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UNIT CORPORATION REPORTS 2011 THIRD QUARTER RESULTS

Tulsa, Oklahoma . . . Unit Corporation (NYSE - UNT) reported net income of \$53.4 million, or \$1.11 per diluted share, for the three months ended September 30, 2011. For the same period in 2010, net income was \$34.5 million, or \$0.73 per diluted share. Total revenues for the third quarter of 2011 were \$323.8 million (39% contract drilling, 42% oil and natural gas, and 19% mid-stream), compared to \$218.1 million (39% contract drilling, 44% oil and natural gas, and 17% mid-stream) for the third quarter of 2010.

For the first nine months of 2011, Unit reported net income of \$144.2 million, or \$3.01 per diluted share. For the same period in 2010, net income was \$102.8 million, or \$2.17 per diluted share. Total revenues for the first nine months of 2011 were \$862.7 million (39% contract drilling, 44% oil and natural gas, and 17% mid-stream), compared to \$629.3 million (35% contract drilling, 46% oil and natural gas, and 18% mid-stream) for the first nine months of 2010.

CONTRACT DRILLING SEGMENT INFORMATION

The average number of drilling rigs used in the third quarter of 2011 was 78.9, an increase of 21% from the third quarter of 2010, and an increase of 8% from the second quarter of 2011. Per day drilling rig rates for the third quarter of 2011 averaged \$19,309, up 22%, or \$3,495, from the third quarter of 2010, and up 2%, or \$448 from the second quarter of 2011. Average per day operating margin for the third quarter of 2011 was \$8,413 (before elimination of intercompany drilling rig profit of \$4.8 million). This compares to \$7,056 (before elimination of intercompany drilling rig profit of \$2.9 million) for the third quarter of 2010, an increase of 19% or \$1,357. As compared to the second quarter of 2011 (\$8,370 before elimination of intercompany drilling rig profit of \$5.1 million) third quarter 2011 operating margin increased 1% (in each case with regard to the elimination of intercompany drilling rig profit see Non-GAAP Financial Measures below).

For the first nine months of 2011, Unit averaged 74.0 drilling rigs working, up 27% from 58.2 drilling rigs working during the first nine months of 2010. Average per day operating margin for the first nine months of 2011 was \$8,295 (before elimination of intercompany drilling rig profit of \$15.0 million) as compared to \$5,649 (before elimination of intercompany drilling rig profit of \$4.7 million) for the first nine months of 2010, an increase of 47% (in each case with regard to the elimination of intercompany drilling rig profit see Non-GAAP Financial Measures below).

The following table illustrates Unit's drilling rig count at the end of each period and average utilization rate during the period:

	3 rd Qtr 11	2 nd Qtr 11	1 st Qtr 11	4 th Qtr 10	3 rd Qtr 10	2 nd Qtr 10	1 st Qtr 10	4 th Qtr 09	3 rd Qtr 09
Rigs	126	123	122	121	123	123	125	130	130
Utilization	63%	60%	58%	59%	54%	47%	40%	28%	26%

Larry Pinkston, Unit's Chief Executive Officer and President, said: "During the third quarter, both our utilization rate and drilling day rates increased over those for the second quarter of 2011. Approximately 79% of our drilling rigs working today are drilling for oil or natural gas liquids and approximately 95% are drilling horizontal or directional wells. During the third quarter of 2011 we were awarded two additional new build drilling rig contracts. Both contracts have an initial term of three years and are for 1,500 horsepower diesel-electric drilling rigs. Delivery of these rigs is anticipated during the fourth quarter of 2011. On completion of these two new drilling rigs, we will have 128 drilling rigs in our fleet. Currently, 82 of our 126 drilling rigs are under contract. Term contracts (contracts with original terms ranging from six months to three years in length) are in place for 59 of the 82 contracted drilling rigs. Of these contracts, nine are up for renewal in the fourth quarter of 2011, 38 during 2012, and 12 during 2013. The two contracts for the two new drilling rigs we are building are not reflected in the term contracts reported above."

OIL AND NATURAL GAS SEGMENT INFORMATION

- Completed 40 and 119 gross wells during the third quarter and first nine months of 2011, respectively.
- 38% of third quarter 2011 production was oil and natural gas liquids compared to 30% for the third quarter of 2010.
- Increased our anticipated 2011 production to now fall within the range of 11.8 to 12.1 MMBoe.

Third quarter 2011 oil production was 620,000 barrels, as compared to 379,000 barrels for the same period of 2010, an increase of 64%. Natural gas liquids (NGLs) production during the third quarter of 2011 was 578,000 barrels, an increase of 53% when compared to 378,000 barrels for the same period of 2010. Third quarter 2011 natural gas production increased 11% to 11.6 billion cubic feet (Bcf) compared to 10.4 Bcf for the comparable quarter of 2010. Third quarter 2011 equivalent production averaged 33.9 MBoe per day, up 26% over the third quarter of 2010 and up 4% over the second quarter of 2011. Total production for the first nine months of 2011 was 8.8 MMBoe.

Unit's average natural gas price, including the effects of hedges, for the third quarter of 2011 decreased 21% to \$4.39 per thousand cubic feet (Mcf) as compared to \$5.55 per Mcf for the third quarter of 2010. Unit's average oil price, including the effects of hedges, for the third quarter of 2011 was \$86.19 per barrel compared to \$66.94 per barrel for the third quarter of 2010, up 29%, and Unit's average NGLs price, including the effects of hedges, for the third quarter of 2011 was \$45.40 per barrel compared to \$31.67 per barrel for the third quarter of 2010, up 43%. For the first nine months of 2011, Unit's average natural gas price, including the effects of hedges, decreased 24% to \$4.33 per Mcf as compared to \$5.71 per Mcf for the first nine months of 2010. Unit's average oil price, including the effects of hedges, for the first nine months of 2011 was \$86.80 per barrel compared to \$67.05 per barrel during the first nine months of 2010, a 29% increase. Unit's average NGLs price, including the effects of hedges, for the first nine months of 2011 was \$43.72 per barrel compared to \$35.91 per barrel during the first nine months of 2010, a 22% increase.

Currently for the remainder of 2011, Unit has hedged 80,000 MMBtu per day of its natural gas production, 4,000 Bbls per day of its oil production and 2,535 Bbls per day of its NGLs production. The natural gas production is hedged under swap contracts at a comparable average NYMEX price of \$4.70. The average basis differential for the swaps is (\$0.19). The oil production is hedged under swap contracts at an average price of \$84.28 per barrel. The NGLs production is hedged under swap contracts at an average price of \$43.94 per barrel.

For 2012, Unit has to date hedged 45,000 MMBtu per day of its natural gas production and 4,500 Bbls per day of its oil production. For the first quarter of 2012, Unit hedged 1,988 Bbls per day of its NGLs production and 683 Bbls per day of its second quarter 2012 NGLs production. The natural gas production is hedged under swap contracts at a comparable average NYMEX price of \$5.24. The oil production is hedged under swap contracts at an average price of \$95.91 per barrel. The NGLs production is hedged under swap contracts at an average price of \$42.53 per barrel for the first quarter and \$44.47 per barrel for the second quarter.

For 2013, Unit has to date hedged 2,000 Bbls per day of its oil production. The oil production is hedged under swap contracts at an average price of \$102.05 per barrel.

The following table illustrates certain results for the periods indicated:

	3 rd Qtr 11	2 nd Qtr 11	1 st Qtr 11	4 th Qtr 10	3 rd Qtr 10	2 nd Qtr 10	1 st Qtr 10	4 th Qtr 09	3 rd Qtr 09
Oil and NGL Production, MBo	1,197.5	1,158.6	1,034.0	925.5	756.5	708.6	679.4	641.0	658.2
Natural Gas Production, Bcf	11.6	10.9	10.2	10.6	10.4	9.7	10.0	10.5	10.7
Production, MBoe	3,123	2,983	2,739	2,698	2,478	2,325	2,352	2,389	2,444
Production, MBoe/day	33.9	32.8	30.4	29.3	27.0	25.6	26.1	26.0	26.6
Realized price, Boe (1)	\$41.75	\$42.23	\$40.00	\$41.58	\$38.16	\$38.22	\$40.92	\$36.72	\$35.52

(1) Realized price includes oil, natural gas liquids, natural gas and associated hedges.

In the Marmaton horizontal oil play located in Beaver County, Oklahoma, Unit had first sales on a total of 25 wells during the first nine months of 2011. These wells had an overall 30-day average rate of 242 Boe per day consisting of 78% oil, 14% NGLs and 8% natural gas. Unit owned an average working interest of approximately 81% in the wells. The average ultimate recovery for a Marmaton well is estimated at 130 MBoe with an average cost per well of \$2.7 million. Unit has two drilling rigs operating in the Marmaton and expects to complete a total of 34 gross wells during the year with an approximate net cost of \$70 million. Unit currently has leases on approximately 84,000 net acres in the play.

In the Granite Wash (GW) play located in the Texas Panhandle, Unit had first sales on five horizontal wells during the third quarter. Unit's average working interest in these wells is 79%. Of the five new wells, one well was completed in the GW "A", three in the GW "B", and one in the GW "C1" zone. The average 30-day rate for these five wells was 7.2 MMcf per day. For the first nine months of 2011, Unit had first sales on a total of 14 new GW horizontal wells with an average 30-day production rate of 6.5 MMcf per day consisting of 15% oil, 36% NGLs and 49% natural gas. The average ultimate recovery for a GW horizontal well is estimated at 4.1 Bcfe with an average cost per well of \$5.5 million. Unit anticipates operating three to four Unit drilling rigs in the Granite Wash during the remainder of 2011, which should result in a total of 19 operated GW wells during the year at a projected net cost of \$85 million.

On August 31, 2011, Unit acquired certain producing oil and gas properties for \$30.5 million in cash, subject to closing adjustments, 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 proved reserves associated with the acquisition are approximately 31.2 Bcfe (99% natural gas), 83% of which is proved developed. The acquisition also included approximately 55,000 net acres of which 96% is held by production.

Pinkston said: "We are pleased with the third quarter results from our exploration operations. This quarter marks the fifth consecutive quarter that production has increased. Our strategy of drilling oil or NGLs rich wells is evident in our third quarter 2011 production results. Total liquids (oil and NGLs) production increased 58% between the third quarter of 2011 and the third quarter of 2010. For the year, we plan to drill 160 gross wells. We are also increasing our anticipated annual production guidance to a range between 11.8 to 12.1 MMBoe from our previous guidance of 11.3 to 11.6 MMBoe."

MID-STREAM SEGMENT INFORMATION

- Increased third quarter 2011 liquids sold per day volumes, processing volumes per day, and gathering volumes per day by 73%, 54% and 25%, respectively, over the third quarter of 2010.
- Construction of 16-mile pipeline and related compressor station in Preston County, West Virginia is scheduled to be complete and the pipeline operational during the fourth quarter of 2011.
- Signed a letter of intent to construct a 7-mile, 16" pipeline in Allegheny and Butler Counties, Pennsylvania scheduled for completion during the fourth quarter of 2011.

Third quarter of 2011 per day processing volumes were 129,820 MMBtu while liquids sold volumes were 449,604 gallons per day, an increase of 54% and 73%, respectively, over the third quarter of 2010. Third quarter 2011 per day gathering volumes were 228,247 MMBtu, up 25% over the third quarter of 2010. Operating profit (as defined in the Selected Financial and Operational

Highlights) for the third quarter was \$7.4 million, an increase of 11% from the third quarter of 2010, primarily due to increases in volumes gathered, processed and liquids sold, partially offset by increased cost for gas purchased. Compared to the second quarter of 2011, operating profit decreased 3% primarily because of the lower amounts we now receive under certain contracts that we were required to renegotiate during the first quarter when the original term of those contracts expired.

For the first nine months of 2011, processing volumes of 102,493 MMBtu per day and liquids sold volumes of 378,585 gallons per day increased 26% and 43%, respectively, from the first nine months of 2010. Gathering volumes for the first nine months of 2011 were 201,788 MMBtu per day, an 11% increase from the first nine months of 2010.

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

	3 rd Qtr 11	2 nd Qtr 11	1 st Qtr 11	4 th Qtr 10	3 rd Qtr 10	2 nd Qtr 10	1 st Qtr 10	4 th Qtr 09	3 rd Qtr 09
Gas gathered MMBtu/day	228,247	190,921	185,730	188,252	183,161	183,858	180,117	177,145	179,047
Gas processed MMBtu/day	129,820	90,737	86,445	85,195	84,175	82,699	76,513	77,501	77,923
Liquids sold Gallons/day	449,604	356,484	328,333	291,186	260,519	279,736	253,707	263,668	251,830

Pinkston said: "Processing and liquids sold volumes continue to increase and gas gathered volumes remain strong. In our Mid-continent operations, we are in the process of replacing the existing plant on our Cashion system with a high-efficiency gas processing plant. The new plant is expected to be operational during the first quarter of 2012. It will increase our processing capacity and will improve our liquids recovery capability by 12 to 15%. The Cashion plant gathers gas across Logan, Canadian, Oklahoma and Kingfisher Counties in Oklahoma. In the Mississippi Lime play in Grant County, Oklahoma, our new gathering system and processing plant became operational in October. One well is online and three more wells are in the process of being connected. We anticipate an additional 25 to 30 wells to be connected during 2012 due to active drilling by multiple producers in the area around the plant. This is our entrance into the Mississippi Lime play. In our Appalachian operations, we are in the final stages of completing a 16-mile, 16" pipeline and a compressor station in Preston County, West Virginia, which will have a capacity of approximately 220.0 MMcf per day. Currently, we have four wells connected with an expected total initial flow volume in the 8 to 10 MMcf per day range. Three additional wells have been drilled and are waiting on completion prior to being connected. We anticipate this pipeline will be operational during the fourth quarter of 2011. In addition to the Preston County pipeline, we recently signed a letter of intent with a third party to construct a pipeline in Allegheny and Butler Counties of Pennsylvania. First flow of gas from this new system is expected to occur in the fourth quarter of 2011. Expectations are that the first well will flow up to 10 MMcf per day, and we anticipate four more wells to be drilled and connected during the first half of 2012."

FINANCIAL INFORMATION

Unit ended the third quarter of 2011 with working capital of \$57.9 million, long-term debt of \$305.4 million (\$250 million of senior subordinated notes and \$55.4 million of senior credit facility), and a debt to capitalization ratio of 14%. On September 13, 2011, Unit entered into a new five year unsecured senior credit facility. Under the credit facility, the amount available for Unit to borrow is the lesser of the amount Unit elects as the commitment amount (currently \$250 million) or the value of the borrowing base as determined by the lenders (currently \$600 million), but in either event not to exceed the maximum credit facility amount of \$750 million. As of September 30, 2011, Unit had \$55.4 million in borrowings outstanding under its credit facility.

MANAGEMENT COMMENT

Larry Pinkston said: "We are pleased with the operating results of the third quarter and first nine months of 2011. For the remainder of the year, we will continue to focus our exploration efforts on our oil and natural gas liquids rich prospects like the Granite Wash and Marmaton formations. Our contract drilling operations will continue responding to our customers' demands for horizontal drilling by continuing to refurbish and upgrade our existing drilling rigs and, where appropriate, adding new drilling rigs to our fleet. Our midstream segment continues to grow its operations as evidenced by the new projects in the Mid-continent and Appalachia areas. We are optimistic about the remainder of 2011 and we are well positioned, especially given the recent financing arrangements we have completed, to take advantage of growth opportunities that arise in all three of our business segments."

WEBCAST

Unit will webcast its third quarter earnings conference call live over the Internet on November 2, 2011 at 10:00 a.m. Central Time (11:00 a.m. Eastern). To listen to the live call, please go to www.unitcorp.com 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 listed on the New York Stock Exchange under the symbol UNT. For more information about Unit Corporation, visit its website at <http://www.unitcorp.com>.

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. A number of risks and uncertainties could cause actual results to differ materially from these statements, including the impact that the current decline in wells being drilled will have on production and drilling rig utilization, productive capabilities of the Company's wells, future demand for oil and natural gas, future drilling rig utilization and dayrates, projected growth of the Company's oil and natural gas production, oil and gas reserve information, as well as its ability to meet its future reserve replacement goals, anticipated gas gathering and processing rates and throughput volumes, the prospective capabilities of the reserves associated with the Company's inventory of future drilling sites, anticipated oil and natural gas prices, the number of wells to be drilled by the Company's exploration segment, development, operational, implementation and opportunity risks, possible delays caused by limited availability of third party services needed in the course of its operations, possibility of future growth opportunities, 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 as a result of new information, future events or otherwise.

Unit Corporation
Selected Financial and Operations Highlights
(In thousands except per share and operations data)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
Statement of Operations:				
Revenues:				
Contract drilling	\$ 128,927	\$ 85,004	\$ 342,098	\$ 217,919
Oil and natural gas	134,897	96,562	376,393	286,751
Gas gathering and processing	60,688	37,429	144,820	114,908
Other, net	(667)	(879)	(566)	9,691
Total revenues	323,845	218,116	862,745	629,269
Expenses:				
Contract drilling:				
Operating costs	73,004	45,406	190,086	132,847
Depreciation	20,818	18,469	57,333	48,700
Oil and natural gas:				
Operating costs	29,598	27,092	93,796	75,943
Depreciation, depletion and amortization	47,195	30,091	132,013	81,746
Gas gathering and processing:				
Operating costs	53,299	30,743	119,143	92,407
Depreciation and amortization	4,017	3,823	11,627	11,746
General and administrative	7,800	6,637	22,188	19,372
Interest, net	1,351	---	2,078	---
Total expenses	237,082	162,261	628,264	462,761
Income Before Income Taxes	86,763	55,855	234,481	166,508
Income Tax Expense:				
Current	(3,949)	(8,553)	(3,949)	(2,488)
Deferred	37,352	29,917	94,224	66,177
Total income taxes	33,403	21,364	90,275	63,689
Net Income	\$ 53,360	\$ 34,491	\$ 144,206	\$ 102,819
Net Income per Common Share:				
Basic	\$ 1.12	\$ 0.73	\$ 3.03	\$ 2.18
Diluted	\$ 1.11	\$ 0.73	\$ 3.01	\$ 2.17
Weighted Average Common Shares Outstanding:				
Basic	47,687	47,358	47,642	47,217
Diluted	47,968	47,495	47,932	47,384

	September 30, 2011	December 31, 2010
Balance Sheet Data:		
Current assets	\$ 235,970	\$ 188,180
Total assets	\$ 3,165,251	\$ 2,669,240
Current liabilities	\$ 178,056	\$ 147,128
Long-term debt	\$ 305,400	\$ 163,000
Other long-term liabilities	\$ 112,701	\$ 92,389
Deferred income taxes	\$ 658,659	\$ 556,106
Shareholders' equity	\$ 1,910,435	\$ 1,710,617

	Nine Months Ended September 30, 2011	2010
Statement of Cash Flows Data:		
Cash Flow From Operations before Changes in Operating Assets and Liabilities (1)	\$ 450,725	\$ 309,861
Net Change in Operating Assets and Liabilities	(32,874)	(25,965)
Net Cash Provided by Operating Activities	<u>\$ 417,851</u>	<u>\$ 283,896</u>
Net Cash Used in Investing Activities	\$ (583,790)	\$ (393,804)
Net Cash Provided by Financing Activities	\$ 165,740	\$ 109,901

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
Contract Drilling Operations Data:				
Rigs Utilized	78.9	65.4	74.0	58.2
Operating Margins (2)	43%	47%	44%	39%
Operating Profit Before Depreciation (2) (\$MM)	\$ 55.9	\$ 39.6	\$ 152.0	\$ 85.1

Oil and Natural Gas Operations Data:				
Production:				
Oil – MBbls	620	379	1,767	1,002
Natural Gas Liquids - MBbls	578	378	1,623	1,143
Natural Gas - MMcf	11,553	10,385	32,730	30,121
Average Prices:				
Oil price per barrel received	\$ 86.19	\$ 66.94	\$ 86.80	\$ 67.05
Oil price per barrel received, excluding hedges	\$ 89.47	\$ 72.52	\$ 93.75	\$ 74.11
NGLs price per barrel received	\$ 45.40	\$ 31.67	\$ 43.72	\$ 35.91
NGLs price per barrel received, excluding hedges	\$ 46.33	\$ 31.27	\$ 44.65	\$ 35.70
Natural Gas price per Mcf received	\$ 4.39	\$ 5.55	\$ 4.33	\$ 5.71
Natural Gas price per Mcf received, excluding hedges	\$ 4.01	\$ 3.94	\$ 3.94	\$ 4.27
Operating Profit Before DD&A (2) (\$MM)	\$ 105.3	\$ 69.5	\$ 282.6	\$ 210.8

Mid-Stream Operations Data:				
Gas Gathering - MMBtu/day	228,247	183,161	201,788	182,390
Gas Processing - MMBtu/day	129,820	84,175	102,493	81,157
Liquids Sold – Gallons/day	449,604	260,519	378,585	264,679
Operating Profit Before Depreciation and Amortization (2) (\$MM)	\$ 7.4	\$ 6.7	\$ 25.7	\$ 22.5

(1) The company considers its cash flow from operations before changes in operating assets and liabilities an important measure in meeting the performance goals of the company (see Non-GAAP Financial Measures below).

(2) Operating profit before depreciation is calculated by taking operating revenues by segment less operating expenses excluding depreciation, depletion, amortization general and administrative and interest expense. Operating margins are calculated by dividing operating profit by segment revenue.

Non-GAAP Financial Measures

We report our financial results in accordance with generally accepted account principles (“GAAP”). We believe certain non-GAAP performance measures provide users of our financial information and our management additional meaningful information to evaluate the performance of our company.

This press release includes cash flow from operations before changes in operating assets and liabilities and our drilling segment’s average daily operating margin before elimination of intercompany drilling rig profit.

Below is a reconciliation of GAAP financial measures to non-GAAP financial measures for the three and nine months ended September 30, 2011 and 2010. Non-GAAP financial measures should not be considered by themselves or a substitute for our results reported in accordance with GAAP.

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

	Nine Months Ended September 30,	
	2011	2010
	(In thousands)	
Net cash provided by operating activities	\$ 417,851	\$ 283,896
Subtract:		
Net change in operating assets and liabilities	32,874	25,965
Cash flow from operations before changes in operating assets and liabilities	<u>\$ 450,725</u>	<u>\$ 309,861</u>

We have included the cash flow from operations before changes in operating assets and liabilities because:

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

Unit Corporation Reconciliation of Average Daily Operating Margin Before Elimination of Intercompany Rig Profit

	Three Months Ended			Nine Months Ended	
	June 30,	September 30,		September 30,	
	2011	2011	2010	2011	2010
	(In thousands)				
Contract drilling revenue	\$ 115,183	\$ 128,927	\$ 85,004	\$ 342,098	\$ 217,919
Contract drilling operating cost	64,238	73,004	45,406	190,086	132,847
Operating profit from contract drilling	50,945	55,923	39,598	152,012	85,072
Add:					
Elimination of intercompany rig profit	5,092	4,820	2,888	14,955	4,717
Operating profit from contract drilling before elimination of intercompany rig profit	56,037	60,743	42,486	166,967	89,789
Contract drilling operating days	6,695	7,220	6,021	20,129	15,894
Average daily operating margin before elimination of intercompany rig profit	<u>\$ 8,370</u>	<u>\$ 8,413</u>	<u>\$ 7,056</u>	<u>\$ 8,295</u>	<u>\$ 5,649</u>

We have included the average daily operating margin before elimination of intercompany rig profit because:

- Our management uses the measurement to evaluate the cash flow performance of our 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 our company.