UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 8-K

CURRENT REPORT

**Pursuant to Section 13 or 15(d) of The
Securities Exchange Act of 1934**

Date of Report – July 30, 2010
(Date of earliest event reported)

QEP RESOURCES, INC.
(Exact name of registrant as specified in its charter)

STATE OF DELAWARE	001-34778	87-0287750
(State or other jurisdiction of incorporation)	(Commission File No.)	(I.R.S. Employer Identification No.)

1050 17th Street, Suite 500, Denver, Colorado 80265
(Address of principal executive offices)

Registrant's telephone number, including area code 303-672-6900

Not Applicable
(Former name or former address, if changed since last report)

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions (see General Instruction A.2. below):

☐ Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

☐ Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)

☐ Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))

☐ Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

Section 2 - Financial Information

Item 2.01 Completion of Acquisition or Disposition of Assets

On June 30, 2010, Questar Corporation (Questar) distributed all of the shares of common stock of QEP Resources, Inc. (QEP) held by Questar to Questar shareholders in a tax-free, pro rata dividend (the Spinoff). Each Questar shareholder received one share of QEP common stock for each share of Questar common stock held (including fractional shares) at the close of business on the record date. In connection therewith, QEP distributed Wexpro Company (Wexpro), a wholly-owned subsidiary of QEP, to Questar. The financial information presented in this Current Report on Form 8-K recasts QEP's financial results as an independent company separate from Questar and reflects Wexpro's financial condition and operating results as discontinued operations for all periods presented.

Section 9 - Financial Statements and Exhibits

Item 9.01 Financial Statements and Exhibits.

(d) Exhibits.

Exhibit No.	Exhibit
99.1	QEP Resources, Inc. recast consolidated financial statements

SIGNATURE

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.

QEP Resources, Inc.
(Registrant)

July 30, 2010

/S/ RICHARD J. DOLESHEK

Richard J. Doleshek
Executive Vice President,
Chief Financial Officer and
Treasurer

List of Exhibits:

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99.1	QEP Resources, Inc. recast consolidated financial statements

Exhibit 99.1

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EXPLANATORY NOTE

Effective May 18, 2010, Questar Market Resources, Inc., (Market Resources) a wholly-owned subsidiary of Questar, merged with and into its newly-formed, wholly-owned subsidiary, QEP, a Delaware corporation in order to reincorporate in the State of Delaware (Reincorporation Merger). The Reincorporation Merger was effected pursuant to an Agreement and Plan of Merger entered into between Market Resources and QEP. The Reincorporation Merger was approved by the boards of directors of Market Resources and QEP and submitted to a vote of, and approved by, Questar, as sole shareholder of Market Resources, and by Market Resources, as sole shareholder of QEP on May 18, 2010.

On June 30, 2010, Questar Corporation (Questar) distributed all of the shares of common stock of QEP Resources, Inc. (QEP or the Company) held by Questar to Questar shareholders in a tax-free, pro rata dividend (the Spinoff). Each Questar shareholder received one share of QEP common stock for each one share of Questar common stock held (including fractional shares) at the close business on the record date. In connection therewith, QEP distributed Wexpro Company (Wexpro), a wholly-owned subsidiary of QEP, to Questar. In addition, Questar contributed $250.0 million of equity to QEP prior to the Spinoff.

QEP renamed its subsidiaries in connection with the reorganization as follows:

- QEP Energy Company (formerly Questar Exploration and Production Company),
- QEP Field Services Company (formerly Questar Gas Management Company), and
- QEP Marketing Company (formerly Questar Energy Trading Company).

The financial information presented in this Current Report on Form 8-K recasts QEP’s financial results as an independent company separate from Questar and reflects Wexpro’s financial condition and operating results as discontinued operations for all periods presented. A summary of discontinued operations can be found in Note 3 to the consolidated financial statements in Item 8 of this Current Report on Form 8-K.

PART II

ITEM 6. SELECTED FINANCIAL DATA.

Selected financial data for the five years ending December 31, 2009, is provided in the table below. Refer to Item 7 and Item 8 in Part II of this annual report for discussion of facts affecting the comparability.

	Year Ended December 31,				
	2009 (recast)	**2008 (recast)**	**2007 (recast)**	**2006 (recast)**	**2005 (recast)**
	(in millions, except per-share amounts)				
Results Of Operations					
Revenues	**$ 1,972.5**	$ 2,318.8	$1,688.1	$1,685.7	$1,693.2
Operating income	**585.5**	933.2	584.1	511.7	359.7
Income from continuing operations	**215.4**	520.6	361.6	306.1	214.5
Discontinued operations net of income tax	**80.7**	73.9	59.2	50.0	43.7
Net income attributable to QEP	**293.5**	585.5	420.8	356.1	258.2
Earnings per common share attributable to QEP					
Basic from continuing operations	**$ 1.23**	$ 2.96	$ 2.11	$ 1.79	$ 1.26
Basic from discontinued operations	**0.46**	0.43	0.34	0.29	0.26
Basic total	**$ 1.69**	$ 3.39	$ 2.45	$ 2.08	$ 1.52
Diluted from continuing operations	**$ 1.21**	$ 2.90	$ 2.05	1.74	$ 1.23
Diluted from discontinued operations	**0.46**	0.42	0.34	0.29	0.25
Diluted total	**$ 1.67**	$ 3.32	$ 2.39	$ 2.03	$ 1.48
Weighted-average common shares outstanding					
Used in basic calculation	**174.1**	172.8	172.0	170.9	169.6
Used in diluted calculation	**176.3**	176.1	175.9	175.2	174.3
Financial Position					
Total Assets at December 31,	**$ 6,481.4**	$ 6,342.7	$3,821.6	$3,261.8	$2,634.5
Capitalization at December 31,					
Long-term debt	**1,348.7**	1,299.1	499.3	399.2	350.0
Total equity	**2,808.7**	2,779.4	1,860.1	1,544.8	873.8
Total Capitalization	**$ 4,157.4**	$ 4,078.5	$2,359.4	$1,944.0	$1,223.8
Cash Flow From Continuing Operations					
Net cash provided by operating activities	**$ 1,149.4**	$ 1,224.7	$ 807.0	$ 654.8	$ 449.2
Capital expenditures	**(1,198.4)**	(2,136.7)	(838.9)	(670.0)	(518.4)
Net cash used in investing activities	**(1,146.4)**	(2,021.0)	(867.9)	(621.9)	(556.4)
Net cash provided by (used in) financing activities	**(8.8)**	818.7	44.1	(17.2)	111.2

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS.

SUMMARY

QEP's net income decreased 58% in 2009 compared with 2008 due to lower realized natural gas, crude oil and NGL prices and lower processing margins at QEP Field Services. Net income increased 41% in 2008 compared to 2007 primary due to higher realized natural gas, crude oil and NGL prices, higher gathering and processing margins.

Following are comparisons of income from continuing operations attributable to QEP by line of business:

	Year Ended December 31,			Change	
	2009	2008	2007	2009 vs.2008	2008 vs.2007
			(in millions)		
Exploration and production	**$134.9**	$408.0	$285.5	**$ (273.1)**	$ 122.5
Midstream field services	**69.4**	81.5	55.3	**(12.1)**	26.2
Marketing and other	**8.5**	22.1	20.8	**(13.6)**	1.3
Income from continuing operations attributable to QEP	**$212.8**	$511.6	$361.6	**$ (298.8)**	$ 150.0

RESULTS OF OPERATIONS

EXPLORATION AND PRODUCTION

Exploration and production activities reported net income of $134.9 million in 2009, down 67% from $408.0 million in 2008 and $285.5 million in 2007. Lower realized natural gas, crude oil and NGL prices and an 11% increase in 2009 average production costs more than offset an 11% increase in 2009 production. Unrealized losses on natural gas basis-only swaps decreased pre-tax income $164.0 million in 2009 compared to a net pre-tax loss of $79.2 million a year-earlier. Net gains from sales of assets increased pre-tax income $1.6 million in 2009 compared to a net pre-tax gain of $60.4 million in the year-earlier period. Following is a summary of financial and operating results:

	Year Ended December 31,			Change	
	2009	2008	2007	2009 vs. 2008	2008 vs. 2007
			(in millions)		
Operating Income					
REVENUES					
Natural gas sales	**$1,103.9**	$1,147.7	$786.9	**$ (43.8)**	$ 360.8
Oil and NGL sales	**158.5**	237.5	164.2	**(79.0)**	73.3
Other	**4.9**	6.9	4.9	**(2.0)**	2.0
Total Revenues	**1,267.3**	1,392.1	956.0	**(124.8)**	436.1
OPERATING EXPENSES					
Lease operating expenses	**127.5**	125.4	87.9	**2.1**	37.5
General and administrative	**68.0**	55.8	56.3	**12.2**	(0.5)
Production and property taxes	**58.3**	104.0	60.1	**(45.7)**	43.9
Depreciation, depletion and amortization	**512.8**	330.9	243.5	**181.9**	87.4
Exploration	**25.0**	29.3	22.0	**(4.3)**	7.3
Abandonment and impairment	**20.3**	44.6	10.8	**(24.3)**	33.8
Natural gas purchases		0.5	2.2	**(0.5)**	(1.7)
Total Operating Expenses	**811.9**	690.5	482.8	**121.4**	207.7
Net gain (loss) from asset sales	**1.6**	60.4	(0.6)	**(58.8)**	61.0
Operating Income	**$ 457.0**	$ 762.0	$472.6	**$ (305.0)**	$ 289.4
Operating Statistics					
Production Volumes					
Natural gas (Bcf)	**168.7**	151.9	121.9	**16.8**	30.0
Oil and NGL (MMbbl)	**3.5**	3.3	3.0	**0.2**	0.3
Total production (Bcfe)	**189.5**	171.4	140.2	**18.1**	31.2
Average daily production (MMcfe)	**519.1**	468.3	384.1	**50.8**	84.2
Average realized price, net to the well (including hedges)					
Natural gas (per Mcf)	**$ 6.54**	$ 7.56	$ 6.45	**$ (1.02)**	$ 1.11
Oil and NGL (per bbl)	**45.91**	72.96	53.99	**(27.05)**	18.97

Production volumes totaled 189.5 Bcfe in 2009 compared to 171.4 Bcfe in 2008 and 140.2 Bcfe in 2007. On an energy-equivalent basis, natural gas comprised approximately 89% of 2009 production. A comparison of natural gas-equivalent production by major operating area is shown in the following table:

	Year Ended December 31,			Change	
	2009	2008	2007	2009 vs. 2008	2008 vs. 2007
	(in Bcfe)				
Midcontinent	**87.8**	67.8	51.0	**20.0**	16.8
Pinedale Anticline	**61.8**	56.8	47.4	**5.0**	9.4
Uinta Basin	**23.2**	26.9	25.4	**(3.7)**	1.5
Rockies Legacy	**16.7**	19.9	16.4	**(3.2)**	3.5
Total production	**189.5**	171.4	140.2	**18.1**	31.2

Net production in the Midcontinent grew 29% or 20.0 Bcfe to 87.8 Bcfe in 2009 compared to 2008. Midcontinent production growth was driven by the first quarter 2008 acquisition of natural gas properties in northwest Louisiana, ongoing infill-development drilling in the Cotton Valley and Haynesville formations in the Elm Grove, Thorn Lake and Woodardville fields in northwest Louisiana, continued development of the Granite Wash/Atoka/Morrow play in the Texas Panhandle, and production from new outside-operated Woodford Shale horizontal gas wells in the Anadarko Basin in central Oklahoma.

Net production from the Pinedale Anticline in western Wyoming grew 9% to 61.8 Bcfe in 2009 as a result of ongoing development drilling. Historically, seasonal access restrictions imposed by the Bureau of Land Management have limited the ability to drill and complete wells at Pinedale during the mid-November to early May period. In September 2008, the BLM issued a Record of Decision (ROD) on the Final Supplemental Environmental Impact Statement for long-term development of natural gas resources in the Pinedale Anticline Project Area (PAPA). Under the ROD, QEP Energy is allowed to drill and complete wells year-round in one of the five Concentrated Development Areas defined in the PAPA. The ROD contains additional requirements and restrictions on development of the PAPA.

In the Uinta Basin, net production decreased 14% to 23.2 Bcfe in 2009. Production volumes were adversely impacted by decreased drilling activity in response to low natural gas prices.

Rockies Legacy net production in 2009 decreased 16% to 16.7 Bcfe, 3.2 Bcfe lower than the year-ago period. Production volumes were adversely impacted by decreased drilling activity in response to low natural gas prices. QEP Energy Rockies Legacy properties include all Rocky Mountain region properties except the Pinedale Anticline and the Uinta Basin.

In 2009, the weighted-average realized natural gas price (including the impact of hedging) was $6.54 per Mcf compared to $7.56 per Mcf in 2008, a 13% decrease. Realized oil and NGL prices in 2009 averaged $45.91 per bbl, compared with $72.96 per bbl during the prior year, a 37% decrease. A regional comparison of average realized prices, including the impact of hedges, is shown in the following table:

	Year Ended December 31,			Change	
	2009	2008	2007	2009 vs. 2008	2008 vs. 2007
Natural gas (per Mcf)					
Midcontinent	**$ 7.01**	$ 8.63	$ 7.42	**$ (1.62)**	$ 1.21
Rocky Mountains	**6.12**	6.85	5.90	**(0.73)**	0.95
Volume-weighted average	**6.54**	7.56	6.45	**(1.02)**	1.11
Oil and NGL (per bbl)					
Midcontinent	**$46.05**	$72.82	$54.85	**$ (26.77)**	$ 17.97
Rocky Mountains	**45.82**	73.05	53.51	**(27.23)**	19.54
Volume-weighted average	**45.91**	72.96	53.99	**(27.05)**	18.97

QEP Energy's net realized natural gas prices averaged $6.39 per Mcfe in 2009 including $0.15 per Mcfe realized losses on basis-only swaps. Realized losses on basis-only swaps were de minimis in 2008 and 2007. Realized losses on basis-only swaps $25.6 million are reported after operating income in the Consolidated Statements of Income.

QEP Energy hedged approximately 77% of gas production in 2009 with fixed price swaps. An additional 15% of gas production was subject to basis-only swaps. In 2008, approximately 82% of gas production was hedged with fixed price swaps. An additional 3% of gas production was subject to basis-only swaps. Hedging increased QEP Energy gas revenues by $599.3 million in 2009 and increased revenues $125.8 million in 2008. Approximately 42% of 2009 and 50% of 2008 QEP Energy oil production was hedged with fixed price swaps. Oil hedges increased oil revenues by $1.6 million in 2009 and reduced oil revenues $31.9 million in 2008. Derivative positions as of December 31, 2009, are summarized in Note 8 to the consolidated financial statements in Item 8 of this Report on Form 8-K.

In 2009, production costs (the sum of depreciation, depletion and amortization expense, lease operating expense, general and administrative expense, allocated-interest expense and production taxes) per Mcfe of production increased 11% to $4.39 per Mcfe versus $3.94 per Mcfe in 2008. Production costs are summarized in the following table:

	Year Ended December 31,			Change	
	2009	2008	2007	2009 vs. 2008	2008 vs. 2007
			(per Mcfe)		
Depreciation, depletion and amortization	**$ 2.71**	$ 1.93	$ 1.74	**$ 0.78**	$ 0.19
Lease operating expenses	**0.67**	0.73	0.63	**(0.06)**	0.10
General and administrative expense	**0.36**	0.33	0.40	**0.03**	(0.07)
Allocated-interest expense	**0.34**	0.34	0.18		0.16
Production taxes	**0.31**	0.61	0.43	**(0.30)**	0.18
Total Production Costs	**$ 4.39**	$ 3.94	$ 3.38	**$ 0.45**	$ 0.56

In 2009, production volume-weighted per-unit depreciation, depletion and amortization (DD&A) expense increased compared to 2008 primarily due to price-related negative reserve revisions in certain fields and the growing proportion of total production from fields in the Midcontinent that have higher DD&A rates. Lease operating expenses per Mcfe decreased primarily as a result of higher production volumes and reduced well-workover activity. General and administrative expense per Mcfe increased as a result of increased labor and outside services. Allocated interest expense per Mcfe of production was unchanged. Production taxes per Mcfe decreased in 2009 as the result of lower natural gas and oil sales prices. In most states, the Company pays production taxes based on a percentage of sales prices excluding the impact of hedges.

Exploration expense decreased $4.3 million or 15% in 2009 compared to 2008. Abandonment and impairment expense decreased $24.3 million or 54% in 2009 compared to 2008 primarily due to the impairment of certain gas and oil assets in 2008.

In the third quarter of 2008, QEP Energy sold certain outside-operated producing properties and leaseholds in the Gulf Coast region of south Texas and recognized a pre-tax gain of approximately $61.2 million. These properties contributed 2.8 Bcfe to net production in 2008.

Major Operating Areas

Midcontinent

Midcontinent properties are distributed over a large area, including the Anadarko Basin of Oklahoma and the Texas Panhandle, the Arkoma Basin of Oklahoma and western Arkansas, and the Ark-La-Tex region of Arkansas and Louisiana. With the exception of northwest Louisiana, the Granite Wash play in the Texas Panhandle and the Woodford Shale "Cana" play in western Oklahoma, QEP Energy Midcontinent leasehold interests are fragmented, with no significant concentration of property interests. In aggregate, Midcontinent properties contributed 87.8 Bcfe or 46% of 2009 production and comprised 1,100.5 Bcfe or 40% of QEP Energy total proved reserves at December 31, 2009.

QEP Energy has approximately 46,000 net acres of Haynesville Shale lease rights in northwest Louisiana. The true vertical depth to the top of the Haynesville Shale ranges from approximately 10,500 feet to 12,500 feet across QEP Energy's leasehold and is below the Hosston and Cotton Valley formations that QEP Energy has been developing in northwest Louisiana for over a decade. QEP Energy continues infill-development drilling in the Cotton Valley and Hosston formations in northwest Louisiana and intends to drill or participate in up to 48 (operated and non-operated) horizontal Haynesville Shale wells in 2010. As of December 31, 2009, QEP Energy had seven operated rigs drilling in the project area and operated or had working interests in 31 Haynesville formation wells and 610 total producing wells in northwest Louisiana compared to six Haynesville formation wells and 539 total producing wells at December 31, 2008.

QEP Energy has approximately 26,000 net acres of Woodford Shale lease rights in Blaine, Caddo and Canadian Counties in western Oklahoma. The true vertical depth to the top of the Woodford Shale ranges from approximately 11,000 feet to 14,000 feet across QEP Energy's leasehold. QEP Energy intends to drill or participate in up to 44 horizontal Woodford Shale wells in 2010. As of December 31, 2009, QEP Energy had one operated rig drilling in the project area and operated or had working interests in 49 producing Woodford Shale wells in western Oklahoma compared to 13 at December 31, 2008.

QEP Energy has over 25,000 net acres of Granite Wash lease rights in the Texas Panhandle and western Oklahoma and has been drilling vertical Granite Wash wells in the Texas Panhandle for over a decade. In the past year, other operators have drilled several successful horizontal wells in the Granite Wash Play. The true vertical depth to the top of the Granite Wash interval ranges from approximately 11,100 feet to 15,900 feet across QEP Energy's leasehold. As of December 31, 2009, QEP Energy had one rig drilling horizontal Granite Wash wells in the Texas Panhandle and had working interests in 10 producing horizontal Granite Wash wells in the Texas Panhandle or Washita County, Oklahoma compared to four wells at December 31, 2008. QEP Energy intends to drill or participate in up to 21 horizontal Granite Wash wells in 2010.

Pinedale Anticline

As of December 31, 2009, QEP Energy operated and had working interests in 426 producing wells on the Pinedale Anticline compared to 330 at December 31, 2008. Of the 426 producing wells, QEP Energy has working interests in 405 wells and overriding royalty interests in an additional 21 wells. The Pinedale Anticline contributed 61.8 Bcfe or 33% of 2009 production and comprised 1,300.7 Bcfe or 47% of QEP Energy total proved reserves at December 31, 2009.

In 2005, the Wyoming Oil and Gas Conservation Commission (WOGCC) approved 10-acre-density drilling for Lance Pool wells on about 12,700 acres of QEP Energy's 17,872-acre (gross) Pinedale leasehold. The area approved for increased density corresponds to the currently estimated productive limits of QEP Energy core acreage in the field. In January 2008, the WOGCC approved five-acre-density drilling for Lance Pool wells on about 4,200 gross acres of QEP Energy's Pinedale leasehold. The true vertical depth to the top of the Lance Pool tight gas sand reservoir interval ranges from 8,500 to 9,500 feet across QEP Energy's acreage.

At December 31, 2009, QEP Energy had booked 432 proved undeveloped locations on a combination of 5-, 10- and 20-acre density. The Company continues to evaluate development on five-acre density at Pinedale. If five-acre-density development is appropriate for a majority of its leasehold, the Company currently estimates that up to 1,400 additional wells will be required to fully develop the Lance Pool on its acreage.

Uinta Basin

As of December 31, 2009, QEP Energy had an operating interest in 2,334 gross producing wells in the Uinta Basin of eastern Utah, compared to 909 at December 31, 2008. The significant increase in well count was due to the inclusion of QEP Energy acreage within the outside operated Greater Monument Butte enhanced recovery unit in 2009; resulting in QEP Energy having a very small interest in 1,313 wells. At December 31, 2009, properties in the Uinta Basin contributed 23.2 Bcfe or 12% of 2009 production and comprised 197.7 Bcfe or 7% of QEP Energy total proved reserves at December 31, 2009. There were nine booked proved undeveloped locations. Uinta Basin reserves declined 24% due to lower average 2009 gas and oil prices and a price-related slow down in development drilling. Uinta Basin proved reserves are found in a series of vertically stacked, laterally discontinuous reservoirs at depths of 5,000 feet to deeper than 18,000 feet. QEP Energy owns interests in over 244,000 net leasehold acres in the Uinta Basin.

Rockies Legacy

The remainder of QEP Energy Rocky Mountain region leasehold interests, productive wells and proved reserves are distributed over a number of fields and properties managed as the Company's Rockies Legacy division. Most of the properties are located in the Greater Green River Basin of western Wyoming. In aggregate, Rockies Legacy properties contributed 16.7 Bcfe or 9% of 2009 production and comprised 148.0 Bcfe or 6% of QEP Energy total proved reserves at December 31, 2009. Exploration and development activity for 2010 includes wells in the San Juan, Paradox, Powder River, Green River, Vermillion and Williston Basins.

QEP Energy has approximately 80,000 net acres of Bakken formation lease rights in Mountrail, McLean and McKenzie counties in North Dakota. The true vertical depth to the top of the Bakken formation ranges from approximately 9,500 feet to 10,000 feet across QEP Energy's leasehold. The Three Forks Sanish formation lies approximately 60-70 feet below the middle Bakken formation and is also a target for horizontal drilling. QEP Energy intends to drill or participate in 20-25 horizontal Bakken or Three Forks Sanish wells in 2010. As of December 31, 2009, QEP Energy had one operated rig drilling in the project area and operated or had working interests in 26 producing Bakken or Three Forks Sanish wells in North Dakota compared to 15 at December 31, 2008.

MIDSTREAM FIELD SERVICES

Midstream field services activities reported net income of $69.4 million in 2009 compared to $81.5 million in 2008, a 15% decrease and $55.3 million in 2007. Net income was impacted by lower processing margins. Following is a summary of financial and operating results:

	Year Ended December 31,			Change	
	2009	2008	2007	**2009 vs. 2008**	2008 vs. 2007
			(in millions)		
Operating Income					
REVENUES					
NGL sales	**$ 71.9**	$106.0	$ 75.0	**$ (34.1)**	$ 31.0
Processing	**32.6**	31.0	19.9	**1.6**	11.1
Gathering	**127.3**	121.0	94.0	**6.3**	27.0
Other gathering	**32.8**	32.2	17.4	**0.6**	14.8
Total Revenues	**264.6**	290.2	206.3	**(25.6)**	83.9
OPERATING EXPENSES					
Processing	**10.3**	10.2	9.3	**0.1**	0.9
Processing plant shrinkage	**28.1**	48.7	30.1	**(20.6)**	18.6
Gathering	**36.6**	36.1	44.2	**0.5**	(8.1)
General and administrative	**25.0**	23.7	17.2	**1.3**	6.5
Property taxes	**4.6**	2.6	1.4	**2.0**	1.2
Depreciation, depletion and amortization	**44.3**	28.7	19.1	**15.6**	9.6
Abandonment and impairments		0.8	0.4	**(0.8)**	0.4
Total Operating Expenses	**148.9**	150.8	121.7	**(1.9)**	29.1
Net loss from asset sales	**(0.1)**			**(0.1)**	
Operating Income	**$115.6**	$139.4	$ 84.6	**$ (23.8)**	$ 54.8
Operating Statistics					
Natural gas processing volumes					
NGL sales (MMgal)	**101.6**	89.5	76.5	**12.1**	13.0
NGL sales price (per gal)	**$ 0.71**	$ 1.18	$ 0.98	**$ (0.47)**	$ 0.20
Fee-based processing volumes (recast) (in millions of MMBtu)					
For unaffiliated customers	**110.6**	97.0	46.8	**13.6**	50.2
For affiliated customers	**99.4**	104.5	79.8	**(5.1)**	24.7
Total Fee Based Processing Volumes	**210.0**	201.5	126.6	**8.5**	74.9
Fee-based processing (per MMBtu)	**$ 0.15**	$ 0.14	$ 0.15	**$ 0.01**	$ (0.01)
Natural gas gathering volumes (recast) (in millions of MMBtu)					
For unaffiliated customers	**301.2**	278.3	196.1	**22.9**	82.2
For affiliated customers	**112.6**	114.2	94.1	**(1.6)**	20.1
Total Gas Gathering Volumes	**413.8**	392.5	290.2	**21.3**	102.3
Gas gathering revenue (per MMBtu)	**$ 0.31**	$ 0.31	$ 0.32		$ (0.01)

Processing margin (processing revenue minus process and processing plant shrinkage) in 2009 decreased 15% to $66.1 million compared to $78.1 million in 2008. Fee-based gas processing volumes were 210.0 million MMBtu in 2009, a 4% increase compared to 2008. In 2009, fee-based gas processing revenues increased 12% or $3.4 million, while the frac spread from keep-whole processing decreased 24% or $13.5 million. Approximately 81% of net operating revenue (revenue minus processing plant shrinkage) in 2009 was derived from fee-based contracts, up from 75% in 2008. QEP Field Services may use forward sales contracts to reduce margin volatility associated with keep-whole contracts. Forward sales contracts had no impact in 2009 and reduced NGL revenues by $1.4 million in 2008.

Gathering margin (gathering revenue minus gathering expense) in 2009 increased 5% to $123.5 million compared to $117.1 million in 2008. Expanding Pinedale production and new projects serving third parties in the Uinta Basin contributed to a 10% increase in third-party volumes in 2009. Gathering volumes increased 21.3 million MMBtu, or 5% to 413.8 million MMBtu in 2009. Rendezvous Gas Services LLC (Rendezvous) was consolidated with QEP Field Services beginning in 2008. Rendezvous provides gas gathering services for the Pinedale and Jonah producing areas of Wyoming.

MARKETING

Marketing net income was $8.5 million in 2009, a decrease of 62% compared to 2008 net income of $22.1 million and 2007 net income of $20.8 million as a result of lower marketing and storage margins. Revenues from unaffiliated customers were $442.5 million in 2009 compared to $637.9 million in 2008, a 31% decrease, primarily the result of lower natural gas prices. The weighted-average natural gas sales price decreased 48% in 2009 to $3.29 per MMBtu, compared to $6.34 per MMBtu in 2008.

Consolidated Results below Operating Income

Interest and Other Income

Interest and other income decreased $5.7 million in 2009 compared with 2008 due to less activity in sales of inventory. Interest and other income increased $2.4 million or 31% in 2008 compared with 2007 primarily from gains on inventory sales.

Income from unconsolidated affiliates

Income from unconsolidated affiliates was $2.7 million in 2009 compared to $1.7 million in 2008 and $8.9 million in 2007. Rendezvous represented the majority of income from unconsolidated affiliates in 2007.

Realized and unrealized gain (loss) on basis-only swaps

The Company has used basis-only swaps to manage the risk of widening basis differentials. Basis-only swaps do not qualify for hedge accounting. As of December 31, 2009, all of the Company's basis-only swaps were paired with fixed-price swaps and re-designated as cash flow hedges. Changes in the fair value of the derivative instruments subsequent to the re-designation were recorded in Accumulative Other Comprehensive Income. Fair value changes occurring prior to re-designation were recorded in income. The Company recognized unrealized losses of $164.0 million in 2009, $79.2 million in 2008 and $5.7 million gain in 2007. The Company realized losses of $25.6 million on settlements of basis-only swaps in 2009, which were reported after operating income in the Consolidated Statements of Income.

Interest expense

Interest expense rose 14% in 2009 compared with 2008 and 84% in 2008 compared to 2007 due primarily to financing activities associated with the purchase of natural gas development properties in northwest Louisiana. Interest rates on commercial-paper borrowings in 2009 averaged less than 1% per annum after reaching the highest level in recent years in September 2008.

Income taxes

The effective combined federal and state income tax rate was 35.3% in 2009 compared with 35.3% in 2008 and 36.9% in 2007.

LIQUIDITY AND CAPITAL RESOURCES

Operating Activities

Net cash provided by operating activities from continuing operations decreased 6% in 2009 compared to 2008 and 52% in 2008 compared to 2007. Noncash adjustments to net income consisted primarily of depreciation, depletion and amortization, and deferred income taxes. Cash sources from operating assets and liabilities were lower in 2009 primarily due to changes in the values of inventories and receivables. Receivables decreased at December 31, 2009, because of lower natural gas prices for gas distribution. Net cash provided by operating activities is presented below:

	Year Ended December 31,			Change	
	2009	2008	2007	2009 vs. 2008	2008 vs. 2007
			(in millions)		
Net income	**$ 296.1**	$ 594.5	$420.8	**$ (298.4)**	$ 173.7
Noncash adjustments to net income	**782.3**	692.6	407.8	**89.7**	284.8
Changes in operating assets and liabilities	**71.0**	(62.4)	(21.6)	**133.4**	(40.8)
Net cash provided by operating activities from continuing operations	**$1,149.4**	$1,224.7	$807.0	**$ (75.3)**	$ 417.7

Investing Activities

Capital spending for continuing operations in 2009 amounted to $1,198.4 million. The details of capital expenditures in 2009 and 2008 and a forecast for 2010 are shown in the table below:

	Year Ended December 31,		
	2010 Forecast	2009	2008
		(in millions)	
Exploration and production	$ 873.6	**$1,108.6**	$1,777.3
Midstream field services	289.0	**88.3**	357.9
Marketing and other	1.2	**1.5**	1.5
Total capital expenditures	$1,163.8	**$1,198.4**	$2,136.7

Exploration and production

QEP Energy capital expenditures decreased in 2009 compared to 2008 due to lower property acquisitions in 2009 and a reduced drilling program in 2009. In February 2008, QEP Energy acquired natural gas development properties in northwest Louisiana for an aggregate purchase price of $652.1 million. During 2009, QEP Energy participated in 398 wells, resulting in 158.2 net successful gas and oil wells. The 2009 net drilling-success rate was 100.0%. There were 112 gross wells in progress at year-end.

Midstream field services

QEP Field Services increased investment in its gathering and processing-services to expand capacity in both western Wyoming and eastern Utah in anticipation of growing production volumes.

Financing Activities

As a result of the recent economic downturn, the Company limited 2009 capital expenditures to approximate internally generated cash flow. In 2009, net cash provided by operating activities of $1,149.4 million exceeded net cash used in investing activities of $1,146.4 million by $3.0 million reflecting the strategy. Long-term debt increased by a net change of $47.0 million and short-term debt decreased by a net change of $50.1 million. In 2008, the acquisition of natural gas development properties in northwest Louisiana resulted in net cash used in investing activities of $2,021.0 million exceeding net cash flow from operating activities by $796.3 million. In 2008, long-term debt increased by $795.2 million net and short-term debt increased by $31.8 million.

In August 2009, QEP issued $300.0 million of notes due March 2020 with a 6.82% effective interest rate and used the net proceeds to reduce the balance outstanding under its long-term revolving-credit facility.

QEP's consolidated capital structure consisted of 34% combined short- and long-term debt and 66% common shareholders' equity at December 31, 2009 and December 31, 2008. At December 31, 2009, QEP had unused capacity of $600.0 million on a revolving-credit facility with banks. The Company has no long-term debt maturing until 2011.

At December 31, 2009, QEP's long-term debt was rated BBB+ by Standard & Poor's Corporation and Baa3 by Moody's Investors Services.

Contractual Cash Obligations and Other Commitments

In the course of ordinary business activities, QEP enters into a variety of contractual cash obligations and other commitments. The following table summarizes the significant contractual cash obligations as of December 31, 2009:

	Payments Due by Year						
	Total	2010	2011	2012	2013	2014	After 2014
				(in millions)			
Long-term debt	$1,350.0		$150.0		$200.0		$1,000.0
Interest on fixed-rate long-term debt	585.7	$ 77.4	68.0	$ 66.1	66.1	$ 66.1	242.0
Drilling contracts	75.0	51.2	19.8	4.0			
Transportation contracts	444.0	17.3	37.2	42.0	40.2	39.3	268.0
Operating leases	17.9	4.3	4.3	4.1	3.0	1.0	1.2
Total	**$2,472.6**	**$150.2**	**$279.3**	**$116.2**	**$309.3**	**$106.4**	**$1,511.2**

At December 31, 2009, the Company had $200.0 million of variable-rate long-term debt with an interest rate of 0.73% outstanding under its revolving credit facility, which matures in March of 2013.

Critical Accounting Policies, Estimates and Assumptions

QEP's significant accounting policies are described in Note 1 to the consolidated financial statements included in Item 8 of Part II of its Annual Report. The Company's consolidated financial statements are prepared in accordance with U.S. generally accepted accounting principles. The preparation of consolidated financial statements requires management to make assumptions and estimates that affect the reported results of operations and financial position. The following accounting policies may involve a higher degree of complexity and judgment on the part of management.

Gas and Oil Reserves

Gas and oil reserve estimates require significant judgments in the evaluation of all available geological, geophysical, engineering and economic data. The data for a given field may change substantially over time as a result of numerous factors including, but not limited to, additional development activity, production history, and economic assumptions relating to commodity prices, production costs, severance and other taxes, capital expenditures and remediation costs. The subjective judgments and variances in data for various fields make these estimates less precise than other estimates included in the financial statement disclosures. See Note 16 to the consolidated financial statements included in Item 8 of this Report on Form 8-K for more information on the Company's estimated proved reserves.

Successful Efforts Accounting for Gas and Oil Operations

The Company follows the successful efforts method of accounting for gas- and oil-property acquisitions, exploration, development and production activities. Under this method, the acquisition costs of proved and unproved properties, successful exploratory wells and development wells are capitalized. Other exploration costs, including geological and geophysical costs, the delay rental and administrative costs associated with unproved property and unsuccessful exploratory well costs are expensed. Costs to operate and maintain wells and field equipment are expensed as incurred.

The capitalized costs of unproved properties are generally combined and amortized over the expected holding period for such properties. Individually significant unproved properties are periodically reviewed for impairment. Capitalized costs of unproved properties are reclassified as proved property when related proved reserves are determined or charged against the impairment allowance when abandoned.

Capitalized proved-property-acquisition costs are amortized by field using the unit-of-production method based on proved reserves. Capitalized exploratory-well and development costs are amortized similarly by field based on proved developed reserves. The calculation takes into consideration estimated future equipment dismantlement, surface restoration and property-abandonment costs, net of estimated equipment-salvage values. Other property and equipment are generally depreciated using the straight-line method over estimated useful lives or the unit-of-production method for certain processing plants. A gain or loss is generally recognized only when an entire field is sold or abandoned, or if the unit-of-production amortization rate would be significantly affected.

QEP Energy engages an independent reservoir-engineering consultant to prepare estimates of the proved gas and oil reserves. Reserve estimates are based on a complex and highly interpretive process that is subject to continuous revision as additional production and development-drilling information becomes available.

Long-lived assets are assessed for impairment whenever changes in facts and circumstances indicate a possible significant deterioration in the future cash flows expected to be generated on a field-by-field basis. Impairment is indicated when a triggering event occurs and the sum of estimated undiscounted future net cash flows of the evaluated asset is less than the asset's carrying value. The asset value is written down to estimated fair value, which is determined using discounted future net cash flows.

Accounting for Derivative Contracts

The Company uses derivative contracts, typically fixed-price swaps and costless collars, to hedge against a decline in the realized prices of its gas and oil production. Accounting rules for derivatives require marking these instruments to fair value at the balance-sheet reporting date. The change in fair value is reported either in net income or Accumulated Other Comprehensive Income (AOCI) depending on the structure of the derivative. The Company has historically structured substantially all energy-derivative instruments as cash flow hedges as defined in ASC 815 "Derivatives and Hedging." Changes in the fair value of cash flow hedges are recorded on the balance sheet and in AOCI until the underlying gas or oil is produced. When a derivative is terminated before its contract expires, the associated gain or loss is recognized in income over the life of the previously hedged production.

Revenue Recognition

Revenues are recognized in the period that services are provided or products are delivered. QEP Energy uses the sales method of accounting whereby revenue is recognized for all gas, oil and NGL sold to purchasers. Revenues include estimates for the two most recent months using published commodity-price indexes and volumes supplied by field operators. A liability is recorded to the extent that QEP Energy has an imbalance in excess of its share of remaining reserves in an underlying property. QEP Marketing presents revenues on a gross-revenue basis. QEP Marketing does not engage in speculative hedging transactions, nor does it buy and sell energy contracts with the objective of generating profits on short-term differences in prices.

Recent Accounting Developments

Refer to Note 1 to the consolidated financial statements included in Item 8 of Part II of its Annual Report for a discussion of the SEC's "Modernization of Oil and Gas Reporting," which amends the disclosures for oil and gas producers.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK.

QEP's primary market-risk exposure arises from changes in the market price for natural gas, oil and NGL, and volatility in interest rates. QEP Marketing has long-term contracts for pipeline capacity and is obligated to pay for transportation services with no guarantee that it will be able to fully utilize the contractual capacity of these transportation commitments.

Commodity-Price Risk Management

QEP's subsidiaries use commodity-price derivative instruments in the normal course of business to reduce the risk of adverse commodity-price movements. However, these same arrangements typically limit future gains from favorable price movements. Derivative contracts are currently in place for a significant share of QEP Energy-owned gas and oil production and a portion of QEP Marketing gas-marketing transactions.

As of December 31, 2009, QEP held commodity-price derivative contracts for 409.6 million MMBtu of natural gas and 2.7 million barrels of oil. A year earlier QEP held derivative contracts for 234.4 million MMBtu of natural gas, 0.7 million barrels of oil and natural gas basis-only swaps on an additional 204.9 Bcf. A table of the QEP derivative positions for equity production as of December 31, 2009, is shown below:

	Cash flow Hedges	Basis-only Swaps	Total
		(in millions)	
Net fair value of gas-and oil-derivative contracts outstanding at Dec. 31, 2008	$ 543.6	$ (75.5)	$ 468.1
Contracts realized or otherwise settled	(431.2)	14.7	(416.5)
Change in gas and oil prices on futures markets	(300.7)	60.8	(239.9)
Contracts added	87.4		87.4
Contracts re-designated as fixed-price swaps	239.4	(239.4)	
Net Fair Value Of Gas- and Oil-Derivative Contracts Outstanding at Dec. 31, 2009	**$ 138.5**	**$ (239.4)**	**($ 100.9)**

A table of the net fair value of gas- and oil-derivative contracts as of December 31, 2009, is shown below. Cash flow hedges representing 72% of the net fair value will settle in the next 12 months and will be reclassified from AOCI:

	Cash flow Hedges	Basis-only Swaps	Total
		(in millions)	
Contracts maturing by Dec. 31, 2010	$ 100.2	$(121.7)	$ (21.5)
Contracts maturing between Jan. 1, 2011 and Dec. 31, 2011	21.6	(117.7)	(96.1)
Contracts maturing between Jan. 1, 2012 and Dec. 31, 2012	9.3		9.3
Contracts maturing between Jan. 1, 2013 and Dec. 31, 2013	7.4		7.4
Net Fair Value Of Gas- and Oil-Derivative Contracts Outstanding at Dec. 31, 2009	**$ 138.5**	**$(239.4)**	**$(100.9)**

The following table shows the sensitivity of fair value of gas- and oil-derivative contracts and basis-only swaps to changes in the market price of gas and oil and basis differentials:

	At December 31, 2009	2008
	(in millions)	
Net fair value-asset (liability)	**$(100.9)**	$468.1
Value if market prices of gas and oil and basis differentials decline by 10%	**174.2**	590.4
Value if market prices of gas and oil and basis differentials increase by 10%	**(375.8)**	345.9

Credit Risk

QEP requests credit support and, in some cases, prepayment from companies that pose unfavorable credit risks. The Company's five largest customers are Sempra Energy Trading Corp., Chevron USA Inc., Enterprise Products Operating, Texan Energy Management Inc. and BP Energy Company. Sales to these companies accounted for 23% of QEP revenues before elimination of intercompany transactions in 2009, and their accounts were current at December 31, 2009.

Interest-Rate Risk

The fair value of fixed-rate debt is subject to change as interest rates fluctuate. The Company's ability to borrow and the rates quoted by lenders can be adversely affected by the illiquid credit markets as described in Item 1A. Risk Factors of Part I of its Annual Report on Form 10-K. The Company had $1,148.7 million of fixed-rate long-term debt with a fair value of $1,194.1 million at December 31, 2009. A year earlier the Company had $849.1 million of fixed-rate long-term debt with a fair value of $730.9 million. If interest rates had declined 10%, fair value would increase to $1,236.0 million in 2009 and $767.8 million in 2008. The fair value calculations do not represent the cost to retire the debt securities.

Climate-Change Risk

Federal and state courts and administrative agencies are considering the scope and scale of climate-change regulation under various laws pertaining to the environment, energy use and development, and greenhouse gas emissions. QEP's ability to access and develop new natural gas reserves may be restricted by climate-change regulation. There are bills pending in Congress that would regulate greenhouse gas emissions through a cap-and-trade system under which emitters would be required to buy allowances for offsets of emissions of greenhouse gases. The EPA has adopted final regulations for the measurement and reporting of greenhouse gases emitted from certain large facilities (25,000 tons/year of CO_2 equivalent) beginning with operations in 2010. The first report is to be filed with the EPA by March 31, 2011. In addition, several of the states in which QEP operates are considering various greenhouse gas registration and reduction programs. Carbon dioxide regulation could increase the price of natural gas, restrict access to or the use of natural gas, and/or reduce natural gas demand. Federal, state and local governments may also pass laws mandating the use of alternative energy sources, such as wind power and solar energy, which may reduce demand for natural gas. While future climate-change regulation is likely, it is too early to predict how this regulation will affect QEP's business, operations or financial results. It is uncertain whether QEP's operations and properties, located in the Rocky Mountain and Midcontinent regions of the United States, are exposed to possible physical risks, such as severe weather patterns, due to climate change as a result of man-made greenhouse gases. However, management does not believe that such physical risks are reasonably likely to have a material effect on the Company's financial condition or results of operations.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA.

Financial Statements:

All other schedules are omitted because they are not applicable or the required information is shown in the consolidated financial statements or Notes thereto.

Report of Independent Registered Public Accounting Firm

The Board of Directors and Shareholders of
QEP Resources, Inc.

We have audited the accompanying consolidated balance sheets of QEP Resources, Inc. (formerly Questar Market Resources) as of December 31, 2009 and 2008, and the related consolidated statements of income, shareholders' equity, and cash flows for each of the three years in the period ended December 31, 2009. Our audits also included the financial statement schedule listed in the Index at Item 8. These financial statements and schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and schedule based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. We were not engaged to perform an audit of the Company's internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of QEP Resources, Inc. as of December 31, 2009 and 2008, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2009, in conformity with U.S. generally accepted accounting principles. Also, in our opinion, the related financial statement schedule, when considered in relation to the basic financial statements taken as a whole, presents fairly in all material respects the information set forth therein.

As discussed in Note 1 to the consolidated financial statements, during 2009, the Company adopted a new accounting standard relating to the presentation of noncontrolling interests in consolidated subsidiaries and the Company adopted new oil and gas reserve estimation and disclosure requirements.

Ernst & Young LLP

Salt Lake City, Utah
July 30, 2010

QEP RESOURCES, INC.

CONSOLIDATED STATEMENTS OF INCOME

	Year Ended December 31, 2009 (recast)	2008 (recast)	2007 (recast)
	(in millions)		
REVENUES			
Natural gas sales	**$1,103.9**	$1,147.7	$ 786.9
Oil and NGL sales	**158.5**	237.5	164.2
Gathering, processing and other	**268.3**	297.0	208.9
Marketing sales	**441.8**	636.6	528.1
Total Revenues	**1,972.5**	2,318.8	1,688.1
OPERATING EXPENSES			
Marketing purchases	**427.8**	604.6	496.5
Lease operating expenses	**126.7**	124.0	86.8
Gathering, processing and other	**75.0**	96.2	84.6
General and administrative	**91.7**	78.1	76.8
Production and property taxes	**62.9**	106.9	61.6
Depreciation, depletion and amortization	**559.1**	361.5	263.9
Exploration	**25.0**	29.3	22.0
Abandonment and impairment	**20.3**	45.4	11.2
Total Operating Expenses	**1,388.5**	1,446.0	1,103.4
Net gain (loss) from asset sales	**1.5**	60.4	(0.6)
OPERATING INCOME	**585.5**	933.2	584.1
Interest and other income	**4.5**	10.2	7.8
Income from unconsolidated affiliates	**2.7**	1.7	8.9
Unrealized and realized gain (loss) on basis-only swaps	**(189.6)**	(79.2)	5.7
Interest expense	**(70.1)**	(61.7)	(33.6)
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAXES	**333.0**	804.2	572.9
Income taxes	**(117.6)**	(283.6)	(211.3)
INCOME FROM CONTINUING OPERATIONS	**215.4**	520.6	361.6
Discontinued operations, net of income tax	**80.7**	73.9	59.2
NET INCOME	**296.1**	594.5	420.8
Net income attributable to noncontrolling interest	**(2.6)**	(9.0)	
NET INCOME ATTRIBUTABLE TO QEP	**$ 293.5**	$ 585.5	$ 420.8
Earnings Per Common Share Attributable To QEP			
Basic from continuing operations	**$ 1.23**	$ 2.96	$ 2.11
Basic from discontinued operations	**0.46**	0.43	0.34
Basic total	**$ 1.69**	$ 3.39	$ 2.45
Diluted from continuing operations	**$ 1.21**	$ 2.90	$ 2.05
Diluted from discontinued operations	**0.46**	0.42	0.34
Diluted total	**$ 1.67**	$ 3.32	$ 2.39
Weighted-average common shares outstanding			
Used in basic calculation	**174.1**	172.8	172.0
Used in diluted calculation	**176.3**	176.1	175.9

See notes accompanying the consolidated financial statements

QEP RESOURCES, INC.

CONSOLIDATED BALANCE SHEETS

	December 31, 2009 (recast)	December 31, 2008 (recast)
	(in millions)	
ASSETS		
Current Assets		
Cash and cash equivalents	**$ 19.3**	$ 25.1
Notes receivable from Questar	**52.9**	40.7
Federal income taxes receivable		10.7
Accounts receivable, net	**219.8**	262.4
Fair value of derivative contracts	**128.2**	431.3
Inventories, at lower of average cost or market		
Gas and oil storage	**17.5**	23.6
Materials and supplies	**74.3**	81.9
Prepaid expenses and other	**29.2**	26.0
Deferred income taxes – current	**21.2**	
Current assets of discontinued operations	**42.8**	51.0
Total Current Assets	**605.2**	952.7
Property, Plant and Equipment – successful efforts method of accounting for gas and oil properties		
Proved properties	**5,721.5**	4,948.2
Unproved properties, not being depleted	**389.6**	193.2
Midstream field services	**1,037.5**	976.6
Marketing and other	**42.4**	41.3
Total Property, Plant and Equipment	**7,191.0**	6,159.3
Less accumulated depreciation, depletion and amortization		
Exploration and production	**1,890.9**	1,421.8
Midstream field services	**198.7**	159.3
Marketing and other	**10.1**	8.4
Total Accumulated Depreciation, Depletion and Amortization	**2,099.7**	1,589.5
Net property, plant and equipment of discontinued operations	**593.9**	536.6
Net Property, Plant and Equipment	**5,685.2**	5,106.4
Long-term note receivable from Questar		50.0
Investment in unconsolidated affiliates	**43.9**	40.8
Other Assets		
Goodwill	**60.1**	60.2
Fair value of derivative contracts	**61.2**	106.3
Other noncurrent assets	**10.0**	12.2
Noncurrent assets of discontinued operations	**15.8**	14.1
Total Other Assets	**147.1**	192.8
TOTAL ASSETS	**$6,481.4**	$6,342.7

LIABILITIES AND EQUITY

	December 31, 2009 (recast)	December 31, 2008 (recast)
	(in millions)	
Current Liabilities		
Notes payable to Questar	**$ 39.3**	$ 89.4
Accounts payable and accrued expenses	**321.2**	411.2
Federal income taxes payable	**13.5**	
Production and property taxes	**34.2**	31.6
Interest payable	**26.3**	19.5
Fair value of derivative contracts	**149.7**	0.5
Deferred income taxes – current		143.0
Current liabilities of discontinued operations	**91.4**	82.6
Total Current Liabilities	**675.6**	777.8
Long-term debt	**1,348.7**	1,299.1
Deferred income taxes	**1,175.8**	1,058.7
Asset retirement obligations	**124.7**	116.7
Fair value of derivative contracts	**140.6**	69.0
Other long-term liabilities	**34.4**	47.3
Noncurrent liabilities of discontinued operations	**172.9**	194.7
Commitments and contingencies – Note 11		
EQUITY		
Common stock – par value $0.01 per share; 500.0 million shares authorized; 174.6 million and 173.6 million shares issued and Outstanding at December 31, 2009 and 2008, respectively.	**1.7**	1.7
Additional paid-in capital	**126.8**	144.5
Retained earnings	**2,538.2**	2,262.1
Accumulated other comprehensive income	**87.1**	341.6
Total Common Shareholders' Equity	**2,753.8**	2,749.9
Noncontrolling interest	**54.9**	29.5
Total Equity	**2,808.7**	2,779.4
TOTAL LIABILITIES AND EQUITY	**$6,481.4**	$6,342.7

See notes accompanying the consolidated financial statements

QEP RESOURCES, INC.

CONSOLIDATED STATEMENTS OF EQUITY

	Common Stock (recast)	Additional Paid-in Capital (recast)	Retained Earnings	Accum. Other Comprehensive Income (Loss)	Non-controlling Interest	Comprehensive Income (Loss)
			(in millions)			
Balances at January 1, 2007	$ 1.7	$ 124.6	$1,290.4	$ 128.1		
2007 net income			420.8			$ 420.8
Dividends paid			(17.3)			
Share-based compensation		8.9				
Other comprehensive income						
Change in unrealized fair value of derivatives				(156.1)		(156.1)
Income taxes				59.0		59.0
Total comprehensive income						$ 323.7
Balances at December 31, 2007	1.7	133.5	1,693.9	31.0		
2008 net income			585.5		$ 9.0	$ 594.5
Dividends paid			(17.3)			
Share-based compensation		11.0				
Consolidation of noncontrolling interest					29.8	
Distribution to noncontrolling interest					(9.3)	
Other comprehensive income						
Change in unrealized fair value of derivatives				494.0		494.0
Income taxes				(183.4)		(183.4)
Total comprehensive income						$ 905.1
Balances at December 31, 2008	**1.7**	**144.5**	**2,262.1**	**341.6**	**29.5**	
2009 net income			**293.5**		**2.6**	**$ 296.1**
Dividends paid			**(17.4)**			
Share-based compensation		**13.9**				
Noncontrolling interest equity adjustment		**(28.5)**			**28.5**	
Tax on equity adjustment		**(3.1)**				
Distribution to noncontrolling interest					**(5.7)**	
Other comprehensive income						
Change in unrealized fair value of derivatives				**(405.1)**		**(405.1)**
Income taxes				**150.6**		**150.6**
Total comprehensive income						**$ 41.6**
Balances at December 31, 2009	**$ 1.7**	**$ 126.8**	**$2,538.2**	**$ 87.1**	**$ 54.9**	

See notes accompanying the consolidated financial statements

QEP RESOURCES, INC.

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2009 (recast)	**2008 (recast)**	**2007 (recast)**
		(in millions)	
OPERATING ACTIVITIES			
Net income	**$ 296.1**	$ 594.5	$ 420.8
Discontinued operations, net of income tax	**(80.7)**	(73.9)	(59.2)
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion and amortization	**560.3**	362.5	264.4
Deferred income taxes	**103.3**	319.8	175.1
Abandonment and impairment	**20.3**	45.4	11.2
Share-based compensation	**13.4**	10.5	8.6
Dry exploratory well expense	**4.7**	9.7	12.3
Net (gain) loss from asset sales	**(1.5)**	(60.4)	0.6
(Income) from unconsolidated affiliates	**(2.7)**	(1.7)	(8.9)
Distributions from unconsolidated affiliates	**1.1**	0.5	10.4
Unrealized (gain) loss on basis-only swaps	**164.0**	79.2	(5.7)
Other operating	**0.1**	1.0	(1.0)
Changes in operating assets and liabilities			
Accounts receivable	**42.7**	(16.4)	(9.9)
Inventories	**13.7**	(52.5)	7.1
Prepaid expenses	**(3.2)**	(9.4)	4.6
Accounts payable and accrued expenses	**9.3**	13.8	(28.6)
Federal income taxes	**21.3**	(7.6)	(1.4)
Other	**(12.8)**	9.7	6.6
Net Cash Provided By Operations From Continuing Operations	**1,149.4**	1,224.7	807.0
INVESTING ACTIVITIES			
Property, plant and equipment including dry exploratory well expense	**(1,196.9)**	(2,115.2)	(824.1)
Other investments	**(1.5)**	(21.5)	(14.8)
Total capital expenditures	**(1,198.4)**	(2,136.7)	(838.9)
Proceeds from disposition of assets	**14.2**	103.2	4.4
Change in note receivable from Questar	**(12.2)**	62.5	(33.4)
Change in long-term note receivable from Questar	**50.0**	(50.0)	
Net Cash Used In Investing Activities From Continuing Operations	**(1,146.4)**	(2,021.0)	(867.9)
FINANCING ACTIVITIES			
Change in notes payable to Questar	**(50.1)**	31.8	(55.9)
Long-term debt issued, net of issuance costs	**422.0**	1,395.2	100.0
Long-term debt repaid	**(375.0)**	(600.0)	
Distribution to noncontrolling interest	**(5.7)**	(9.3)	
Other		1.0	
Net Cash Provided By (Used In) Financing Activities From Continuing Operations	**(8.8)**	818.7	44.1
CASH (USED IN) PROVIDED BY CONTINUING OPERATIONS	**(5.8)**	22.4	(16.8)
Cash provided by operations from discontinued operations	**174.4**	129.4	88.5
Cash used in investing activities from discontinued operations	**(116.2)**	(143.6)	(104.8)
Cash provided by financing activities from discontinued operations	**(55.2)**	12.1	14.9
Effect of change in cash and cash equivalents of discontinued operations	**(3.0)**	2.1	1.4
Change in cash and cash equivalents	**(5.8)**	22.4	(16.8)
Beginning cash and cash equivalents	**25.1**	2.7	19.5
Ending cash and cash equivalents	**$ 19.3**	$ 25.1	$ 2.7
Supplemental Disclosure of Cash Paid (Received) During the Year for:			
Interest	**$ 62.2**	$ 55.3	$ 32.6
Income taxes	**(10.0)**	(21.9)	40.9

See notes accompanying the consolidated financial statements

Note 1 – Summary of Significant Accounting Policies

Nature of Business

QEP Resources, Inc (QEP or the Company) is a leading independent natural gas and oil exploration and production company, which also gathers, compresses, treats, and processes natural gas. The Company has three lines of business – gas and oil exploration and production, midstream field services, and energy marketing – which are conducted through its three principal subsidiaries:

- QEP Energy Company, (QEP Energy) acquires, explores for, develops and produces natural gas, oil, and NGL;
- QEP Field Services Company (QEP Field Services) provides midstream field services including natural gas-gathering and processing, compressing and treating services for affiliates and third parties; and
- QEP Marketing Company (QEP Marketing) markets equity and third-party gas and oil, provides risk-management services, and owns and operates an underground gas-storage reservoir.

Operations are focused in the Rocky Mountain and Midcontinent regions of the United States. Headquarters are in Denver, Colorado. Shares of QEP common stock trade on the New York Stock Exchange (NYSE:QEP).

Accounting Standards References

In July 2009, the Financial Accounting Standards Board (FASB) completed a revision of non-governmental U.S. generally accepted accounting principles (GAAP) into a single authoritative source and issued a codification of accounting rules and references. Authoritative standards included in the codification are designated by their Accounting Standards Codification (ASC) topical reference, and revised standards are designated as Accounting Standards Updates (ASU), with a year and assigned sequence number. The codification effort, while not creating or changing accounting rules, changed how users would cite accounting regulations. Citations in financial statements must identify the sections within the new codification. The codification is effective for interim and annual periods ending after September 15, 2009. The Company is complying with the new codification standards.

Principles of Consolidation

The consolidated financial statements contain the accounts of QEP and its majority-owned or controlled subsidiaries. The consolidated financial statements were prepared in accordance GAAP and with the instructions for annual reports on Form 10-K and Regulations S-X and S-K. Rendezvous Gas Services, an affiliate, was consolidated beginning in 2008 as a result of a step acquisition caused by disproportionate ownership. QEP Field Services's ownership interest increased from 50% to 78%. All significant intercompany accounts and transactions have been eliminated in consolidation.

On January 1, 2009, QEP adopted “Noncontrolling Interests in Consolidated Financial Statements” (ASC 810-10-65-1) for the accounting, reporting and disclosure of noncontrolling interests. The new guidance requires that noncontrolling interest, previously known as minority interest, be clearly identified, labeled, and presented in the consolidated financial statements separate from the parent's equity; the amount of consolidated net income attributable to the parent and to the noncontrolling interest be clearly identified and presented in the consolidated income statement; changes in a parent's ownership interest while the parent retains its controlling financial interest in its subsidiary be accounted for consistently; and any retained noncontrolling equity investment in a former subsidiary be initially measured at fair value. The new provisions are applied prospectively from the date of adoption, except for the presentation and disclosure requirements, which are applied retrospectively for all periods presented.

Effective May 18, 2010, Questar Market Resources, Inc. (Market Resources) a wholly-owned subsidiary of Questar, merged with and into its newly-formed, wholly-owned subsidiary, QEP, a Delaware corporation in order to reincorporate in the State of Delaware (Reincorporation Merger). The Reincorporation Merger was effected pursuant to an Agreement and Plan of Merger entered into between Market Resources and QEP. The Reincorporation Merger was approved by the boards of directors of Market Resources and QEP and submitted to a vote of, and approved by, Questar, as sole shareholder of Market Resources, and by Market Resources, as sole shareholder of QEP on May 18, 2010.

On June 30, 2010, Questar distributed all of the shares of QEP common stock held by Questar to Questar shareholders in a tax-free, pro rata dividend. Each Questar shareholder received one share of QEP common stock for each one share of Questar common stock held at the close business on the record date (including fractional shares). In connection therewith, QEP distributed Wexpro, a wholly-owned subsidiary of QEP, to Questar. In addition, Questar contributed $250.0 million of equity to QEP prior to the Spinoff.

The financial information presented in this Current Report on Form 8-K recasts QEP's financial results as an independent company separate from Questar and reflects Wexpro Company (Wexpro) financial condition and operating results as discontinued operations for all periods presented. A summary of discontinued operations can be found in Note 3.

SEC's Modernization of Oil and Gas Reporting Requirements

In December 2008, the SEC issued Release No. 33-8995, "Modernization of Oil and Gas Reporting," which amends the oil and gas disclosures for oil and gas producers contained in Regulations S-K and S-X. The goal of Release No. 33-8995 is to provide investors with a more meaningful and comprehensive understanding of oil and gas reserves. The most significant amendments affecting the Company include the following: (i) economic producibility of reserves and discounted cash flows are to be based on the arithmetic average of the price on the first day of each month within the 12-month period prior to the end of the reporting period, unless contractual arrangements designate the price to be used; and (ii) reserves may be estimated and categorized through the use of reliable technologies. Release No. 33-8995 is effective for financial statements for fiscal years ending on or after December 31, 2009.

Investment in Unconsolidated Affiliates

QEP uses the equity method to account for investment in unconsolidated affiliates where it does not have control, but has significant influence. Generally, the investment in unconsolidated affiliates on the Company's consolidated balance sheets equals the Company's proportionate share of equity reported by the unconsolidated affiliates. Investment is assessed for possible impairment when events indicate that the fair value of the investment may be below the Company's carrying value. When such a condition is deemed to be other than temporary, the carrying value of the investment is written down to its fair value, and the amount of the write-down is included in the determination of net income.

The principal unconsolidated affiliates and QEP's ownership percentage as of December 31, 2009, were Uintah Basin Field Services, LLC, (38%) and Three Rivers Gathering, LLC, (50%), both limited liability companies engaged in gathering and compressing natural gas.

Use of Estimates

The preparation of consolidated financial statements and notes in conformity with GAAP requires that management formulate estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses and the disclosure of contingent assets and liabilities. The Company also incorporates estimates of proved developed and proved gas and oil reserves in the calculation of depreciation, depletion and amortization rates of its gas and oil properties. Changes in estimated quantities of its reserves could impact the Company's reported financial results as well as disclosures regarding the quantities and value of proved gas and oil reserves. Actual results could differ from these estimates.

Revenue Recognition

QEP subsidiaries recognize revenues in the period that services are provided or products are delivered. Revenues reflect the impact of price-hedging instruments. Revenues associated with the production of gas and oil are accounted for using the sales method, whereby revenue is recognized as gas and oil is sold to purchasers. A liability is recorded to the extent that the Company has sold volumes in excess of its share of remaining gas and oil reserves in an underlying property. QEP imbalance obligations at December 31, was $4.2 million in 2009 and $3.1 million in 2008.

QEP Marketing reports revenues on a gross basis because, in the judgment of management, the nature and circumstances of its marketing transactions are consistent with guidance for gross revenue reporting. QEP is primarily engaged in gas and oil exploration and production and midstream field services. QEP Marketing markets equity and third-party natural gas, oil and NGL volumes. QEP Marketing uses derivatives to secure a known price for a specific volume over a specific time period. QEP Marketing does not engage in speculative hedging transactions, nor does it buy and sell energy contracts with the objective of generating profits on short-term differences in price. QEP Marketing has not engaged in buy/sell arrangements, as described in ASC 845-10-25-4 "Accounting for Purchases and Sales of Inventory with the Same Counterparty."

Regulation of Underground Storage

QEP through Clear Creek Storage Company, LLC, operates a gas-storage facility under the jurisdiction of the Federal Energy Regulatory Commission (FERC). The FERC establishes rates for the storage of natural gas. The FERC also regulates, among other things, the extension and enlargement or abandonment of jurisdictional natural gas facilities. Regulation is intended to permit the recovery, through rates, of the cost of service, including a return on investment.

Cash and Cash Equivalents

Cash equivalents consist principally of repurchase agreements with maturities of three months or less. In almost all cases, the repurchase agreements are highly liquid investments in overnight securities made through commercial-bank accounts that result in available funds the next business day.

Notes Receivable from or Payable to Questar Corporation

Prior to the Spinoff, Questar Corporation (Questar) centrally managed cash. Notes receivable from or payable to Questar represent interest bearing demand notes for cash loaned to or borrowed from Questar until needed in operations. Amounts loaned to Questar earn an interest rate that is identical to the interest rate paid by the Company for borrowings from Questar.

Property, Plant and Equipment

Property, plant and equipment balances are stated at historical cost. Maintenance and repair costs are expensed as incurred with the exception of compressor maintenance costs, which are capitalized and depreciated based on hours of usage in accordance with ASC 360-10-25-5.

Gas and oil properties

QEP Energy uses the successful efforts method to account for gas and oil properties. The costs of acquiring leaseholds, drilling development wells, drilling successful exploratory wells, purchasing related support equipment and facilities are capitalized. Geological and geophysical studies and other exploratory activities are expensed as incurred. Costs of production and general-corporate activities are expensed in the period incurred. A gain or loss is generally recognized only when an entire field is sold or abandoned, or if the unit-of-production depreciation, depletion and amortization rate would be significantly affected.

Capitalized costs of unproved properties are generally combined and amortized over the expected holding period for such properties. Capitalized costs of unproved properties are reclassified as proved property when related proved reserves are determined or charged against the impairment allowance when abandoned.

Capitalized exploratory well costs

The Company capitalizes exploratory-well costs until it determines whether an exploratory well is commercial or noncommercial. If the Company deems the well commercial, capitalized costs are depreciated on a field basis using the unit-of-production method and the estimated proved developed gas and oil reserves. If the Company concludes that the well is noncommercial, well costs are immediately charged to exploration expense. Exploratory-well costs capitalized for a period greater than one year since the completion of drilling are expensed unless the Company remains engaged in substantial activities to assess whether the well is commercial.

Depreciation, depletion and amortization

Capitalized proved leasehold costs are depleted on a field-by-field basis using the unit-of-production method and the estimated proved gas and oil reserves. Oil and NGL volumes are converted to natural gas equivalents using the ratio of one barrel of crude oil, condensate or NGL to 6,000 cubic feet of natural gas. Capitalized costs of exploratory wells that have found proved gas and oil reserves and capitalized development costs are depreciated using the unit-of-production method based on estimated proved developed reserves on a field basis. The Company capitalizes an estimate of the fair value of future abandonment costs. Future abandonment costs, less estimated future salvage values, are depreciated over the life of the related asset using a unit-of-production method. The volume-weighted average depreciation, depletion and amortization rates of the Company’s capitalized costs: per Mcfe were $2.71 in 2009, $1.93 in 2008 and $1.74 in 2007.

Depreciation, depletion and amortization for the remaining Company properties is based upon rates that will systematically charge the costs of assets against income over the estimated useful lives of those assets using either a straight-line or unit-of-production method. Investment in gas-gathering and processing fixed assets is charged to expense using either the straight-line or unit-of-production method depending upon the facility.

Impairment of Long-Lived Assets

Proved gas and oil properties are evaluated on a field-by-field basis for potential impairment. Other properties are evaluated on a specific-asset basis or in groups of similar assets, as applicable. Impairment is indicated when a triggering event occurs and the sum of the estimated undiscounted future net cash flows of an evaluated asset is less than the asset’s carrying value. Triggering events could include, but are not limited to, an impairment of gas and oil reserves caused by mechanical problems, faster-than-expected decline of reserves, lease-ownership issues, other-than-temporary decline in gas and oil prices and changes in the utilization of pipeline assets. If impairment is indicated, fair value is calculated using a discounted-cash flow approach. Cash flow estimates require forecasts and assumptions for many years into the future for a variety of factors, including commodity prices and operating costs.

The Company also performs periodic assessments of individually significant unproved gas and oil properties for impairment and recognizes a loss at the time of impairment. In determining whether a significant unproved property is impaired the Company considers numerous factors including, but not limited to, current exploration plans, favorable or unfavorable exploration activity on adjacent leaseholds, in-house geologists’ evaluations of the lease, and the remaining lease term.

Goodwill and Other Intangible Assets

Goodwill represents the excess of the amount paid over the fair value of net assets acquired in a business combination and is not subject to amortization. Goodwill and indefinite lived intangible assets are tested for impairment at a minimum of once a year or when a triggering event occurs. If a triggering event occurs, the undiscounted net cash flows of the intangible asset or entity to which the goodwill relates are evaluated. Impairment is indicated if undiscounted cash flows are less than the carrying value of the assets. The amount of the impairment is measured using a discounted-cash flow model considering future revenues, operating costs, a risk-adjusted discount rate and other factors.

Capitalized Interest

The Company capitalizes interest costs when applicable. Interest expense was reduced by $4.9 million in 2008.

Derivative Instruments

In November 2008, the Company adopted the updated disclosure provisions of ASC 815 “Derivatives and Hedging” and modified the disclosures accordingly. The Company may elect to designate a derivative instrument as a hedge of exposure to changes in fair value or cash flows. If the hedged exposure is a fair-value exposure, the gain or loss on the derivative instrument is recognized in earnings in the period of the change together with the offsetting gain or loss from the change in fair value of the hedged item. If the hedged exposure is a cash flow exposure, the effective portion of the gain or loss on the derivative instrument is reported initially as a component of AOCI and subsequently reclassified into earnings when the forecasted transaction affects earnings. Any amount excluded from the assessment of hedge effectiveness, as well as the ineffective portion of the gain or loss, is reported in the current period income statement. A derivative instrument qualifies as a cash flow hedge if all of the following tests are met:

- The item to be hedged exposes the Company to price risk.
- The derivative reduces the risk exposure and is designated as a hedge at the time the Company enters into the contract.
- At the inception of the hedge and throughout the hedge period, there is a high correlation between changes in the market value of the derivative instrument and the fair value of the underlying hedged item.

When the designated item associated with a derivative instrument matures, is sold, extinguished or terminated, derivative gains or losses are included in income in the same period that the underlying production or other contractual commitment is delivered. When a derivative instrument is associated with an anticipated transaction that is no longer probable, the gain or loss on the derivative is reclassified from other comprehensive income and recognized currently in the results of operations. When a derivative is terminated before its contract expires, the associated gain or loss is recognized in income over the life of the previously hedged production.

Physical Contracts

Physical-hedge contracts have a nominal quantity and a fixed price. Contracts representing both purchases and sales settle monthly based on quantities valued at a fixed price. Purchase contracts fix the purchase price paid and are recorded as cost of sales in the month the contracts are settled. Sales contracts fix the sales price received and are recorded as revenues in the month they are settled. Due to the nature of the physical market, there is a one-month delay for the cash settlement. QEP accrues for the settlement of contracts in the current month’s revenues and cost of sales.

Financial Contracts

Financial contracts are contracts that are net settled in cash without delivery of product. Financial contracts also have a nominal quantity and exchange an index price for a fixed price, and are net settled with the brokers as the price bulletins become available. Financial contracts are recorded in revenues or cost of sales in the month of settlement.

Basis-Only Swaps

Basis-only swaps are used to manage the risk of widening basis differentials. These contracts are marked to market monthly with any change in the valuation recognized in the determination of income.

Credit Risk

The Rocky Mountain and Midcontinent regions constitute the Company’s primary market areas. Exposure to credit risk may be affected by the concentration of customers in these regions due to changes in economic or other conditions. Customers include individuals and numerous commercial and industrial enterprises that may react differently to changing conditions. Management believes that its credit-review procedures, loss reserves, customer deposits and collection procedures have adequately provided for usual and customary credit-related losses. Commodity-based hedging arrangements also expose the Company to credit risk. The Company monitors the creditworthiness of its counterparties, which generally are major financial institutions and energy companies. Loss reserves are periodically reviewed for adequacy and may be established on a specific case basis. QEP requests credit support and, in some cases, fungible collateral from companies with unacceptable credit risks. The Company has master-netting agreements with some counterparties that allow the offsetting of receivables and payables in a default situation.

Bad debt expense associated with accounts receivable for the year ended December 31, amounted to $0.4 million in 2009 and 2008 and $0.1 million in 2007. The allowance for bad-debt expenses was $3.0 million at December 31, 2009, and $2.7 million at December 31, 2008.

Income Taxes

Prior to the Spinoff, Questar and its subsidiaries filed consolidated federal income tax returns. QEP accounts for income tax expense on a separate-return basis and records tax benefits as they are generated. Deferred income taxes are provided for the temporary differences arising between the book and tax-carrying amounts of assets and liabilities. These differences create taxable or tax-deductible amounts for future periods. The Company records interest earned on income tax refunds in interest and other income and records penalties and interest charged on tax deficiencies in interest expense.

ASC 740 “Income Taxes” specifies the accounting for uncertainty in income taxes by prescribing a minimum recognition threshold for a tax position to be reflected in the financial statements. If recognized, the tax benefit is measured as the largest amount of tax benefit that is more-likely-than-not to be realized upon ultimate settlement. Management has considered the amounts and the probabilities of the outcomes that could be realized upon ultimate settlement and believes that it is more-likely-than-not that the Company’s recorded income tax benefits will be fully realized. There were no unrecognized tax benefits at the beginning or at the end of the twelve-month periods ended December 31, 2009, 2008 and 2007. Income tax returns for 2006 and subsequent years are subject to examination.

Earnings Per Share

Basic earnings per share (EPS) is computed by dividing net income attributable to QEP by the weighted-average number of common shares outstanding during the reporting period. Diluted EPS includes the potential increase in the number of outstanding shares that could result from the exercise of in-the-money stock options. During the first quarter of 2009, the Company adopted the updated provisions of ASC 260, “Earnings Per Share.” ASC 260 addresses whether instruments granted in share-based payment transactions are participating securities and therefore have a potential dilutive effect on EPS. The adoption was applied retrospectively and did not have a material effect on the Company’s EPS calculations. See Note 2 for further discussion on EPS.

Share-Based Compensation

Questar issued stock options and restricted shares to certain officers, employees and non-employee directors under its Long-Term Stock Incentive Plan (LTSIP), including certain officers and employees of QEP. Since January 1, 2006, the fair value of stock options is expensed during the vesting period. Questar uses the Black-Scholes-Merton mathematical model in estimating the fair value of stock options for accounting purposes. The granting of restricted shares results in recognition of compensation cost measured at the grant-date market price. Questar uses an accelerated method in recognizing share-based compensation costs with graded-vesting periods. See Note 12 for further discussion on share-based compensation.

Comprehensive Income

Comprehensive income is the sum of net income attributable to QEP as reported in the Consolidated Statements of Income and other comprehensive income (loss). As reported in the Consolidated Statements of Equity, other comprehensive income (loss) consists of changes in the market value of commodity-based derivative instruments. These transactions are not the culmination of the earnings process but result from periodically adjusting historical balances to fair value. Income or loss is realized when the physical gas, oil or NGL underlying the derivative instrument is sold.

Unrealized gain on derivatives is a component of AOCI on the Consolidated Balance Sheets. The following table sets forth the changes in unrealized gain on derivatives, net of income taxes, during 2009:

	Year Ended December 31, 2009 (in millions)
Balance at January 1,	**$ 341.6**
Realized or otherwise settled	**(271.0)**
Change due to commodity price changes	**(38.3)**
Net fair value of hedges added during the year	**54.8**
Balance at December 31,	**$ 87.1**

Business Segments

Line of business information is presented according to senior management's basis for evaluating performance considering differences in the nature of products, services and regulation. Certain intersegment sales include intercompany profit.

All dollar and share amounts in this Current Report on Form 8-K are in millions, except per-share information and where otherwise noted.

Note 2 – Earnings Per Share

The number of QEP common shares outstanding reflects the number of Questar common shares outstanding at the same date. Questar distributed all of the shares of common stock of QEP held by Questar to Questar shareholders in a tax-free, pro rata dividend. Each Questar shareholder received one share of QEP common stock for each one share of Questar common stock held, including fractional shares. Basic earnings per share (EPS) is computed by dividing net income attributable to QEP by the weighted-average number of common shares outstanding during the reporting period. Diluted EPS includes the potential increase in the number of outstanding shares that could result from the exercise of in-the-money stock options. A reconciliation of the components of basic and diluted shares used in the EPS calculation follows:

	Year Ended December 31,		
	2009	2008	2007
		(in millions)	
Weighted-average basic common shares outstanding	**174.1**	172.8	172.0
Potential number of shares issuable under the LTSIP	**2.2**	3.3	3.9
Average diluted common shares outstanding	**176.3**	176.1	175.9

Note 3 – Discontinued Operations

Wexpro's operating results are reflected in this Current Report on Form 8-K as discontinued operations and summarized below:

	Year Ended December 31,		
	2009	2008	2007
	(in millions, except per share amounts)		
Revenues	**$ 242.9**	$ 241.0	$ 177.3
Income before income taxes	**126.9**	115.2	89.2
Income taxes	**(46.2)**	(41.3)	(30.0)
Discontinued operations, net of income taxes	**$ 80.7**	$ 73.9	$ 59.2
Earnings Per Common Share Attributable To QEP			
Basic from discontinued operations	**$ 0.46**	$ 0.43	$ 0.34
Diluted from discontinued operations	**0.46**	0.42	0.34

Note 4 – Property, Plant and Equipment

In February 2008, QEP Energy acquired natural gas development properties in northwest Louisiana for an aggregate purchase price of $652.1 million effective January 1, 2008. The acquisition was accounted for as a purchase and, accordingly, the results of operations of the properties were included in net income from the closing date of the acquisition. Including deferred income taxes of $13.1 million, the purchase price allocated to proved properties was $570.9 million and to unproved properties was $81.2 million.

In conjunction with the acquisition of the Louisiana properties, the Company identified and subsequently sold certain outside-operated producing properties and leaseholds in the Gulf Coast region of south Texas. These properties contributed 2.8 Bcfe to QEP Energy net production in 2008. For income tax purposes, the Company structured a portion of the purchase of the Louisiana properties and the July 31, 2008, sale of the south Texas properties as a reverse like-kind exchange of property under Section 1031 of the Internal Revenue Code of 1986, as amended. The Company recognized a pre-tax gain on the sale of the Texas properties of approximately $61.2 million.

Abandonment and impairment expense decreased $24.3 million or 54% in 2009 compared to 2008 primarily due to the impairment of certain gas and oil assets in 2008.

QEP Field Services constructed a gathering pipeline for $203.5 million and contributed the asset to Rendezvous. As a result, QEP Field Services's ownership interest in Rendezvous increased from 50% to 78%. Common stock was reduced by $31.6 million and noncontrolling interest increased by $28.5 million. Rendezvous operates gas-gathering facilities for Pinedale Anticline and Jonah field producers for delivery to various interstate pipelines.

Note 5 – Asset Retirement Obligations

QEP records asset retirement obligations (ARO) when there are legal obligations associated with the retirement of tangible long-lived assets. The Company's ARO apply primarily to abandonment costs associated with gas and oil wells, production facilities and certain other properties. The fair value of retirement costs are estimated by Company personnel based on abandonment costs of similar properties available to field operations and depreciated over the life of the related assets. Income or expense resulting from the settlement of ARO liabilities is included in net gain or (loss) from asset sales on the Consolidated Statements of Income. The ARO liability is adjusted to present value each period through an accretion calculation using a credit-adjusted risk-free interest rate. Changes in ARO were as follows:

	2009	2008
	(in millions)	
ARO liability at January 1,	**$ 116.7**	$ 96.5
Accretion	**7.7**	6.6
Liabilities incurred	**2.3**	15.5
Liabilities settled	**(2.0)**	(1.9)
ARO liability at December 31,	**$124.7**	$116.7

Note 6 – Capitalized Exploratory Well Costs

Net changes in capitalized exploratory well costs are presented in the table below and exclude amounts that were capitalized and subsequently expensed in the period. All of these costs have been capitalized for less than one year.

	2009	2008	2007
		(in millions)	
Balance at January 1,	**$ 17.0**	$ 1.5	$ 10.5
Additions to capitalized exploratory well costs pending the determination of proved reserves	**51.7**	17.0	1.5
Reclassifications to property, plant and equipment after the determination of proved reserves	**(14.3)**		
Capitalized exploratory well costs charged to expense	**(2.7)**	(1.5)	(10.5)
Balance at December 31,	**$ 51.7**	$17.0	$ 1.5

Note 7 – Fair Value Measurements

Beginning in 2008, QEP adopted the effective provisions of ASC 820 "Fair Value Measurements and Disclosures." ASC 820 defines fair value in applying GAAP, establishes a framework for measuring fair value and expands disclosures about fair-value measurements. ASC 820 does not change existing guidance as to whether or not an instrument is carried at fair value. ASC 820 establishes a fair-value hierarchy. Level 1 inputs are quoted prices (unadjusted) for identical assets or liabilities in active markets that the Company has the ability to access at the measurement date. Level 2 inputs are inputs other than quoted prices included within Level 1 that are observable for the asset or liability, either directly or indirectly. Level 3 inputs are unobservable inputs for the asset or liability. The Level 2 fair value of derivative contracts (see Note 8) is based on market prices posted on the NYMEX on the last trading day of the reporting period and industry-standard discounted cash flow models. The Level 3 fair value of derivative contracts is based on NYMEX market prices in combination with unobservable volatility inputs and industry-standard option pricing models.

QEP primarily applies the market approach for recurring fair value measurements and maximizes its use of observable inputs and minimizes its use of unobservable inputs. QEP considers bid and ask prices for valuing the majority of its assets and liabilities measured and reported at fair value. In addition to using market data, QEP makes assumptions in valuing its assets and liabilities, including assumptions about risk and the risks inherent in the inputs to the valuation technique.

Certain of QEP's derivative instruments, however, are valued using industry-standard models that consider various inputs, including quoted forward prices for commodities, time value, volatility, and current market and contractual prices for the underlying instruments, as well as other relevant economic measures. Substantially all of these inputs are observable in the marketplace throughout the full term of the instrument, can be derived from observable data or are supported by observable prices at which transactions are executed in the marketplace. The determination of fair value for derivative assets and liabilities also incorporates nonperformance risk for counterparties and for QEP. Derivative contract fair values are reported on a net basis to the extent a legal right of offset with a counterparty exists.

In February 2008, the FASB delayed the effective date of ASC 820 for one year for certain nonfinancial assets and nonfinancial liabilities, except those recognized or disclosed at fair value in the financial statements on a recurring basis. On January 1, 2009, QEP adopted, without material impact on the Consolidated Financial Statements, the delayed provisions of ASC 820 related to nonfinancial assets and nonfinancial liabilities that are not required or permitted to be measured at fair value on a recurring basis. QEP did not have any assets or liabilities measured at fair value on a non-recurring basis at December 31, 2009. The fair values of assets and liabilities at December 31, 2009, are shown in the table below:

	Level 2	Level 3 (in millions)	Total
Assets			
Derivative contracts-short term	**$127.9**	**$ 0.3**	**128.2**
Derivative contracts-long term	**56.0**	**5.2**	**61.2**
Total assets	**$183.9**	**$ 5.5**	**$189.4**
Liabilities			
Derivative contracts-short term	**$149.7**		**$149.7**
Derivative contracts-long term	**140.6**		**140.6**
Total liabilities	**$290.3**		**$290.3**

The change in the fair value of Level 3 assets and liabilities is shown below:

	Change in Level 3 Fair Value Measurements 2009 (in millions)
Balance at January 1,	
Purchases, sales, issuances and settlements (net)	
Realized gains and losses	
Unrealized gains and losses included in other comprehensive income	**$ 5.5**
Balance at December 31,	**$ 5.5**

QEP did not have any assets or liabilities measured at fair value on a non-recurring basis or Level 3 at December 31, 2008. The fair values of assets and liabilities at December 31, 2008, are shown in the table below:

	Level 2 (in millions)
Assets	
Derivative contracts-short term	$ 431.3
Derivative contracts-long term	106.3
Total assets	$ 537.6
Liabilities	
Derivative contracts-short term	$ 0.5
Derivative contracts-long term	69.0
Total liabilities	$ 69.5

The following table discloses the fair value and related carrying amount of certain financial instruments not disclosed in other notes to the Consolidated Financial Statements in this Report on Form 8-K:

	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
	December 31, 2009		December 31, 2008	
	(in millions)			
Financial assets				
Cash and cash equivalents	**$ 19.3**	**$ 19.3**	$ 25.1	$ 25.1
Notes receivable from Questar	**52.9**	**52.9**	40.7	40.7
Financial liabilities				
Notes payable to Questar	**$ 39.3**	**$ 39.3**	$ 89.4	$ 89.4
Long-term debt	**1,348.7**	**1,394.1**	1,299.1	1,180.9

The carrying amounts of cash and cash equivalents, notes receivable from Questar and notes payable to Questar approximate fair value. The fair value of fixed-rate long-term debt is based on the discounted present value of future cash flows using the Company's current borrowing rates. The borrowing rates are credit-risk adjusted. The carrying amount of variable-rate long-term debt approximates fair value.

Note 8 – Derivative Contracts

QEP's subsidiaries use commodity-price derivative instruments in the normal course of business. QEP has established policies and procedures for managing commodity-price risks through the use of derivative instruments. On January 1, 2009, the Company adopted a revision to ASC 815 "Derivatives and Hedging," which requires more detailed information about hedging transactions including the location and effect on the primary consolidated financial statements.

QEP uses derivative instruments to support rate of return and cash flow targets and protect earnings from downward movements in commodity prices. However, these same instruments typically limit future gains from favorable price movements. Derivative contracts are currently in place for a significant share of QEP Energy-owned gas and oil production and a portion of QEP Marketing gas marketing transactions. The volume of production with associated derivative instruments and the mix of the instruments are frequently evaluated and adjusted by management in response to changing market conditions. QEP may match derivative contracts with up to 100% of forecast production from proved reserves when prices meet earnings and cash flow objectives. QEP does not enter into derivative instruments for speculative purposes.

QEP uses derivative instruments known as fixed-price swaps and costless collars to realize a known price or range of prices for a specific volume of production delivered into a regional sales point. Swap agreements do not require the physical transfer of natural gas between the parties at settlement. Swap transactions are settled in cash with one party paying the other for the net difference in prices, multiplied by the relevant volume, for the settlement period. Collars are combinations of put and call options that have a floor price and a ceiling price and are only triggered if the settlement price is outside the range of the floor and ceiling prices. In the past, QEP Energy has also used natural gas basis-only swaps to protect cash flows and net income from widening natural gas-price basis differentials. However, natural gas basis-only swaps exposed the Company to losses from narrowing natural gas price-basis differentials.

QEP enters into derivative instruments that do not have margin requirements or collateral provisions that would require funding prior to the scheduled cash settlement dates. Derivative-arrangement counterparties are normally financial institutions and energy-trading firms with investment-grade credit ratings. The Company routinely monitors and manages its exposure to counterparty risk by requiring specific minimum credit standards for all counterparties and transacting with multiple counterparties.

All derivative instruments are required to be recorded on the balance sheet as either assets or liabilities measured at their fair values. The designation of a derivative instrument as a hedge and its ability to meet hedge accounting criteria determines how the change in fair value of the derivative instrument is reflected in the consolidated financial statements. A derivative instrument qualifies for hedge accounting, if at inception, the derivative is expected to be highly effective in offsetting the underlying hedged cash flows. Generally, QEP's derivative instruments are matched to equity gas and oil production and are highly effective, thus qualifying as cash flow hedges. Changes in the fair value of effective cash flow hedges are recorded as a component of AOCI on the Condensed Consolidated Balance Sheets and reclassified to earnings as gas and oil sales when the underlying physical transactions occur. Gas hedges are typically structured as fixed-price swaps into regional pipelines, locking in basis and hedge effectiveness. Costless collars qualify for cash flow hedge accounting. A basis-only swap does not qualify for hedge accounting treatment. QEP regularly reviews the effectiveness of derivative instruments. The ineffective portion of cash flow hedges and the mark to market adjustment of basis-only swaps are immediately recognized in the determination of net income.

	Year Ended December 31, 2009 (in millions)
Effect of derivative instruments designated as cash flow hedges	
Gains recognized in AOCI for the effective portion of hedges	$ 214.4
Gains (losses) reclassified from AOCI into income for the effective portion of hedges	
Natural gas sales	599.3
Oil and NGL sales	1.6
Marketing sales	27.8
Marketing purchases	(9.2)
(Losses) recognized in income for the ineffective portion of hedges	
Interest and other income	(0.1)
Effect of derivative instruments not designated as hedges	
Unrealized (loss) on basis-only swaps	(164.0)
Realized (loss) on basis-only swaps	(25.6)

In the next twelve months $63.6 million, based on year-end 2009 prices, will be settled and reclassified from AOCI to the Consolidated Statements of Income. The following table discloses the fair value of derivative contracts on a gross-contract basis as opposed to the net-contract basis presentation in the Consolidated Balance Sheets.

	December 31, 2009 (in millions)
Assets	
Fixed-price swaps	$ 312.6
Option contracts	2.4
Fair value of derivative instruments-short term	$ 315.0
Fixed-price swaps	$ 194.3
Option contracts	16.1
Fair value of derivative instruments-long term	$ 210.4
Liabilities	
Fixed-price swaps	$ 212.7
Basis-only swaps	121.7
Option contracts	2.1
Fair value of derivative instruments-short term	$ 336.5
Fixed-price swaps	$ 161.2
Basis-only swaps	117.7
Option contracts	10.9
Fair value of derivative instruments-long term	$ 289.8

Previously reported basis-only swaps have been combined with fixed-price NYMEX gas swaps for 2010 and 2011 and now qualify as cash flow hedges. The following table sets forth QEP's volumes and average net to the well prices for transactions with associated risk management derivative contracts as of December 31, 2009:

Production

Year		Time Periods	Quantity	Average hedge price per Mcf or Bbl, net to the well(a) (estimated)
	Gas (Bcf) Fixed-price Swaps			
2010		12 months	150.9	$5.26
2011		12 months	102.1	4.91
2012		12 months	40.6	5.91
2013		12 months	47.2	5.98
	Gas (Bcf) Collars			
				Floor - Ceiling
2010		12 months	6.7	$4.65 - $6.51
2011		12 months	27.7	4.63 - 6.66
	Oil (Mbbl) Fixed-price Swaps			
2010		12 months	913	$60.66
	Oil (Mbbl) Collars			
				Floor - Ceiling
2010		12 months	730	$47.60 - $96.10
2011		12 months	1,095	51.73 - 102.10

Marketing

Year		Time Periods	Quantity	Average price per MMBtu
	Gas Sales (millions of MMBtu) Fixed-price Swaps			
2010		12 months	7.6	$4.83
	Gas Purchases (millions of MMBtu) Fixed-price Swaps			
2010		12 months	2.8	$4.11

(a) The fixed-price swap and collar prices are reduced by gathering costs and adjusted for product quality to determine the net-to-the-well price.

Note 9 – Debt

Prior to the Spinoff, Questar made loans to QEP under a short-term borrowing arrangement. Short-term notes payable to Questar are subordinated to obligations under the revolving credit agreement. Short-term notes payable to Questar amounted to $39.3 million with an interest rate of 0.66% at December 31, 2009 and $89.4 million with an interest rate of 3.39% at December 31, 2008.

All short-term and long-term notes and the term-bank loan are unsecured obligations and rank equally with all other unsecured liabilities. At December 31, 2009, QEP's $800.0 million revolving-credit facility had $200.0 million outstanding at a weighted-average interest rate of 0.73%. This credit agreement carries an annual commitment fee of 0.115% on the unused balance. At December 31, 2009, QEP could pay dividends of $1.1 billion without violating its limitation of total outstanding debt to total capitalization debt covenant.

In August 2009, QEP issued $300.0 million of notes due March 2020 with a 6.82% effective interest rate and used the net proceeds to reduce the balance outstanding under its long-term revolving-credit facility. The details of long-term debt are as follows:

	December 31, 2009	December 31, 2008
	(in millions)	
Revolving-credit facility, 0.73% at December 31, 2009, due 2013	**$ 200.0**	$ 450.0
7.50% notes due 2011	**150.0**	150.0
6.05% notes due 2016	**250.0**	250.0
6.80% notes due 2018	**450.0**	450.0
6.80% notes due 2020	**300.0**	
Total long-term debt outstanding	**1,350.0**	1,300.0
Less unamortized-debt discount	**(1.3)**	(0.9)
Total long-term debt outstanding	**$1,348.7**	$1,299.1

Maturities of long-term debt for the five years following December 31, 2009, are $150.0 million in 2011 and $200.0 million in 2013.

Note 10 – Income Taxes

Details of income tax expenses and deferred income taxes from continuing operations are provided in the following tables. The components of income tax expenses were as follows:

	Year Ended December 31, 2009	2008	2007
		(in millions)	
Federal			
Current	**$ 11.5**	$ (32.6)	$ 34.9
Deferred	**101.3**	308.1	157.8
State			
Current	**2.6**	(3.6)	1.3
Deferred	**2.2**	11.7	17.3
Total income tax expense	**$ 117.6**	$ 283.6	$ 211.3

The difference between the statutory federal income tax rate and the Company's effective income tax rate is explained as follows:

	Year Ended December 31, 2009	2008	2007
Federal income taxes statutory rate	**35.0%**	35.0%	35.0%
Increase (decrease) in rate as a result of:			
State income taxes, net of federal income tax benefit	**0.9**	0.7	2.1
Domestic production benefit			(0.1)
Other	**(0.6)**	(0.4)	(0.1)
Effective income tax rate	**35.3%**	35.3%	36.9%

Significant components of the Company's deferred income taxes were as follows:

	December 31, 2009	December 31, 2008
	(in millions)	
Deferred tax liabilities		
Property, plant and equipment	**$1,217.5**	$1,051.8
Energy-price derivatives		13.6
Total deferred tax liabilities	**1,217.5**	1,065.4
Deferred tax assets		
Energy-price derivatives	**29.5**	
Employee benefits and compensation costs	**12.2**	6.7
Total deferred tax assets	**41.7**	6.7
Deferred income taxes-noncurrent	**$1,175.8**	$1,058.7
Deferred income taxes–current		
Energy-price derivatives	**$ 8.0**	$ (160.4)
Other	**13.2**	17.4
Deferred income taxes–current asset (liability)	**$ 21.2**	$ (143.0)

Note 11 – Commitments and Contingencies

QEP is involved in various commercial and regulatory claims and litigation and other legal proceedings that arise in the ordinary course of its business. Management does not believe any of them will have a material adverse effect on the Company's financial position, results of operations or cash flows. A liability is recorded for a loss contingency when its occurrence is probable and damages can be reasonably estimated based on the anticipated most likely outcome. Disclosures are provided for contingencies reasonably likely to occur which would have a material adverse effect on the Company's financial position, results of operations or cash flows. Some of the claims involve highly complex issues relating to liability, damages and other matters subject to substantial uncertainties and, therefore, the probability of liability or an estimate of loss cannot be reasonably determined.

Environmental Claims

In *United States of America v. QEP Field Services Co.*, Civil No. 208CV167, filed on February 29, 2008, in Utah Federal District Court, the Environmental Protection Agency (EPA) alleges that QEP Field Services violated the federal Clean Air Act (CAA) and seeks substantial penalties and a permanent injunction involving the manner of operation of five compressor stations located in the Uinta Basin of eastern Utah. EPA further alleges that the facilities are located within the original boundaries of the former Uncompahgre Indian Reservation and are therefore within "Indian Country." EPA asserts primary CAA jurisdiction over "Indian Country" where state CAA programs do not apply. EPA contends that the potential to emit, on a hypothetically uncontrolled basis, for QEP Field Services' facilities render them "major sources" of emissions for criteria and hazardous air pollutants. Categorization of the facilities as "major sources" affects the particular regulatory program applicable to those facilities. EPA claims that QEP Field Services failed to obtain the necessary major source pre-construction or modification permits, and failed to comply with hazardous air-pollutant regulations for testing and reporting, among other things. QEP Field Services contends that its facilities have pollution controls installed that reduce their actual air emissions below major source thresholds, rendering them subject to different regulatory requirements. QEP Field Services intends to vigorously defend against the EPA's claims, and believes that the major source permitting and regulatory requirements at issue can be legally avoided by applying Utah's CAA program or EPA's prior practice for similar facilities elsewhere in Indian Country, among other defenses. Because of the complexities and uncertainties of this legal dispute, it is difficult to predict all reasonably possible outcomes; however, management believes the Company has accrued a reasonable loss contingency for the anticipated most likely outcome, and that the amount of the accrual is not material.

On July 10, 2009, QEP Energy filed a petition with the U.S. Tenth Circuit Court of Appeals challenging an administrative compliance order dated May 12, 2009, (Order) issued by the EPA which asserts that QEP Energy's Flat Rock 14P Well and associated equipment is a major source of emissions of hazardous air pollutants and that its operation fails to comply with certain regulations of the CAA. The Order required immediate compliance and threatened substantial penalties for failure to do so. QEP Energy denies that the drilling and operation of the 14P Well and associated equipment violates any provision of the CAA and intends to vigorously defend against this Order.

In October 2009, QEP Energy received a cease and desist order from the U.S. Army Corps of Engineers (COE) to refrain from further discharge of dredged and/or fill material into wetlands of the United States at three well sites without a permit under the Clean Water Act (CWA). The order specifically references prior construction activities at the sites located in Caddo and Red River Parishes, Louisiana. EPA Region 6 has now assumed lead responsibility for enforcement of the pending order and any possible future orders for the removal of unauthorized fills and/or civil penalties under Section 309 of the CWA. The Company is working with the COE and EPA to resolve the matter.

Commitments

Subsidiaries of QEP have contracted for firm-transportation services with various third-party pipelines through 2040. Market conditions and competition may prevent full utilization of the contractual capacity. Annual payments and the years covered are as follows:

	(in millions)
2010	$ 17.3
2011	37.2
2012	42.0
2013	40.2
2014	39.3
2015 through 2040	268.0

QEP rents office space throughout its scope of operations from third-party lessors. Rental expense amounted to $4.0 million in 2009, $3.4 million in 2008 and $2.6 million in 2007. Minimum future payments under the terms of long-term operating leases for the Company’s primary office locations for the six years following December 31, 2009, are as follows:

	(in millions)
2010	$ 4.3
2011	4.3
2012	4.1
2013	3.0
2014	1.0
2015	1.2

Note 12 – Share-Based Compensation

Questar issued stock options and restricted shares to certain officers and employees of QEP under its LTSIP. Share-based compensation expense for continuing operations amounted to $13.4 million in 2009 compared with $10.6 million in 2008 and $8.6 million in 2007. Expense is recognized over time as stock options or restricted shares vest.

The Company uses the Black-Scholes-Merton mathematical model in estimating the fair value of stock options for accounting purposes. Fair-value calculations rely upon subjective assumptions used in the mathematical model and may not be representative of future results. The Black-Scholes-Merton model was intended for measuring the value of options traded on an exchange. The calculated fair value of options granted and major assumptions used in the model at the date of grant are listed below:

	2009 Range of Stock Option Variables	2008 Range of Stock Option Variables	2007 Stock Option Variables
Fair value of options at grant date	$31.06 –$35.38	$28.58 –$53.83	$41.08
Risk-free interest rate	1.78% – 2.51%	2.72% – 3.20%	4.77%
Expected price volatility	28.1% –29.9%	20.3% – 32.3%	22.4%
Expected dividend yield	1.39% –1.61%	0.91 – 1.72%	1.14%
Expected life in years	5.0 – 5.0	5.0 – 5.0	5.2

Unvested stock options increased by 335,495 shares to 882,995 in 2009. Stock-option transactions under the terms of the LTSIP for the three years ended December 31, 2009, are summarized below:

	Options Outstanding	Price Range	Weighted-Average Price
Balance at January 1, 2007	1,293,012	$7.50 – $38.57	$ 16.49
Granted	60,000	41.08	41.08
Exercised	(139,464)	7.50 –17.55	12.83
Employee transferred	(16,064)	10.69	10.69
Forfeited	(1,000)	14.01	14.01
Balance at December 31, 2007	1,196,484	7.50 – 41.08	18.23
Granted	287,500	28.58	28.58
Exercised	(82,454)	7.50 – 17.55	11.44
Employee transferred	(58,210)	7.50 – 14.01	12.39
Balance at December 31, 2008	1,343,320	7.50 – 41.08	21.00
Granted	**493,000**	**35.38**	**35.38**
Exercised	**(128,826)**	**7.50 – 14.01**	**11.26**
Employee transferred	**6,000**	**11.48 –13.56**	**13.21**
Forfeited	**(60,000)**	**28.58 – 35.38**	**29.15**
Balance at December 31, 2009	**1,653,494**	**$ 7.50 $41.08**	**$ 25.72**

Range of exercise prices	Options Outstanding			Options Exercisable		Unvested Options	
	Number outstanding at Dec. 31, 2009	Weighted-average remaining term in years	Weighted-average exercise price	Number exercisable at Dec. 31, 2009	Weighted-average exercise price	Number unvested at Dec. 31, 2009	Weighted-average exercise price
$7.50	23,000	0.1	$ 7.50	23,000	$ 7.50		
$11.48 – $11.98	337,842	2.1	11.73	337,842	11.73		
$13.56 – $14.01	297,878	2.8	13.62	297,878	13.62		
$17.55 – $28.58	246,774	5.7	27.94	91,779	26.86	154,995	$ 28.58
$35.38 – $41.08	748,000	5.2	36.69	20,000	41.08	728,000	$ 36.57
	1,653,494	**4.1**	**$ 25.72**	**770,499**	**$ 14.90**	**882,995**	**$ 35.17**

Restricted shares are valued at the grant-date market price and amortized to expense over the vesting period. Most restricted share grants vest in equal installments over a three or four year period from the grant date. The weighted average vesting period of unvested restricted shares at December 31, 2009, was 14 months. Transactions involving restricted shares under the terms of the LTSIP for the three years ended December 31, 2009, are summarized below:

	Restricted Shares Outstanding	Price Range	Weighted-Average Price
Balance at January 1, 2007	441,150	$14.36 – $44.77	$ 29.39
Granted	285,040	38.96 – 56.65	46.12
Distributed	(158,096)	14.36 – 49.98	23.36
Forfeited	(26,202)	18.45 – 49.97	37.89
Balance at December 31, 2007	541,892	17.45 – 56.65	39.53
Granted	226,140	25.12 – 70.13	53.96
Distributed	(170,161)	17.45 – 56.65	34.40
Employee transferred	(866)	17.45 – 36.75	26.92
Forfeited	(26,916)	25.50 – 70.13	47.30
Balance at December 31, 2008	570,089	25.12 – 70.13	46.44
Granted	**204,250**	**29.30 – 36.88**	**35.11**
Distributed	**(196,066)**	**25.12 – 70.13**	**39.88**
Employee transferred	**966**	**25.50 – 53.83**	**43.89**
Forfeited	**(29,854)**	**35.23 – 62.50**	**47.67**
Balance at December 31, 2009	**549,385**	**$25.12 – $70.13**	**$ 44.50**

Note 13 – Employee Benefits

Pension Plan

Certain QEP employees were covered by Questar's defined benefit pension plan. Benefits were generally based on the employee's age at retirement, years of service and highest earnings in a consecutive 72 semimonthly pay period during the 10 years preceding retirement. Questar is subject to and complies with minimum required and maximum allowed annual contribution levels mandated by the Employee Retirement Income Security Act and by the Internal Revenue Code. Subject to the above limitations, Questar intends to fund the qualified pension plan approximately equal to the yearly expense. Questar also has a nonqualified pension plan that covers certain management employees in addition to the qualified pension plan. The nonqualified pension plan provides for defined benefit payments upon retirement of the management employee, or to the spouse upon death of the management employee above the benefit limit defined by the Internal Revenue Service for the qualified plan. The nonqualified pension plan is unfunded. Claims are paid from the Company's general funds. Qualified pension plan assets consist principally of equity securities and corporate and U.S. government debt obligations. A third-party consultant calculates the pension plan projected benefit obligation. Pension expense was $4.2 million in 2009, $2.9 million in 2008 and $3.6 million in 2007.

At December 31, 2009, QEP's portion of plan assets and benefit obligations could not be determined because the plan assets were not segregated or restricted to meet the Company's pension obligations. If the Company were to withdraw from the pension plan, the pension obligation for the Company's employees would be retained by the pension plan. At December 31, 2009 and 2008, Questar's projected benefit obligation exceeded the fair value of plan assets.

Postretirement Benefits Other Than Pensions

Eligible QEP employees participate in Questar's postretirement benefits other than pensions plan. Postretirement health care benefits and life insurance are provided only to employees hired before January 1, 1997. The Company pays a portion of the costs of health care benefits, based on an employee's years of service, and generally limits payments to 170% of the 1992 contribution. Plan assets consist of equity securities and corporate and U.S. government debt obligations. A third party consultant calculates the projected benefit obligation. The cost of postretirement benefits other than pensions was $1.1 million in 2009, $1.0 million in 2008 and 2007, respectively.

At December 31, 2009, the Company's portion of plan assets and benefit obligations related to post-retirement medical and life insurance benefits could not be determined because the plan assets were not segregated or restricted to meet the Company's obligations. At December 31, 2009 and 2008, Questar's accumulated benefit obligation exceeded the fair value of plan assets.

Employee Investment Plan

QEP subsidiaries participate in Questar's Employee Investment Plan (EIP). The EIP allows eligible employees to purchase shares of Questar common stock or other investments through payroll deduction at the current fair market value on the transaction date. The Company currently contributes an overall match of 100% of employees' pre-tax purchases up to a maximum of 6% of their qualifying earnings. In addition, the Company contributes $200 annually to the EIP for each eligible employee. The EIP trustee purchases Questar shares on the open market with cash received. The Company recognizes expense equal to its yearly contributions, which amounted to $4.2 million in 2009, $3.7 million in 2008 and $3.1 million in 2007.

Note 14 – Operations by Line of Business

QEP's lines of business include gas and oil exploration and production (QEP Energy), midstream field services (QEP Field Services) and marketing (QEP Marketing). Line of business information is presented according to senior management's basis for evaluating performance including differences in the nature of products, services and regulation. Following is a summary of operations by line of business for the three years ended December 31, 2009:

2009 (recast)	QEP Consolidated	Interco Transactions	QEP Energy	QEP Field Services	QEP Marketing
			(in millions)		
Revenues					
From unaffiliated customers	$ 1,972.5		$1,267.3	$262.7	$ 442.5
From affiliated companies		($ 370.0)		1.9	368.1
Total Revenues	1,972.5	(370.0)	1,267.3	264.6	810.6
Operating expenses					
Marketing purchases	427.8	(362.8)			790.6
Lease operating expense, gathering, processing and other	201.7	(2.0)	127.5	75.0	1.2
General and administrative	91.7	(5.2)	68.0	25.0	3.9
Production and property taxes	62.9		58.3	4.6	
Depreciation, depletion and amortization	559.1		512.8	44.3	2.0
Other operating expenses	45.3		45.3		
Total operating expenses	1,388.5	(370.0)	811.9	148.9	797.7

Net gain (loss) from asset sales	**1.5**		**1.6**	**(0.1)**	
Operating income	**585.5**		**457.0**	**115.6**	**12.9**
Interest and other income	**(185.1)**	**(70.7)**	**(185.7)**	**(0.2)**	**71.5**
Income from unconsolidated affiliates	**2.7**		**0.1**	**2.6**	
Interest expense	**(70.1)**	**70.7**	**(63.9)**	**(6.0)**	**(70.9)**
Income tax expense	**(117.6)**		**(72.6)**	**(40.0)**	**(5.0)**
Income from continuing operations	**215.4**		**134.9**	**72.0**	**8.5**
Income from continuing operations attributable to noncontrolling interest	**(2.6)**			**(2.6)**	
Income from continuing operations attributable to QEP	**$ 212.8**		**$ 134.9**	**$ 69.4**	**$ 8.5**
Identifiable assets	**$5,828.9**		**$4,633.0**	**$929.2**	**$ 266.7**
Investment in unconsolidated affiliates	**43.9**			**43.9**	
Cash capital expenditures	**1,198.4**		**1,108.6**	**88.3**	**1.5**
Accrued capital expenditures	**1,108.4**		**1,033.7**	**73.3**	**1.4**
Goodwill	**60.1**		**60.1**		
2008 (recast)					
Revenues					
From unaffiliated customers	$2,318.8		$1,392.1	$288.8	$ 637.9
From affiliated companies		($ 806.1)		1.4	804.7
Total Revenues	2,318.8	(806.1)	1,392.1	290.2	1,442.6
Operating expenses					
Marketing purchases	604.6	(800.3)	0.5		1,404.4
Lease operating expense, gathering, processing and other	220.2	(1.4)	125.4	95.0	1.2
General and administrative	78.1	(4.4)	55.8	23.7	3.0
Production and property taxes	106.9		104.0	2.6	0.3
Depreciation, depletion and amortization	361.5		330.9	28.7	1.9
Other operating expenses	74.7		73.9	0.8	
Total operating expenses	1,446.0	(806.1)	690.5	150.8	1,410.8
Net gain (loss) from asset sales	60.4		60.4		
Operating income	933.2		762.0	139.4	31.8
Interest and other income	(69.0)	(66.4)	(71.7)		69.1
Income from unconsolidated affiliates	1.7		0.5	1.2	
Interest expense	(61.7)	66.4	(58.3)	(3.6)	(66.2)
Income tax expense	(283.6)		(224.5)	(46.5)	(12.6)
Income from continuing operations	520.6		$ 408.0	90.5	22.1
Income from continuing operations attributable to noncontrolling interest	(9.0)			(9.0)	
Income from continuing operations attributable to QEP	$ 511.6		$ 408.0	$ 81.5	$ 22.1
Identifiable assets	$5,741.0		$4,516.2	$918.5	$ 306.3
Investment in unconsolidated affiliates	40.8			40.8	
Cash capital expenditures	2,136.7		1,777.3	357.9	1.5
Accrued capital expenditures	2,260.3		1,864.2	394.5	1.6
Goodwill	60.2		60.2		

2007 (recast)					
Revenues					
From unaffiliated customers	$1,688.1		$ 956.0	$205.2	$526.9
From affiliated companies		($ 462.7)		1.1	461.6
Total Revenues	1,688.1	(462.7)	956.0	206.3	988.5
Operating expenses					
Marketing purchases	496.5	(461.0)	2.2		955.3
Lease operating expense, gathering, processing and other	171.4	(1.1)	87.9	83.6	1.0
General and administrative	76.8	(0.6)	56.3	17.2	3.9
Production and property taxes	61.6		60.1	1.4	0.1
Depreciation, depletion and amortization	263.9		243.5	19.1	1.3
Other operating expenses	33.2		32.8	0.4	
Total operating expenses	1,103.4	(462.7)	482.8	121.7	961.6
Net (loss) from asset sales	(0.6)		(0.6)		
Operating income	584.1		472.6	84.6	26.9
Interest and other income	13.5	(26.9)	6.2	0.2	34.0
Income from unconsolidated affiliates	8.9		0.4	8.5	
Interest expense	(33.6)	26.9	(25.2)	(6.9)	(28.4)
Income tax expense	(211.3)		(168.5)	(31.1)	(11.7)
Income from continuing operations attributable to QEP	$ 361.6		$ 285.5	$ 55.3	$ 20.8
Identifiable assets	$3,336.8		$2,534.4	$489.9	$312.5
Investment in unconsolidated affiliates	52.8			52.8	
Cash capital expenditures	838.9		708.5	128.3	2.1
Accrued capital expenditures	854.9		724.8	128.1	2.0
Goodwill	60.9		60.9		

Note 15 – Quarterly Financial Information (Unaudited)

Following is a summary of unaudited quarterly financial information:

	First Quarter (recast)	Second Quarter (recast)	Third Quarter (recast)	Fourth Quarter (recast)	Year (recast)
	(in millions, except per share information)				
2009 (recast)					
Revenues	**$482.1**	**$442.7**	**$487.9**	**$559.8**	**$1,972.5**
Operating income	**155.1**	**118.6**	**147.4**	**164.4**	**585.5**
Income from continuing operations	**2.4**	**45.5**	**72.0**	**95.5**	**215.4**
Discontinued operations, net of tax	**18.8**	**19.8**	**20.6**	**21.5**	**80.7**
Net income attributable to QEP	**20.7**	**64.7**	**92.0**	**116.1**	**293.5**
Per share information attributable to QEP					
Basic EPS from continuing operations	**$ 0.01**	**$ 0.26**	**$ 0.41**	**$ 0.55**	**$ 1.23**
Basic EPS attributable to QEP	**0.12**	**0.37**	**0.53**	**0.67**	**1.69**
Diluted EPS from continuing operations	**0.01**	**0.26**	**0.40**	**0.54**	**1.21**
Diluted EPS attributable to QEP	**0.12**	**0.37**	**0.52**	**0.66**	**1.67**
2008 (recast)					
Revenues	$570.7	$628.8	$603.4	$515.9	$2,318.8
Operating income	197.3	231.7	323.9	180.3	933.2
Income from continuing operations	125.5	145.4	179.6	70.1	520.6
Discontinued operations, net of tax	16.2	18.8	20.4	18.5	73.9
Net income attributable to QEP	139.3	162.1	197.6	86.5	585.5
Basic EPS from continuing operations	$ 0.72	$ 0.83	$ 1.02	$ 0.39	$ 2.96
Basic EPS attributable to QEP	0.81	0.94	1.14	0.50	3.39
Diluted EPS from continuing operations	0.70	0.81	1.01	0.38	2.90
Diluted EPS attributable to QEP	0.79	0.92	1.12	0.49	3.32

Note 16 – Supplemental Gas and Oil Information (Unaudited)

The Company is making the following supplemental disclosures of gas and oil producing activities, in accordance with ASC 932 "Extractive Activities - Oil and Gas" as amended by ASU 2010-03 "Oil and Gas Reserve Estimation and Disclosures" and SEC Regulation S-X.

The Company uses the successful efforts accounting method for its gas and oil exploration and development activities. All located in the United States.

Capitalized Costs

The aggregate amounts of costs capitalized for gas and oil exploration and development activities and the related amounts of accumulated depreciation, depletion and amortization are shown below:

	December 31,	
	2009	2008
	(in millions)	
Proved properties	**$ 5,721.5**	$ 4,948.2
Unproved properties	**389.6**	193.2
	6,111.1	5,141.4
Accumulated depreciation, depletion and amortization	**(1,890.9)**	(1,421.8)
Net capitalized costs	**$ 4,220.2**	$ 3,719.6

Costs Incurred

The costs incurred in gas and oil exploration and development activities are displayed in the table below. The costs incurred to develop proved undeveloped reserves were $216.1 million in 2009, $219.9 million in 2008 and $125.8 million in 2007.

	Year Ended December 31,		
	2009	2008	2007
		(in millions)	
Property acquisition			
Unproved	**$ 215.1**	$ 167.3	$ 28.9
Proved	**6.4**	602.7	45.1
Exploration (capitalized and expensed)	**92.9**	58.7	14.9
Development	**741.1**	1,061.2	652.2
Total costs incurred	**$1,055.5**	$1,889.9	$741.1

Results of Operation

Following are the results of operation of QEP Energy gas and oil exploration and development activities, before corporate overhead and interest expenses.

	Year Ended December 31,		
	2009	2008	2007
		(in millions)	
Revenues	**$1,267.3**	$1,392.1	$ 956.0
Production costs	**185.8**	229.4	148.0
Exploration expenses	**25.0**	29.3	22.0
Depreciation, depletion and amortization	**512.8**	330.9	243.5
Abandonment and impairment	**20.3**	44.6	10.8
Total expenses	**743.9**	634.2	424.3
Revenues less expenses	**523.4**	757.9	531.7
Income taxes	**(183.2)**	(269.1)	(197.3)
Results of operation from producing activities excluding corporate overhead and interest expenses	**$ 340.2**	$ 488.8	$ 334.4

Estimated Quantities of Proved Gas and Oil Reserves

Estimates of proved gas and oil reserves have been completed in accordance with professional engineering standards and the Company's established internal controls, which includes the compliance oversight of a multi-functional reserves review committee responsible to the Company's board of directors. QEP Energy's estimated proved reserves have been prepared by Ryder Scott Company, L.P., independent reservoir engineering consultants, in accordance with the SEC's Regulation S-X and ASC 932 as amended. The individuals performing reserves estimates possess professional qualifications and demonstrate competency in reserves estimation and evaluation.

	Natural Gas (Bcf)	Oil and NGL (MMbbl)	Natural Gas Equivalents (Bcfe)
Proved Reserves			
Balance at January 1, 2007	1,461.2	28.4	1,631.4
Revisions -			
Previous estimates	26.3	3.3	46.2
Pinedale increased-density*(a)*	120.6	1.0	126.8
Extensions and discoveries	172.6	3.3	192.7
Purchase of reserves in place	16.0	0.2	17.1
Sale of reserves in place	(6.3)		(6.4)
Production	(121.9)	(3.0)	(140.2)
Balance at December 31, 2007	1,668.5	33.2	1,867.6
Revisions -			
Previous estimates	(128.5)	(4.0)	(152.9)
Pinedale increased-density*(a)*	154.5	1.2	161.8
Extensions and discoveries	208.0	5.2	239.1
Purchase of reserves in place	289.8	0.4	292.4
Sale of reserves in place	(11.9)	(1.1)	(18.5)
Production	(151.9)	(3.3)	(171.4)
Balance at December 31, 2008	2,028.5	31.6	2,218.1
Revisions-previous estimates	**(318.9)**	**3.4**	**(298.8)**
Extensions and discoveries*(a)*	**982.4**	**5.4**	**1,014.6**
Purchase of reserves in place	**1.7**	**0.1**	**2.5**
Production	**(168.7)**	**(3.5)**	**(189.5)**
Balance at December 31, 2009	**2,525.0**	**37.0**	**2,746.9**
Proved Developed Reserves			
Balance at January 1, 2007	852.0	23.1	990.7
Balance at December 31, 2007	987.4	26.7	1,147.4
Balance at December 31, 2008	1,128.1	23.6	1,269.4
Balance at December 31, 2009	**1,178.7**	**27.4**	**1,342.8**
Proved Undeveloped Reserves			
Balance at January 1, 2007	609.2	5.3	640.7
Balance at December 31, 2007	681.1	6.5	720.2
Balance at December 31, 2008	900.4	8.0	948.7
Balance at December 31, 2009	**1,346.3**	**9.6**	**1,404.1**

(a) Estimates of the quantity of proved reserves from the Company's Pinedale Anticline leasehold in western Wyoming have changed substantially over time as a result of numerous factors including, but not limited to, additional development drilling

activity, producing well performance and the development and application of reliable technologies. The continued analysis of new data has led to progressive increases in estimates of original gas-in-place at Pinedale and to a better understanding of the appropriate well density to maximize the economic recovery of the in-place volumes. With the application of the amendments of ASC 932 in ASU 2010-03, reserves associated with Pinedale increased density drilling are included in extensions and discoveries for the year ended December 31, 2009, because each new well drilled recovers incremental reserves that would otherwise be unrecoverable.

	2009 (Bcfe)
Proved undeveloped reserves at January 1,	**948.7**
Transferred to proved developed reserves	**(124.4)**
Revisions-previous estimates(a)	**(217.2)**
Extensions and discoveries(b)	**797.0**
Proved undeveloped reserves at December 31, *(c)*	**1,404.1**

(a) Revisions include price-related reductions of 220.4 Bcfe. Year-end 2009 proved reserve estimates were based on SEC-prescribed 12-month average prices of $3.06 per Mcf and $45.54 per barrel. Such price-related reductions would not have occurred under the SEC's prior end-of-year pricing rules.

(b) Extensions and discoveries include 578.1 Bcfe resulting from the application of the amendments of ASC 932 in ASU 2010-03 relative to booking proved undeveloped reserves for locations more than one location away from an existing producing well when reliable technology can be demonstrated. Such additions are based on empirical data including subsurface well control, long-term well performance, pressure testing and pressure studies, core data, and ongoing pilot programs of increased density development, which have confirmed with reasonable certainty the areal extent and continuity of the subject hydrocarbon accumulations. The Company routinely applies multi-stage hydraulic fracture stimulation technology and in some instances horizontal drilling combined with multi-stage fracture stimulation technology in development of its reserves. Empirical data has also been incorporated in detailed reservoir models supported by three dimensional seismic data and numerical simulation studies to further corroborate such conclusions.

(c) All of QEP Energy's proved undeveloped reserves at December 31, 2009, are scheduled to be developed within five years from the date such locations were initially disclosed as proved undeveloped reserves, except for 350 Bcfe located within the northernmost portion of the Company's Pinedale Anticline leasehold in western Wyoming. As discussed in Item 7 of Part I of this Report on Form 8-K, long-term development of natural gas reserves in the PAPA is governed by the BLM's September 2008, ROD on the FSEIS. Under the ROD, QEP Energy and Wexpro are allowed to drill and complete wells year-round in designated concentrated development areas defined in the PAPA. The ROD contains additional requirements and restrictions on the sequence of development of the PAPA, which requires the Company to develop its leasehold from the south to the north. These restrictions result in protracted, phased development of the PAPA that is beyond the control of the Company. The Company has an ongoing development plan for the PAPA and the financial capability to continue development in the manner estimated.

Standardized Measure of Future Net Cash Flows Relating to Proved Reserves

Future net cash flows were calculated at December 31, 2009, by applying prices used in estimating 2009 reserves, which was the simple average of the first-of-the-month prices for the twelve months of 2009 with consideration of known contractual price changes. Future net cash flow calculations for years prior to 2009 used year-end prices and known contract-price changes. The prices used do not include any impact of hedging activities. The average price per Mcf used to calculate proved natural gas reserves was $3.06 in 2009, $4.62 in 2008 and $6.01 in 2007. The average price per barrel of proved oil and NGL reserves combined used to calculate reserves was $45.54 in 2009, $28.41 in 2008 and $80.86 in 2007. Year-end production costs, development costs and appropriate statutory income tax rates, with consideration of future tax rates already legislated, were used to compute the future net cash flows. All cash flows were discounted at 10% to reflect the time value of cash flows, without regard to the risk of specific properties. The estimated future costs to develop booked proved undeveloped reserves are $436.8 million in 2010, $467.9 million in 2011 and $389.1 million in 2012. At the end of the five-year period ending in 2014, the Company expects to have evaluated 100% of the current booked proved undeveloped reserves.

The assumptions used to derive the standardized measure of future net cash flows are those required by accounting standards and do not necessarily reflect the Company's expectations. The usefulness of the standardized measure of future net cash flows is impaired because of the reliance on reserve estimates and production schedules that are inherently imprecise.

Management considers a number of factors when making investment and operating decisions. They include estimates of probable and proved reserves and varying price and cost assumptions considered more representative of a range of anticipated economic conditions. The standardized measure of future net cash flows relating to proved reserves is presented in the table below:

	Year Ended December 31,		
	2009	2008	2007
		(in millions)	
Future cash inflows	**$ 9,419.3**	$10,263.4	$12,704.3
Future production costs	**(2,841.8)**	(2,717.6)	(2,863.4)
Future development costs	**(2,252.7)**	(1,884.0)	(1,232.4)
Future income tax expenses	**(674.0)**	(1,241.3)	(2,668.8)
Future net cash flows	**3,650.8**	4,420.5	5,939.7
10% annual discount for estimated timing of net cash flows	**(2,207.8)**	(2,418.6)	(3,105.7)
Standardized measure of discounted future net cash flows	**$ 1,443.0**	$ 2,001.9	$2,834.0

The principal sources of change in the standardized measure of future net cash flows relating to proved reserves is presented in the table below:

	Year Ended December 31,		
	2009	2008	2007
		(in millions)	
Balance at January 1,	**$ 2,001.9**	$ 2,834.0	$1,567.8
Sales of gas and oil produced during the period, net of production costs	**(1,081.5)**	(1,162.7)	(808.0)
Net change in prices and production costs related to future production	**(813.1)**	(1,306.1)	1,554.6
Net change due to extensions and discoveries	**1,291.6**	438.7	523.6
Net change due to revisions of quantity estimates	**(380.4)**	16.3	470.0
Net change due to purchases and sales of reserves in place	**6.4**	499.9	41.8
Previously estimated development costs incurred during the period	**216.1**	219.9	125.8
Changes in future development costs	**(347.4)**	(662.6)	(214.5)
Accretion of discount	**256.4**	410.7	221.0
Net change in income taxes	**295.8**	711.2	(635.0)
Other	**(2.8)**	2.6	(13.1)
Net change	**(558.9)**	(832.1)	1,266.2
Balance at December 31,	**$ 1,443.0**	$ 2,001.9	$2,834.0

Financial Statement Schedule:

QEP RESOURCES, INC.
Schedule of Valuation and Qualifying Accounts

Column A Description	Column B Beginning Balance	Column C Amounts charged to expense	Column D Deductions for accounts written off and other	Column E Ending Balance
	(in millions)			
Year-Ended December 31, 2009				
Allowance for bad debts	**$ 2.7**	**$ 0.4**	**($ 0.1)**	**$ 3.0**
Year Ended December 31, 2008				
Allowance for bad debts	3.3	0.4	(1.0)	2.7
Year Ended December 31, 2007				
Allowance for bad debts	4.3	0.1	(1.1)	3.3

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES.

Financial statements and financial statement schedules filed as part of this report are listed in the index included in Item 8. Financial Statements and Supplementary Data of this report.

(b) Exhibits. The following is a list of exhibits required to be filed as a part of this report in Item 15(b).

Exhibit No.	Description
1.1.*	Purchase Agreement, dated May 11, 2006, by and among Questar Market Resources, Inc., and named Underwriters. (Exhibit No. 99.1 to the Company's Current Report on Form 8-K dated May 11, 2006.)
1.2.*	Purchase Agreement, dated April 1, 2008, by and among Questar Market Resources Inc., and the Underwriters named on Schedule A thereto. (Exhibit No. 1.1. to the Company's Current Report on Form 8-K dated April 1, 2008.)
3.1.*	Articles of Incorporation dated April 27, 1988, for Utah Entrada Industries, Inc. (Exhibit No. 3.1. to the Company's Form 10 dated April 12, 2000.)
3.2.*	Articles of Merger dated May 20, 1988, of Entrada Industries, Inc., a Delaware corporation and Utah Entrada Industries, Inc, a Utah corporation. (Exhibit No. 3.2. to the Company's Form 10 dated April 12, 2000.)
3.3.*	Articles of Amendment dated August 31, 1998, changing the name of Entrada Industries, Inc. to Questar Market Resources, Inc. (Exhibit No. 3.3. to the Company's Form 10 dated April 12, 2000.)
3.4.*	Bylaws, as amended effective February 8, 2005, (Exhibit No. 3.4. to the Company's Annual Report on Form 10-K for 2004.)[1]
4.1.*[1]	Indenture dated as of March 1, 2001, between Questar Market Resources, Inc. and Bank One, NA, as Trustee for the Company's Notes. (Exhibit No. 4.01. to the Company's Current Report on Form 8-K dated March 6, 2001.)
4.2.*	Form of the Registrant's 6.05% Notes due 2016. (Incorporated by reference to Exhibit 99.2 to the Company's Current Report on Form 8-K filed with the Securities and Exchange Commission on May 11, 2006.)
4.3.*	Form of Officers' Certificate setting forth the terms of the 6.05% Notes. (Incorporated by reference to Exhibit 99.3 to the Company's Current Report on Form 8-K filed with the Securities and Exchange Commission on May 11, 2006.)

4.4.*	Credit Agreement dated March 11, 2008, by and among Questar Market Resources, Inc., Bank of America, N.A. and other lenders. (Exhibit No. 4.1. to the Company's Quarterly Report on Form 10-Q for the Quarter Ended March 31, 2008.)
10.1.*	Stipulation and Agreement dated October 14, 1981, executed by Mountain Fuel Supply Company [Questar Gas Company]; Wexpro Company; the Utah Department of Business Regulations, Division of Public Utilities; the Utah Committee of Consumer Services; and the staff of the Public Service Commission of Wyoming. (Exhibit No. 10(a) to Questar Gas Company's Annual Report on Form 10-K for 1981.)
10.2.*	Purchase and Sale Agreement dated January 25, 2008, by and among Will-Drill Resources, Inc. and other sellers party thereto and Questar Exploration and Production Company. (Exhibit No. 10.1 to the Company's Current Report on Form 8-K dated February 29, 2008.)
10.3.*	Purchase Agreement, dated August 24, 2009, by and among Questar Market Resources Inc., and the Underwriters. (Exhibit No. 1.1 to the Company's Form 8-K dated August 24, 2009).
12.	Ratio of earnings to fixed charges.
23.1	Consent of Independent Registered Public Accounting Firm.
23.2	Consent of Independent Petroleum Engineers and Geologists.
23.3	Qualifications and Report of Independent Petroleum Engineers and Geologists.
24.*	Power of Attorney.
31.1	Certification signed by Charles B. Stanley, QEP Resources, Inc. President and Chief Executive Officer, pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2.	Certification signed by Richard J. Doleshek, QEP Resources, Inc. Executive Vice President, Chief Financial Officer and Treasurer, pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.	Certification signed by Charles B. Stanley and Richard J. Doleshek, QEP Resources, Inc. President and Chief Executive Officer and Executive Vice President, Chief Financial Officer and Treasurer, respectively, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

* Exhibits so marked have been filed with the Securities and Exchange Commission as part of the referenced filing and are incorporated herein by reference.

[1] Wells Fargo Bank, N.A. serves as the successor trustee.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) 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, on the 30th day of July, 2010.

QEP RESOURCES, INC.
(Registrant)

By: /s/ C. B. Stanley
C. B. Stanley
President and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the date indicated.

/s/ C. B. Stanley C. B. Stanley	President and Chief Executive Officer Director (Principal Executive Officer)
/s/ Richard J. Doleshek Richard J. Doleshek	Executive Vice President, Chief Financial Officer and Treasurer (Principal Financial Officer)
/s/ B. Kurtis Watts B. Kurtis Watts	Vice President and Controller (Principal Accounting Officer)
*Keith O. Rattie	Chairman of the Board; Director
*Phillips S. Baker, Jr.	Director
*L. Richard Flury	Director
*James A. Harmon	Director
*Robert E. McKee III	Director
*M. W. Scoggins Director	
*C. B. Stanley	Director

July 30, 2010
Date

*By /s/ C. B. Stanley
C. B. Stanley, Attorney in Fact

Exhibits List

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12.	Ratio of earnings to fixed charges.
23.1	Consent of Independent Registered Public Accounting Firm.
23.2	Consent of Independent Petroleum Engineers and Geologists.
23.3	Qualifications and Report of Independent Petroleum Engineers and Geologists.
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32.	Certification signed by Charles B. Stanley and Richard J. Doleshek, QEP Resources, Inc. President and Chief Executive Officer and Executive Vice President, Chief Financial Officer and Treasurer, respectively, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

* Exhibits so marked have been filed with the Securities and Exchange Commission as part of the referenced filing and are incorporated herein by reference.

[1] Wells Fargo Bank, N.A. serves as the successor trustee.

Exhibit 12.

QEP Resources, Inc.
Ratio of Earnings to Fixed Charges

	Year Ended December 31,		
	2009 (recast)	2008 (recast)	2007 (recast)
	(dollars in millions)		
Earnings			
Income from continuing operations before income taxes and adjustment for income or loss from equity investees	**$330.3**	$802.5	$564.0
Add (deduct):			
Fixed charges	**72.1**	68.3	34.9
Distributed income from equity investees	**1.1**	0.5	10.4
Capitalized interest		(4.9)	
Noncontrolling interest in pre-tax income of subsidiary that has not incurred fixed charges	**(2.6)**	(9.0)	
Total Earnings	**$400.9**	$857.4	$609.3
Fixed Charges			
Interest expense	**$ 70.1**	$ 61.7	$ 33.6
Capitalized interest		4.9	
Estimate of the interest within rental expense	**2.0**	1.7	1.3
Total Fixed Charges	**$ 72.1**	$ 68.3	$ 34.9
Ratio of Earnings to Fixed Charges	**5.6**	12.6	17.5

For purposes of this presentation, earnings represent income from continuing operations before income taxes adjusted for fixed charges, earnings and distributions of equity investees. Income before income taxes includes QEP Resources’ share of pretax earnings of equity investees. Fixed charges consist of total interest charges (expensed and capitalized), amortization of debt issuance costs and losses from reacquired debt, and the interest portion of rental expense estimated at 50%.

Exhibit 23.1

Consent of Independent Registered Public Accounting Firm

We consent to the incorporation by reference in the following Registration Statements:

1. Registration Statement (Form S-8 No. 333-167726) pertaining to the QEP Resources, Inc. Long-Term Stock Incentive Plan,

2. Registration Statement (Form S-8 No. 333-167727) pertaining to the QEP Resources, Inc. Employee Investment Plan,

3. Registration Statement (Form S-3 No. 333-165805) of Questar Market Resources, Inc. (predecessor of QEP Resources, Inc.) and in the related Prospectus

of our report dated July 30, 2010, with respect to the consolidated financial statements and schedule of QEP Resources, Inc. included in this Form 8-K for the year ended December 31, 2009.

Ernst & Young LLP

Salt Lake City, Utah
July 30, 2010

Exhibit 23-2

RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS
TBPE FIRM LIC. NO. F-1580

FAX (303) 623-4258

621 SEVENTEENTH STREET,SUITE 1550 DENVER, COLORADO 80293 TELEPHONE (303) 623-9147

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS

As independent petroleum engineers, we hereby consent to the reference of our appraisal reports relating to the proved gas and oil reserves of QEP Energy Company (formerly Questar Exploration and Production Company) in the Annual Report on Form 10-K of QEP Resources, Inc. (formerly Questar Market Resources, Inc.) as of the years ended December 31, 2006, 2007, 2008 and 2009 incorporated herein by reference into Registration Statement Nos. 333-165805 on Form S-3, 333-167726 and 333-167727 on
Form S-8.

/s/ Ryder Scott Company, L.P.
Ryder Scott Company, L.P.

Denver, Colorado
July 30, 2010

RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS
TBPE FIRM LIC. NO. F-1580

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Exhibit 23.3

June 21, 2010

Questar Exploration and Production Company
1050 Seventeenth Street, Suite 500
Denver, Colorado 80265

Gentlemen:

At your request, Ryder Scott Company (Ryder Scott) has prepared an estimate of the proved reserves, future production, and income attributable to certain leasehold and royalty interests of Questar Exploration and Production Company (Questar) as of December 31, 2009. The subject properties are located in the states of Arkansas, California, Colorado, Kansas, Louisiana, Mississippi, Montana, North Dakota, New Mexico, Oklahoma, Texas, Utah and Wyoming. The reserves and income data were estimated based on the definitions and disclosure guidelines of the United States Securities and Exchange Commission (SEC) contained in Title 17, Code of Federal Regulations, Modernization of Oil and Gas Reporting, Final Rule released January 14, 2009 in the Federal Register (SEC regulations). Our third party study, completed on February 4, 2010 and presented herein, was prepared for public disclosure by Questar in filings made with the SEC in accordance with the disclosure requirements set forth in the SEC regulations. The properties reviewed by Ryder Scott represent 100 percent of the total net proved liquid hydrocarbon reserves and 100 percent of the total net proved gas reserves of Questar.

The estimated reserves and future net income amounts presented in this report, as of December 31, 2009 are related to hydrocarbon prices. The hydrocarbon prices used in the preparation of this report are based on the average prices during the 12-month period prior to the ending date of the period covered in this report, determined as unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period, unless prices were defined by contractual arrangements as required by the SEC regulations. Actual future prices may vary significantly from the prices required by SEC regulations; therefore, volumes of reserves actually recovered and the amounts of income actually received may differ significantly from the estimated quantities presented in this report. The results of this study are summarized below.

SEC PARAMETERS
Estimated Net Reserves and Income Data
Certain Leasehold Interests of
Questar Exploration and Production Company
As of December 31, 2009

	Proved			
	Developed			
	Producing	Non-Producing	Undeveloped	Total Proved
Net Remaining Reserves				
Oil/Condensate – Barrels	22,142,327	285,996	6,876,630	29,304,951
Plant Products – Barrels	4,830,391	88,218	2,759,574	7,678,184
Gas – MMCF	1,159,191	19,512	1,346,296	2,524,999
Income Data M$				
Future Gross Revenue	$ 4,419,955	$ 76,103	$4,414,699	$ 8,910,756
Deductions	1,343,483	36,387	2,987,870	4,367,739
Future Net Income (FNI)	$ 3,076,472	$ 39,715	$1,426,829	$ 4,543,016
Discounted FNI @ 10%	$ 1,738,726	$ 19,119	$ 6,835	$ 1,764,680

Liquid hydrocarbons are expressed in standard 42 gallon barrels. All gas volumes are reported on an as “sold basis” expressed in millions of cubic feet (MMCF) at the official temperature and pressure bases of the areas in which the gas reserves are located.

The estimates of the reserves, future production, and income attributable to properties in this report were prepared using the economic software package Aries™ System Petroleum Economic Evaluation Software, a copyrighted program of Halliburton. The program was used solely at the request of Questar. Ryder Scott has found this program to be generally acceptable, but notes that certain summaries and calculations may vary due to rounding and may not exactly match the sum of the properties being summarized. Furthermore, one line economic summaries may vary slightly from the more detailed cash flow projections of the same properties, also due to rounding. The rounding differences are not material.

The future gross revenue is after the deduction of production taxes. The deductions incorporate the normal direct costs of operating the wells, ad valorem taxes, recompletion costs, and development costs. The future net income is before the deduction of state and federal income taxes and general administrative overhead, and has not been adjusted for outstanding loans that may exist nor does it include any adjustment for cash on hand or undistributed income. Liquid hydrocarbon reserves account for approximately 13 percent and gas reserves account for the remaining 87 percent of total future gross revenue from proved reserves.

The discounted future net income shown above was calculated using a discount rate of 10 percent per annum compounded monthly. Future net income was discounted at four other discount rates which were also compounded monthly. These results are shown in summary form as follows.

Discount Rate Percent	Discounted Future Net Income As of December 31, 2009 Total Proved M$
5	$ 2,666,509
15	$ 1,260,560
20	$ 949,107
25	$ 742,943

The results shown above are presented for your information and should not be construed as our estimate of fair market value.

Reserves Included in This Report

The proved reserves included herein conform to the definition as set forth in the Securities and Exchange Commission’s Regulations Part 210.4-10(a). An abridged version of the SEC reserves definitions from 210.4-10(a) entitled “Petroleum Reserves Definitions” is included as an attachment to this report.

The various reserve status categories are defined under the attachment entitled “Petroleum Reserves Definitions” in this report. The developed non-producing reserves included herein consist of the behind-pipe and shut-in categories.

No attempt was made to quantify or otherwise account for any accumulated gas production imbalances that may exist. The gas volumes included herein do not attribute gas consumed in operations as reserves.

Reserves are those estimated remaining quantities of petroleum which are anticipated to be economically producible, as of a given date, from known accumulations under defined conditions. All reserve estimates involve some degree of uncertainty. The uncertainty depends chiefly on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal classifications, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be further sub-classified as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. At Questar's request, this report addresses only the proved reserves attributable to the properties evaluated herein.

Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward. The reserves included herein were estimated using deterministic methods.

Reserves estimates will generally be revised as additional geologic or engineering data become available or as economic conditions change. Moreover, estimates of reserves may increase or decrease as a result of future operations, effects of regulation by governmental agencies or geopolitical or economic risks. As a result, the estimates of oil and gas reserves have an intrinsic uncertainty. The reserves included in this report are therefore estimates only and should not be construed as being exact quantities. They may or may not be actually recovered, and if recovered, the revenues therefrom, and the actual costs related thereto, could be more or less than the estimated amounts.

Questar's operations may be subject to various levels of governmental controls and regulations. These controls and regulations may include matters relating to land tenure, drilling, production practices, environmental protection, marketing and pricing policies, royalties, various taxes and levies including income tax and are subject to change from time to time. Such changes in governmental regulations and policies may cause volumes of reserves actually recovered and amounts of income actually received to differ significantly from the estimated quantities.

The estimates of reserves presented herein were based upon a detailed study of the properties in which Questar owns an interest; however, we have not made any field examination of the properties. No consideration was given in this report to potential environmental liabilities that may exist nor were any costs included for potential liabilities to restore and clean up damages, if any, caused by past operating practices.

Estimates of Reserves

The estimation of reserves involves two distinct determinations. The first determination results in the estimation of the quantities of recoverable oil and gas and the second determination results in the estimation of the uncertainty associated with those estimated quantities in accordance with the definitions set forth by the Securities and Exchange Commission's Regulations Part 210.4-10(a). The process of estimating the quantities of recoverable oil and gas reserves relies on the use of certain generally accepted analytical procedures. These analytical procedures fall into three broad categories or methods: (1) performance-based methods, (2) volumetric-based methods and (3) analogy. These methods may be used singularly or in combination by the reserve evaluator in the process of estimating the quantities of reserves. The reserve evaluator must select the method or combination of methods which in their professional judgment is most appropriate given the nature and amount of reliable geoscience and engineering data available at the time of the estimate, the established or anticipated performance characteristics of the reservoir being evaluated and the stage of development or producing maturity of the property.

In many cases, the analysis of the available geoscience and engineering data and the subsequent interpretation of this data may indicate a range of possible outcomes in an estimate irrespective of the method selected by the evaluator. When a range in the quantity of reserves is identified, the evaluator must determine the uncertainty associated with the incremental quantities of the reserves. If the reserve quantities are estimated using the deterministic incremental approach, the uncertainty for each discrete incremental quantity of the reserves is addressed by the reserve category assigned by the evaluator. Therefore, it is the categorization of reserve quantities as proved, probable and/or possible that addresses the inherent uncertainty in the estimated quantities reported. All quantities of reserves within the same reserve category have the same level of uncertainty under the SEC definitions.

Estimates of reserves quantities and their associated reserve categories may be revised in the future as additional geoscience or engineering data become available. Furthermore, estimates of reserves quantities and their associated reserve categories may also be revised due to other factors such as changes in economic conditions, results of future operations, effects of regulation by governmental agencies or geopolitical or economic risks as previously noted herein.

The reserves for the properties included herein were estimated by performance methods, the volumetric method, analogy, or a combination of methods. Approximately 100 percent of the proved producing reserves attributable to producing wells and/or reservoirs were estimated by performance methods. These performance methods include, but may not be limited to decline curve analysis and/or material balance which utilized extrapolations of historical production and pressure data available through December, 2009 in those cases where such data were considered to be definitive. The data utilized in this analysis were supplied to Ryder Scott by Questar or obtained from public data sources and were considered sufficient for the purpose thereof.

Approximately 100 percent of the proved non-producing and undeveloped reserves included herein were estimated by the volumetric method, analogy, or a combination of methods. The non-producing reserves were generally estimated by the volumetric method. The undeveloped reserves were generally estimated by analogy with, in many cases, a volumetric check for reasonableness. The volumetric analysis utilized pertinent well data supplied to Ryder Scott by Questar or which we have obtained from public data sources that was available through December, 2009. The data utilized from the well data incorporated into our volumetric analysis were considered sufficient for the purpose thereof. In summary, we consider the assumptions, data, methods and analytical procedures used in this report appropriate for the purpose hereof, and we have used all such methods and procedures that we consider necessary and appropriate to prepare the estimates of reserves herein.

To estimate economically recoverable oil and gas reserves and related future net cash flows, we consider many factors and assumptions including, but not limited to, the use of reservoir parameters derived from geological, geophysical and engineering data which cannot be measured directly, economic criteria based on current costs and SEC pricing requirements, and forecasts of future production rates. Under the SEC regulations 210.4-10(a)(22)(v) and (26), proved reserves must be anticipated to be economically producible from a given date forward based on existing economic conditions including the prices and costs at which economic producibility from a reservoir is to be determined. While it may reasonably be anticipated that the future prices received for the sale of production and the operating costs and other costs relating to such production may increase or decrease from those under existing economic conditions, such changes were, in accordance with rules adopted by the SEC, omitted from consideration in making this evaluation.

Questar has informed us that they have furnished us all of the material accounts, records, geological and engineering data, and reports and other data required for this investigation. In preparing our forecast of future production and income, we have relied upon data furnished by Questar with respect to property interests owned, production and well tests from examined wells, normal direct costs of operating the wells or leases, other costs such as transportation and/or processing fees, ad valorem and production taxes, recompletion and development costs, product prices based on the SEC regulations, geological structural and isochore maps, well logs, core analyses, and pressure measurements. Ryder Scott reviewed such factual data for its reasonableness; however, we have not conducted an independent verification of the data supplied by Questar. We consider the factual data used in this report appropriate and sufficient for the purpose of preparing the estimates of reserves and future net revenues herein.

Future Production Rates

Our forecasts of future production rates are based on historical performance from wells currently on production. Test data and other related information were used to estimate the anticipated initial production rates for those wells or locations that are not currently producing. If no production decline trend has been established, future production rates were held constant, or adjusted for the effects of curtailment where appropriate, until a decline in ability to produce was anticipated. An estimated rate of decline was then applied to depletion of the reserves. If a decline trend has been established, this trend was used as the basis for estimating future production rates. For reserves not yet on production, sales were estimated to commence at an anticipated date furnished by Questar.

The future production rates from wells currently on production may be more or less than estimated because of changes in market demand or allowables set by regulatory bodies. Wells or locations that are not currently producing may start producing earlier or later than anticipated in our estimates.

Hydrocarbon Prices

As previously stated, the hydrocarbon prices used herein are based on SEC price parameters using the average prices during the 12-month period prior to the ending date of the period covered in this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period, unless prices were defined by contractual arrangements. For hydrocarbon products sold under contract, the contract prices, including fixed and determinable escalations, exclusive of inflation adjustments, were used until expiration of the contract. Upon contract expiration, the prices were adjusted to the 12-month unweighted arithmetic average as previously described. Oil prices are based on a West Texas Intermediate Cushing, Oklahoma crude oil spot price of $61.18 per barrel. Gas prices are based on a Henry Hub Cash Market gas price of $3.87 per MMBTU. Product prices which were actually used for each property reflect adjustment for gravity, quality, local conditions, and/or distance from market. Price differentials and adjustments to physical spot prices as of December 2009 were furnished by Questar and were accepted as presented. Oil and gas prices are held constant throughout the life of the properties.

The effects of derivative instruments designated as price hedges of oil and gas quantities are not reflected in our individual property evaluations.

Costs

Operating costs for the leases and wells in this report are based on the operating expense reports of Questar and include only those costs directly applicable to the leases or wells. The operating costs include a portion of general and administrative costs allocated directly to the leases and wells. For operated properties, the operating costs include an appropriate level of corporate general administrative and overhead costs. The operating costs for non-operated properties include the COPAS overhead costs that are allocated directly to the leases and wells under terms of operating agreements. No deduction was made for loan repayments, interest expenses, or exploration and development prepayments that were not charged directly to the leases or wells.

Development costs were furnished to us by Questar and are based on authorizations for expenditure for the proposed work or actual costs for similar projects. Questar's estimates of zero abandonment costs after salvage value for onshore properties were used in this report. Ryder Scott has not performed a detailed study of the abandonment costs or the salvage value and makes no warranty for Questar's estimate.

Because of the direct relationship between volumes of proved undeveloped reserves and development plans, we include in the proved undeveloped category only reserves assigned to undeveloped locations that we have been assured will definitely be drilled. Questar has assured us of their intent and ability to proceed with the development activities included in this report, and that they are not aware of any legal, regulatory, political or economic obstacles that would significantly alter their plans.

Current costs used by Questar were held constant throughout the life of the properties.

Standards of Independence and Professional Qualification

Ryder Scott is an independent petroleum engineering consulting firm that has been providing petroleum consulting services throughout the world for over seventy years. Ryder Scott is employee-owned and maintains offices in Houston, Texas; Denver, Colorado; and Calgary, Alberta, Canada. We have over eighty engineers and geoscientists on our permanent staff. By virtue of the size of our firm and the large number of clients for which we provide services, no single client or job represents a material portion of our annual revenue. We do not serve as officers or directors of any publicly-traded oil and gas company and are separate and independent from the operating and investment decision-making process of our clients. This allows us to bring the highest level of independence and objectivity to each engagement for our services.

Ryder Scott actively participates in industry-related professional societies and organizes an annual public forum focused on the subject of reserves evaluations and SEC regulations. Many of our staff have authored or co-authored technical papers on the subject of reserves related topics. We encourage our staff to maintain and enhance their professional skills by actively participating in ongoing continuing education.

Prior to becoming an officer of the Company, Ryder Scott requires that staff engineers and geoscientists have received professional accreditation in the form of a registered or certified professional engineer's license or a registered or certified professional geoscientist's license, or the equivalent thereof, from an appropriate governmental authority or a recognized self-regulating professional organization.

We are independent petroleum engineers with respect to Questar. Neither we nor any of our employees have any interest in the subject properties and neither the employment to do this work nor the compensation is contingent on our estimates of reserves for the properties which were reviewed.

The results of this study, presented herein, are based on technical analysis conducted by teams of geoscientists and engineers from Ryder Scott. The professional qualifications of the undersigned, the technical person primarily responsible for overseeing the evaluation of the reserves information discussed in this report, are included as an attachment to this letter.

Terms of Usage

The results of our third party study, presented in report form herein, were prepared in accordance with the disclosure requirements set forth in the SEC regulations and intended for public disclosure as an exhibit in filings made with the SEC by Questar Corporation.

Questar Corporation makes periodic filings on Form 10-K with the SEC under the 1934 Exchange Act. Furthermore, Questar Corporation has certain registration statements filed with the SEC under the 1933 Securities Act that automatically incorporate by reference any subsequently filed Form 10-K. We have consented to the incorporation by reference in the registration statements on Form S-8 of Questar Corporation of the references to our name as well as to the references to our third party report for Questar Exploration and Production Company, which appears in the December 31, 2009 annual report on Form 10-K of Questar Corporation. Our written consent for such use is included as a separate exhibit to the filings made with the SEC by Questar Corporation.

We have provided Questar with a digital version of the original signed copy of this report letter. In the event there are any differences between the digital version included in filings made by Questar and the original signed report letter, the original signed report letter shall control and supersede the digital version.

The data and work papers used in the preparation of this report are available for examination by authorized parties in our offices. Please contact us if we can be of further service.

Very truly yours,

[SEAL]

STATE OF COLORADO
RICHARD J. MARSHALL
23260
LICENSED PROFESSIONAL ENGINEER

RYDER SCOTT COMPANY, L.P.
TBPE Firm Registration No. F-1580

/s/ Richard J. Marshall
Richard J. Marshall, P.E.
Colorado P.E. License No. 23260
Vice President

Approved:

/s/James L. Baird
James L. Baird
Senior Vice President

RYDER SCOTT COMPANY, L.P.
TBPE Firm Registration No. F-1580

[SEAL]
STATE OF TEXAS
DON P. ROESLE
56406
LICENSED
PROFESSIONAL ENGINEER

/s/ Don P. Roesle
Don P. Roesle, P.E.
TBPE License No. 56406
Chief Executive Officer

* The work performed in this report for properties located in the state of Texas has been reviewed and approved by a licensed Texas professional engineer according to the rules of the Texas Board of Professional Engineers (TBPE).

Professional Qualifications of Primary Technical Person

The conclusions presented in this report are the result of technical analysis conducted by teams of geoscientists and engineers from Ryder Scott Company, L.P. Richard J. Marshall was the primary technical person responsible for overseeing the estimate of the future net reserves and income.

Marshall, an employee of Ryder Scott Company L.P. (Ryder Scott) beginning in 1981, is a Vice President responsible for coordinating and supervising staff and consulting engineers of the company in ongoing reservoir evaluation studies. Before joining Ryder Scott, Marshall served in a number of engineering positions with Texaco, Phillips Petroleum, and others. For more information regarding Mr. Marshall’s geographic and job specific experience, please refer to the Ryder Scott Company website at www.ryderscott.com/Experience/Employees.

Marshall earned a B.S. in Geology from the University of Missouri in 1974 and a M.S. in Geological Engineering from the University of Missouri at Rolla in 1976. Marshall is a registered Professional Engineer in the State of Colorado. He is a member of the Society of Petroleum Engineers, Wyoming Geological Association, Rocky Mountain Association of Geologists and the Society of Petroleum Evaluation Engineers.

Based on Marshall’s educational background, professional training and more than 30 years of practical experience in the estimation and evaluation of petroleum reserves, Marshall has attained the professional qualifications as a Reserves Estimator and Reserves Auditor as set forth in Article III of the “Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information” promulgated by the Society of Petroleum Engineers as of February 19, 2007.

Questar Exploration and Production Company

Estimated

Future Reserves and Income

Attributable to Certain

Leasehold Interests

As of

December 31, 2009

[SEAL]	[SEAL]
Don P. Roesle, P.E. TBPE License No. 56406	Richard J. Marshall, P.E. Colorado License No. 23260
/s/ Don P. Roesle	/s/ Richard J. Marshall
Don P. Roesle, P.E. TBPE License No. 56406 Chief Executive Officer	Richard J. Marshall, P.E. Colorado License No. 23260 Vice President

RYDER SCOTT COMPANY, L.P.
TBPE Firm Registration No. F-1580

* The work performed in this report for properties located in the state of Texas has been reviewed and approved by a licensed Texas professional engineer according to the rules of the Texas Board of Professional Engineers (TBPE).

PETROLEUM RESERVES DEFINITIONS

As Adapted From:
RULE 4-10(a) of REGULATION S-X PART 210
UNITED STATES SECURITIES AND EXCHANGE COMMISSION (SEC)

PREAMBLE

On January 14, 2009, the United States Securities and Exchange Commission ("the Commission") published the "Modernization of Oil and Gas Reporting; Final Rule" in the Federal Register of National Archives and Records Administration (NARA). The "Modernization of Oil and Gas Reporting; Final Rule" includes revisions and additions to the definition section in Rule 4-10 of Regulation S-X, revisions and additions to the oil and gas reporting requirements in Regulation S-K, and amends and codifies Industry Guide 2 in Regulation S-K. The "Modernization of Oil and Gas Reporting; Final Rule", including all references to Regulation S-X and Regulation S-K, shall be referred to herein collectively as the "SEC Regulations". The SEC Regulations take effect with all filings made with the United States Securities and Exchange Commission as of December 31, 2009, or after January 1, 2010. Reference should be made to the full text under Title 17, Code of Federal Regulations, Regulation S-X Part 210, Rule 4-10 (a) for the complete definitions, as the following definitions, descriptions and explanations rely wholly or in part on excerpts from the original document (direct passages excerpted from the aforementioned SEC document are denoted in italics herein).

Reserves are those quantities of petroleum which are anticipated to be commercially recovered from known accumulations from a given date forward under defined conditions. All reserve estimates involve some degree of uncertainty. The uncertainty depends chiefly on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal classifications, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be further sub-classified as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. Under the SEC Regulations as of December 31, 2009, or after January 1, 2010, a company may optionally disclose estimated quantities of probable or possible oil and gas reserves in documents publicly filed with the Commission. The SEC Regulations continue to prohibit disclosure of estimates of oil and gas resources other than reserves and any estimated values of such resources in any document publicly filed with the Commission unless such information is required to be disclosed in the document by foreign or state law as noted in §229.102 (5).

Reserves estimates will generally be revised as additional geologic or engineering data become available or as economic conditions change.

Reserves may be attributed to either natural energy or improved recovery methods. Improved recovery methods include all methods for supplementing natural energy or altering natural forces in the reservoir to increase ultimate recovery. Examples of such methods are pressure maintenance, cycling, waterflooding, thermal methods, chemical flooding, and the use of miscible and immiscible displacement fluids. Other improved recovery methods may be developed in the future as petroleum technology continues to evolve.

RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §229.4 -10(a) (26) defines reserves as follows:

Reserves. *Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.*

Note to paragraph (a)(26): Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results). Such areas may contain prospective resources (i.e., potentially recoverable resources from undiscovered accumulations).

PROVED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §229.4 -10(a) (22) defines proved oil and gas reserves as follows:

Proved oil and gas reserves. *Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.*

(i) The area of the reservoir considered as proved includes:

(A) The area identified by drilling and limited by fluid contacts, if any, and

(B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.

(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.

(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

(A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and

(B) The project has been approved for development by all necessary parties and entities, including governmental entities.

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

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RESERVES STATUS DEFINITIONS AND GUIDELINES

As Adapted From:
RULE 4-10(a) of REGULATION S-X PART 210
UNITED STATES SECURITIES AND EXCHANGE COMMISSION (SEC)

and

PETROLEUM RESOURCES MANAGEMENT SYSTEM (SPE-PRMS)
Sponsored and Approved by:
SOCIETY OF PETROLEUM ENGINEERS (SPE),
WORLD PETROLEUM COUNCIL (WPC)
AMERICAN ASSOCIATION OF PETROLEUM GEOLOGISTS (AAPG)
SOCIETY OF PETROLEUM EVALUATION ENGINEERS (SPEE)

Reserves status categories define the development and producing status of wells and reservoirs.

DEVELOPED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §229.4-10(a) (6) defines developed oil and gas reserves as follows:

Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

(i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and

(ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Developed Producing (SPE-PRMS Definitions)

While not a requirement for disclosure under the SEC regulations, developed oil and gas reserves may be further sub-classified according to the guidance contained in the SPE-PRMS as Producing or Non-Producing.

Developed Producing Reserves

Developed Producing Reserves are expected to be recovered from completion intervals that are open and producing at the time of the estimate.

Improved recovery reserves are considered producing only after the improved recovery project is in operation.

Developed Non-Producing

Developed Non-Producing Reserves include shut-in and behind-pipe reserves.

Shut-In

Shut-in Reserves are expected to be recovered from:

(1) completion intervals which are open at the time of the estimate but which have not yet started producing;

(2) wells which were shut-in for market conditions or pipeline connections; or

(3) wells not capable of production for mechanical reasons.

Behind-Pipe

Behind-pipe Reserves are expected to be recovered from zones in existing wells which will require additional completion work or future re-completion prior to start of production.

In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

UNDEVELOPED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §229.4 -10(a) (31) defines undeveloped oil and gas reserves as follows:

Undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

(i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.

(ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time.

(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, as defined in paragraph (a)(2) of this section, or by other evidence using reliable technology establishing reasonable certainty.

Qualifications of Questar Reservoir Engineer

DENNIS R. BECCUE
QUALIFICATIONS

PROFESSIONAL EXPERIENCE

- Registered Professional Engineer with over 30 years diversified oil and gas engineering experience with both major and independent exploration and production companies
- Questar Market Resources (QMR) Chief Reservoir Engineer, and member QMR Reserves Review Committee, since 2006
- Over 15 years oil and gas reserves estimating experience with QMR
- QMR Pinedale Division Production/Reservoir Engineering Manager since June 2000
    - Directed all well production/completion activities
    - Responsible for evaluation of division reserves
- Reservoir/Operations engineering experience spanning most active domestic basins including Rocky Mountains, San Juan, Permian, Mid-Continent and onshore Gulf Coast

EDUCATIONAL BACKGROUND

THE UNIVERSITY OF TULSA, Tulsa, Oklahoma
Bachelor of Science, Petroleum Engineering - May 1979

PROFESSIONAL LICENSES AND AFFILIATIONS

Registered Professional Engineer (Oklahoma #15172)

Society of Petroleum Engineers – Member 1979

Exhibit 31.1

CERTIFICATION

I, Charles B. Stanley, certify that:

1. I have reviewed this report of QEP Resources, Inc. on Form 10-K for the period ended December 31, 2009;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and we have:
   (a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting.
5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent function):
   (a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

July 30, 2010

/s/ Charles B. Stanley
Charles B. Stanley
President and Chief Executive Officer

Exhibit 31.2

CERTIFICATION

I, Richard J. Doleshek, certify that:

6. I have reviewed this report of QEP Resources, Inc. on Form 10-K for the period ended December 31, 2009;

7. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

8. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

9. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and we have:

   (e) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (f) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (g) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (h) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting.

10. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent function):

   (c) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (d) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

July 30, 2010

/s/ Richard J. Doleshek
Richard J. Doleshek
Executive Vice President,
Chief Financial Officer and Treasurer

Exhibit 32

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with this report of QEP Resources, Inc. (the Company) on Form 10-K for the period ended December 31, 2009, as filed with the Securities and Exchange Commission on the date hereof (the Report), C. B. Stanley, President and Chief Executive Officer of the Company, and Richard J. Doleshek, Executive Vice President, Chief Financial Officer and Treasurer of the Company, each hereby certifies, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that, to the best of his knowledge:

(1) The Report fully complies with the requirements of Section 13(a) or Section 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

QEP RESOURCES, INC.

July 30, 2010

/s/ C. B. Stanley
C. B. Stanley
President and Chief Executive Officer

July 30, 2010

/s/ Richard J. Doleshek
Richard J. Doleshek
Executive Vice President,
Chief Financial Officer and Treasurer