Copano Energy

Copano Energy Reports Second Quarter 2011 Results

HOUSTON, Aug. 4, 2011 /PRNewswire via COMTEX/ --

Copano Energy, L.L.C. (NASDAQ: CPNO) today announced its financial results for the three and six months ended June 30, 2011.

"During the second quarter, our operating segment gross margin benefited from continued growth of volumes in the Eagle Ford Shale and the north Barnett Shale Combo areas, a strong NGL pricing environment and our recent acquisition of the Harrah plant in Oklahoma," said R. Bruce Northcutt, Copano Energy's President and Chief Executive Officer. "As we look to the second half of 2011, we expect the successful completion and start-up of several of our key Eagle Ford Shale projects, including the Eagle Ford Gathering joint venture pipeline, the Liberty NGL pipeline, the Houston Central fractionation expansion and the DK pipeline extension. Once in service, these projects are expected to immediately add distributable cash flow and drive significant growth for years to come."

Second Quarter Financial Results

Total distributable cash flow for the second quarter of 2011 increased 12% to $37.6 million from $33.5 million for the second quarter of 2010 and from $33.4 million in the first quarter of 2011. Second quarter 2011 total distributable cash flow represents 97% coverage of the second quarter distribution of $0.575 per unit, based on common units outstanding on the distribution record date.

Revenue for the second quarter of 2011 increased 50% to $346.1 million compared to $230.1 million for the second quarter of 2010 and increased 19% compared to $290.0 million in the first quarter of 2011. Operating segment gross margin increased 38% to $75.6 million compared to $54.7 million for the second quarter of 2010 and increased 9% compared to $69.1 million in the first quarter of 2011. Total segment gross margin increased 15% to $65.3 million for the second quarter of 2011 compared to $56.8 million for the second quarter of 2010 and increased 8% compared to $60.3 million for the first quarter of 2011.

Adjusted EBITDA for the second quarter of 2011 was $54.4 million compared to $48.6 million for the second quarter of 2010 and $47.4 million for the first quarter of 2011.

Net loss was $9.4 million for the second quarter of 2011 compared to net loss of $21.1 million for the second quarter of 2010. Net loss for the second quarter of 2011 includes a loss on the refinancing of unsecured debt of $18.2 million and is prior to deducting in-kind distributions on Copano's Series A convertible preferred units issued in July 2010.

Net loss to common units after deducting $8.0 million of in-kind preferred unit distributions totaled $17.4 million, or $0.26 per unit on a diluted basis, for the second quarter of 2011 compared to net loss to common units of $21.1 million, or $0.32 per unit on a diluted basis, for the second quarter of 2010. Weighted average diluted units outstanding totaled 66.1 million for the second quarter of 2011 as compared to 65.5 million for the same period in 2010.

Total distributable cash flow, total segment gross margin, adjusted EBITDA, and segment gross margin are non-GAAP financial measures, which are reconciled to their most directly comparable GAAP measures at the end of this press release. Copano has revised its method for calculating adjusted EBITDA and its presentation of total distributable cash flow from prior periods. For a detailed discussion of these changes, please read *"Use of Non-GAAP Financial Measures"* beginning on page 5 of this press release.

Second Quarter Operating Results by Segment

Copano manages its business in three geographical operating segments: Texas, which provides midstream natural gas services in north and south Texas and also includes a processing plant in southwest Louisiana; Oklahoma, which provides midstream natural gas services in central and east Oklahoma; and the Rocky Mountains, which provides midstream natural gas services to producers in Wyoming's Powder River Basin and includes managing member interests in Bighorn Gas Gathering, L.L.C. (Bighorn) of 51% and in Fort Union Gas Gathering, L.L.C. (Fort Union) of 37.04%.

Texas

Segment gross margin for Texas increased 45% to $46.1 million for the second quarter of 2011 compared to $31.8 million for the second quarter of 2010 and increased 2% from $45.0 million for the first quarter of 2011. The year-over-year increase resulted primarily from (i) a 23% increase in realized margins on service throughput compared to the second quarter of 2010 ($0.76 per MMBtu in 2011 compared to $0.62 per MMBtu in 2010) reflecting higher NGL prices, (ii) the impact of Copano's fractionation facilities, which were placed in service in May 2010 and (iii) an increase of pipeline throughput associated with fee-based contracts in the Eagle Ford Shale and the north Barnett Shale Combo plays. During the second quarter of 2011, throughput volumes for the Eagle Ford Shale and the north Barnett Shale Combo plays increased 65% and 50%, respectively, from the first quarter of 2011. During the second quarter of 2011, weighted-average NGL prices on the Mont Belvieu index, based on Copano's product mix for the period, were $58.57 per barrel compared to $43.14 per barrel during the second quarter of 2010, an increase of 36%. During the second quarter of 2011, natural gas prices on the Houston Ship Channel index averaged $4.29 per MMBtu compared to $4.04 per MMBtu during the second quarter of 2010, an increase of 6%.

During the second quarter of 2011, the Texas segment provided gathering, transportation and processing services for an average of 665,040 MMBtu/d of natural gas compared to 559,876 MMBtu/d for the second quarter of 2010, an increase of 19%. The Texas segment gathered an average of 444,186 MMBtu/d of natural gas, an increase of 35% over last year's second quarter, primarily due to increased volumes from the Eagle Ford Shale and north Barnett Shale Combo plays. Processed volumes increased 25% to an average of 588,533 MMBtu/d of natural gas at Copano's plants and third-party plants. NGL production increased 46% to an average of 26,913 Bbls/d at Copano's plants and third-party plants, reflecting increased volumes behind Copano's Houston Central complex in south Texas and the Saint Jo plant in the north Barnett Shale Combo play.

Oklahoma

Segment gross margin for Oklahoma increased 32% to $28.7 million for the second quarter of 2011 compared to $21.8 million for the second quarter of 2010 and increased 24% from $23.1 million for the first quarter of 2011. The year-over-year increase resulted primarily from (i) a 21% increase in realized margins on service throughput compared to the second quarter of 2010 ($1.11 per MMBtu in 2011 compared to $0.92 per MMBtu in 2010), primarily reflecting higher natural gas and NGL prices, (ii) the acquisition of the Harrah plant on April 1, 2011 which added an additional $1.5 million of gross margin for the second quarter of 2011 and (iii) an increase in service throughput attributable to volume growth from the Woodford Shale. During the second quarter of 2011, weighted-average NGL prices on the Conway index, based on Copano's product mix for the period, were $50.17 per barrel compared to $36.34 per barrel during the second quarter of 2010, an increase of 38%. During the second quarter of 2011, natural gas prices on the CenterPoint East index averaged $4.14 per MMBtu compared to $3.86 per MMBtu during the second quarter of 2010, an increase of 7%.

The Oklahoma segment gathered an average of 283,870 MMBtu/d of natural gas, processed an average of 157,424 MMBtu/d of natural gas and produced an average of 17,331 Bbls/d of NGLs at its own plants and third-party plants during the second quarter of 2011. Compared to the second quarter of 2010, this represents a 9% increase in service throughput, a 1% increase in plant inlet volumes and a 4% increase in NGL production. The increase in service throughput is primarily attributable to increased drilling and production of lean gas in the Woodford Shale area near Copano's Cyclone Mountain system, offset by normal production declines in rich gas areas.

Rocky Mountains

Segment gross margin for the Rocky Mountains segment totaled $0.8 million in the second quarter of 2011 compared to $1.1 million for the second quarter of 2010 and $1.0 million for the first quarter of 2011. The Rocky Mountains segment gross margin results do not include the financial results and volumes associated with Copano's interests in Bighorn and Fort Union, which are accounted for under the equity method of accounting and are shown in Copano's financial statements under "Equity in (earnings) loss from unconsolidated affiliates." Average pipeline throughput for Bighorn and Fort Union on a combined basis decreased 41% to 533,329 MMBtu/d in the second quarter of 2011 as compared to 900,047 MMBtu/d in the second quarter of 2010. The volume decline is primarily due to certain Fort Union shippers diverting gas volumes to TransCanada's Bison Pipeline upon its start up in January 2011. However, Fort Union also received payments based on an additional 327,894 MMBtu/d in long-term contractually committed volumes for the three months ended June 30, 2011.

Corporate and Other

Corporate and other gross margin includes Copano's commodity risk management activities. These activities contributed a loss of $10.3 million for the second quarter of 2011 compared to income of $2.1 million for the second quarter of 2010 and a loss of $8.8 million for the first quarter of 2010. The loss for the second quarter of 2011 included $7.4 million of non-cash amortization expense relating to the option component of Copano's risk management portfolio, $2.7 million of net cash settlements paid for expired commodity derivative instruments and $0.2 million of unrealized losses on undesignated economic hedges. The second quarter 2010 gain included $9.5 million of net cash settlements received for expired commodity derivative instruments and $0.7 million of unrealized mark-to-market gains on undesignated economic hedges offset by $8.1 million of non-cash amortization expense relating to the option component of Copano's risk management portfolio.

Year to Date Financial Results

Revenue for the six months ended June 30, 2011 increased 28% to $636.0 million compared to $496.7 million for the same period in 2010. Operating segment gross margin increased 35% to $144.7 million compared to $107.3 million for the six months ended June 30, 2010. Total segment gross margin increased 16% to $125.6 million for the six months ended June 30, 2011 compared to $108.0 million for the same period in 2010.

Adjusted EBITDA for the six months ended June 30, 2011 was $101.8 million compared to $95.3 million for the same period in 2010.

Net loss was $5.8 million for the six months ended June 30, 2011 compared to net loss of $22.4 million for the same period in 2010. Net loss for the first half of 2011 includes a loss on the refinancing of unsecured debt of $18.2 million and is prior to deducting in-kind distributions on Copano's Series A convertible preferred units issued in July 2010.

Net loss to common units after deducting $16.0 million of in-kind preferred unit distributions totaled $21.8 million, or $0.33 per unit on a diluted basis, for the six months ended June 30, 2011 compared to net loss to common units of $22.4 million, or $0.36 per unit on a diluted basis, for the same period in 2010. Weighted average diluted units outstanding totaled 66.1 million for the six months ended June 30, 2011 as compared to 61.9 million for the same period in 2010.

Cash Distributions

On July 13, 2011, Copano announced its second quarter 2011 cash distribution of $0.575 per unit, or $2.30 per unit on an annualized basis, for all of its outstanding common units. This distribution is unchanged from the first quarter of 2011 and will be paid on August 11, 2011 to common unitholders of record at the close of business on August 1, 2011.

Conference Call Information

Copano will hold a conference call to discuss its second quarter 2011 financial results on August 5, 2011 at 10:00 a.m. Eastern Time (9:00 a.m. Central Time). To participate in the call, dial (480) 629-9722 and ask for the Copano call 10 minutes prior to the start time, or access it live over the internet at www.copanoenergy.com on the "Investor Overview" page of the "Investor Relations" section of Copano's website.

A replay of the audio webcast will be available shortly after the call on Copano's website. A telephonic replay will be available through August 12, 2011 by calling (303) 590-3030 and using the pass code 4453816#.

Use of Non-GAAP Financial Measures

This news release and the accompanying schedules include the non-generally accepted accounting principles, or non-GAAP, financial measures of total distributable cash flow, total segment gross margin, adjusted EBITDA and segment gross margin. The accompanying schedules provide reconciliations of these non-GAAP financial measures to their most directly comparable financial measures calculated and presented in accordance with accounting principles generally accepted in the United States, or GAAP. Non-GAAP financial measures should not be considered as alternatives to GAAP measures such as net income (loss), operating income (loss), income (loss) from continuing operations, cash flows from operating activities or any other GAAP measure of liquidity or financial performance. Copano's non-GAAP financial measures may not be comparable to similarly titled measures of other companies, which may not calculate their measures in the same manner.

Copano's management team uses non-GAAP financial measures to evaluate its core profitability and to assess the financial performance of its assets. Subject to the limitations expressed above, Copano believes that investors and other market participants benefit from access to the same financial measures that its management uses in evaluating its performance.

Adjusted EBITDA. Commencing with the second quarter of 2011, Copano revised its calculation of adjusted EBITDA to more closely resemble that of many of Copano's peers in terms of measuring the company's ability to generate cash. Adjusted EBITDA (as revised) equals:

- net income (loss);
- *plus* interest and other financing costs, provision for income taxes, depreciation, amortization and impairment expense, non-cash amortization expense associated with commodity derivative instruments, distributions from unconsolidated affiliates, loss on refinancing of unsecured debt and equity-based compensation expense;
- *minus* equity in earnings (loss) from unconsolidated affiliates and unrealized gains (losses) from commodity risk management activities; and
- *plus or minus* other miscellaneous non-cash amounts affecting net income (loss) for the period.

In calculating adjusted EBITDA as revised, Copano no longer adds to EBITDA (earnings before interest, taxes, depreciation and amortization) its share of the depreciation, amortization and impairment expense and interest and other financing costs embedded in equity in earnings (loss) from unconsolidated affiliates; instead, Copano now adds to EBITDA (i) its impairment expense and other non-cash amounts affecting net income (loss) for the period, (ii) non-cash amortization expense associated with commodity derivative instruments, (iii) loss on refinancing of unsecured debt and (iv) distributions from unconsolidated affiliates.

Copano believes that the revised calculation of adjusted EBITDA is a more effective tool for its management in evaluating operating performance for several reasons. Although Copano's historical method for calculating adjusted EBITDA was useful in assessing the performance of Copano's assets (including its unconsolidated affiliates) without regard to financing methods, capital structure or historical cost basis, the prior calculation was not as useful in evaluating the core performance of its assets and their ability to generate cash because adjustments for a number of non-cash expenses and other non-cash and non-operating items were not reflected in the calculation, and the impact of cash distributions from unconsolidated affiliates was likewise not reflected. Additionally, Copano believes that the revised calculation of adjusted EBITDA is more consistent with the method and presentation used by many of its peers and will allow management to better evaluate the company's performance relative to its peer companies.

Also, Copano believes that the revised calculation more effectively represents what lenders and debt holders, as well as industry analysts and many of its unitholders, have indicated is useful in assessing Copano's core performance and outlook and comparing Copano to other companies in its industry. For example, Copano believes that adjusted EBITDA as revised may provide investors and analysts with a more useful tool for evaluating the company's leverage because it more closely resembles Consolidated EBITDA (as defined under Copano's revolving credit facility), which is used by lenders to calculate financial covenants. Consolidated EBITDA differs from adjusted EBITDA in that it includes further adjustments to (i) reflect the pro forma effects of material acquisitions and dispositions and (ii) in the case of leverage ratio calculations, includes projected EBITDA from significant capital projects under construction.

Total Distributable Cash Flow. Commencing with the second quarter of 2011, Copano presents total distributable cash flow as net income (loss) plus all adjustments included in the adjusted EBITDA calculation described above and minus: (i) interest expense, (ii) current tax expense and (iii) maintenance capital expenditures. Although Copano has revised its presentation of total distributable cash flow, the components of the calculation have not changed, except that total distributable cash flow now eliminates the impact of any loss on refinancing of unsecured debt because such losses do not reduce operating cash flow.

Houston-based Copano Energy, L.L.C. is a midstream natural gas company with operations in Texas, Oklahoma, Wyoming and Louisiana. Its assets include approximately 6,400 miles of active natural gas gathering and transmission pipelines, 250 miles of NGL pipelines and ten natural gas processing plants, with more than one billion cubic feet per day of combined processing capacity and 22,000 barrels per day of fractionation capacity. For more information, please visit www.copanoenergy.com.

This press release includes "forward-looking statements," as defined by the Securities and Exchange Commission. Statements that address activities or events that Copano believes will or may occur in the future are forward-looking statements. These statements include, but are not limited to, statements about future producer activity and Copano's total distributable cash flow and distribution coverage. These statements are based on management's experience and perception of historical trends, current conditions, expected future developments and other factors management believes are reasonable. Important factors that could cause actual results to differ materially from those in the forward-looking statements include, without limitation, the following risks and uncertainties, many of which are beyond Copano's control: The volatility of prices and market demand for natural gas and NGLs; Copano's ability to continue to obtain new sources of natural gas supply and retain its key customers; the impact on volumes and resulting cash flow of technological, economic and other uncertainties inherent in estimating future production and producers' ability to drill and successfully complete and attach new natural gas supplies and the availability of downstream transportation systems and other facilities for natural gas and NGLs; higher construction costs or project delays due to inflation, limited availability of required resources, or the effects of environmental, legal or other uncertainties; general economic conditions; the effects of government regulations and policies; and other financial, operational and legal risks and uncertainties detailed from time to time in Copano's filings with the Securities and Exchange Commission.

- financial statements to follow -

Contacts: Carl Luna, SVP & CFO
Copano Energy, L.L.C.
713-621-9547

Jack Lascar / jlascar@drg-l.com
Anne Pearson / apearson@drg-l.com
DRG&L / 713-529-6600

(21,005)

COPANO ENERGY, L.L.C. AND SUBSIDIARIES

UNAUDITED CONSOLIDATED STATEMENTS OF OPERATIONS

	Three Months Ended June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010
	(In thousands, except per unit information)			
Revenue:				
Natural gas sales	$ 123,928	$ 84,819	$ 227,723	$ 205,035
Natural gas liquids sales	180,758	114,802	329,759	234,120
Transportation, compression and processing fees	27,898	16,516	52,369	29,630
Condensate and other	13,472	13,914	26,130	27,932
Total revenue	346,056	230,051	635,981	496,717
Costs and expenses:				
Cost of natural gas and natural gas liquids(1)	274,398	167,613	498,128	377,478
Transportation (1)	6,362	5,603	12,211	11,279
Operations and maintenance	15,763	13,230	30,862	25,333
Depreciation and amortization	17,363	15,583	34,232	30,784
General and administrative	11,901	10,900	24,499	21,442
Taxes other than income	1,397	1,181	2,527	2,343
Equity in (earnings) loss from unconsolidated affiliates	(1,306)	23,632	(3,008)	21,837
Total costs and expenses	325,878	237,742	599,451	490,496
Operating income (loss)	20,178	(7,691)	36,530	6,221
Other income (expense):				
Interest and other income	8	37	15	44
Loss on refinancing of unsecured debt	(18,233)	-	(18,233)	-
Interest and other financing costs	(11,454)	(13,351)	(23,370)	(28,296)
Loss before income taxes	(9,501)		(5,058)	(22,031)
Provision for income taxes	140	(106)	(771)	(340)
Net loss	(9,361)	(21,111)	(5,829)	(22,371)
Preferred unit distributions	(8,076)	-	(15,956)	-
Net loss to common units	$ (17,437)	$ (21,111)	$ (21,785)	$ (22,371)
Basic and diluted net loss per common unit	$ (0.26)	$ (0.32)	$ (0.33)	$ (0.36)
Weighted average number of common units	66,143	65,516	66,065	61,941
Distributions declared per common unit	$ 0.575	$ 0.575	$ 1.150	$ 1.150

(1) Exclusive of operations and maintenance and depreciation and amortization shown separately below.

COPANO ENERGY, L.L.C. AND SUBSIDIARIES
UNAUDITED CONSOLIDATED STATEMENTS OF CASH FLOWS

	Six Months Ended June 30,	
	2011	2010
Cash Flows From Operating Activities:	(In thousands)	
Net loss	$ (5,829)	$ (22,371)
Adjustments to reconcile net loss to net cash provided by operating activities:		

Depreciation and amortization	34,232	30,784
Amortization of debt issue costs	1,949	1,790
Equity in (earnings) loss from unconsolidated affiliates	(3,008)	21,837
Distributions from unconsolidated affiliates	12,323	10,993
Loss on refinancing of unsecured debt	18,233	-
Non-cash gain on risk management activities, net	(1,536)	(1,049)
Equity-based compensation	5,340	4,688
Deferred tax provision	168	(98)
Other non-cash items	(10)	(369)
Changes in assets and liabilities, net of acquisitions:		
Accounts receivable	(15,637)	12,231
Prepayments and other current assets	2,110	2,605
Risk management activities	5,455	6,002
Accounts payable	21,498	(3,151)
Other current liabilities	718	1,522
Net cash provided by operating activities	76,006	65,414
Cash Flows From Investing Activities:		
Additions to property, plant and equipment	(98,289)	(59,438)
Additions to intangible assets	(4,140)	(930)
Acquisitions	(16,084)	-
Investments in unconsolidated affiliates	(65,027)	(1,538)
Distributions from unconsolidated affiliates	1,249	1,997
Escrow cash	6	-
Proceeds from sale of assets	141	266
Other	(185)	523
Net cash used in investing activities	(182,329)	(59,120)
Cash Flows From Financing Activities:		
Proceeds from long-term debt	605,000	80,000
Repayment of long-term debt	(392,665)	(170,000)
Payments of premiums and expenses on redemption of unsecured debt	(14,572)	-
Deferred financing costs	(15,670)	-
Distributions to unitholders	(76,571)	(69,430)
Proceeds from public offering of common units, net of underwriting discounts and commissions of $7,223	-	164,786
Equity offering costs	(4)	(531)
Proceeds from option exercises	2,431	991
Net cash provided by financing activities	107,949	5,816
Net increase in cash and cash equivalents	1,626	12,110
Cash and cash equivalents, beginning of year	59,930	44,692
Cash and cash equivalents, end of period	$ 61,556	$ 56,802

COPANO ENERGY, L.L.C. AND SUBSIDIARIES
UNAUDITED CONSOLIDATED BALANCE SHEETS

	June 30, 2011	December 31, 2010
	(In thousands, except unit information)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 61,556	$ 59,930

Accounts receivable, net	112,641	96,662
Risk management assets	4,616	7,836
Prepayments and other current assets	3,249	5,179
Total current assets	182,062	169,607
Property, plant and equipment, net	1,007,879	912,157
Intangible assets, net	186,872	188,585
Investments in unconsolidated affiliates	658,424	604,304
Escrow cash	1,850	1,856
Risk management assets	12,912	11,943
Other assets, net	28,908	18,541
Total assets	$ 2,078,907	$ 1,906,993
LIABILITIES AND MEMBERS' CAPITAL		
Current liabilities:		
Accounts payable	$ 146,178	$ 117,706
Accrued interest	8,037	10,621
Accrued tax liability	586	913
Risk management liabilities	9,784	9,357
Other current liabilities	22,139	14,495
Total current liabilities	186,724	153,092
Long term debt (includes $0 and $546 bond premium as of June 30, 2011 and December 31, 2010, respectively)	804,525	592,736
Deferred tax provision	2,051	1,883
Risk management and other noncurrent liabilities	2,986	4,525
Commitments and contingencies (Note 9)		
Members' capital:		
Series A convertible preferred units, no par value, 11,121,071 units and 10,585,197 units issued and outstanding as of June 30, 2011 and December 31, 2010, respectively	285,168	285,172
Common units, no par value, 66,225,657 units and 65,915,173 units issued and outstanding as of June 30, 2011 and December 31, 2010, respectively	1,164,083	1,161,652
Paid in capital	57,312	51,743
Accumulated deficit	(396,253)	(313,454)
Accumulated other comprehensive loss	(27,689)	(30,356)
	1,082,621	1,154,757
Total liabilities and members' capital	$ 2,078,907	$ 1,906,993

COPANO ENERGY, L.L.C. AND SUBSIDIARIES
UNAUDITED OPERATING STATISTICS

	Three Months Ended June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010
	($ In thousands)			
Total segment gross margin(1)	$ 65,296	$ 56,835	$ 125,642	$ 107,960
Operations and maintenance expenses	15,763	13,230	30,862	25,333
Depreciation and amortization	17,363	15,583	34,232	30,784
General and administrative expenses	11,901	10,900	24,499	21,442
Taxes other than income	1,397	1,181	2,527	2,343
Equity in (earnings) loss from unconsolidated affiliates(2)(3)(4)	(1,306)	23,632	(3,008)	21,837

Operating income (loss)(2)	20,178	(7,691)	36,530	6,221
Loss on retirement of unsecured debt	(18,233)	-	(18,233)	-
Interest and other financing costs, net	(11,446)	(13,314)	(23,355)	(28,252)
Provision for income taxes	140	(106)	(771)	(340)
Net loss	(9,361)	(21,111)	(5,829)	(22,371)
Preferred unit distributions	(8,076)	-	(15,956)	-
Net loss to common units	$ (17,437)	$ (21,111)	$ (21,785)	$ (22,371)
Total segment gross margin:				
Texas	$ 46,134	$ 31,751	$ 91,145	$ 58,916
Oklahoma	28,665	21,821	51,747	46,096
Rocky Mountains(5)	771	1,148	1,813	2,251
Segment gross margin	75,570	54,720	144,705	107,263
Corporate and other(6)	(10,274)	2,115	(19,063)	697
Total segment gross margin(1)	$ 65,296	$ 56,835	$ 125,642	$ 107,960
Segment gross margin per unit:				
Texas:				
Service throughput ($/MMBtu)	$ 0.76	$ 0.62	$ 0.76	$ 0.57
Oklahoma:				
Service throughput ($/MMBtu)	$ 1.11	$ 0.92	$ 1.03	$ 1.00
Volumes:				
Texas: (7)				
Service throughput (MMBtu/d)(8)	665,040	559,876	660,741	571,358
Pipeline throughput (MMBtu/d)	444,186	327,839	422,429	322,423
Plant inlet volumes (MMBtu/d)	588,533	469,019	574,794	463,158
NGLs produced (Bbls/d)	26,913	18,382	25,080	16,869
Oklahoma:(9)				
Service throughput (MMBtu/d)(8)	283,870	259,972	280,293	254,386
Plant inlet volumes (MMBtu/d)	157,424	156,204	156,856	154,208
NGLs produced (Bbls/d)	17,331	16,653	17,067	15,994
Capital Expenditures:				
Maintenance capital expenditures	$ 5,555	$ 1,649	$ 7,601	$ 3,080
Expansion capital expenditures	69,382	51,536	120,901	71,942
Total capital expenditures	$ 74,937	$ 53,185	$ 128,502	$ 75,022
Operations and maintenance expenses:				
Texas	$ 8,908	$ 7,497	$ 17,733	$ 14,066
Oklahoma	6,794	5,670	13,013	11,103
Rocky Mountains	61	63	116	164
Total operations and maintenance expenses	$ 15,763	$ 13,230	$ 30,862	$ 25,333

(1) Total segment gross margin is a non-GAAP financial measure. Please read "-- How We Evaluate Our Operations" for a reconciliation of total segment gross margin to its most directly comparable GAAP measure of operating income.

(2) Includes results and volumes associated with our interests in Bighorn and Fort Union. Combined volumes gathered by Bighorn and Fort Union were 533,329 MMBtu/d and 900,047 MMBtu/d for the three months ended June 30, 2011 and 2010, respectively. Combined volumes gathered by Bighorn and Fort Union were 557,059 MMBtu/d and 915,596 MMBtu/d for the six months ended June 30, 2011 and 2010, respectively. The volume decline is primarily due to certain Fort Union shippers diverting gas volumes to TransCanada's Bison Pipeline upon its start up in January 2011. However, Fort Union also received payments based on an additional 327,894 MMBtu/d and 308,566 MMBtu/d in long-term contractually committed volumes for the three and six months ended June 30, 2011, respectively.

(3) Includes results and volumes associated with our interest in Southern Dome. For the three months ended June 30, 2011, plant inlet volumes for Southern Dome averaged 11,730 MMBtu/d and NGLs produced averaged 432 Bbls/d. For the three months ended June 30, 2010, plant inlet volumes for Southern Dome averaged 12,689 MMBtu/d and NGLs produced averaged 456 Bbls/d. For the six months ended June 30, 2011, plant inlet volumes for Southern Dome averaged 11,457 MMBtu/d and NGLs produced averaged 413 Bbls/d. For the six months ended June 30, 2010, plant inlet volumes for Southern Dome averaged 13,406 MMBtu/d and NGLs produced averaged 477 Bbls/d.

(4) Includes results and volumes associated with our interest in Webb Duval. Gross volumes transported by Webb Duval, net of intercompany volumes, were 48,045 MMBtu/d and 54,747 MMBtu/d for the three months ended June 30, 2011 and 2010, respectively. Gross volumes transported by Webb Duval, net of intercompany volumes, were 48,744 MMBtu/d and 57,405 MMBtu/d for the six months ended June 30, 2011 and 2010, respectively.

(5) Rocky Mountains segment gross margin includes results from producer services, including volumes purchased for resale, volumes gathered under firm capacity gathering agreements with Fort Union, volumes transported using our firm capacity agreements with Wyoming Interstate Gas Company and compressor rental services provided to Bighorn. Excludes results and volumes associated with our interest in Bighorn and Fort Union.

(6) Corporate and other includes results attributable to our commodity risk management activities.

(7) Plant inlet volumes and NGLs produced represent total volumes processed and produced by the Texas segment at all plants, including plants owned by the Texas segment and plants owned by third parties. Plant inlet volumes averaged 572,486 MMBtu/d and NGLs produced averaged 25,889 Bbls/d for the three months ended June 30, 2011 for plants owned by the Texas segment. Plant inlet volumes averaged 461,880 MMBtu/d and NGLs produced averaged 17,864 Bbls/d for the three months ended June 30, 2010 for plants owned by the Texas segment. Plant inlet volumes averaged 557,900 MMBtu/d and NGLs produced averaged 24,016 Bbls/d for the six months ended June 30, 2011 for plants owned by the Texas segment. Plant inlet volumes averaged 456,180 MMBtu/d and NGLs produced averaged 16,366 Bbls/d for the six months ended June 30, 2010 for plants owned by the Texas segment.

(8) "Service throughput" means the volume of natural gas delivered to our wholly owned processing plants by third-party pipelines plus our "pipeline throughput," which is the volume of natural gas transported or gathered through our pipelines.

(9) Plant inlet volumes and NGLs produced represent total volumes processed and produced by the Oklahoma segment at all plants, including plants owned by the Oklahoma segment and plants owned by third parties. For the three months ended June 30, 2011, plant inlet volumes averaged 134,315 MMBtu/d and NGLs produced averaged 15,298 Bbls/d for plants owned by the Oklahoma segment. For the three months ended June 30, 2010, plant inlet volumes averaged 119,030 MMBtu/d and NGLs produced averaged 13,289 Bbls/d for plants owned by the Oklahoma segment. For the six months ended June 30, 2011, plant inlet volumes averaged 128,797 MMBtu/d and NGLs produced averaged 14,625 Bbls/d for plants owned by the Oklahoma segment. For the three months ended June 30, 2010, plant inlet volumes averaged 118,320 MMBtu/d and NGLs produced averaged 12,881 Bbls/d for plants owned by the Oklahoma segment.

Non-GAAP Financial Measures

The following table presents a reconciliation of the non-GAAP financial measures of (i) total segment gross margin (which consists of the sum of individual segment gross margins and the results of our risk management activities, which are included in corporate and other) to the GAAP financial measure of operating income and (ii) EBITDA, adjusted EBITDA and total distributable cash flow to the GAAP financial measures of net loss, for each of the periods indicated.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2011	**2010**	**2011**	**2010**
	($ in thousands)			
Reconciliation of total segment gross margin to operating income:				
Operating income (loss)	$ 20,178	$ (7,691)	$ 36,530	$ 6,221
Add: Operations and maintenance expenses	15,763	13,230	30,862	25,333
Depreciation and amortization	17,363	15,583	34,232	30,784
General and administrative expenses	11,901	10,900	24,499	21,442
Taxes other than income	1,397	1,181	2,527	2,343
Equity in (earnings) loss from unconsolidated affiliates	(1,306)	23,632	(3,008)	21,837
Total segment gross margin	$ 65,296	$ 56,835	$ 125,642	$ 107,960
Reconciliation of EBITDA, adjusted EBITDA and total distributable cash flow to net loss:				
Net loss	$ (9,361)	$ (21,111)	$ (5,829)	$ (22,371)
Add: Depreciation and amortization	17,363	15,583	34,232	30,784
Interest and other financing costs	11,454	13,351	23,370	28,296
Provision for income taxes	(140)	106	771	340
EBITDA	19,316	7,929	52,544	37,049
Add: Amortization of commodity derivative options	7,357	8,070	14,627	16,048
Distributions from unconsolidated affiliates	7,099	6,254	13,572	12,991
Loss on refinancing of unsecured debt	18,233	-	18,233	-
Equity-based compensation	4,109	2,686	7,091	5,401
Equity in (earnings) loss from unconsolidated affiliates	(1,306)	23,632	(3,008)	21,837
Unrealized loss (gain) from commodity risk management activities	180	(694)	(363)	(240)
Other non-cash operating items	(572)	701	(848)	2,228
Adjusted EBITDA	54,416	48,578	101,848	95,314
Less: Interest expense	(10,988)	(13,344)	(22,594)	(27,315)
Current income tax expense and other	(293)	(119)	(624)	(599)

Maintenance capital expenditures	(5,555)	(1,649)	(7,601)	(3,080)
Total distributable cash flow (1)	$ 37,580	$ 33,466	$ 71,029	$ 64,320
Actual quarterly distribution ("AQD")	$ 38,687	$ 38,295		
Total distributable cash flow coverage of AQD	97 %	87 %		

(1) Prior to any retained cash reserves established by Copano's Board of Directors.

	Year 2010				Three Months Ended March 31,
	Three Months Ended				
	March 31,	June 30,	September 30,	December 31,	2011
	($ in thousands)				
Reconciliation of total segment gross margin to operating income:					
Operating income (loss)	$ 13,912	$ (7,691)	$ 20,546	$ 19,010	$ 16,352
Add: Operations and maintenance expenses	12,103	13,230	13,004	15,150	15,099
Depreciation and amortization	15,201	15,583	15,218	16,570	16,869
General and administrative expenses	10,542	10,900	9,869	9,036	12,598
Taxes other than income	1,162	1,181	1,315	1,068	1,130
Equity in (earnings) loss from unconsolidated affiliates	(1,795)	23,632	(2,049)	692	(1,702)
Total segment gross margin	$ 51,125	$ 56,835	$ 57,903	$ 61,526	$ 60,346
Reconciliation of EBITDA, adjusted EBITDA and total distributable cash flow to net loss:					
Net loss	$ (1,260)	$ (21,111)	$ 7,298	$ 6,392	$ 3,532
Add: Depreciation and amortization	15,201	15,583	15,218	16,570	16,869
Interest and other financing costs	14,945	13,351	12,943	12,366	11,916
Provision for income taxes	234	106	320	271	911
EBITDA	29,120	7,929	35,779	35,599	33,228
Add: Amortization of commodity derivative options	7,978	8,070	8,163	8,167	7,270
Distributions from unconsolidated affiliates	6,737	6,254	6,563	6,401	6,473
Equity-based compensation	2,715	2,686	2,448	2,539	2,982
Equity in (earnings) loss from unconsolidated affiliates	(1,795)	23,632	(2,049)	692	(1,702)
Unrealized loss (gain) from commodity risk management activities	456	(694)	389	433	(543)
Other non-cash operating items	1,525	701	(295)	(615)	(275)
Adjusted EBITDA	46,736	48,578	50,998	53,216	47,433
Less: Interest expense	(13,972)	(13,344)	(11,855)	(12,246)	(11,606)
Current income tax expense and other	(479)	(119)	(141)	(251)	(331)
Maintenance capital expenditures	(1,431)	(1,649)	(3,290)	(3,193)	(2,046)
Total distributable cash flow	$ 30,854	$ 33,466	$ 35,712	$ 37,526	$ 33,450

SOURCE Copano Energy, L.L.C.