The reduction of safety incidents also leads to substantial savings in our daily costs."

The following table illustrates certain comparative results from this segment's operations for the periods indicated:

	Three Months Ended			Three Months Ended			Twelve Months Ended		
	Dec 31, 2015	Dec 31, 2014	Change	Dec 31, 2015	Sept 30, 2015	Change	Dec 31, 2015	Dec 31, 2014	Change
Rigs Utilized	27.2	80.9	(66)%	27.2	31.2	(13)%	34.7	75.4	(54)%
Operating Profit Before Depreciation & Impairment (MM) (1)	$ 17.9	$ 57.1	(69)%	$ 17.9	$ 29.5	(39)%	$ 109.3	$ 201.6	(46)%

(1) Operating profit before depreciation is calculated by taking operating revenues for this segment less operating expenses excluding depreciation and impairment.

MID-STREAM SEGMENT INFORMATION

For the quarter, per day gas gathered and gas processed volumes increased 10% and 4%, respectively, while liquids sold volumes decreased 18% as compared to the fourth quarter of 2014. Compared to the third quarter of 2015, gas gathered volumes per day increased 1% while gas processed and liquids sold volumes per day decreased 8% and 3%, respectively. Operating profit (as defined in the footnote below) for the quarter was $9.4 million, a decrease of 6% from the fourth quarter of 2014 and a decrease of 10% from the third quarter of 2015.

For 2015, per day gas gathered and gas processed volumes increased 11% and 13%, respectively, while liquids sold volumes decreased 21% as compared to 2014. Operating profit (as defined in the footnote below) for 2015 was $41.2 million, a decrease of 15% from 2014.

The following table illustrates certain comparative results from this segment's operations for the periods indicated:

	Three Months Ended			Three Months Ended			Twelve Months Ended		
	Dec 31, 2015	Dec 31, 2014	Change	Dec 31, 2015	Sept 30, 2015	Change	Dec 31, 2015	Dec 31, 2014	Change
Gas Gathering, Mcf/day	360,159	327,331	10%	360,159	357,427	1%	353,771	319,348	11%
Gas Processing, Mcf/day	170,087	163,979	4%	170,087	185,625	(8)%	182,684	161,282	13%
Liquids Sold, Gallons/day	561,941	687,713	(18)%	561,941	579,556	(3)%	577,513	733,406	(21)%
Operating Profit Before Depreciation, Amortization & Impairment (MM) (1)	$ 9.4	$ 10.0	6%	$ 9.4	$ 10.4	(10)%	$ 41.2	$ 49.5	(17)%

(1) Operating profit before depreciation is calculated by taking operating revenues for this segment less operating expenses excluding depreciation, amortization, and impairment.

Pinkston said: "In the Appalachian area, we completed the expansion of the Pittsburgh Mills pipeline in Butler County, Pennsylvania. That system includes approximately seven miles of pipeline, the new Clinton compressor station, and provides an additional outlet for the gas, all of which became operational in the fourth quarter. We completed the construction of our new fee-based Snow Shoe gathering system, located in Centre County, Pennsylvania, and it became operational in January 2016. At our various gas processing facilities in the Mid-Continent, we continue to operate in full ethane rejection mode due to low liquids prices, which continues to impact our liquids sold volumes."

2016 CAPITAL BUDGET & PRODUCTION GUIDANCE

Pinkston said: "We have continued to see a great deal of commodity price volatility during the last few months. Our focus has been and will continue to be on maintaining a strong balance sheet. Our goal in 2016 is to keep our total corporate capital budget within anticipated cash flow with the objective we end the year with lower bank debt than we began the year. We have established our initial capital budget with that goal in mind, recognizing we may need to adjust it as future conditions may warrant."

Unit's overall capital budget is 59% to 65% less as compared to 2015, excluding acquisitions and asset retirement obligation liability. The reduction is designed to keep the budget below anticipated internally generated cash flow plus proceeds from any non-core asset sales. The range of capital expenditures will depend on prevailing conditions. The capital budget is allocated as follows between Unit's three business segments: a range of $109.0 million to $131.0 million for its oil and natural gas segment; $9.0 million to $11.0 million for its contract drilling segment; and $22.0 million to $24.0 million for its midstream segment. This budget does not include costs for any possible acquisitions, and is based on realized prices for the year averaging $35.00 per barrel of oil, $14.55 per barrel of natural gas liquids, and $2.25 per Mcf of natural gas (all prices are before differentials and hedges applied). Funding for the budget will come primarily from internally generated cash flow, proceeds from possible additional non-core asset divestitures, and (if necessary) borrowings under Unit's bank credit facility.

Unit's oil and natural gas segment's 2016 production is anticipated to decline on a year over year basis by 13% to 16%. Approximately 3% of this decline is attributable to two of the non-core asset packages sold in early 2016. The balance of the decline is attributable to the reduction in this segment's capital budget. In view of current pricing, it is anticipated that this segment will cease all drilling activity by the end of the first quarter, pending the company's evaluation of future industry conditions.

FINANCIAL INFORMATION

Unit ended the quarter with long-term debt of $927.7 million (consisting of $646.7 million of senior subordinated notes net of unamortized discount and $281.0 million of borrowings under its credit agreement). Under the credit agreement, the amount Unit can borrow is the lesser of the amount it elects as the commitment amount ($500 million) or the value of its borrowing base as determined by the lenders ($550 million), but in either event not to exceed $550 million. At February 12, 2016, Unit had $262.9 million of borrowings under its credit agreement.

WEBCAST

Unit will webcast its fourth quarter earnings conference call live over the Internet on February 25, 2016 at 10:00 a.m. Central Time (11:00 a.m. Eastern). To listen to the live call, please go to https://www.unitcorp.com/investor/calendar.htm at least fifteen minutes prior to the start of the call to download and install any necessary audio software. For those who are not available to listen to the live webcast, a replay will be available shortly after the call and will remain on the site for 90 days.

Unit Corporation is a Tulsa-based, publicly held energy company engaged through its subsidiaries in oil and gas exploration, production, contract drilling, and gas gathering and processing. Unit's Common Stock is on the New York Stock Exchange under the symbol UNT. For more information about Unit Corporation, visit its website at https://www.unitcorp.com.

FORWARD-LOOKING STATEMENT

This news release contains forward-looking statements within the meaning of the private Securities Litigation Reform Act. All statements, other than statements of historical facts, included in this release that address activities, events, or developments that the company expects or anticipates will or may occur in the future are forward-looking statements. Several risks and uncertainties could cause actual results to differ materially from these statements, including changes in commodity prices, the productive capabilities of the company's wells, future demand for oil and natural gas, future drilling rig utilization and dayrates, projected rate of the company's oil and natural gas production, the amount available to the company for borrowings, its anticipated borrowing needs under its credit agreement, the number of wells to be drilled by the company's oil and natural gas segment, and other factors described from time to time in the company's publicly available SEC reports. The company assumes no obligation to update publicly such forward-looking statements, whether because of new information, future events, or otherwise.

Unit Corporation
Selected Financial Highlights
(In thousands except per share amounts)

	Three Months Ended December 31, 2015	Three Months Ended December 31, 2014	Twelve Months Ended December 31, 2015	Twelve Months Ended December 31, 2014
Statement of Operations:				
Revenues:				
Oil and natural gas	$ 75,830	$ 164,903	$ 385,774	$ 740,079
Contract drilling	50,554	134,987	265,668	476,517
Gas gathering and processing	45,908	78,661	202,789	356,348
Total revenues	172,292	378,551	854,231	1,572,944
Expenses:				
Oil and natural gas:				
Operating costs	36,175	53,937	166,046	187,916
Depreciation, depletion, and amortization	49,566	75,130	251,944	276,088
Impairment of oil and natural gas properties	458,295	76,683	1,599,348	76,683
Contract drilling:				
Operating costs	32,691	77,908	156,408	274,933
Depreciation	13,602	24,176	56,135	85,370
Impairment of contract drilling equipment	-	74,318	8,314	74,318
Gas gathering and processing:				
Operating costs	36,475	68,665	161,556	306,831
Depreciation and amortization	11,158	10,462	43,676	40,434
Impairment of gas gathering and processing systems	26,966	7,068	26,966	7,068
General and administrative	8,708	11,614	35,345	42,023
(Gain) loss on disposition of assets	959	139	7,229	(8,953)
Total operating expenses	674,595	480,100	2,512,967	1,362,711
Income (loss) from operations	(502,303)	(101,549)	(1,658,736)	210,233
Other income (expense):				
Interest, net	(8,481)	(5,170)	(31,963)	(17,371)
Gain (loss) on derivatives not designated as hedges	13,428	39,381	26,345	30,147
Other	7	(73)	45	(70)
Total other income (expense)	4,954	34,138	(5,573)	12,706
Income (loss) before income taxes	(497,349)	(67,411)	(1,664,309)	222,939
Income tax expense (benefit):				
Current	(18,900)	(14,343)	(20,616)	9,378
Deferred	(169,112)	(10,517)	(606,332)	77,285
Total income taxes	(188,012)	(24,860)	(626,948)	86,663
Net income (loss)	$(309,337)	$ (42,551)	$(1,037,361)	$ 136,276
Net income (loss) per common share:				
Basic	$ (6.29)	$ (0.88)	$ (21.12)	$ 2.80
Diluted	$ (6.29)	$ (0.88)	$ (21.12)	$ 2.78
Weighted average shares outstanding:				
Basic	49,157	48,656	49,110	48,611
Diluted	49,157	48,656	49,110	49,083

		December 31, 2015		December 31, 2014
Balance Sheet Data:				
Current assets	$	140,258	$	252,491
Total assets	$	2,808,509	$	4,473,728
Current liabilities	$	150,891	$	304,171
Long-term debt	$	927,662	$	812,163
Other long-term liabilities	$	140,626	$	148,785
Deferred income taxes	$	275,750	$	876,215
Shareholders' equity	$	1,313,580	$	2,332,394

	Twelve Months Ended December 31,			
		2015		2014
Statement of Cash Flows Data:				
Cash flow from operations before changes in operating assets and liabilities	$	397,859	$	764,984
Net change in operating assets and liabilities		49,085		(55,991)
Net cash provided by operating activities	$	446,944	$	708,993
Net cash used in investing activities	$	(549,778)	$	(920,597)
Net cash provided by financing activities	$	102,620	$	194,060

Non-GAAP Financial Measures

Unit Corporation reports its financial results in accordance with generally accepted accounting principles ("GAAP"). The Company believes certain non-GAAP performance measures provide users of its financial information and its management additional meaningful information to evaluate the performance of the company.

This press release includes net income (loss) and earnings (loss) per share including impairment adjustments and the effect of the cash settled commodity derivatives, its exploration and production segment's reconciliation of PV-10 to standard measure, its drilling segment's average daily operating margin before elimination of intercompany drilling rig profit and bad debt expense, its cash flow from operations before changes in operating assets and liabilities, and its reconciliation of net income (loss) to adjusted EBITDA.

Below is a reconciliation of GAAP financial measures to non-GAAP financial measures for the three and twelve months ended December 31, 2015 and 2014. Non-GAAP financial measures should not be considered by themselves or a substitute for results reported in accordance with GAAP.

Unit Corporation
Reconciliation of Adjusted Net Income (Loss) and Adjusted Diluted Earnings (Loss) per Share

	Three Months Ended December 31,		Twelve Months Ended December 31,	
	2015	2014	2015	2014
	(In thousands except earnings per share)			
Adjusted net income:				
Net income (loss)	$(309,337)	$(42,551)	$(1,037,361)	$136,276
Impairment adjustment (net of income tax)	302,075	98,398	1,017,556	98,398
(Gain) loss on derivatives not designated as hedges (net of income tax)	(8,363)	(24,088)	(16,421)	(18,429)
Settlements during the period of matured derivative contracts (net of income tax)	8,995	7,944	29,055	(3,691)
Adjusted net income (loss)	$ (6,630)	$ 39,703	$ (7,171)	$212,554
Adjusted diluted earnings per share:				
Diluted earnings (loss) per share	$ (6.29)	$ (0.88)	$ (21.12)	$ 2.78
Diluted earnings per share from the impairments	6.15	2.02	20.72	2.01
Diluted earnings per share from the (gain) loss on derivatives	(0.18)	(0.51)	(0.34)	(0.38)
Diluted earnings (loss) per share from the settlements of matured derivative contracts	0.18	0.17	0.59	(0.08)
Adjusted diluted earnings (loss) per share	$ (0.14)	$ 0.80	$ (0.15)	$ 4.33

The Company has included the net income and diluted earnings per share including only the cash settled commodity derivatives because:

- It uses the adjusted net income to evaluate the operational performance of the company.
- The adjusted net income is more comparable to earnings estimates provided by securities analysts.

Unaudited Reconciliation of PV-10 to Standard Measure
December 31, 2015

PV-10 is the estimated future net cash flows from proved reserves discounted at an annual rate of 10 percent before giving effect to income taxes. Standardized Measure is the after-tax estimated future cash flows from proved reserves discounted at an annual rate of 10 percent, determined in accordance with GAAP. The company uses PV-10 as one measure of the value of its proved reserves and to compare relative values of proved reserves among exploration and production companies without regard to income taxes. The company believes that securities analysts and rating agencies use PV-

10 in similar ways. The company's management believes PV-10 is a useful measure for comparison of proved reserve values among companies because, unlike Standardized Measure, it excludes future income taxes that often depend principally on the characteristics of the owner of the reserves rather than on the nature, location and quality of the reserves themselves. Below is a reconciliation of PV-10 to Standardized Measure:

	2015
	(In millions)
PV-10 at December 31, 2015	$ 690.7
Discounted effect of income taxes	(101.2)
Standardized Measure at December 31, 2015	$ 589.5

Unit Corporation
Reconciliation of Average Daily Operating Margin Before Elimination of Intercompany Rig Profit and Bad Debt Expense

	Three Months Ended			Twelve Months Ended	
	September 30,	December 31,		December 31,	
	2015	2015	2014	2015	2014
	(In thousands except for operating days and operating margins)				
Contract drilling revenue	$ 65,022	$50,554	$134,987	$265,668	$476,517
Contract drilling operating cost	35,486	32,691	77,908	156,408	274,933
Operating profit from contract drilling	29,536	17,863	57,079	109,260	201,584
Add:					
Elimination of intercompany rig profit and bad debt expense	219	325	8,669	3,991	29,343
Operating profit from contract drilling before elimination of intercompany rig profit and bad debt expense	29,755	18,188	65,748	113,251	230,927
Contract drilling operating days	2,870	2,506	7,443	12,681	27,516
Average daily operating margin before elimination of intercompany rig profit and bad debt expense	$ 10,368	$ 7,258	$ 8,834	$ 8,931	$ 8,392

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The Company has included the average daily operating margin before elimination of intercompany rig profit and bad debt expense because:

- Its management uses the measurement to evaluate the cash flow performance of its contract drilling segment and to evaluate the performance of contract drilling management.
- It is used by investors and financial analysts to evaluate the performance of the company.

Unit Corporation
Reconciliation of Cash Flow From Operations Before Changes in Operating Assets and Liabilities

	Twelve Months Ended December 31,	
	2015	2014
	(In thousands)	
Net cash provided by operating activities	$ 446,944	$ 708,993
Net change in operating assets and liabilities	(49,085)	55,991
Cash flow from operations before changes in operating assets and liabilities	$ 397,859	$ 764,984

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The Company has included the cash flow from operations before changes in operating assets and liabilities because:

- It is an accepted financial indicator used by its management and companies in the industry to measure the company's ability to generate cash which is used to internally fund its business activities.
- It is used by investors and financial analysts to evaluate the performance of the company.

Unit Corporation
Reconciliation of EBITDA and Adjusted EBITDA

	Three Months Ended December 31,		Twelve Months Ended December 31,	
	2015	2014	2015	2014
	(In thousands except earnings per share)			
Net income (loss)	$(309,337)	$(42,551)	$(1,037,361)	$136,276
Income taxes	(188,012)	(24,860)	(626,948)	86,663
Depreciation, depletion and amortization	75,091	110,531	354,830	404,943
Impairments	485,261	158,069	1,634,628	158,069
Interest expense	8,481	5,170	31,963	17,371
(Gain) loss on derivatives not designated as hedges	(13,428)	(39,381)	(26,345)	(30,147)
Settlements during the period of matured derivative contracts	14,459	12,946	46,615	(6,038)
(Gain) loss on disposition of assets	959	139	7,229	(8,953)
Adjusted EBITDA	$ 73,474	$180,063	$ 384,611	$758,184
Diluted earnings (loss) per share	$ (6.29)	$ (0.88)	$ (21.12)	$ 2.78
Diluted earnings per share from income taxes	(3.83)	(0.50)	(12.77)	1.77
Diluted earnings per share from depreciation , depletion and amortization	1.50	2.25	7.20	8.25
Diluted earnings per share from impairments	9.90	3.22	33.28	3.22
Diluted earnings per share from interest expense	0.17	0.11	0.65	0.35
Diluted earnings per share from the (gain) loss on derivatives not designated as hedges	(0.27)	(0.80)	(0.53)	(0.61)
Diluted earnings per share from the settlements during the period of matured derivative contracts	0.29	0.25	0.94	(0.13)
Diluted earnings per share (gain) loss on disposition of assets	0.02	0.01	0.15	(0.18)
Adjusted EBITDA per diluted share	$ 1.49	$ 3.66	$ 7.80	$ 15.45

The Company has included the adjusted EBITDA excluding gain or loss on disposition of assets and including only the cash settled commodity derivatives because:

- It uses the adjusted EBITDA to evaluate the operational performance of the company.
- The adjusted EBITDA is more comparable to estimates provided by securities analysts.

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