Western Gas Partners LP
Form 10-Q
May 13, 2009

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-Q

þ **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the quarterly period ended March 31, 2009

Or

o **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from to

Commission file number: 001-34046

WESTERN GAS PARTNERS, LP

(Exact name of registrant as specified in its charter)

Delaware	**26-1075808**
(State or other jurisdiction of incorporation or organization)	*(I.R.S. Employer Identification No.)*
1201 Lake Robbins Drive The Woodlands, Texas	**77380**
(Address of principal executive offices)	*(Zip Code)*

(832) 636-6000

(Registrant s telephone number, including area code)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes þ No o

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes o No o

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of large accelerated filer, accelerated filer and smaller reporting company in Rule 12b-2 of the Exchange Act.

Large accelerated filer o	Accelerated filer o	Non-accelerated filer þ	Smaller reporting company o
		(Do not check if smaller reporting company)	

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

There were 29,093,197 common units outstanding as of April 30, 2009.

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Definitions

As generally used within the energy industry and in this Quarterly Report on Form 10-Q, the identified terms have the following meanings:

Barrel or Bbl*:* 42 U.S. gallons measured at 60 degrees Fahrenheit.
Bcf/d*:* One billion cubic feet per day.
Btu*:* British thermal unit.
Condensate*:* A natural gas liquid with a low vapor pressure mainly composed of propane, butane, pentane and heavier hydrocarbon fractions.
Drip condensate: Heavier hydrocarbon liquids that fall out of the natural gas stream and are recovered in the gathering system without processing.
Imbalance: Imbalances result from (i) differences between gas volumes nominated by customers and gas volumes received from those customers and (ii) differences between gas volumes received from customers and gas volumes delivered to those customers.
MMBtu*:* One million British thermal units.
MMBtu/d*:* One million British thermal units per day.
MMcf/d: One million cubic feet per day.
Natural gas*:* Hydrocarbon gas found in the earth composed of methane, ethane, butane, propane and other gases.
Natural gas liquids or NGLs*:* The combination of ethane, propane, butane and natural gasolines that when removed from natural gas become liquid under various levels of higher pressure and lower temperature.
Plant condensate: Heavier hydrocarbon liquids that fall out of the natural gas stream and are recovered at the plant.
Residue gas*:* The natural gas remaining after being processed or treated.
Sour gas*:* Natural gas containing more than four parts per million of hydrogen sulfide.
Tcf*:* One trillion cubic feet of natural gas.
Wellhead*:* The equipment at the surface of a well used to control the well s pressure; the point at which the hydrocarbons and water exit the ground.

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PART I. FINANCIAL INFORMATION
Item 1. Financial Statements

Western Gas Partners, LP
CONSOLIDATED STATEMENTS OF INCOME
(Unaudited, in thousands, except per-unit amounts)

	Three Months Ended March 31,	
	2009	**2008** (1)
Revenues affiliates		
Gathering, processing and transportation of natural gas	$ 26,911	$ 27,195
Natural gas, natural gas liquids and condensate sales	16,509	42,607
Equity income and other	1,730	650
Total revenues affiliates	45,150	70,452
Revenues third parties		
Gathering, processing and transportation of natural gas	3,806	4,110
Natural gas, natural gas liquids and condensate sales	1,470	5,327
Other	462	1,533
Total revenues third parties	5,738	10,970
Total Revenues	50,888	81,422
Operating Expenses(2)		
Cost of product	12,528	33,728
Operation and maintenance	9,236	10,946
General and administrative	4,723	1,960
Property and other taxes	1,757	1,633
Depreciation and amortization	8,621	7,782
Total Operating Expenses	36,865	56,049
Operating Income	14,023	25,373
Interest income (expense), net affiliates	2,440	(1,789)
Other income, net	5	4
Income Before Income Taxes	16,468	23,588
Income Tax (Benefit) Expense	(490)	8,467
Net Income	$ 16,958	$ 15,121

Calculation of Limited Partner Interest in Net Income:		
Net income	$ 16,958	n/a(3)
Less general partner interest in net income	339	n/a
Limited partner interest in net income	$ 16,619	n/a
Net income per limited partner unit basic and diluted	$ 0.30	n/a
Limited partner units outstanding basic and diluted	55,629	n/a

(1) Financial information for 2008 has been revised to include results attributable to the Powder River assets. See *Note 1 Description of Business and Basis of Presentation Powder River acquisition*.

(2) Operating expenses include amounts charged by Anadarko and its affiliates to the Partnership for services as well as reimbursement of amounts paid by Anadarko and its affiliates to third parties on behalf of the Partnership. Cost of product expenses include product purchases from Anadarko and its affiliates of $1.7 million and $7.1 million for the three months ended March 31, 2009 and 2008, respectively. Operation and maintenance expenses include charges from

affiliates of $3.7 million and $4.1 million for the three months ended March 31, 2009 and 2008, respectively. General and administrative expenses include charges from affiliates of $3.4 million and $1.9 million for the three months ended March 31, 2009 and 2008, respectively. See *Note 5 Transactions with Affiliates.*

(3) Not applicable because the Partnership did not complete its initial public offering until May 2008.

See accompanying notes to the unaudited consolidated financial statements.

Western Gas Partners, LP
CONSOLIDATED BALANCE SHEETS
(Unaudited, in thousands, except number of units)

	March 31, 2009	December 31, 2008
ASSETS		
Current Assets		
Cash and cash equivalents	$ 27,296	$ 33,306
Accounts receivable, net third parties	5,758	5,878
Accounts receivable affiliates	7,759	3,235
Natural gas imbalance receivables third parties	379	389
Natural gas imbalance receivables affiliates	2,022	1,422
Other current assets	815	1,149
Total current assets	44,029	45,379
Note receivable Anadarko	260,000	260,000
Property, Plant and Equipment		
Cost	685,677	680,591
Less accumulated depreciation	171,096	162,776
Net property, plant and equipment	514,581	517,815
Goodwill	14,436	14,436
Equity investment	18,622	18,183
Other assets	596	628
Total Assets	$ 852,264	$ 856,441
LIABILITIES AND PARTNERS CAPITAL		
Current Liabilities		
Accounts payable	$ 4,252	$ 5,544
Natural gas imbalance payable third parties	162	244
Natural gas imbalance payable affiliates	1,844	1,198
Accrued ad valorem taxes	3,075	1,330
Income taxes payable	211	146
Accrued liabilities third parties	4,349	7,726
Accrued liabilities affiliates	162	153
Total current liabilities	14,055	16,341
Long-Term Liabilities		
Note payable Anadarko	175,000	175,000
Deferred income taxes	498	1,053
Asset retirement obligations and other	9,240	9,093
Total long-term liabilities	184,738	185,146

Total Liabilities		198,793		201,487
Commitments and Contingencies (Note 11)				
Partners Capital				
Common units (29,093,197 units issued and outstanding at March 31, 2009 and December 31, 2008)		366,638		368,049
Subordinated units (26,536,306 units issued and outstanding at March 31, 2009 and December 31, 2008)		275,847		275,917
General partner units (1,135,296 units issued and outstanding at March 31, 2009 and December 31, 2008)		10,986		10,988
Partners Capital		653,471		654,954
Total Liabilities and Partners Capital	$	852,264	$	856,441

See accompanying notes to the unaudited consolidated financial statements.

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Western Gas Partners, LP
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited, in thousands)

	Three Months Ended March 31, 2009	Three Months Ended March 31, 2008[1]
Cash Flows from Operating Activities		
Net income	$ 16,958	$ 15,121
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	8,621	7,782
Deferred income taxes	(555)	2,103
Changes in assets and liabilities:		
(Increase) decrease in accounts receivable	(5,940)	1,698
(Increase) in natural gas imbalance receivable	(590)	(327)
Increase (decrease) in accounts payable and accrued expenses	(817)	604
Increase (decrease) in other items, net	(112)	343
Net cash provided by operating activities	17,565	27,324
Cash Flows from Investing Activities		
Capital expenditures	(6,546)	(6,707)
Net cash used in investing activities	(6,546)	(6,707)
Cash Flows from Financing Activities		
Distributions to unitholders	(17,029)	
Net distributions to Anadarko		(20,617)
Net cash (used in) financing activities	(17,029)	(20,617)
Net Increase (Decrease) in Cash and Cash Equivalents	(6,010)	
Cash and Cash Equivalents at Beginning of Period	33,306	
Cash and Cash Equivalents at End of Period	$ 27,296	$
Supplemental Disclosures		
Decrease in accrued capital expenditures	$ 1,469	$ 1,016
Interest paid	1,454	

(1) Financial information for 2008 has been revised to include activity attributable to the Powder River assets. See *Note*

1 Description of Business and Basis of Presentation Powder River acquisition.

See accompanying notes to the unaudited consolidated financial statements.

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Notes to unaudited consolidated financial statements of Western Gas Partners, LP

1. DESCRIPTION OF BUSINESS AND BASIS OF PRESENTATION

Basis of presentation

Western Gas Partners, LP (the Partnership) is a Delaware limited partnership formed in August 2007. The Partnership s assets consist of nine gathering systems, six natural gas treating facilities, two gas processing facilities and one interstate pipeline. The Partnership s assets are located in East and West Texas, the Rocky Mountains (Utah and Wyoming) and the Mid-Continent (Kansas and Oklahoma). The Partnership is engaged in the business of gathering, compressing, processing, treating and transporting natural gas for Anadarko Petroleum Corporation and its consolidated subsidiaries and third-party producers and customers. For purposes of these financial statements, Anadarko refers to Anadarko Petroleum Corporation and its consolidated subsidiaries, excluding the Partnership and affiliates refers to wholly owned and partially owned subsidiaries of Anadarko, excluding the Partnership. The Partnership s general partner is Western Gas Holdings, LLC, a wholly owned subsidiary of Anadarko.

The consolidated financial statements include the accounts of the Partnership and entities in which it holds a controlling financial interest. All significant intercompany transactions have been eliminated. Investments in non-controlled entities over which the Partnership exercises significant influence are accounted for under the equity method. The information furnished herein reflects all normal recurring adjustments that are, in the opinion of management, necessary for a fair statement of financial position as of March 31, 2009 and December 31, 2008 and for the results of operations, changes in partners capital and cash flows for the three months ended March 31, 2009 and 2008. The Partnership s financial results for the three months ended March 31, 2009 are not necessarily indicative of the results for the full year ending December 31, 2009.

The accompanying consolidated financial statements of the Partnership have been prepared in accordance with accounting principles generally accepted in the United States. To conform to these accounting principles, management makes estimates and assumptions that affect the amounts reported in the consolidated financial statements and the notes thereto. These estimates are evaluated on an ongoing basis, utilizing historical experience and other methods considered reasonable under the particular circumstances. Although these estimates are based on management s best available knowledge at the time, actual results may differ. Effects on the Partnership s business, financial position and results of operations resulting from revisions to estimates are recognized when the facts that give rise to the revision become known. Changes in facts and circumstances or discovery of new facts or circumstances may result in revised estimates and actual results may differ from these estimates.

The accompanying consolidated financial statements and notes should be read in conjunction with the Partnership s annual report on Form 10-K, as filed with the Securities and Exchange Commission on March 13, 2009.

Initial public offering

On May 14, 2008, the Partnership closed its initial public offering of 18,750,000 common units at a price of $16.50 per unit. On June 11, 2008, the Partnership issued an additional 2,060,875 common units to the public pursuant to the partial exercise of the underwriters over-allotment option. The May 14 and June 11 issuances are referred to collectively as the initial public offering. The common units are listed on the New York Stock Exchange under the symbol WES.

Concurrent with the closing of the initial public offering, Anadarko contributed the assets and liabilities of Anadarko Gathering Company LLC (AGC), Pinnacle Gas Treating LLC (PGT) and MIGC LLC (MIGC) to the Partnership in exchange for 1,083,115 general partner units, representing a 2.0% general partner interest in the Partnership, 100% of the incentive distribution rights (IDRs), 5,725,431 common units and 26,536,306 subordinated units. AGC, PGT and MIGC are referred to collectively as the initial assets. The common units issued to Anadarko include 751,625 common units issued following the expiration of the underwriters over-allotment option and represent the portion of the common units for which the underwriters did not exercise their over-allotment option. See *Note 4 Partnership Equity and Distributions* in Item 8 of our annual report on Form 10-K for information related to the distribution rights of the common and subordinated unitholders and to the IDRs held by the general partner.

Notes to unaudited consolidated financial statements of Western Gas Partners, LP

Powder River acquisition

On December 19, 2008, the Partnership acquired certain midstream assets from Anadarko for consideration consisting of $175.0 million cash, which was financed by borrowing $175.0 million from Anadarko pursuant to the terms of a five-year term loan agreement, 2,556,891 common units and 52,181 general partner units. The acquisition consisted of (i) a 100% ownership interest in the Hilight system, (ii) a 50% interest in the Newcastle system and (iii) a 14.81% limited liability company membership interest in Fort Union Gas Gathering, L.L.C. (Fort Union). These assets are referred to collectively as the Powder River assets and the acquisition is referred to as the Powder River acquisition.

General information

As of March 31, 2009 and December 31, 2008, Anadarko held 1,135,296 general partner units representing a 2.0% general partner interest in the Partnership, 100% of the Partnership incentive distribution rights, 8,282,322 common units and 26,536,306 subordinated units. Anadarko s common and subordinated unit ownership represents an aggregate 61.3% limited partner interest in the Partnership. The public held 20,810,875 common units, representing a 36.7% limited partner interest in the Partnership.

Anadarko acquired MIGC and the Powder River assets in connection with its August 23, 2006 acquisition of Western Gas Resources, Inc. The acquisition of the initial assets and the Powder River assets were considered transfers of net assets between entities under common control pursuant to the provisions of Statement of Financial Accounting Standards (SFAS) No. 141, *Business Combinations*, (SFAS 141) Appendix D. SFAS 141 requires that all income statements be revised to include the results of the acquired assets as of the date of common control. Accordingly, the Partnership s historical financial statements for the three months ended March 31, 2008 have been recast to reflect the results attributable to the Powder River assets for this period.

The Partnership as used herein refers to the combined financial results and operations of AGC, PGT and MIGC from January 1, 2008 through May 14, 2008 and to the Partnership thereafter, combined with the financial results and operations of the Powder River assets for all periods presented herein. The consolidated financial statements for periods prior to May 14, 2008 with respect to the initial assets and prior to December 19, 2008 with respect to the Powder River assets have been prepared from Anadarko s historical cost-basis accounts and may not necessarily be indicative of the actual results of operations that would have occurred if the Partnership had owned the assets and operated as a separate entity during the periods reported.

2. NEW ACCOUNTING STANDARDS

SFAS No. 141 (revised 2007), Business Combinations (SFAS 141(R)). SFAS 141(R) applies fair value measurement in accounting for business combinations, expands financial disclosures, defines an acquirer and modifies the accounting for some business combinations items. Under SFAS 141(R), an acquirer is required to record 100% of assets and liabilities, including goodwill, contingent assets and contingent liabilities, at fair value. This replaces the cost allocation process applied under SFAS No. 141. In addition, contingent consideration must be recognized at fair value at the acquisition date, acquisition-related costs must be expensed rather than treated as an addition to the assets being acquired and restructuring costs are required to be recognized separately from the business combination. SFAS 141(R) did not change the accounting for transfers of assets between entities under common control. SFAS 141(R) became effective on January 1, 2009 for the Partnership.

Emerging Issues Task Force (EITF) Issue No. 07-4, Application of the Two-Class Method under FASB Statement No. 128, Earnings per Share, to Master Limited Partnerships (EITF 07-4), and Financial Accounting Standards Board (FASB) Staff Position EITF Issue No. 03-6-1, Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities (FSP EITF 03-6-1). EITF 07-4 addresses the application of the two-class method under SFAS No. 128, *Earnings per Share* (SFAS 128), in determining income per unit for master limited partnerships having multiple classes of securities including limited partnership units, general partnership units and, when applicable, IDRs of the general partner. EITF 07-4 clarifies that the two-class method would apply, and provides the methodology for and circumstances under which undistributed earnings are allocated to the general partner, limited partners and IDR holders. In June 2008, the FASB issued FSP EITF 03-6-1 addressing whether instruments granted in share-based payment transactions are participating securities prior to vesting and therefore required to be accounted for in calculating earnings per unit under the two-class

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Notes to unaudited consolidated financial statements of Western Gas Partners, LP

method described in SFAS 128. FSP EITF 03-6-1 requires companies to treat unvested share-based payment awards that have non-forfeitable rights to dividend or dividend equivalents as a separate class of securities in calculating earnings per unit. The Partnership adopted EITF 07-4 and FSP EITF 03-6-1 effective January 1, 2009 and has applied these provisions with respect to all periods in which earnings per unit is presented. EITF 07-4 did not impact earnings per unit for the periods presented herein and FSP EITF 03-6-1 did not have a significant impact on earnings per unit for the periods presented herein.

3. PARTNERSHIP DISTRIBUTIONS

The partnership agreement requires that, within 45 days subsequent to the end of each quarter, beginning with the quarter ended June 30, 2008, the Partnership distribute all of its available cash (as defined in the partnership agreement) to unitholders of record on the applicable record date. On February 13, 2009, the Partnership paid cash distributions to its unitholders of $0.30 per unit, representing the distribution for the quarter ended on December 31, 2008. See also *Note 12 Subsequent Event* concerning distributions approved in April 2009.

4. NET INCOME PER LIMITED PARTNER UNIT

The Partnership s net income attributable to the initial assets for periods including and subsequent to May 14, 2008 and its net income attributable to the Powder River assets for periods including and subsequent to December 19, 2008 is allocated to the general partner and the limited partners, including any subordinated unitholders, in accordance with their respective ownership percentages, and where applicable, giving effect to unvested units granted under the Western Gas Partners, LP 2008 Long-Term Incentive Plan (LTIP) and incentive distributions allocable to the general partner. The allocation of undistributed earnings, or net income in excess of distributions, to the incentive distribution rights is limited to available cash (as defined by the Partnership Agreement) for the period. The Partnership s net income allocable to the limited partners is allocated between the common and subordinated unitholders by applying the provisions of the partnership agreement that govern actual cash distributions as if all earnings for the period had been distributed. Accordingly, if current net income allocable to the limited partners is less than the minimum quarterly distribution, or if cumulative net income allocable to the limited partners since May 14, 2008 is less than the cumulative minimum quarterly distributions, more income is allocated to the common unitholders than the subordinated unitholders for that quarterly period.

Basic and diluted net income per limited partner unit is calculated by dividing limited partners interest in net income by the weighted average number of limited partner units outstanding during the period.

The following table illustrates the Partnership s calculation of net income per unit for common and subordinated limited partner units (in thousands, except per-unit information):

	Three Months Ended March 31, 2009	
Net income	$	16,958
Less general partner interest in net income		339
Limited partner interest in net income	$	16,619
Net income allocable to common units	$	8,728
Net income allocable to subordinated units		7,891
Limited partner interest in net income	$	16,619
Net income per limited partner unit basic and diluted		

Common units	$	0.30
Subordinated units	$	0.30
Total	$	0.30
Weighted average limited partner units outstanding basic and diluted		
Common units		29,093
Subordinated units		26,536
Total		55,629

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5. TRANSACTIONS WITH AFFILIATES

Affiliate transactions

The Partnership provides natural gas gathering, compression, treating and transportation services to Anadarko and a portion of the Partnership s expenditures were paid by or to Anadarko, which results in affiliate transactions. In addition, contributions to and distributions from Fort Union were paid or received by Anadarko. Prior to May 14, 2008 with respect to the initial assets and prior to December 19, 2008 with respect to the Powder River assets, balances arising from affiliate transactions were net-settled on a non-cash basis by way of an adjustment to parent net equity. Anadarko charged the Partnership interest at a variable rate (6.42% for March 2008) on outstanding affiliate balances owed by the Partnership to Anadarko for the periods these balances remained outstanding. The outstanding affiliate balances were entirely settled through an adjustment to parent net equity in connection with the initial public offering and the Powder River acquisition. Subsequent to May 14, 2008 with respect to the initial assets and subsequent to December 19, 2008 with respect to the Powder River assets, affiliate transactions are cash-settled and affiliate-based interest expense on intercompany balances is not charged.

Note receivable from Anadarko

Concurrent with the closing of the initial public offering, the Partnership loaned $260.0 million to Anadarko in exchange for a 30-year note bearing interest at a fixed annual rate of 6.50%. Interest on the note is payable quarterly.

Term Loan Agreement with Anadarko

Concurrent with the closing of the Powder River acquisition, the Partnership entered into a five-year, $175.0 million term loan agreement with Anadarko under which the Partnership pays Anadarko interest at a fixed rate of 4.0% for the first two years and a floating rate of interest at three-month LIBOR plus 150 basis points for the final three years. See *Note 9 Debt*.

Commodity Price Swap Agreements

The Partnership entered into commodity price swap agreements with Anadarko in December 2008 to mitigate exposure to commodity price volatility that would otherwise be present as a result of the Partnership s acquisition of the Hilight and Newcastle systems. Beginning on January 1, 2009, the commodity price swap agreements fix the margin the Partnership will realize on its share of revenues under percent-of-proceeds contracts applicable to natural gas processing activities at the Hilight and Newcastle systems. In this regard, the Partnership s notional volumes for each of the swap agreements are not specifically defined; instead, the commodity price swap agreements apply to volumes equal in amount to the Partnership s share of actual volumes processed at the Hilight and Newcastle systems. Because the notional volumes are not fixed, the commodity price swap agreements do not satisfy the definition of a derivative financial instrument. The Partnership reports realized gains and losses on the commodity price swap agreements in natural gas, natural gas liquids and condensate sales affiliates in the consolidated statements of income in the period in which the associated revenues are recognized. During the three months ended March 31, 2009, the Partnership recorded realized gains of $1.8 million attributable to the commodity price swap agreements.

Below is a summary of the fixed prices on the Partnership s commodity price swap agreements outstanding as of March 31, 2009. The commodity price swap arrangements expire in December 2010 and the Partnership at its option may extend the agreements annually for three additional years.

	Year Ended December 31,	
	2009	**2010**
	(per barrel)	
Natural Gasoline	$55.60	$63.20
Condensate	$62.27	$70.72
Propane	$35.56	$40.63
Butane	$42.24	$48.15
	(per MMBtu)	

Natural Gas	$ 4.85	$ 5.61

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Notes to unaudited consolidated financial statements of Western Gas Partners, LP

Cash management

Anadarko operates a cash management system whereby excess cash from most of its subsidiaries, held in separate bank accounts, is swept to a centralized account. Prior to May 14, 2008 with respect to the initial assets and prior to December 19, 2008 with respect to the Powder River assets, sales and purchases related to third-party transactions were received or paid in cash by Anadarko within the centralized cash management system and were settled with the Partnership through an adjustment to parent net equity. Subsequent to May 14, 2008 with respect to the initial assets and subsequent to December 19, 2008 with respect to the Powder River assets, the Partnership cash-settles transactions directly with third parties and with Anadarko affiliates.

Credit facilities

In March 2008, Anadarko entered into a five-year $1.3 billion credit facility under which the Partnership may borrow up to $100.0 million. Concurrent with the closing of the initial public offering, the Partnership entered into a two-year $30.0 million working capital facility with Anadarko as the lender. See *Note 9 Debt* for more information on these credit facilities.

Omnibus agreement

Concurrent with the closing of the initial public offering, the Partnership entered into an omnibus agreement with the general partner and Anadarko that addresses the following:

- Anadarko s obligation to indemnify the Partnership for certain liabilities and the Partnership s obligation to indemnify Anadarko for certain liabilities with respect to the initial assets;

- the Partnership s obligation to reimburse Anadarko for all expenses incurred or payments made on the Partnership s behalf in conjunction with Anadarko s provision of general and administrative services to the Partnership, including salary and benefits of the general partner s executive management and other Anadarko personnel and general and administrative expenses which are attributable to the Partnership s status as a separate publicly traded entity;

- the Partnership s obligation to reimburse Anadarko for all insurance coverage expenses it incurs or payments it makes with respect to the Partnership s assets; and

- the Partnership s obligation to reimburse Anadarko for the Partnership s allocable portion of commitment fees that Anadarko incurs under its $1.3 billion credit facility.

Pursuant to the omnibus agreement, Anadarko performs centralized corporate functions for the Partnership, such as legal, accounting, treasury, cash management, investor relations, insurance administration and claims processing, risk management, health, safety and environmental, information technology, human resources, credit, payroll, internal audit, tax, marketing and midstream administration. The Partnership s reimbursement to Anadarko for certain general and administrative expenses allocated to the Partnership is currently capped at $6.65 million annually through December 31, 2009, subject to adjustment to reflect expansions of the Partnership s operations through the acquisition or construction of new assets or businesses and with the concurrence of the special committee of our general partner s board of directors. The cap contained in the omnibus agreement does not apply to incremental general and administrative expenses allocated to or incurred by the Partnership as a result of being a publicly traded partnership. The consolidated financial statements of the Partnership include costs allocated by Anadarko pursuant to the omnibus agreement for periods including and subsequent to May 14, 2008.

Services and secondment agreement

Concurrent with the closing of the initial public offering, the general partner and Anadarko entered into a services and secondment agreement pursuant to which specified employees of Anadarko are seconded to the general partner to provide operating, routine maintenance and other services with respect to the assets owned and operated by the Partnership under the direction, supervision and control of the general partner. Pursuant to the services and secondment agreement, the Partnership will reimburse Anadarko for services provided by the seconded employees. The initial term of the services and secondment agreement is 10 years and the term will automatically extend for additional twelve-month periods unless either party provides 180 days written notice otherwise before the applicable twelve-month period expires. The consolidated financial statements

Notes to unaudited consolidated financial statements of Western Gas Partners, LP

of the Partnership include costs allocated by Anadarko pursuant to the services and secondment agreement for periods including and subsequent to May 14, 2008 with respect to the initial assets and periods including and subsequent to December 1, 2008 with respect to the Powder River assets.

Tax sharing agreement

Concurrent with the closing of the initial public offering, the Partnership and Anadarko entered into a tax sharing agreement pursuant to which the Partnership reimburses Anadarko for the Partnership s share of Texas margin tax borne by Anadarko as a result of the Partnership s results being included in a combined or consolidated tax return filed by Anadarko with respect to periods subsequent to May 14, 2008. Anadarko may use its tax attributes to cause its combined or consolidated group, of which the Partnership may be a member for this purpose, to owe no tax. However, the Partnership is nevertheless required to reimburse Anadarko for the tax the Partnership would have owed had the attributes not been available or used for the Partnership s benefit, regardless of whether Anadarko pays taxes for the period.

Allocation of costs

The consolidated financial statements of the Partnership include costs allocated by Anadarko in the form of a management services fee for periods prior to May 14, 2008 with respect to the initial assets and prior to December 1, 2008 with respect to the Powder River assets. General, administrative and management costs were allocated to the Partnership based on its proportionate share of Anadarko s assets and revenues. Management believes these allocation methodologies are reasonable.

The employees supporting the Partnership s operations are employees of Anadarko. Anadarko charges the Partnership its allocated share of personnel costs, including costs associated with Anadarko s non-contributory defined pension and postretirement plans and defined contribution savings plan, through the management services fee or pursuant to the omnibus agreement and services and secondment agreement described above.

Equity-based compensation

Pursuant to SFAS No. 123 (revised 2004), *Shared-Based Payment,* (SFAS 123(R)), grants made under equity-based compensation plans result in equity-based compensation expense which is determined by reference to the fair value of equity compensation as of the date of the relevant equity grant.

Long-term incentive plan

The general partner awarded 30,304 phantom units valued at $16.50 each to the general partner s independent directors in May 2008. These phantom units were granted under the LTIP and will vest in May 2009. Compensation expense attributable to the phantom units granted under the LTIP is recognized entirely by the Partnership and, during the three months ended March 31, 2009, was approximately $123,000. The Partnership expects to recognize approximately $53,000 of additional compensation expense during the three months ending June 30, 2009 related to the phantom units currently granted under the LTIP.

Equity incentive plan and Anadarko incentive plans

The Partnership s general and administrative expenses include equity-based compensation costs allocated by Anadarko to the Partnership for grants made pursuant to the Western Gas Holdings, LLC Amended and Restated Equity Incentive Plan (Incentive Plan), as well as the Anadarko Petroleum Corporation 1999 Stock Incentive Plan and the Anadarko Petroleum Corporation 2008 Omnibus Incentive Compensation Plan (Anadarko s plans are referred to collectively as the Anadarko Incentive Plans). Under the Incentive Plan, participants are granted Unit Value Rights (UVRs), Unit Appreciation Rights (UARs) and Dividend Equivalent Rights (DERs). In April 2008, the general partner awarded to its executive officers an aggregate of 50,000 UVRs, UARs and DERs under its Incentive Plan. The Partnership s general and administrative expense for the three months ended March 31, 2009 included approximately $878,000 of equity-based compensation expense for grants made pursuant to the Incentive Plan and Anadarko Incentive Plans. This amount excludes compensation expense associated with the LTIP. No such expense was included in the Partnership s general and administrative expense for the three months ended March 31, 2008. These expenses are allocated to the Partnership by Anadarko as a component of compensation expense for the executive officers of the Partnership s general partner and other employees pursuant to the omnibus agreement and employees who provide services to the Partnership pursuant to the services and secondment agreement.

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Notes to unaudited consolidated financial statements of Western Gas Partners, LP

Summary of affiliate transactions

Affiliate expenses do not bear a direct relationship to affiliate revenues and third-party expenses do not bear a direct relationship to third-party revenues. Accordingly, the Partnership s affiliate expenses are not those expenses necessary for generating affiliate revenues. Operating expenses include all amounts accrued or paid to affiliates for the operation of the Partnership s systems, whether in providing services to affiliates or to third parties, including field labor, measurement and analysis, and other disbursements. The following table summarizes affiliate transactions.

	Three Months Ended March 31,	
	2009	2008
	(in thousands)	
Affiliate transactions		
Revenues affiliates	$45,150	$70,452
Operating expenses affiliates	8,825	13,118
Interest income affiliates	4,225	
Interest expense affiliates	1,785	1,789
Distributions to unitholders affiliates	$10,786	$

6. INCOME TAXES

The following table summarizes the Partnership s effective tax rate:

	Three Months Ended March 31,	
	2009	2008
	(in thousands, except effective tax rate)	
Income before income taxes	$16,468	$23,588
Income tax (benefit) expense	$ (490)	$ 8,467
Effective tax rate	(3)%	36%

The decrease in income tax expense for the three months ended March 31, 2009 is primarily due to the Partnership s U.S. federal income tax status as a non-taxable entity. Income earned by the Partnership for the three months ended March 31, 2009, was subject only to Texas margin tax while income earned by the Partnership for the three months ended March 31, 2008 was subject to federal and state tax. In addition, the estimated income attributed to Texas relative to total income decreased in 2009 compared to the prior year, which resulted in a reduction of previously recognized deferred taxes of $560,000, offset by the recognition of $70,000 of current year Texas margin tax expense, resulting in a net tax benefit for the period. For 2008, the Partnership s variance from the federal statutory rate is primarily attributable to state income taxes.

7. CONCENTRATION OF CREDIT RISK

Anadarko was the only customer from whom revenues exceeded 10% of the Partnership s consolidated revenues for the three months ended March 31, 2009 and 2008. The percentage of revenues from Anadarko and the Partnership s other customers are as follows:

	Three Months Ended March 31,	
Customer	2009	2008
Anadarko	86%	86%
Other	14%	14%

Total	100%	100%

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Notes to unaudited consolidated financial statements of Western Gas Partners, LP

8. PROPERTY, PLANT AND EQUIPMENT

A summary of the historical cost of the Partnership s property, plant and equipment is as follows:

	Estimated useful life	March 31, 2009	December 31, 2008
		(dollars in thousands)	
Land	n/a	$ 354	$ 354
Gathering systems	15 to 25 years	589,527	585,304
Pipeline and equipment	30 to 34.5 years	85,821	85,598
Assets under construction	n/a	8,315	7,690
Other	3 to 25 years	1,660	1,645
Total property, plant and equipment		685,677	680,591
Accumulated depreciation		171,096	162,776
Total net property, plant and equipment		$ 514,581	$ 517,815

The cost of property classified as Assets under construction is excluded from capitalized costs being depreciated. This amount represents property elements that are works-in-progress and not yet suitable to be placed into productive service as of the balance sheet date.

9. DEBT

In December 2008, the Partnership entered into a five-year $175.0 million term loan agreement with Anadarko in order to finance the cash portion of the purchase price for the Powder River acquisition. The interest rate is fixed at 4.0% for the first two years and is a floating rate equal to three-month LIBOR plus 150 basis points for the final three years. The Partnership has the option to repay the outstanding principal amount in whole or in part commencing upon the second anniversary of the term loan agreement. The provisions of the term loan agreement are non-recourse to our general partner and our limited partners and contain customary events of default, including (i) nonpayment of principal when due or nonpayment of interest or other amounts within three business days of when due; (ii) certain events of bankruptcy or insolvency with respect to the Partnership; or (iii) a change of control. At March 31, 2009, the Partnership was in compliance with all covenants.

In March 2008, Anadarko entered into a five-year $1.3 billion credit facility under which the Partnership may borrow up to $100.0 million to the extent that sufficient amounts remain available to Anadarko and its subsidiaries. As of March 31, 2009, the full $100.0 million was available for borrowing by the Partnership. Interest on borrowings under the credit facility is calculated based on the election by the borrower of either: (i) a floating rate equal to the federal funds effective rate plus 0.50% or (ii) a periodic fixed rate equal to LIBOR plus an applicable margin. The applicable margin, which was 0.44% at March 31, 2009, and the commitment fees on the facility, are based on Anadarko s senior unsecured long-term debt rating. Pursuant to the omnibus agreement, as a co-borrower under Anadarko s credit facility, the Partnership is required to reimburse Anadarko for its allocable portion of commitment fees (currently 0.11% of the Partnership s committed and available borrowing capacity, including the Partnership s outstanding balances) that Anadarko incurs under its credit facility, or up to $110,000 annually. Under Anadarko s credit agreements, the Partnership and Anadarko are required to comply with certain covenants, including a financial covenant that requires Anadarko to maintain a debt-to-capitalization ratio of 60% or less. As of March 31, 2009, Anadarko and the Partnership were in compliance with all covenants. Should the Partnership or Anadarko fail to comply with any covenant in Anadarko s credit facility, the Partnership may not be permitted to borrow under the credit facility. Anadarko is a guarantor of all borrowings, including the Partnership s borrowings, under the credit facility. The Partnership is not a guarantor of Anadarko s borrowings under the credit facility. The $1.3 billion credit facility expires in March 2013.

In May 2008, the Partnership entered into a two-year $30.0 million working capital facility with Anadarko as the lender. At March 31, 2009, no borrowings were outstanding under the working capital facility. The facility is available exclusively to fund working capital expenditures. Borrowings under the facility will bear interest at the same rate that would apply to borrowings under the Anadarko credit facility described above. Pursuant to the omnibus agreement, the Partnership will pay a commitment fee of 0.11% annually to Anadarko on the unused portion of the working capital facility, or up to $33,000 annually. The Partnership is required to reduce all borrowings under the working capital facility to zero for a period of at least 15 consecutive days at least once during each of the twelve-month periods prior to the maturity date of the facility.

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Notes to unaudited consolidated financial statements of Western Gas Partners, LP

10. SEGMENT INFORMATION

The Partnership s operations are organized into a single business segment, the assets of which consist of natural gas gathering and processing systems, treating facilities, a pipeline and related plant and equipment. To assess the operating results of the Partnership s segment, management uses Adjusted EBITDA, which it defines as net income (loss) plus distributions from equity investee, non-cash share-based compensation expense, interest expense, income tax expense, depreciation and amortization, less income from equity investee, interest income, income tax benefit and other income (expense). The Partnership changed its definition of Adjusted EBITDA from the definition used in prior periods. Adjusted EBITDA has been calculated using the revised definition for all periods presented.

Adjusted EBITDA is a supplemental financial measure that management and external users of the Partnership s consolidated financial statements, such as industry analysts, investors, lenders and rating agencies, use to assess, among other measures:

- the Partnership s operating performance as compared to other publicly traded partnerships in the midstream energy industry, without regard to financing methods, capital structure or historical cost basis;

- the ability of the Partnership s assets to generate cash flow to make distributions; and

- the viability of acquisitions and capital expenditure projects and the returns on investment of various investment opportunities.

Management believes that the presentation of Adjusted EBITDA provides information useful in assessing the Partnership s financial condition and results of operations and that Adjusted EBITDA is a widely accepted financial indicator of a company s ability to incur and service debt, fund capital expenditures and make distributions. Adjusted EBITDA, as defined by the Partnership, may not be comparable to similarly titled measures used by other companies. Therefore, the Partnership s consolidated Adjusted EBITDA should be considered in conjunction with net income and other performance measures, such as operating income or cash flow from operating activities.

Below is a reconciliation of Adjusted EBITDA to net income.

	Three Months Ended March 31,	
	2009	**2008**
	(in thousands)	
Reconciliation of Adjusted EBITDA to net income		
Adjusted EBITDA	$ 23,051	$ 34,220
Less:		
Distributions from equity investee	1,111	1,407
Non-cash share-based compensation expense	846	
Interest expense, net affiliates	35	1,789
Interest expense from note affiliate	1,750	
Income tax expense		8,467
Depreciation and amortization	8,621	7,782
Add:		
Equity income, net	1,550	342
Interest income from note affiliate	4,225	
Other income	5	4
Income tax benefit	490	
Net Income	$ 16,958	$ 15,121

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Notes to unaudited consolidated financial statements of Western Gas Partners, LP

11. COMMITMENTS AND CONTINGENCIES

Environmental

The Partnership is subject to federal, state and local regulations regarding air and water quality, hazardous and solid waste disposal and other environmental matters. Management believes there are no such matters that could have a material adverse effect on the Partnership s results of operations, cash flows or financial position.

Litigation and legal proceedings

From time to time, the Partnership is involved in legal, tax, regulatory and other proceedings in various forums regarding performance, contracts and other matters that arise in the ordinary course of business. Management is not aware of any such proceeding for which a final disposition could have a material adverse effect on the Partnership s results of operations, cash flows or financial position.

Lease commitments

Anadarko, on behalf of the Partnership, formerly leased compression equipment used exclusively by the Partnership. As a result of lease modifications in October 2008, Anadarko became the owner of the compression equipment, effectively terminating the lease. Pursuant to the Contribution, Conveyance and Assumption Agreement signed in connection with the initial public offering, Anadarko contributed the compression equipment to the Partnership in November 2008. The carrying value of the compression equipment at the contribution date was approximately $14.1 million. Rent expense associated with the compression equipment was approximately $372,000 for the three months ended March 31, 2008. As of March 31, 2009, the Partnership does not have significant non-cancelable lease commitments.

12. SUBSEQUENT EVENT

On April 21, 2009, the board of directors of the Partnership s general partner declared a cash distribution to the Partnership s unitholders of $0.30 per unit, or $17.0 million in aggregate. The cash distribution is payable on May 15, 2009 to unitholders of record at the close of business on May 1, 2009.

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Item 2. Management s Discussion and Analysis of Financial Condition and Results of Operations

The following discussion analyzes our financial condition and results of operations and should be read in conjunction with our historical consolidated financial statements, and the notes thereto, included in Item 8 of our annual report on Form 10-K. Unless the context clearly indicates otherwise, references in this report to the Partnership, we, our, us like terms, when used in the historical context, refer to the combined financial results and operations of Anadarko Gathering Company LLC, or AGC, Pinnacle Gas Treating LLC, or PGT, and MIGC LLC, or MIGC from January 1, 2008 through May 14, 2008 and to Western Gas Partners, LP and its subsidiaries thereafter, combined with the financial results and operations of the Powder River assets, as described in Powder River Acquisition below, for all periods presented herein. When used in the present tense or prospectively, the Partnership, we, our, us or like term refer to Western Gas Partners, LP and its subsidiaries. Anadarko refers to Anadarko Petroleum Corporation (NYSE: APC) and its consolidated subsidiaries, excluding the Partnership and Western Gas Holdings, LLC, our general partner. Affiliates refers to wholly owned and partially owned subsidiaries of Anadarko, excluding the Partnership.

We have made in this report, and may from time to time otherwise make in other public filings, press releases and discussions by Partnership management, forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934 concerning our operations, economic performance and financial condition. These statements can be identified by the use of forward-looking terminology including may, believe, expect, anticipate, estimate, continue, or other similar words. These statements discu expectations, contain projections of results of operations or financial condition or include other forward-looking information. For such statements, the Partnership claims the protection of the safe harbor for forward-looking statements contained in the Private Securities Litigation Reform Act of 1995. Although we believe that the expectations reflected in such forward-looking statements are reasonable, we can give no assurance that such expectations will prove to have been correct.

These forward-looking statements involve risks and uncertainties. Important factors that could cause actual results to differ materially from our expectations include, but are not limited to, the following risks and uncertainties:

- *our assumptions about the energy market;*
- *future treating and processing volumes and pipeline throughput, including Anadarko s production, which is gathered or transported through our assets;*
- *operating results;*
- *competitive conditions;*
- *technology;*
- *the availability of capital resources, capital expenditures and other contractual obligations;*
- *the supply of and demand for, and the price of oil, natural gas, NGLs and other products or services;*
- *the weather;*
- *inflation;*
- *the availability of goods and services;*
- *general economic conditions, either internationally or nationally or in the jurisdictions in which we are doing business;*

legislative or regulatory changes, including changes in environmental regulation, environmental risks, regulations by FERC and liability under federal and state environmental laws and regulations;

our ability to access the capital markets;

our ability to access credit, including under Anadarko s $1.3 billion credit facility;

our ability to maintain and/or obtain rights to operate our assets on land owned by third parties;

our ability to acquire assets on acceptable terms;

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non-payment or non-performance of Anadarko or other significant customers, including under our gathering, processing and transportation agreements and our $260.0 million note receivable from Anadarko; and

other factors discussed below and elsewhere in Item 1A Risk Factors and in Item 7 Management s Discussion and Analysis of Financial Condition and Results of Operations Critical Accounting Policies and Estimates included in our annual report on Form 10-K filed with the Securities and Exchange Commission (SEC) on March 13, 2009 and in our other public filings and press releases.

The risk factors and other factors noted throughout or incorporated by reference in this report could cause our actual results to differ materially from those contained in any forward-looking statement. We undertake no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise.

EXECUTIVE SUMMARY

We are a growth-oriented Delaware limited partnership organized by Anadarko to own, operate, acquire and develop midstream energy assets. We currently operate in East and West Texas, the Rocky Mountains (Utah and Wyoming) and the Mid-Continent (Kansas and Oklahoma) and are engaged in the business of gathering, compressing, treating, processing and transporting natural gas for Anadarko and third-party producers and customers.

The current commodity price environment has resulted in lower drilling activity in recent months throughout the areas in which we operate. Our throughput volumes were relatively flat for the three months ended March 31, 2009 compared to the three months ended March 31, 2008 in the face of reduced drilling activity across the industry resulting from the current natural gas price environment. Consistent with our expectations, the predominantly fee-based and fixed-price structure of our contracts mitigated the impact of changes in commodity prices on our gross margin.

INITIAL PUBLIC OFFERING

On May 14, 2008, we closed our initial public offering of 18,750,000 common units at a price of $16.50 per unit. On June 11, 2008, we issued an additional 2,060,875 common units to the public pursuant to the partial exercise of the underwriters over-allotment option granted in connection with our initial public offering. Concurrent with the initial closing of the offering, Anadarko contributed the assets and liabilities of AGC, PGT and MIGC to us in exchange for a 2.0% general partner interest in the Partnership, 5,725,431 common units, 26,536,306 subordinated units and 100% of the IDRs. We refer to AGC, PGT and MIGC as our initial assets.

POWDER RIVER ACQUISITION

On December 19, 2008, we acquired certain midstream assets from Anadarko, consisting of (i) a 100% ownership interest in the Hilight system, (ii) a 50% interest in the Newcastle system and (iii) a 14.81% limited liability company membership interest in Fort Union Gas Gathering, L.L.C., or Fort Union. We refer to these assets collectively as the Powder River assets. The Powder River assets provide a combination of gathering, treating and processing services in the Powder River Basin of Wyoming.

PARTNERSHIP AGREEMENT AMENDMENT

On April 15, 2009, after receiving the unanimous approval of the special committee of the board of directors of Western Gas Holdings, LLC, the general partner of the Partnership, the general partner s board of directors unanimously approved an amendment (the Amendment) to the Partnership s First Amended and Restated Agreement of Limited Partnership, effective on the date of approval. The purpose of the Amendment was to ensure that the Partnership s common unitholders maintain, to the maximum extent possible, their existing share of allocable tax deductions throughout the subordination period. Absent this amendment, it would have been possible, as a result of equity issuances at a price less than the initial public offering price during the subordination period, that the common unitholders allocable share of tax deductions would be significantly diminished.

The foregoing general description of the Amendment is not complete and is qualified in its entirety by reference to the full and complete terms of the Amendment, which is attached to the Form 8-K, filed with the SEC on April 20, 2009, and the partnership agreement, which is incorporated herein.

HOW WE EVALUATE OUR OPERATIONS

Our management relies on certain financial and operational metrics to analyze our performance. These metrics are significant factors in assessing our operating results and profitability and include (1) throughput volumes, (2) operating expenses, (3) Adjusted EBITDA and (4) gross margin.

Throughput volumes

In order to maintain or increase throughput volumes on our gathering and processing systems, we must connect additional wells to our systems. Our success in maintaining or increasing throughput is impacted by successful drilling of new wells by producers which will be dedicated to our systems, our ability to secure volumes from new wells drilled on non-dedicated acreage and our ability to attract natural gas volumes currently gathered, processed or treated by our competitors.

To maintain and increase throughput volumes on our MIGC system, we must continue to contract capacity to shippers, including producers and marketers, for transportation of their natural gas. Although firm capacity on the MIGC system is fully subscribed, we nevertheless monitor producer and marketing activities in the area served by our transportation system to maintain a full subscription of MIGC s firm capacity and to identify new opportunities.

Operating expenses

We analyze operating expenses to evaluate our performance. Operating expenses include all amounts accrued or paid for the operation of our systems, including cost of product, utilities, field labor, measurement and analysis and other disbursements. The primary components of our operating expenses that we evaluate include operation and maintenance expenses, cost of product expenses and general and administrative expenses. Certain of our operating expenses are paid to affiliates; however, affiliate expenses do not bear a direct relationship to affiliate revenues and third-party expenses do not bear a direct relationship to third-party revenues. Accordingly, our affiliate expenses are not those expenses necessary for generating our affiliate revenues and our third-party expenses are not those expenses necessary for generating our third-party revenues.

Operation and maintenance expenses include, among other things, direct labor, insurance, repair and maintenance, contract services, utility costs and services provided to us or on our behalf. For periods commencing on and subsequent to May 14, 2008 with respect to our initial assets and for periods commencing on and subsequent to December 1, 2008 with respect to the Powder River assets, certain of these expenses are incurred under and governed by our services and secondment agreement with Anadarko.

Cost of product expenses include (i) costs associated with the purchase of natural gas and NGLs pursuant to our percent-of-proceeds processing contracts, (ii) costs associated with the valuation of our gas imbalances, (iii) costs associated with our obligations under certain contracts to redeliver a volume of natural gas to shippers which is thermally equivalent to condensate retained by us and sold to third parties and (iv) costs associated with our fuel tracking mechanism, which tracks the difference between actual fuel usage and loss and amounts recovered for estimated fuel usage and loss under our contracts. These expenses are subject to variability, although our exposure to commodity price risk attributable to our percent-of-proceeds contracts is mitigated through our commodity price swap agreements with Anadarko.

General and administrative expenses for periods prior to May 14, 2008 with respect to our initial assets, and for periods prior to December 1, 2008 with respect to the Powder River assets, include reimbursements attributable to costs incurred by Anadarko on our behalf and allocations of general and administrative costs by Anadarko to us. For these periods, Anadarko received compensation or reimbursement through a management services fee. Subsequent to May 14, 2008 with respect to our initial assets and subsequent to December 1, 2008 with respect to the Powder River assets, Anadarko is no longer compensated for corporate services through a management services fee. Instead, we reimburse Anadarko for general and administrative expenses it incurs on our behalf pursuant to the terms of our omnibus agreement with Anadarko.

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Amounts required to be reimbursed to Anadarko under the omnibus agreement include those expenses attributable to our status as a publicly traded partnership, such as:

- expenses associated with annual and quarterly reporting;
- tax return and Schedule K-1 preparation and distribution expenses;
- expenses associated with listing on the New York Stock Exchange; and
- independent auditor fees, legal fees, investor relations expenses, and registrar and transfer agent fees.

In addition to the above, we are required pursuant to the terms of the omnibus agreement with Anadarko to reimburse Anadarko for allocable general and administrative expenses. The amount required to be reimbursed by us to Anadarko for allocated general and administrative expenses is capped at $6.65 million for the year ended December 31, 2009, subject to adjustment to reflect expansions of our operations through the acquisition or construction of new assets or businesses and with the concurrence of the special committee of our general partner s board of directors. After December 31, 2009, our general partner will determine the general and administrative expenses to be reimbursed by us in accordance with our partnership agreement. The cap contained in the omnibus agreement does not apply to incremental general and administrative expenses incurred by or allocated to us as a result of being a separate publicly traded entity. We currently expect public company expenses not subject to the cap contained in the omnibus agreement to be approximately $5.6 million per year, excluding equity-based compensation.

Adjusted EBITDA

We define Adjusted EBITDA as net income (loss), plus distributions from equity investee, non-cash share-based compensation expense, interest expense, income tax expense, depreciation and amortization, less income from equity investments, interest income, income tax benefit and other income (expense). We changed our definition of Adjusted EBITDA from the definition used in prior periods. Adjusted EBITDA has been calculated using the revised definition for all periods presented. We believe that the presentation of Adjusted EBITDA provides information useful to investors in assessing our financial condition and results of operations and that Adjusted EBITDA is a widely accepted financial indicator of a company s ability to incur and service debt, fund capital expenditures and make distributions. Adjusted EBITDA is a supplemental financial measure that management and external users of our consolidated financial statements, such as industry analysts, investors, lenders and rating agencies, use to assess, among other measures:

- our operating performance as compared to other publicly traded partnerships in the midstream energy industry, without regard to financing methods, capital structure or historical cost basis;
- the ability of our assets to generate cash flow to make distributions; and
- the viability of acquisitions and capital expenditure projects and the returns on investment of various investment opportunities.

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The following tables present a reconciliation of the non-GAAP financial measure of Adjusted EBITDA to the GAAP financial measures of net income and net cash provided by operating activities (in thousands):

	Three Months Ended March 31, 2009	Three Months Ended March 31, 2008[1]
Reconciliation of Adjusted EBITDA to net income		
Adjusted EBITDA	$ 23,051	$ 34,220
Less:		
Distributions from equity investee	1,111	1,407
Non-cash share-based compensation expense	846	
Interest expense, net affiliates	35	1,789
Interest expense from note affiliate	1,750	
Income tax expense		8,467
Depreciation and amortization	8,621	7,782
Add:		
Equity income, net	1,550	342
Interest income from note affiliate	4,225	
Other income	5	4
Income tax benefit	490	
Net income	$ 16,958	$ 15,121
Reconciliation of Adjusted EBITDA to Net Cash Provided by Operating Activities		
Adjusted EBITDA	$ 23,051	$ 34,220
Interest income (expense), net affiliates	2,440	(1,789)
Non-cash share-based compensation expense	(846)	
Current income tax expense	(65)	(6,364)
Other income (expense), net	5	4
Distributions from equity investee less than (in excess of) equity income, net	439	(1,065)
Changes in operating working capital:		
Accounts receivable and natural gas imbalances	(6,530)	1,371
Accounts payable and accrued expenses	(817)	604
Other, including changes in non-current assets and liabilities	(112)	343
Net cash provided by operating activities	$ 17,565	$ 27,324

(1) Financial information for 2008 has been revised to include results attributable to the Powder River assets. See *Note*

1 Description of Business and Basis of Presentation Powder River acquisition of the notes to the unaudited consolidated financial statements in *Part I, Item 1* of this Form 10-Q.

Gross margin

We define gross margin as total revenues less cost of product. We changed our definition of gross margin from the definition used in prior periods. Gross margin has been calculated using the revised definition for all periods presented. We consider gross margin to provide information useful in assessing our results of operations, our ability to internally fund capital expenditures and to service or incur additional debt.

ITEMS AFFECTING THE COMPARABILITY OF OUR FINANCIAL RESULTS

As a result of our initial public offering and the Powder River acquisition, our historical results of operations for the periods presented may not be comparable to future or historic results of operations for the reasons described below:

We anticipate incurring approximately $5.6 million of general and administrative expenses annually, excluding equity-based compensation expense, attributable to operating as a publicly traded entity. General and administrative expenses such as these are not reflected in our historical consolidated financial statements for the three months ended March 31, 2008.

Additionally, we anticipate incurring up to $6.65 million in general and administrative expenses annually to be charged by Anadarko to us pursuant to the omnibus agreement, which became effective in connection with our initial public offering. This amount is expected to be greater than amounts allocated to us by Anadarko for the management services fee reflected in our historical consolidated financial statements for the three months ended March 31, 2008.

During the three months ended March 31, 2008, all affiliate transactions were net settled within our consolidated financial statements because these transactions related to Anadarko and were funded by Anadarko s working capital. During the three months ended March 31, 2009, all affiliate and third-party transactions are funded by our working capital. This impacts the comparability of our cash flow statements, working capital analysis and liquidity discussion.

During the three months ended March 31, 2008, we incurred interest expense or earned interest income on intercompany balances with Anadarko. These intercompany balances were extinguished through non-cash transactions in connection with the closing of our initial public offering and the Powder River acquisition; therefore, interest expense and interest income attributable to these balances is reflected in our historical consolidated financial statements for the three months ended March 31, 2008.

Concurrent with the closing of our initial public offering, we loaned $260.0 million to Anadarko in exchange for a 30-year note bearing interest at a fixed annual rate of 6.50%. Interest income attributable to the note is reflected in our consolidated financial statements for the three months ended March 31, 2009 and will be included in future periods so long as the note remains outstanding.

In connection with the Powder River acquisition, we entered into a five-year, $175.0 million term loan agreement with Anadarko, under which we pay interest at a fixed rate of 4.0% for the first two years and a floating rate of interest at three-month LIBOR plus 150 basis points for the final three years. For periods including and subsequent to the Powder River acquisition, interest expense on the $175.0 million note payable to Anadarko will be incurred so long as the loan agreement remains in place.

Our financial results for historical periods reflect commodity price changes, which, in turn, impact the financial results derived from our percent-of-proceeds processing contracts. Effective January 1, 2009, commodity price risk associated with our percent-of-proceeds processing contracts has been mitigated through our fixed-price commodity price swap agreements with Anadarko that extend through December 31, 2010 with an option to extend through 2013. See *Note 5 Transactions with Affiliates* of the notes to the unaudited consolidated financial statements included in *Part I, Item 1* of this Form 10-Q.

We are generally not subject to federal or state income tax. Federal and state income tax expense was recorded for periods ending prior to and including May 14, 2008 with respect to income generated by our initial assets and prior to and including December 19, 2008 with respect to income generated by the Powder River assets. In periods subsequent to May 14, 2008 with respect to income generated by our initial assets and subsequent to December 19, 2008 with respect to income generated by the Powder River assets, we are only subject to Texas margin tax; therefore, income tax expense attributable to Texas margin tax will continue to be recognized in our consolidated financial statements. We are required to make payments to Anadarko pursuant to a tax sharing arrangement for our share of Texas margin tax included in any combined or consolidated returns of Anadarko. The consolidated financial statements for the three months ended March 31, 2008 include deferred federal and state income taxes which were provided on temporary differences between the financial statement carrying amounts of recognized assets and liabilities and their respective tax bases as if we filed tax returns as a stand-alone entity.

We currently make cash distributions to our unitholders and our general partner at an initial distribution rate of $0.30 per unit per full quarter ($1.20 per unit on an annualized basis). We paid cash distributions to our unitholders of $0.30 per unit, or $17.0 million in aggregate, during the three months ended March 31, 2009. We did not make any such distributions during the three months ended March 31, 2008.

We expect that we will rely upon external financing sources, including commercial bank borrowings and debt and equity issuances, to fund our acquisitions and expansion capital expenditures. Historically, we largely relied on internally generated cash flows and capital contributions from Anadarko to satisfy our capital expenditure requirements.

In connection with the closing of our initial public offering, our general partner adopted two new compensation plans; the Western Gas Partners, LP 2008 Long-Term Incentive Plan, or LTIP, and the Amended and Restated Western Gas Holdings, LLC Equity Incentive Plan, or the Incentive Plan. Phantom unit grants have been made to each of the independent directors of our general partner under the LTIP, and incentive unit grants have been made to each of our general partner s executive officers under the Incentive Plan. Pursuant to Financial Accounting Standards Board Statement No. 123 (revised 2004), *Shared-Based Payment,* or SFAS 123(R), grants made under equity-based compensation plans result in equity-based compensation expense which is determined, in part, by reference to the fair value of equity compensation as of the date of grant. For the three months ended March 31, 2008, equity-based compensation expense attributable to the LTIP and Incentive Plan is not reflected in our historical consolidated financial statements as there were no outstanding equity grants under either plan. For the three months ended March 31, 2008, the Partnership s general and administrative expenses include equity-based compensation costs allocated by Anadarko to the Partnership for grants made under the LTIP and Incentive Plan as well as the Anadarko Petroleum Corporation 1999 Stock Incentive Plan and the Anadarko Petroleum Corporation 2008 Omnibus Incentive Compensation Plan (Anadarko s plans are referred to collectively as the Anadarko Incentive Plans). Share-based compensation expense attributable to grants made under the LTIP will impact our cash flows from operating activities only to the extent our general partner s board of directors, at its discretion, elects to make a cash payment to a participant in lieu of actual receipt of common units by the participant upon the lapse of the relevant vesting period. Equity-based compensation expense attributable to grants made under the Incentive Plan will impact our cash flow from operating activities only to the extent cash payments are made to Incentive Plan participants and such cash payments do not cause total annual reimbursements made by us to Anadarko pursuant to the omnibus agreement to exceed the general and administrative expense limit set forth therein for the periods to which such expense limit applies. See equity-based compensation discussion included in and *Note 5 Transactions with Affiliates* of the notes to the consolidated financial statements included in *Part I, Item 1* of this Form 10-Q and in *Note 2 Summary of Significant Accounting Policies* of the notes to the unaudited consolidated financial statements in *Item 8* of our annual report on Form 10-K.

GENERAL TRENDS AND OUTLOOK

We expect our business to continue to be affected by the following key trends. Our expectations are based on assumptions made by us and information currently available to us. To the extent our underlying assumptions about, or interpretations of, available information prove to be incorrect, our actual results may vary materially from our expectations.

Natural gas supply and demand

There is a natural decline in production from existing wells. In recent years, there has been a significant level of drilling activity offsetting this decline in the areas in which we operate; however, the current natural gas price environment has recently resulted in lower drilling activity throughout areas in which we operate and may result in further reductions in drilling activity or temporary suspension of production. We have no control over this activity. In addition, the recent or further decline in commodity prices could affect production rates and the level of capital investment by Anadarko and third parties in the exploration for and development of new natural gas reserves.

Capital markets

We require periodic access to capital in order to fund acquisitions and expansion projects. Under the terms of our partnership agreement, we are required to distribute all of our available cash to our unitholders, which makes us dependent upon raising capital to fund growth projects. Historically, master limited partnerships have accessed the public debt and equity capital markets to raise money for new growth projects. Recent market turbulence has either raised the cost of those public funds or, in some cases, eliminated the availability of these funds to prospective issuers. If we are unable either to access the public capital markets or find alternative sources of capital, our growth strategy may be more challenging to execute.

Impact of interest rates

Interest rates have been volatile in recent periods. If interest rates rise, our future financing costs could increase accordingly. In addition, because our common units are yield-based securities, rising market interest rates could impact the relative attractiveness of our common units to investors, which could limit our ability to raise funds, or increase the cost of raising funds in the capital markets. Though our competitors may face similar circumstances, such an environment could adversely impact our efforts to expand our operations or make future acquisitions.

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Rising operating costs and inflation

The high level of natural gas exploration, development and production activities across the U.S. in recent years, and the associated construction of required midstream infrastructure, resulted in increased competition for personnel and equipment. Although the activities have slowed in recent months, we have not yet realized a material decline in the prices we pay for labor, supplies and property, plant and equipment. An increase in the general level of prices could have a similar effect. We have the ability to recover increased costs from our customers through escalation provisions provided for in our contracts. However, there may be a delay in recovering these costs or we may be unable to recover all these costs. As a result of the recent decline in commodity prices, we are actively working with our suppliers to negotiate cost savings on services and equipment to more accurately reflect the current industry environment. To the extent we are unable to negotiate lower costs or recover higher costs our operating results will be adversely impacted.

Benefits from system expansions

We expect that expansion projects, including the following, will mitigate the impact of natural production declines and position us to capitalize on future drilling activity by Anadarko and third-party producers and shippers:

We modified and relocated horsepower on our Dew system during the third quarter of 2008, which resulted in lower gathering line pressures and an increase in throughput of approximately 2 MMcf/d.

Further modifications of compression on our Dew system are planned for 2009 which are expected to result in lower gathering line pressures servicing the Holly Branch producing area and may further increase throughput by up to approximately 2 MMcf/d.

In July 2008, we completed the expansion of our Bethel treating facility by installing an additional 11 LTD of sulfur treating capacity in order to provide additional sour gas treating capacity for drilling in the area.

During 2008, Anadarko completed Phase III of the Fort Union expansion project by installing a third parallel 106-mile 24 line, increasing the total Fort Union handling capacity to 1,300 MMcf/d.

We are expanding our Hugoton gathering system to connect wells drilled by third parties and Anadarko. During 2008, we connected 12 third-party wells with an average initial production rate of 2.8 MMcf/d. We also connected eight new Anadarko wells and reconnected six others that were previously connected to third-party gathering systems. These 14 wells collectively produced at a rate of 1.9 MMcf/d during the month of December 2008. During the first quarter of 2009, we connected three third-party wells with an average initial production rate of 4 MMcf/d.

We are continuing to expand our Haley gathering system by connecting wells drilled by third parties and Anadarko. During the first quarter of 2009, we connected one third-party well with an initial production rate of 1.5 MMcf/d and three new Anadarko wells with an initial production rate of 14.7 MMcf/d.

During the fourth quarter of 2008, Anadarko completed train two of the Medicine Bow Plant at the terminus of the Fort Union gathering system, which is designed for 600 gal/min of amine circulation. During the first quarter of 2009, Anadarko completed train three of the Medicine Bow Plant, which is identical to train two. The system s gas treating capacity will vary depending upon the CO_2 content of the inlet gas but at the current level of 3.7% CO_2, the system is capable of treating and blending over 1 Bcf/d while satisfying CO_2 specifications of downstream pipelines.

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RESULTS OF OPERATIONS OVERVIEW
OPERATING RESULTS

The following table and discussion presents a summary of our results of operations for the three months ended March 31, 2009 and 2008:

	Three Months Ended March 31, 2009	Three Months Ended March 31, 2008[(1)]
	(in thousands)	
Revenues		
Gathering, processing and transportation of natural gas	$ 30,717	$ 31,305
Natural gas, natural gas liquids and condensate sales	17,979	47,934
Equity income and other	2,192	2,183
Total Revenues	50,888	81,422
Operating Expenses[(2)]		
Cost of product	12,528	33,728
Operation and maintenance	9,236	10,946
General and administrative	4,723	1,960
Property and other taxes	1,757	1,633
Depreciation and amortization	8,621	7,782
Total Operating Expenses	36,865	56,049
Operating Income	14,023	25,373
Interest income (expense), net affiliates	2,440	(1,789)
Other income (expense), net	5	4
Income Before Income Taxes	16,468	23,588
Income Tax (Benefit) Expense	(490)	8,467
Net Income	$ 16,958	$ 15,121
Adjusted EBITDA[(3)]	$ 23,051	$ 34,220
Gross margin[(3)]	38,360	47,694

(1) Financial information for 2008 has been revised to include results

attributable to the Powder River assets. See *Note 1 Description of Business and Basis of Presentation Powder River acquisition* of the notes to the unaudited consolidated financial statements in *Part I, Item 1* of this Form 10-Q.

(2) Operating expenses include amounts charged by affiliates to the Partnership for services as well as reimbursement of amounts paid by affiliates to third parties on behalf of the Partnership. *See Note* 5 *Transactions with Affiliates* of the notes to the unaudited consolidated financial statements in *Part I, Item 1*of this Form 10-Q.

(3) Adjusted EBITDA and gross margin are defined above within this *Item 2* under the caption *How We Evaluate Our Operations,* which includes a reconciliation of Adjusted EBITDA to its most directly comparable measures calculated and presented in accordance with GAAP.

For purposes of the following discussion, any increases or decreases for the three months ended March 31, 2009 refer to the comparison of the three months ended March 31, 2009 to the three months ended March 31, 2008.

Summary Financial Results

Total revenues decreased $30.5 million for the three months ended March 31, 2009. Gathering, processing and transportation revenues decreased $0.6 million; natural gas, NGLs and condensate revenues decreased $30.0 million and equity income and other revenues were substantially unchanged for the three months ended March 31, 2009.

Net income increased $1.8 million for the three months ended March 31, 2009, primarily due to a $9.0 million decrease in income taxes and a $4.2 million change in net interest, which changed from net interest expense to net interest income for the three months ended March 31, 2009. These items were partially offset by lower operating income of $11.4 million primarily attributable to decreased revenue of $30.5 million and partially offset by lower operating costs of $19.2 million. The changes in revenues, operating expenses, interest expense and income taxes are discussed in more detail below.

Operating Statistics

	Three Months Ended March 31, 2009	2008	Δ
	(in MMcf/d, except per-unit data and percents)		
Gathering and transportation throughput			
Affiliates	782	836	(6)%
Third parties	130	120	8%
Total gathering and transportation throughput	912	956	(5)%
Processing throughput			
Affiliates			
Third parties	28	28	
Total processing throughput	28	28	
Equity investment throughput [(a)]	123	102	21%
Total throughput	1,063	1,086	(2)%
Gross margin per Mcf [(b)]	$ 0.40	$ 0.48	(17)%

(a) Represents the Partnership s 14.81% share of Fort Union s gross volumes.

(b) Calculated as gross margin (total revenues less cost of product) divided by total throughput, including income and volumes attributable to the Partnership s investment in Fort Union. Processing volumes originate from third parties while the related residue natural gas and natural gas liquids are sold to an affiliate, therefore the gross margin per Mcf calculated separately for affiliates and third parties is not meaningful.

Total throughput volumes, which consist of affiliate, third-party and equity investment volumes remained relatively flat for the three months ended March 31, 2009.

Affiliate gathering and transportation volumes decreased 54,000 Mcf/d for the three months ended March 31, 2009, primarily attributable to throughput decreases at the Dew, Pinnacle and Hugoton systems, partially offset by affiliate volume increases at the MIGC system due to contract changes in December 2008 and January 2009 that caused volumes to shift from a third party to an affiliate. Production and associated volumes from these systems have gradually declined due to natural production declines associated with existing wells and reduced rig activity resulting in fewer new well connections. In addition, contract terms for one Pinnacle well changed in August 2008, resulting in shift in volumes from affiliate to third party. Affiliate volumes at the Haley system were relatively flat as volumes from new wells offset declines in affiliate volumes from changes in contract terms in which a third-party customer elected to take their product in kind, which caused an offsetting increase in third-party volumes.

Third-party gathering and transportation volumes increased 10,000 Mcf/d for the three months ended March 31, 2009, primarily attributable to the throughput increases at the Haley, Pinnacle and Hugoton systems, partially offset by third-party throughput declines at the MIGC system. The increase in third-party volumes at the Haley gathering system is primarily due to changes in contract terms in which a customer elected to take their product in-kind. Increased volumes at the Hugoton system are due to a third-party customer s successful drilling program, which resulted in 12 additional wells being connected to the Hugoton gathering system during the year ended December 31, 2008 and three wells connected during the three months ended March 31, 2009. As indicated above, Pinnacle volumes shifted from affiliate to third party due to changes in contract terms for one well. The declines experienced on the MIGC pipeline were primarily due to the contract changes mentioned above that caused volumes to shift from a third party to an affiliate and production outages in March 2009 due to snowstorm activity in Wyoming.

Processing volumes remained relatively unchanged for the three months ended March 31, 2009. Equity investment throughput volumes increased 21,000 Mcf/d primarily due to expansion of the Fort Union system during 2008.

Gathering, Processing and Transportation of Natural Gas Revenues

	Three Months Ended March 31, 2009	Three Months Ended March 31, 2008	Δ
	(in thousands, except percents)		
Gathering, processing and transportation of natural gas:			
Affiliates	$ 26,911	$ 27,195	(1)%
Third parties	3,806	4,110	(7)%
Total	$ 30,717	$ 31,305	(2)%

Total gathering, processing and transportation of natural gas revenues decreased $588,000 for the three months ended March 31, 2009. Revenues from affiliates decreased $284,000 primarily due to decreased volumes in the Dew, Pinnacle and Hugoton systems, partially offset by affiliate volume increases at the MIGC system due to the contract changes that caused volumes and associated revenues to shift from third party to affiliate. Revenues from third parties decreased $304,000 primarily due to a decrease in third-party volumes on the MIGC system attributable to the contract changes described above, partially offset by third-party volume increases at the Haley system from new wells.

Natural Gas, Natural Gas Liquids and Condensate Sales

	Three Months Ended March 31, 2009	Three Months Ended March 31, 2008	Δ
	(in thousands, except percents)		
Natural gas sales:			
Affiliates	$ 7,576	$ 14,969	(49)%
Third parties		8	(100)%
Total	$ 7,576	$ 14,977	(49)%
Natural gas liquids sales affiliates	$ 8,933	$ 27,638	(68)%
Drip condensate sales third parties	$ 1,470	$ 5,319	(72)%
Total natural gas, natural gas liquids and condensate sales:			
Affiliates	$ 16,509	$ 42,607	(61)%
Third parties	1,470	5,327	(72)%
Total	$ 17,979	$ 47,934	(62)%

Total natural gas, natural gas liquids and condensate sales decreased $30.0 million for the three months ended March 31, 2009, consisting of a $7.4 million decrease in natural gas sales, a $18.7 million decrease in NGLs sales and a $3.8 million decrease in drip condensate sales. The decrease in natural gas sales was primarily due to a decrease in the average price for residue sold, which was $3.84 per Mcf and $7.29 per Mcf for the three months ended March 31, 2009 and 2008, respectively, partially offset by a 217,000 Mcf, or 12%, increase in the volume of natural gas sold for the three months ended March 31, 2009. The decrease in NGLs sales for the three months ended March 31, 2009 was primarily due to a decrease in the average price for NGLs sold, which was $37.61 per Bbl and $76.78 per Bbl for the three months ended March 31, 2009 and 2008, respectively. The average natural gas and NGLs prices for the three months ended March 31, 2009 include gains from commodity price swap agreements. The decrease in the NGLs sales per Bbl for the three months ended March 31, 2009 is due to the decrease in 2009 market prices, offset by the fixed price under the commodity price swap agreements, relative to 2008 market prices and the shut-in of a plant at the Hilight system effective September 2008. The volume of NGLs sold decreased approximately 106,000 Bbls, or 29%, for the three months ended March 31, 2009. The decrease in drip condensate sales was primarily due to decreased average prices for drip condensate sold, which were $30.77 per Bbl and $91.56 per Bbl for the three months ended March 31, 2009 and 2008, respectively.

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Equity Income and Other Revenues

	Three Months Ended March 31, 2009	Three Months Ended March 31, 2008	Δ
	(in thousands, except percents)		
Equity income affiliate	$ 1,550	$ 342	353%
Other revenues:			
Affiliates	$ 180	$ 308	(42)%
Third parties	462	1,533	(70)%
Total equity and other revenues	$ 2,192	$ 2,183	%

Total equity income and other revenues was relatively unchanged for the three months ended March 31, 2009 primarily due to an increase in equity income from our investment in Fort Union attributable to system expansions, substantially offset by a decrease in other revenues related to a $0.9 million indemnity payment received from a third party during the first quarter of 2008.

Cost of Product and Operation and Maintenance Expenses

	Three Months Ended March 31, 2009	Three Months Ended March 31, 2008	Δ
	(in thousands, except percents)		
Cost of product	$ 12,528	$ 33,728	(63)%
Operation and maintenance	9,236	10,946	(16)%
Total cost of product and operation and maintenance expenses	$ 21,764	$ 44,674	(51)%

Cost of product expense decreased $21.2 million for the three months ended March 31, 2009, including an approximate $19.3 million decrease in cost of product expense attributable to the lower cost of natural gas and NGLs we purchase from producers and an approximate $1.3 million decrease in cost of product expense from the lower cost of natural gas to compensate shippers on a thermally equivalent basis for drip condensate retained by us and sold to third parties. Purchases from producers for natural gas averaged $2.57 per Mcf and $6.28 per Mcf for the three months ended March 31, 2009 and 2008, respectively. Decreases in natural gas cost of product expense from lower prices were partially offset by a 12% volume increase. Purchases from producers for NGLs averaged $18.18 per Bbl and $57.17 per Bbl for the three months ended March 31, 2009 and 2008, respectively, and NGLs volumes decreased 29%. The decrease in the cost of NGLs for the three months ended March 31, 2009 is due to declines in market prices and the shut-in of a plant at the Hilight system effective September 2008. The decrease in cost of product expense associated with drip condensate was primarily due to lower natural gas prices, which averaged $3.35 per MMBtu and $7.10 per MMBtu for the three months ended March 31, 2009 and 2008, respectively.

Operation and maintenance expense decreased $1.7 million for the three months ended March 31, 2009 primarily due to a $734,000 decrease in operating fuel costs attributable to the shut-in of the plant in the Hilight system effective September 2008, a $665,000 decrease in compressor parts and rental expenses primarily due to the contribution of previously leased compression equipment to the Partnership in November 2008 and lower rates on equipment rentals as a result of renegotiating with suppliers, and a $345,000 decrease in labor and labor related expenses.

Gross Margin

	Three Months Ended March 31, 2009	Three Months Ended March 31, 2008	Δ
	(in thousands, except percents)		
Gross margin	$38,360	$47,694	(20)%
Gross margin per Mcf [(a)]	$ 0.40	$ 0.48	(17)%

(a) Calculated as gross margin (total revenues less cost of product) divided by total throughput, including income and volumes attributable to the Partnership s investment in Fort Union.

Gross margin decreased $9.3 million for the three months ended March 31, 2009 due to a $588,000 decrease in gathering, processing and transportation of natural gas revenues primarily attributable to volume decreases and a $30.0 million decrease in natural gas, natural gas liquids and condensate sales primarily attributable to price decreases and reduced volumes as a result of the shut-in of a plant at the Hilight system, partially offset by a $21.2 million decrease in cost of product primarily attributable to price decreases and the reduced volumes as a result of closure of one plant. Gross margin per Mcf decreased 17% primarily due to lower processing margins and drip condensate margins.

General and Administrative, Depreciation and Other Expenses

	Three Months Ended March 31, 2009	Three Months Ended March 31, 2008	Δ
	(in thousands, except percents)		
General and administrative	$ 4,723	$ 1,960	141%
Property and other taxes	1,757	1,633	8%
Depreciation and amortization	8,621	7,782	11%
Total general and administrative, depreciation and other expenses	$ 15,101	$ 11,375	33%

General and administrative, depreciation and other expenses increased $3.7 million for the three months ended March 31, 2009. The increase is partially attributable to a $2.8 million increase in general and administrative expenses primarily due to $1.9 million of increased expenses attributable to being a publicly traded entity, which includes $198,000 of equity-based compensation, $803,000 attributable to other equity-based compensation expense and $2.0 million of support expense charged pursuant to the omnibus agreement, partially offset by a $1.8 million decrease in expenses charged pursuant to the management services fee allocation. For the three months ended March 31, 2009, general and administrative expenses were charged to us by Anadarko pursuant to the omnibus agreement, which became effective on May 14, 2008. For the three months ended March 31, 2008, general and administrative expenses included costs allocated by Anadarko to the Partnership in the form of a management services fee. Expenses attributable to being a publicly traded entity are comprised of consulting and auditing fees, expenses attributable to accounting personnel dedicated to the operations of the Partnership, legal expenses and director fees. Property and other taxes increased $124,000 for the three months ended March 31, 2009, primarily due to higher ad valorem taxes. Depreciation expense increased $839,000 for the three months ended March 31, 2009, consisting primarily of approximately $594,000 of depreciation on previously leased Hugoton compression equipment that was contributed to the Partnership in November 2008 and $324,000 of depreciation attributable to the expansion to our Bethel treating facility completed in July 2008.

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Interest Income (Expense), Net Affiliates

	Three Months Ended March 31,		
	2009	2008	Δ
	(in thousands, except percents)		
Interest income on note receivable from Anadarko	$ 4,225	$	100%
Interest (expense) on note payable to Anadarko	(1,750)		100%
Interest (expense), net affiliates	(35)	(1,789)	(98)%
Total	$ 2,440	$ (1,789)	nm[(1)]

(1) Not meaningful

We earned net interest income for the three months ended March 31, 2009 as compared to incurring net interest expense for the three months ended March 31, 2008. Interest income, net for the three months ended March 31, 2009 consisted of interest income on our $260.0 million note receivable from Anadarko, partially offset by interest expense attributable to our $175.0 million term loan agreement entered into with Anadarko in connection with our the Powder River acquisition and commitment fees on our $100.0 million portion of Anadarko s $1.3 billion credit facility and our $30.0 million working capital facility. Interest expense, net for the three months ended March 31, 2008 was attributable to interest charged on affiliate balances.

Income Tax Expense

	Three Months Ended March 31,		
	2009	2008	Δ
	(in thousands, except percents)		
Income before income taxes	$16,468	$23,588	(30)%
Income tax (benefit) expense	(490)	8,467	(106)%
Effective tax rate	(3)%	36%	

Income tax expense decreased $9.0 million for the three months ended March 31, 2009, primarily due to the Partnership s U.S. federal income tax status as a non-taxable entity for the three months ended March 31, 2009. Income earned by the Partnership for the three months ended March 31, 2009 was subject only to Texas margin tax while income earned by the Partnership for the three months ended March 31, 2008 was subject to federal and state income tax. In addition, the estimated income attributed to Texas relative to total income decreased in 2009 compared to the prior year, which resulted in a reduction of previously recognized deferred taxes of $560,000, offset by the recognition of $70,000 of current year Texas margin tax expense, resulting in a net tax benefit for the period. For 2008, our effective tax rate approximated the 35% federal statutory rate.

LIQUIDITY AND CAPITAL RESOURCES

Our ability to finance operations, fund maintenance capital expenditures and pay distributions will largely depend on our ability to generate sufficient cash flow to cover these requirements. Our ability to generate cash flow is subject to a number of factors, some of which are beyond our control. Please read *Item 1A Risk Factors* of our annual report on Form 10-K.

Prior to our initial public offering, our sources of liquidity included cash generated from operations and funding from Anadarko. Furthermore, we had participated in Anadarko s cash management program, whereby Anadarko, on a periodic basis, swept cash balances residing in our bank accounts. Thus, our historical consolidated financial statements for periods ending prior to our initial public offering reflect no significant cash balances. Unlike our transactions with third parties, which ultimately are settled in cash, our affiliate transactions were settled on a net basis through an adjustment to parent net equity. Subsequent to our initial public offering, we maintain our own bank accounts and sources of liquidity. Although we continue to utilize Anadarko s cash management system, our cash accounts are not subject to cash sweeps with Anadarko s cash accounts.

Our current sources of liquidity include:

- approximately $30.0 million of working capital as of March 31, 2009, which we define as the amount by which current assets exceed current liabilities;
- cash generated from operations;
- available borrowings of up to $100.0 million under Anadarko s credit facility;
- available borrowings under our $30.0 million working capital facility with Anadarko;
- interest income from our $260.0 million note receivable from Anadarko;
- issuances of additional partnership units; and
- debt offerings.

We believe that cash generated from these sources will be sufficient to satisfy our short-term working capital requirements and long-term capital expenditure requirements. The amount of future distributions to unitholders will depend on earnings, financial conditions, capital requirements and other factors, and will be determined by the board of directors of our general partner on a quarterly basis.

Working capital

Working capital, defined as the amount by which current assets exceed current liabilities, is an indication of our liquidity and potential need for short-term funding. Our working capital requirements are driven by changes in accounts receivable and accounts payable. These changes are primarily impacted by factors such as credit extended to, and the timing of collections from, our customers and our level of spending for maintenance and expansion activity.

Historical cash flow

The following table and discussion presents a summary of our net cash provided by operating activities, net cash used in investing activities, net cash used in financing activities and Adjusted EBITDA for the three months ended March 31, 2009 and 2008.

For the three months ended March 31, 2008, our net cash from operating activities and capital contributions from Anadarko were used to service our cash requirements, which included the funding of operating expenses and capital expenditures. For the three months ended March 31, 2009, transactions with Anadarko were cash-settled.

	Three Months Ended March 31,		
	2009	**2008**	**Δ**
	(in thousands, except percents)		
Net cash provided by (used in):			
Operating activities	$ 17,565	$ 27,324	(36)%
Investing activities	(6,546)	(6,707)	(2)%
Financing activities	(17,029)	(20,617)	(17)%
Net increase (decrease) in cash and cash equivalents	$ (6,010)	$	Nm[(1)]
Adjusted EBITDA	$ 23,051	$ 34,220	(33)%

(1) Not meaningful

For a reconciliation of Adjusted EBITDA to its most directly comparable financial measures calculated and presented in accordance with GAAP, please see above within this *Item 2* under the caption *How We Evaluate Our Operations.*

Operating Activities. Net cash provided by operating activities decreased $9.8 million for the three months ended March 31, 2009, primarily attributable to lower gross margins and higher general and administrative expenses as described in *Results of Operations Overview* above. Additionally, changes in working capital decreased cash flows from operating activities. These items are partially offset by lower current income taxes, higher net interest income and lower operations and maintenance expenses as described in *Results of Operations Overview* above.

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Investing Activities. Net cash used in investing activities decreased $161,000 for the three months ended March 31, 2009. Expansion cash capital expenditures decreased 44% from $4.1 million during the three months ended March 31, 2008 to $2.3 million during the three months ended March 31, 2009, primarily due to expansions of the Bethel facility at the Pinnacle system and at the Dew system completed during 2008. This decrease was substantially offset by a 63% increase in maintenance cash capital expenditures, from $2.6 million during the three months ended March 31, 2008 to $4.2 million during the three months ended March 31, 2009, primarily due to equipment replacements at the Bethel facility during the three months ended March 31, 2009 and an increase in well connections for the three months ended March 31, 2009.

Financing Activities. Net cash used in financing activities decreased $3.6 million for the three months ended March 31, 2009. For the three months ended March 31, 2009, $17.0 million of cash distributions were paid to unitholders. Our initial public offering occurred in May 2008; therefore, no distributions were paid during the three months ended March 31, 2008. We made $20.6 million of net distribution to Anadarko for the three months ended March 31, 2008, representing the net settlement of transactions received from and paid by Anadarko and affiliates on our behalf prior to our initial public offering and Powder River acquisition.

Adjusted EBITDA. Adjusted EBITDA decreased $11.2 million for the three months ended March 31, 2009, primarily due to a $31.7 million decrease in total revenues, excluding equity income, a $1.9 million increase in general and administrative expenses, excluding non-cash share-based compensation, and a $296,000 decrease in distributions from Fort Union, partially offset by a $21.2 million decrease in cost of product and a $1.7 million decrease in operation and maintenance expenses, all of which are discussed above.

Capital requirements

Our business can be capital intensive, requiring significant investment to maintain and improve existing facilities. We categorize capital expenditures as either:

- maintenance capital expenditures, which include those expenditures required to maintain the existing operating capacity and service capability of our assets, including the replacement of system components and equipment that have suffered significant wear and tear, become obsolete or approached the end of their useful lives, those expenditures necessary to remain in compliance with regulatory or legal requirements or those expenditures necessary to complete additional well connections to maintain existing system volumes and related cash flows; or

- expansion capital expenditures, which include those expenditures incurred in order to extend the useful lives of our assets, increase gathering, processing, treating and transmission throughput from current levels, reduce costs or increase revenues.

Total capital incurred for the three months ended March 31, 2009 and 2008 was $5.1 million and $5.7 million, respectively. Capital incurred is presented on an accrual basis. Capital expenditures in the consolidated statement of cash flows reflect capital expenditures on a cash basis, when payments are made. Capital expenditures for the three months ended March 31, 2009 and 2008 were $6.5 million and $6.7 million, respectively. Expansion cash capital expenditures represented approximately 35% and 62% of total capital expenditures for the three months ended March 31, 2009 and 2008, respectively. We estimate our total capital expenditures, excluding acquisitions (if any), to be $23.0 million to $27.0 million and our maintenance capital expenditures to be approximately 75% of total capital expenditures for the twelve months ending December 31, 2009. Our future expansion capital expenditures may vary significantly from period to period based on the investment opportunities available to us, which are dependent, in part, on the drilling activities of Anadarko and third-party producers. From time to time, for projects with significant risk or capital exposure, we may secure indemnity provisions or throughput agreements. We expect to fund future capital expenditures from cash flows generated from our operations, interest income from our note receivable from Anadarko, borrowings under Anadarko s credit facility, the issuance of additional partnership units or debt offerings.

Distributions

We expect to pay a minimum quarterly distribution of $0.30 per unit per full quarter, which equates to approximately $17.0 million per full quarter, or approximately $68.1 million per full year, based on the number of common, subordinated and general partner units outstanding as of March 31, 2009. Our partnership agreement requires that the

Partnership distribute all of its available cash (as defined in the partnership agreement) to unitholders of record on the applicable record date. On February 13, 2009, we paid cash distributions to our unitholders of $0.30 per unit, representing the distribution for the quarter ended on December 31, 2008. On April 21, 2009, the board of directors of our general partner declared a cash distribution to our unitholders of $0.30 per unit, or $17.0 million in aggregate, which is payable on May 15, 2009 to unitholders of record at the close of business on May 1, 2009.

Our borrowing capacity under Anadarko s credit facility

On March 4, 2008, Anadarko entered into a $1.3 billion credit facility under which we are a co-borrower. This credit facility is available for borrowings and letters of credit and permits us to borrow up to $100.0 million under the facility for general partnership purposes, including acquisitions, but only to the extent that sufficient amounts remain unborrowed by Anadarko and its other subsidiaries. At March 31, 2009, the full $100.0 million was available for borrowing by us. The $1.3 billion credit facility expires in March 2013.

Interest on borrowings under the credit facility is calculated based on the election by the borrower of either: (i) a floating rate equal to the federal funds effective rate plus 0.50% or (ii) a periodic fixed rate equal to LIBOR plus an applicable margin. The applicable margin, which was 0.44% at March 31, 2009, and the commitment fees on the facility are based on Anadarko s senior unsecured long-term debt rating. Pursuant to the omnibus agreement, as a co-borrower under Anadarko s credit facility, we are required to reimburse Anadarko for our allocable portion of commitment fees (0.11% of our committed and available borrowing capacity, including our outstanding balances) that Anadarko incurs under its credit facility, or up to $110,000 annually. Under Anadarko s credit agreements, we and Anadarko are required to comply with certain covenants, including a financial covenant that requires Anadarko to maintain a debt-to-capitalization ratio of 60% or less. As of March 31, 2009, we and Anadarko were in compliance with all covenants. Should we or Anadarko fail to comply with any covenant in Anadarko s credit facility, we may not be permitted to borrow thereunder. Anadarko is a guarantor of all borrowings under the credit facility, including our borrowings. We are not a guarantor of Anadarko s borrowings under the credit facility.

Our working capital facility

Concurrent with the closing of our initial public offering, we entered into a two-year, $30.0 million working capital facility with Anadarko as the lender. At March 31, 2009, no borrowings were outstanding under the working capital facility. The facility is available exclusively to fund working capital borrowings. Borrowings under the facility will bear interest at the same rate as would apply to borrowings under the Anadarko credit facility described above. We pay a commitment fee of 0.11% annually to Anadarko on the unused portion of the working capital facility, or up to $33,000 annually.

We are required to reduce all borrowings under our working capital facility to zero for a period of at least 15 consecutive days at least once during each of the twelve-month periods prior to the maturity date of the facility.

Credit risk

We bear credit risk represented by our exposure to non-payment or non-performance by our customers, including Anadarko. Generally, non-payment or non-performance results from a customer s inability to satisfy receivables for services rendered or volumes owed pursuant to gas imbalance agreements. We examine the creditworthiness of third-party customers and may establish credit limits for significant third-party customers.

We are dependent upon a single producer, Anadarko, for the majority of our natural gas volumes and we do not maintain a credit limit with respect to Anadarko. Consequently, we are subject to the risk of non-payment or late payment by Anadarko for gathering, treating and transmission fees and for proceeds from the sale of natural gas, natural gas liquids and condensate to Anadarko.

We expect our exposure to concentrated risk of non-payment or non-performance to continue for as long as we remain substantially dependent on Anadarko for our revenues. Additionally, we are exposed to credit risk on the note receivable from Anadarko that was issued concurrent with the closing of our initial public offering. We are also party to an omnibus agreement with Anadarko under which Anadarko is required to indemnify us for certain environmental claims, losses arising from rights-of-way claims, failures to obtain required consents or governmental permits and income taxes with respect to the initial assets. Finally, we entered into commodity price swap agreements with Anadarko in order to substantially reduce our exposure to commodity price risk attributable to our percent-of-proceeds contracts for the Hilight system and the Newcastle system and are subject to performance risk thereunder.

If Anadarko becomes unable to perform under the terms of our gathering, processing and transportation agreements, natural gas and NGL purchase agreements, its note payable to us, the omnibus agreement, the services and secondment agreement or the commodity price swap agreements, our ability to make distributions to our unitholders may be adversely impacted.

OFF-BALANCE SHEET ARRANGEMENTS

We do not have any off-balance sheet arrangements other than operating leases. The information pertaining to operating leases required for this item is provided in *Note 11 Commitments and Contingencies*, included in the notes to the unaudited consolidated financial statements included under *Part I, Item 1* of this Form 10-Q.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

Commodity Price Risk

We bear a limited degree of commodity price risk with respect to certain of our gathering contracts. Specifically, pursuant to certain of our contracts, we retain and sell drip condensate that is recovered during the gathering of natural gas. As part of this arrangement, we are required to provide a thermally equivalent volume of natural gas or the cash equivalent thereof to the shipper. Thus, our revenues for this portion of our contractual arrangement are based on the price received for the drip condensate and our costs for this portion of our contractual arrangement depend on the price of natural gas. Historically, drip condensate sells at a price representing a slight discount to the price of NYMEX West Texas Intermediate crude oil.

In addition, certain of our processing services are provided under percent-of-proceeds agreements in which Anadarko is typically responsible for the marketing of the natural gas and NGLs. Under these agreements, we receive a specified percent of the net proceeds from the sale of natural gas and NGLs. To mitigate our exposure to changes in commodity prices on these processing agreements, we entered into commodity price swap agreements with Anadarko with fixed commodity prices that extend through December 31, 2010 with an option to extend through 2013. For additional information on the commodity price swap agreements, see *Note 5 Transactions with Affiliates* included in the notes to the unaudited consolidated financial statements under *Part I, Item 1* of this Form 10-Q.

We consider our exposure to commodity price risk associated with the above-described arrangements to be minimal given the relatively small amount of our operating income generated by drip condensate sales and the existence of the commodity price swap agreements with Anadarko. For the three months ended March 31, 2009, a 10% change in the trading margin between drip condensate and natural gas would have resulted in an approximate $69,000, or less than 1%, change in operating income for the period.

We also bear a limited degree of commodity price risk with respect to settlement of our natural gas imbalances that arise from differences in gas volumes received into our systems and gas volumes delivered by us to customers. Natural gas volumes owed to or by us that are subject to monthly cash settlement are valued according to the terms of the contract as of the balance sheet dates, and generally reflect market index prices. Other natural gas volumes owed to or by us are valued at our weighted average cost of natural gas as of the balance sheet dates and are settled in-kind. Our exposure to the impact of changes in commodity prices on outstanding imbalances depends on the timing of settlement of the imbalances.

Interest Rate Risk

Interest rates during the periods discussed above were low compared to rates over the last 50 years. If interest rates rise, our future financing costs will increase. As of March 31, 2009, we owed $175.0 million to Anadarko under our five-year term loan we entered into in connection with the Powder River acquisition and had $100.0 million of credit available for borrowing under Anadarko s five-year credit facility in addition to $30.0 million available under our two-year working capital facility with Anadarko. Our $175.0 million term loan agreement with Anadarko requires us to pay interest at a fixed rate of 4.0% for the first two years and a floating rate of interest at three-month LIBOR plus 150 basis points for the final three years. Interest on borrowings under Anadarko s credit facility is calculated based on the election by the borrower of either: (i) a floating rate equal to the federal funds effective rate plus 0.50% or (ii) a periodic fixed rate equal to LIBOR plus an applicable margin. The applicable margin, which was 0.44% at March 31, 2009, is based on Anadarko s senior unsecured long-term debt rating. Borrowings under our working capital facility bear interest at the same rate that would apply to borrowings under the Anadarko credit facility. We may incur additional debt in the future, either through accessing our working capital facility with Anadarko, our $100.0 million borrowing capacity under Anadarko s existing credit facility or other financing sources, including commercial bank borrowings or debt issuances.

Item 4T. Controls and Procedures

Conclusion Regarding the Effectiveness of Disclosure Controls and Procedures

We carried out an evaluation, under the supervision and with the participation of management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures

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as of the end of the period covered by this report pursuant to Securities Exchange Act Rule 13a-15. Based upon that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that, as of the end of the first quarter of 2009, our disclosure controls and procedures were effective to provide reasonable assurance that material information required to be disclosed by us in reports that we file or submit under the Securities Exchange Act is appropriately recorded, processed, summarized and reported within the time periods specified in the SEC s rules and forms and that information required to be disclosed by us in the reports we file or submit under the Securities Exchange Act is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure.

Changes in Internal Control Over Financial Reporting

There has been no change in our internal control over financial reporting during the quarter ended March 31, 2009 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

PART II. OTHER INFORMATION

Item 1. Legal Proceedings

We are not a party to any legal proceeding other than legal proceedings arising in the ordinary course of our business. We are a party to various administrative and regulatory proceedings that have arisen in the ordinary course of our business. Management believes that there are no such proceedings for which final disposition could have a material adverse effect on our results of operations, cash flows or financial position.

Item 6. Exhibits

Exhibits are listed below in the Exhibit Index of this report on Form 10-Q.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

Date: May 12, 2009	By: */s/ Robert G. Gwin* Robert G. Gwin President and Chief Executive Officer Western Gas Holdings, LLC *(as general partner of Western Gas Partners, LP)*
Date: May 12, 2009	By: */s/ Michael C. Pearl* Michael C. Pearl Senior Vice President and Chief Financial Officer Western Gas Holdings, LLC *(as general partner of Western Gas Partners, LP)*

EXHIBIT INDEX

Exhibits not incorporated by reference to a prior filing are designated by an asterisk (*) and are filed herewith; all exhibits not so designated are incorporated herein by reference to a prior filing as indicated.

3.1	Certificate of Limited Partnership of Western Gas Partners, LP (incorporated by reference to Exhibit 3.1 to Western Gas Partners, LP s Registration Statement on Form S-1 filed on October 15, 2007, File No. 333-146700).
3.2	First Amended and Restated Agreement of Limited Partnership of Western Gas Partners, LP, dated May 14, 2008 (incorporated by reference to Exhibit 3.1 to Western Gas Partners, LP s Current Report on Form 8-K filed on May 14, 2008, File No. 001-34046).
3.3	Amendment No. 1 to First Amended and Restated Agreement of Limited Partnership of Western Gas Partners, LP, dated as of December 19, 2008 (incorporated by reference to Exhibit 3.1 to Western Gas Partners, LP s Current Report on Form 8-K filed on December 24, 2008, File No. 001-34046).
3.4	Amendment No. 2 to First Amended and Restated Agreement of Limited Partnership of Western Gas Partners, LP, dated as of April 15, 2009 (incorporated by reference to Exhibit 3.1 to Western Gas Partners, LP s Current Report on Form 8-K filed on April 20, 2009, File No. 001-34046).
3.5	Certificate of Formation of Western Gas Holdings, LLC (incorporated by reference to Exhibit 3.2 to Western Gas Partners, LP s Registration Statement on Form S-1 filed on October 15, 2007, File No. 333-146700).
3.6	Amended and Restated Limited Liability Company Agreement of Western Gas Holdings, LLC, dated as of May 14, 2008 (incorporated by reference to Exhibit 3.2 to Western Gas Partners, LP s Current Report on Form 8-K filed on May 14, 2008, File No. 001-34046).
4.1	Specimen Unit Certificate for the Common Units (incorporated by reference to Exhibit 4.1 to Western Gas Partners, LP s Quarterly Report on Form 10-Q filed on June 13, 2008, File No. 001-34046).
31.1*	Certification of Chief Executive Officer, pursuant to Rule 13a-14(a)/15d-14(a), as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Certification of Chief Financial Officer, pursuant to Rule 13a-14(a)/15d-14(a), as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1*	Certifications of Chief Executive Officer and Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.