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

AMENDMENT NO. 1 TO
FORM 10-Q

☒ QUARTERLY REPORT UNDER SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the Quarter Ended March 31, 2009

☐ TRANSITION REPORT UNDER SECTION 13 OR 15(d) OF EXCHANGE ACT

Commission File No. 0-12185

NGAS RESOURCES, INC.

(Exact name of registrant as specified in its charter)

Province of British Columbia	**Not Applicable**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
120 Prosperous Place, Suite 201 Lexington, Kentucky	**40509-1844**
(Address of principal executive offices)	(Zip Code)

Registrant's telephone number, including area code: (859) 263-3948

(Former name or former address, if changed since the last report)

Indicate by check mark if the registrant (1) filed all reports required to be filed by Section 13 or 15(d) of the Act during the past 12 months and (2) has been subject to those filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark if the registrant has submitted electronically and posted on its corporate website every indicative data file required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☒ No ☐

Indicate by check mark if the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer or a smaller reporting company (as defined in Rule 12b-2 under the Exchange Act).

Large accelerated filer ☐	Accelerated filer ☒
Non-accelerated filer ☐	Smaller reporting company ☐

Indicate by check mark if the registrant is a shell company (as defined in Rule 12b-2). Yes ☐ No ☒

Number of shares outstanding of each of the registrant's classes of common stock as of the latest practicable date.

Title of Class	Outstanding at May 5, 2009
Common Stock	26,968,646

NGAS RESOURCES, INC.

INDEX TO FORM 10-Q/A

PART I. FINANCIAL INFORMATION

ADDITIONAL INFORMATION

We file annual, quarterly and other reports and information with the Securities Exchange Commission (*SEC*). Promptly after their filing, we provide access to these reports without charge on our website at www.ngas.com. Our principal and administrative offices are located in Lexington, Kentucky. Our common stock is traded on the Nasdaq Global Select Market under the symbol *NGAS*. Unless otherwise indicated, references in this report to the *company* or to *we*, *our* or *us* include NGAS Resources, Inc., our direct and indirect wholly owned subsidiaries and our interests in sponsored drilling partnerships. As used in this report, *Dth* means decatherm, *Mcf* means thousand cubic feet, *Mcfe* means thousand cubic feet of natural gas equivalents, *Mmcf* means million cubic feet, *Bcf* means billion cubic feet and *EUR* means estimated ultimately recoverable volumes of natural gas or oil.

EXPLANATORY NOTE

This amended report (*10-Q/A*) modifies some of the disclosures in our quarterly report on Form 10-Q for the quarter ended March 31, 2009 (*10-Q*) in response to review comments by the staff of the SEC. The 10-Q/A restates Part I of the 10-Q in its entirety but does not change any disclosures except as noted below, and it does not update the 10-Q to reflect any other developments or events after the date of the original filing.

- *Condensed Consolidated Financial Statements* – The condensed consolidated financial statements have been restated to account for the embedded conversion feature of our 6% convertible notes as a derivative liability under ASC 815-40-15 (formerly EITF 07-5), which became effective as of January 1, 2009. The impact of the change in accounting principles is set forth in Note 2 – Restatement Adjustments.
- *MD&A* – The recognition of non-cash interest expense for accretion of the debt discount and related adjustments from the change in accounting principles are reflected under the caption "Results of Operations."
- *Certifications* – The certifications in the exhibits to the 10-Q have been updated as the date of this 10-Q/A.

NGAS RESOURCES, INC.

CONDENSED CONSOLIDATED BALANCE SHEETS

	March 31, 2009	December 31, 2008
ASSETS	(Unaudited)	
Current assets:		
Cash	$ 1,248,066	$ 981,899
Accounts receivable	5,758,219	10,450,173
Prepaid expenses and other current assets	609,850	540,253
Loans to related parties	77,474	79,188
Total current assets	7,693,609	12,051,513
Bonds and deposits	837,898	623,898
Oil and gas properties	232,001,956	229,218,344
Property and equipment	3,099,554	3,285,925
Loans to related parties	171,429	171,429
Deferred financing costs	1,501,959	1,689,580
Goodwill	313,177	313,177
Total assets	$245,619,582	$247,353,866
LIABILITIES		
Current liabilities:		
Accounts payable	$ 5,265,843	$ 12,362,092
Accrued liabilities	641,762	675,141
Deferred compensation	2,209,700	2,246,439
Customer drilling deposits	1,594,248	2,262,955
Long-term debt, current portion	24,000	24,000
Total current liabilities	9,735,553	17,570,627
Deferred compensation	190,376	—
Deferred income taxes	13,116,638	12,949,476
Long-term debt	107,192,740	109,270,818
Fair value of derivative financial instruments	518	—
Other long-term liabilities	3,845,906	3,685,849
Total liabilities	134,081,731	143,476,770
SHAREHOLDERS' EQUITY		
Capital stock		
Authorized:		
5,000,000 Preferred shares		
100,000,000 Common shares		
Issued:		
26,968,646 Common shares (2008 – 26,543,646)	110,988,162	110,626,912
21,100 Common shares held in treasury, at cost	(23,630)	(23,630)
Paid-in capital – options and warrants	4,039,236	3,774,600
To be issued:		
9,185 Common shares (2008 – 9,185)	45,925	45,925
	115,049,693	114,423,807
Deficit	(3,511,842)	(10,546,711)
Total shareholders' equity	111,537,851	103,877,096
Total liabilities and shareholders' equity	$245,619,582	$247,353,866

See accompanying notes.

NGAS Resources, Inc.

CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS

(Unaudited)

	Three Months Ended March 31, 2009	Three Months Ended March 31, 2008
REVENUE		
Contract drilling	$ 7,323,752	$ 6,602,118
Oil and gas production	7,067,219	8,489,434
Gas transmission, compression and processing	2,804,982	2,558,092
Total revenue	17,195,953	17,649,644
DIRECT EXPENSES		
Contract drilling	5,541,426	5,119,849
Oil and gas production	2,324,965	2,764,955
Gas transmission, compression and processing	968,917	1,090,246
Total direct expenses	8,835,308	8,975,050
OTHER EXPENSES (INCOME)		
Selling, general and administrative	3,250,265	3,288,483
Options, warrants and deferred compensation	418,273	137,679
Depreciation, depletion and amortization	3,618,870	2,871,760
Bad debt expense	—	347,840
Interest expense	2,281,008	1,325,970
Interest income	(8,816)	(69,710)
Fair value gain on derivative financial instruments	(14,319)	—
Other, net	79,541	(6,277)
Total other expenses	9,624,822	7,895,745
INCOME (LOSS) BEFORE INCOME TAXES	(1,264,177)	778,849
INCOME TAX EXPENSE	167,162	615,660
NET INCOME (LOSS)	$ (1,431,339)	$ 163,189
NET INCOME (LOSS) PER SHARE		
Basic	$ (0.05)	$ 0.01
Diluted	$ (0.05)	$ 0.01
WEIGHTED AVERAGE COMMON SHARES OUTSTANDING		
Basic	26,671,146	26,235,811
Diluted	26,671,146	26,731,037

See accompanying notes.

NGAS RESOURCES, INC.

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

(Unaudited)

	Three Months Ended March 31, 2009	2008
OPERATING ACTIVITIES		
Net income (loss)	$ (1,431,339)	$ 163,189
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Incentive bonus paid in common shares	361,250	31,570
Options, warrants and deferred compensation	418,273	137,679
Depreciation, depletion and amortization	3,618,870	2,871,760
Bad debt expense	—	347,840
Gain on sale of assets	(9,285)	(1,336)
Fair value gain on derivative financial instruments	(14,319)	—
Accretion of debt discount	908,967	—
Deferred income taxes	167,162	615,660
Changes in assets and liabilities:		
Accounts receivable	4,691,954	(1,156,106)
Prepaid expenses and other current assets	(69,597)	(456,734)
Other non-current assets	—	3,242,790
Accounts payable	(7,096,249)	2,337,766
Accrued liabilities	(33,379)	128,804
Customers' drilling deposits	(668,707)	169,285
Other long-term liabilities	160,057	—
Net cash provided by operating activities	1,003,658	8,432,167
INVESTING ACTIVITIES		
Proceeds from sale of assets	19,696	12,200
Purchase of property and equipment	(29,256)	(155,287)
Increase in bonds and deposits	(214,000)	(75,000)
Additions to oil and gas properties, net	(6,008,612)	(13,096,966)
Net cash used in investing activities	(6,232,172)	(13,315,053)
FINANCING ACTIVITIES		
Decrease in loans to related parties	1,714	1,938
Proceeds from issuance of common shares	—	102,000
Payments of deferred financing costs	(1,033)	(114,293)
Proceeds from issuance of long term debt	5,500,000	5,740,000
Payments of long term debt	(6,000)	(2,020,175)
Net cash provided by financing activities	5,494,681	3,709,470
Change in cash	266,167	(1,173,416)
Cash, beginning of period	981,899	2,816,678
Cash, end of period	$ 1,248,066	$ 1,643,262
SUPPLEMENTAL DISCLOSURE		
Interest paid	$ 1,371,480	$ 1,327,683
Income taxes paid	—	—

See accompanying notes.

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(Unaudited)

Note 1. Summary of Significant Accounting Policies

(a) General. The accompanying condensed consolidated financial statements of NGAS Resources, Inc. (*NGAS*) have been prepared in accordance with accounting principles generally accepted in the United States of America (*U.S. GAAP*). Our accounting policies are described in Note 1 to the consolidated financial statements in our annual report on Form 10-K for the year ended December 31, 2008. Our accounting policies and their method of application in the accompanying condensed consolidated financial statements are consistent with those described in the annual report.

(b) Basis of Presentation. The accompanying condensed consolidated financial statements include the accounts of NGAS, our wholly owned subsidiary, Daugherty Petroleum, Inc. (*DPI*), and its wholly owned subsidiaries. The condensed consolidated financial statements also reflect DPI's interests in a total of 38 drilling programs sponsored to participate in some of its drilling initiatives. We account for those interests using the proportionate consolidation method, with all material inter-company accounts and transactions eliminated on consolidation. References to the *company*, *we*, *our* or *us* include DPI, its subsidiaries and interests in sponsored drilling programs. These interim consolidated financial statements are unaudited and are restated to reflect the adoption of Accounting Standards Codification (*ASC*) Topic 815-40-15, *Contracts in Entity's Own Equity* (formerly EITF 07-5), which became effective as of January 1, 2009. See Note 2 – Restatement Adjustments. In the opinion of our management, the accompanying condensed consolidated financial statements, as restated, reflect all normal recurring adjustments that are necessary to fairly present our financial position at March 31, 2009 and results of operations and cash flows for the three months ended March 31, 2009 and 2008.

(c) *Estimates.* The preparation of financial statements in conformity with U.S. GAAP requires us to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities as of the date of the consolidated financial statements and the reported amounts of revenues and expenses during the reporting periods. The most significant estimates pertain to proved oil and gas reserves and related cash flow estimates used in impairment tests of goodwill and other long-lived assets, estimates of future development, dismantlement and abandonment costs and estimates relating to future oil and gas revenues and expenses. We also make estimates and assumptions in maintaining allowances for doubtful accounts when deemed appropriate to reflect losses that could result from failures by customers or other parties to make payments on our trade receivables. The evaluations required for all of these estimates involve significant uncertainties, and actual results could differ from the estimates.

Note 2. Restatement Adjustments

(a) *Change in Accounting Principle*. Effective as of January 1, 2009, we adopted the revised guidance for equity-linked financial instruments now codified in ASC 815-40-15, which requires the embedded conversion feature of our 6% convertible notes to be bifurcated and treated as a derivative liability based on its fair value as a stand-alone instrument. The notes were issued in December 2005 in the principal amount of $37 million. See Note 8 – Long-Term Debt. Under the revised guidance, the notes are no longer considered to be linked to our own stock due to the weighted average antidilution provisions in their embedded conversion feature. As a result, the notes no longer qualify for the scope exception from derivative fair value accounting under ASC 815-15, *Derivatives and Hedging – Embedded Derivatives* (formerly contained in SFAS 133).

(b) *Cumulative Effect Adjustments*. The transition provisions of ASC 815-40-15 require cumulative effect adjustments as of January 1, 2009 to reflect the amounts that would have been recognized if derivative fair value accounting had been applied from the original issuance date of an equity-linked financial instrument through the implementation date of the revised guidance. Our fair value analysis of the notes reflects an initial derivative liability of $16,575,445 for their embedded conversion feature, primarily reflecting their five-year maturity and 10% conversion premium at issuance. From the note issuance date through the end of 2008, we would have recorded fair value gains on derivative financial instruments of $16,560,608, offset by non-cash interest expenses totaling $8,094,400, reflecting accretion of the debt discount under the effective interest method. The following table shows the cumulative effect adjustment to retained deficit at January 1, 2009.

Cumulative Effect Adjustment:	**Retained Deficit**
As previously reported, December, 31, 2008	$ (10,546,711)
Cumulative effect adjustment	8,466,208
As adjusted, January 1, 2009	$ (2,080,503)

(c) *Impact on Interim Financial Statements*. As restated at March 31, 2009, the carrying amount of our convertible notes has been reduced to $29,427,922. This reflects the unaccreted debt discount to their face amount of $37 million. In addition, a derivative liability has been established at $518, representing the fair value of the embedded conversion feature at the balance sheet date. The following table shows the adjustments on restatement of the condensed consolidated statement of operations previously reported for the three months ended March 31, 2009. The adjustment to interest expense reflect accretion of the debt discount under the effective interest method. The fair value gain on derivative financial instruments reflects a mark-to market change in the fair value of the embedded derivative.

	Three Months Ended March 31, 2009		
Statements of Operations:	**As Previously Reported**	**Restatement Adjustments**	**As Restated**
Total revenue	$ 17,195,953	$ —	$ 17,195,953
Total direct expenses	8,835,308	—	8,835,308
Other expenses (income)			
Selling, general and administrative	3,250,265	—	3,250,265
Options, warrants and deferred compensation	418,273	—	418,273
Depreciation, depletion and amortization	3,618,870	—	3,618,870
Interest expense	1,372,041	908,967	2,281,008
Interest income	(8,816)	—	(8,816)
Fair value gain on derivative financial instruments	—	(14,319)	(14,319)
Other, net	79,541	—	79,541
Total other expenses	8,730,174	894,648	9,624,822
Loss before income taxes	(369,529)	(894,648)	(1,264,177)
Income tax expense	167,162	—	167,162
Net loss	$ (536,691)	$ (894,648)	$ (1,431,339)
EPS – basic and diluted	$ (0.02)	$ (0.03)	$ (0.05)

Note 3. Oil and Gas Properties

(a) *Capitalized Costs and DD&A*. All of our oil and gas development and producing activities are conducted within the continental United States. Capitalized costs and accumulated depreciation, depletion and amortization (*DD&A*) for our oil and gas properties, gathering facilities and well equipment as of March 31, 2009 and December 31, 2008 are summarized below.

	March 31, 2009	December 31, **2008**
Proved oil and gas properties	$197,600,820	$192,186,676
Unproved oil and gas properties	4,840,080	5,065,835
Gathering facilities and well equipment	68,146,668	67,326,445
	270,587,568	264,578,956
Accumulated DD&A	(38,585,612)	(35,360,612)
Net oil and gas properties and equipment	$232,001,956	$229,218,344

(b) *Suspended Well Costs*. We had no suspended exploratory wells costs that were required to be expensed during 2008 or the first three months of 2009 based on the criteria of FSP No. 19-1, *Accounting for Suspended Well Costs*. As of March 31, 2009, we had no wells for which exploratory wells costs had been capitalized for a period of greater than one year after completion of drilling.

Note 4. Property and Equipment

The following table presents the capitalized costs and accumulated depreciation for our other property and equipment as of March 31, 2009 and December 31, 2008.

	March 31, 2009	December 31, 2008
Land	$ 12,908	$ 12,908
Building improvements	64,265	64,265
Machinery and equipment	3,360,793	3,333,981
Office furniture and fixtures	175,862	175,862
Computer and office equipment	665,115	670,349
Vehicles	1,892,449	1,951,279
	6,171,392	6,208,644
Accumulated depreciation	(3,071,838)	(2,922,719)
Net other property and equipment	$ 3,099,554	$ 3,285,925

Note 5. Deferred Financing Costs

Financing costs for our convertible notes and secured credit facility are initially capitalized and amortized at rates based on the terms of the underlying debt instruments. See Note 8 – Long Term Debt. Upon conversion of convertible notes, the principal amount converted is added to equity, net of a proportionate amount of the original financing costs. Unamortized deferred financing costs for our outstanding notes and credit facility aggregated $1,501,959 at March 31, 2009 and $1,689,580 at December 31, 2008.

Note 6 . Goodwill

Goodwill of $1,789,564 was recorded in connection with our acquisition of DPI in 1993 and was amortized over ten years on a straight-line basis until 2002, when we adopted the Canadian equivalent of Financial Accounting Standards (*SFAS*) No. 142, *Goodwill and Other Intangible Assets*. Under the adopted standard, goodwill is no longer amortized but is instead tested for impairment at least annually. Our annual analyses indicated that no impairment charges were required. Accordingly, accumulated amortization of goodwill remained at $1,476,387 as of March 31, 2009 and December 31, 2008, with unamortized goodwill of $313,177.

Note 7. Customer Drilling Deposits

Net proceeds received under drilling contracts with sponsored programs are recorded as customer drilling deposits at the time of receipt. We recognize revenues from drilling operations on the completed contract method as the wells are drilled, rather than when funds are received. We had customer drilling deposits of $1,594,248 at March 31, 2009 and $2,262,955 at December 31, 2008, representing unapplied drilling contract payments for wells that were not yet drilled as of the balance sheet date.

Note 8. Long Term Debt

(a) *Convertible Notes*. We have an outstanding series of 6% convertible notes due December 15, 2010 in the aggregate principal amount of $37 million. The notes are convertible into our common shares at a conversion price of $12.94. We will be entitled to redeem the notes at 100% of their principal amount plus accrued and unpaid interest if the prevailing market price of our common stock exceeds 160% of the note conversion price for specified periods. Upon any event of default under the notes or any change of control, we may be required to redeem the notes at a default rate equal to 125% of their principal amount or at a change of control rate equal to the greater of 110% of their principal amount or the consideration that would be received by the holders for the underlying shares in the change of control transaction. Any notes that are neither redeemed nor converted prior to maturity will be repayable in cash or in common shares, valued for that purpose at 92.5% of their prevailing market price.

(b) *Credit Facility*. We have a senior secured revolving credit facility maintained by DPI with KeyBank National Association, as agent and primary lender. The facility provides for revolving term loans and letters of credit in an aggregate amount up to $125 million, with a borrowing base of $80 million at December 31, 2008 and March 31, 2009. Outstanding borrowings under the facility bear interest at fluctuating rates up to 1.0% above the agent's prime rate, depending on the amount of borrowing base utilization. Alternatively, we may elect Eurodollar based pricing up to 3.0% above quoted Libor rates. As of March 31, 2009, outstanding borrowings under the facility aggregated $77.5 million. The facility is secured by liens on our proved oil and gas properties and open-access gathering facilities. Obligations under the facility have a scheduled maturity in September 2011 and are guaranteed by NGAS.

(c) *Acquisition Debt*. We issued a note for $854,818 to finance our 1986 acquisition of mineral property on Unga Island, Alaska. The debt is repayable without interest in monthly installments of $2,000 and is secured by liens on the acquired property, buildings and equipment. Although the acquisition agreement provides for royalties at 4% of production revenues, the property has remained inactive. The outstanding acquisition debt was $288,818 at March 31, 2009.

(d) *Total Long Term Debt and Maturities*. The following tables summarize our total long term debt at March 31, 2009, as restated, and December 31, 2008, together with the principal payments due each year through 2013 and thereafter.

Principal Amount Outstanding	Restated March 31, 2009	December 31, 2008
Total long term debt (including current portion)[(1)]	$107,216,740	$109,294,818
Less current portion	24,000	24,000
Total long term debt[(1)]	$107,192,740	$109,270,818
Maturities of Debt		
Remainder of 2009	$ 18,000	
2010	29,451,922[(1)]	
2011	77,524,000	
2012	24,000	
2013 and thereafter	198,818	

(1) Reflects the carrying amount of our 6% convertible notes in the principal amount of $37,000,000, net of the unamortized debt discount of $7,572,078 at March 31, 2009 attributable to their embedded conversion feature. See Note 2 – Restatement Adjustments.

Note 9. Capital Stock

(a) *Preferred Shares*. We have 5,000,000 authorized shares of preferred stock, none of which were outstanding at March 31, 2009 and December 31, 2008.

(b) *Common Shares*. The following table reflects transactions involving our common stock during the reported periods.

Common Shares Issued	**Number of Shares**	**Amount**
Balance, December 31, 2007	26,136,064	$108,842,526
Issued to employees as incentive bonus	50,000	259,690
Issued upon exercise of stock options	357,582	1,524,696
Balance, December 31, 2008	26,543,646	110,626,912
Issued as stock awards under incentive plan	425,000	361,250
Balance, March 31, 2009	26,968,646	$110,988,162

Paid In Capital – Options and Warrants	
Balance, December 31, 2007	3,484,148
Recognized	625,142
Exercised	(334,690)
Balance, December 31, 2008	3,774,600
Recognized	264,636
Balance, March 31, 2009	$ 4,039,236

Number of

Common Shares to be Issued	**Shares**	**Amount**
Balance, March 31, 2009 and December 31, 2008	9,185	$ 45,925

(c) *Stock Options and Awards*. We maintain three stock plans for the benefit of our directors, officers, employees and certain consultants or advisors. The plans provide for the grant of options to purchase up to 3,600,000 common shares and, in the case of our most recent plan, either stock awards or options for an aggregate of up to 4,000,000 common shares. Option grants under all the plans must be at prevailing market prices and may be subject to vesting requirements over a period of up to ten years from the date of grant. Stock awards under the third plan may be subject to vesting conditions and trading restrictions specified at the time of grant. Stock awards and option grants were made under these plans for a total of 425,000 shares during the first quarter of 2009 and 2,350,000 shares during 2008. The following table shows transactions in stock options during the reported periods.

	Issued	**Exercisable**	**Weighted Average Exercise Price**
Balance, December 31, 2007	2,681,250	1,739,583	$ 4.75
Granted	2,300,000	—	2.93
Vested	—	41,667	6.02
Exercised	(357,582)	(357,582)	3.33
Forfeited	(10,000)	(10,000)	7.04
Balance, December 31, 2008	4,613,668	1,413,668	3.95
Vested	—	900,000	4.03
Forfeited	(310,000)	(310,000)	4.03
Balance, March 31, 2009	4,303,668	2,003,668	3.94

At March 31, 2009, the exercise prices of options outstanding under our equity plans ranged from $1.51 to $7.64 per share, and their weighted average remaining contractual life was 3.25 years. The following table provides additional information on the terms of stock options outstanding at March 31, 2009.

Options Outstanding				**Options Exercisable**	
Exercise Price or Range	Number	Weighted Average Remaining Life (years)	Weighted Average Exercise Price	Number	Weighted Average Exercise Price
$ 1.51	1,650,000	6.11	$ 1.51	—	$ —
4.03 4.09	1,230,000	0.74	4.05	1,330,000	4.09
6.02 7.64	1,423,668	2.11	6.66	673,668	6.88
	4,303,668			2,003,668	

In accounting for stock options, we apply the fair value recognition provisions of SFAS No. 123(R), *Share-Based Payment*. We use the Black-Scholes pricing model to determine the fair value of each stock option at the grant date, and we recognize the compensation cost ratably over the vesting period. For the periods presented in the interim consolidated financial statements, the fair value estimates for each option grant assumed a risk free interest rate ranging from 0.03% to 6%, no dividend yield, a theoretical volatility ranging from 0.30 to 0.85 and an expected life ranging from six months to six years based on the vesting provisions of the options. This resulted in non-cash charges for options and warrants of $625,142 in 2008 and $264,636 in the first quarter of 2009.

Note 10. Income (Loss) Per Share

The following table shows the computation of basic and diluted earnings (loss) per share (*EPS*) for the reporting periods.

	Three Months Ended March 31,	
	2009 Restated	2008
Numerator:		
Net income (loss) as reported for basic EPS	$ (1,431,339)	$ 163,189
Adjustments to income (loss) for diluted EPS	—	—
Net income (loss) for diluted EPS	$ (1,431,339)	$ 163,189
Denominator:		
Weighted average shares for basic EPS	26,671,146	26,235,811
Effect of dilutive securities:		
Stock options	—	495,226
Adjusted weighted average shares for dilutive EPS	26,671,146	26,731,037
Basic EPS	$ (0.05)	$ 0.01
Diluted EPS	$ (0.05)	$ 0.01

Note 11. Segment Information

We have a single reportable operating segment for our oil and gas business based on the integrated way we are organized by management in making operating decisions and assessing performance. Although our financial reporting reflects our separate revenue streams from drilling, production and transmission activities and the direct expenses for each component, we do not consider the components as discreet operating segments under SFAS No. 131, *Disclosure about Segments of an Enterprise and Related Information.*

Note 12. Commitments

We incurred operating lease expenses of $2,317,526 in 2008 and $675,797 in the first three months of 2009. As of March 31, 2009, we had future obligations under operating leases and other commercial commitments in the amounts listed below.

Year	Operating Leases	Other Commitments(1)	Total
Remainder of 2009	$ 1,752,219	$ 2,343,000	$ 4,095,219
2010	2,267,973	—	2,267,973
2011	2,047,086	—	2,047,086
2012	847,442	—	847,442
2013 and thereafter	73,284	—	73,284
Total	$ 6,988,004	$ 2,343,000	$ 9,331,004

(1) Reflects commitments under a purchase contract for an airplane.

Note 13. Recent Accounting Standards

Oil and Gas Reporting Requirements. In December 2008, the SEC amended its oil and gas reporting rules under the Exchange Act and Industry Guides. The revisions are intended to provide investors with a more meaningful and comprehensive understanding of oil and gas reserves by aligning the oil and gas disclosure requirements with current industry practices and technology. The amendments will be effective for fiscal years ending on or after December 31, 2009 and will significantly impact reserve and resource reporting for all E&P companies.

SFAS No. 162. In May 2008, the FASB issued SFAS No. 162, *The Hierarchy of Generally Accepted Accounting Principles*. SFAS 162 identifies the sources of accounting principles and the framework for selecting principles to be used in the preparation and presentation of financial statements in accordance with U.S. GAAP. The adoption of SFAS 162 had no effect on our consolidated financial statements.

SFAS No. 161. In March 2008, the FASB issued SFAS No. 161, *Disclosures About Derivative Instruments and Hedging Activities*, which expands the quarterly disclosure requirements in SFAS No. 133 for derivative instruments and hedging activities, effective for fiscal years beginning after November 15, 2008. Our adoption of SFAS No. 161 had no effect our consolidated financial position and results of operations.

FSP No. 157-2. In February 2008, the FASB issued FSP No. 157-2, *Effective Date of FASB Statement No. 157*, which defers the effective date of SFAS 157 for certain nonfinancial assets and nonfinancial liabilities, except those recognized or disclosed at fair value in the financial statements on a recurring basis. The deferred provisions of SFAS 157 affect assets measured at fair value in goodwill impairment testing, nonfinancial long-lived assets measured at fair value for impairment assessment and asset retirement obligations initially measured at fair value. Our adoption of these deferred provision on January 1, 2009 had no material impact on our consolidated financial position or results of operations.

Note 14. Subsequent Events

Pending Sale of Interest in Gathering System. On May 11, 2009, DPI and NGAS Gathering, LLC entered into an asset purchase agreement (*APA*) with Seminole Gas Company (*Seminole*) for the sale of a 50% undivided interest in our Appalachian gas gathering and midstream facilities at a purchase price of $28 million. The APA also provides for us to enter into various gas marketing and gas sales arrangements with Seminole Energy Services, L.L.C., the parent company of Seminole (*Seminole Energy*), upon the closing of the sale. Under these arrangements, we will retain firm capacity rights for daily delivery of 30,000 Mcf of controlled gas through the system. We will also provide Seminole Energy with a six-month option to buy our retained 50% interest in these gathering facilities for an additional $22 million. The purchase price for both components is subject to certain adjustments and will be payable for our retained 50% interest $7.5 million in cash upon exercise of the purchase option and the balance over 30 months under a promissory note bearing interest at 8% per annum. DPI will have the right to require Seminole Energy to exercise the purchase option if we complete an equity offering for at least $5 million within the six-month option period following the closing under the APA.

Both components of the pending sale are subject to customary closing conditions. We will also be required to obtain an amendment to our credit facility permitting our sale of the gathering assets, which are currently part of the collateral securing the facility. To reflect the release of the collateral as well as the decrease in our 2008 reserve estimates from lower year-end commodity prices and higher drilling costs, we anticipate an significant reduction in our current $80 million borrowing base at the semi-annual redetermination scheduled by the end of June 2009. An additional APA closing condition limits this reduction to not less than $55 million. At that reduced level, our planned reduction of our currently outstanding debt of $77.5 million from APA sale proceeds would leave approximately $5 million of unused borrowing base commitments under the facility. The APA closing conditions also require us to obtain a waiver of the current ratio financial covenant under our credit facility as of June 30, 2009 and adjustments to the other financial covenants through December 31, 2010.

Expansion of Devonian Shale Play. We entered into a farmout agreement in May 2009 with Chesapeake Appalachia, LLC for a tract of 56,000 gross (42,000 net undeveloped) acres contiguous to the Amvest portion of our Stone Mountain field in Letcher and Harlan Counties, Kentucky. Chesapeake's prior development of the tract includes approximately 100 producing wells and a gathering system that connects to our gathering facilities. Chesapeake and Penn Virginia Operating, LLC, a royalty interest owner, each have participation rights for up to 25% of the working interests in our future wells on the acreage, and we have a minimum annual drilling commitment of four wells under the farmout, with an additional commitment to drill six vertical Devonian shale wells by the beginning of June 2009. To meet our initial commitment, we entered into arrangements with a joint venture partner that provides us with a 15% carried working interest in these wells, which we began drilling at the time we obtained the farmout. We granted our joint venture partner participation rights for up to 50% of our available working interest in subsequent Devonian shale horizontal wells on the acquired acreage.

Item 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

General

We are an independent exploration and production company focused on unconventional natural gas plays in the eastern United States, principally in the southern portion of the Appalachian Basin. We have specialized for over 20 years in generating our own geological prospects in this region, where we have established expertise and recognition. We believe our extensive experience in this region, coupled with our relationships with partners, suppliers and mineral interest owners, gives us competitive advantages in developing these resources to achieve sustained volumetric growth and strong financial returns on a long term basis.

Recent Developments

Pending Sale of Interest in Gathering System. On May 11, 2009, our operating subsidiaries, Daugherty Petroleum, Inc. (*DPI*) and NGAS Gathering, LLC (*NGAS Gathering*), entered into an asset purchase agreement (*APA*) with Seminole Gas Company (*Seminole*) for the sale of a 50% undivided interest in our Appalachian gas gathering and midstream facilities at a purchase price of $28 million. The APA also provides for us to enter into various gas marketing and gas sales arrangements with Seminole Energy Services, L.L.C., the parent company of Seminole (*Seminole Energy*), upon the closing of the sale. Under these arrangements, we will retain firm capacity rights for daily delivery of 30,000 Mcf of controlled gas through the system. We will also provide Seminole Energy with a six-month option to buy our retained 50% interest in these facilities for an additional $22 million, payable $7.5 million in cash upon exercise of the purchase option and the balance over 30 months. If certain conditions are met, we will have the right under the APA to require Seminole Energy to exercise the purchase option. See "Business Strategy" and "Capital Resources."

Expansion of Devonian Shale Play. We entered into a farmout agreement in May 2009 with Chesapeake Appalachia, LLC for a tract of 56,000 gross (42,000 net undeveloped) acres contiguous to the Amvest portion of our Stone Mountain field in Letcher and Harlan Counties, Kentucky. Chesapeake's prior development of the tract includes approximately 100 producing wells and a gathering system that connects to our gathering facilities. Penn Virginia Operating, LLC, the royalty interest owner, and Chesapeake each have participation rights for up to 25% of the working interests in our future wells on the acreage, and we have a minimum annual drilling commitment of four wells under the farmout, with an additional commitment to drill six vertical Devonian shale wells by the beginning of June 2009. To meet our initial commitment, we entered into arrangements with a joint venture partner that provide us with a 15% carried working interest in these wells, which we began drilling at the time we obtained the farmout. We granted our joint venture partner participation rights for up to 50% of our available working interest in subsequent Devonian shale horizontal wells on the acquired acreage.

Business Strategy

Our business is structured for development of natural gas production and reserves, which we are accelerating by our transition to horizontal drilling throughout our operating areas. We began this transition early in 2008 and had 25 horizontal wells on line at the end of the March 2009. Our success with this initiative contributed to growth in our production volumes to 3.7 Bcfe in 2008, up 13% over 2007, with record volumes of 1.0 Bcf in the first quarter of 2009, an increase of 18% from the first quarter of 2008 and 7.4% from the 2008 fourth quarter. Over 71% of our 329,000-acre position in southern Appalachia is undeveloped, along with most of our assembled acreage in the Illinois Basin. This provides us with an extensive inventory of low-risk, repeatable horizontal drilling locations for future growth at considerably lower finding costs than vertical wells. Our strategy for capitalizing on these opportunities under currently unsettled market conditions has several components.

- Organic Growth through Drilling with Reduced Capital Spending. Development drilling is the mainstay of our business model. During 2008, we drilled 75 gross (64.94 net) wells on our operated properties in the Appalachian and Illinois Basins, along with 118 gross (18.45 net) non-operated wells. We have an average working interest of 87% in wells drilled on operated properties during 2008, compared to 56% in the prior year. This reflects the evolution of our business model for accelerating organic growth by retaining more of our available working interest in wells drilled on our operated properties, which we implemented late in 2007. While we are committed to this long-term strategy, we have addressed the challenging conditions in our industry by reducing our 2009 capital spending budget, currently set at $15 million and allocated 80%

to drilling and the balance to infrastructure and lease acquisition projects. This is in line with our anticipated cash flow from operations and may be adjusted during the year in response to market developments. To meet our 2009 drilling commitments and objectives, we are returning to our established partnership structure and sales network, which raised over $34 million for a non-operated program last year. We expect to maintain a 20% interest in this year's program, which will increase to 35% after program payout.

- *Horizontal Drilling Initiatives*. Recent advances in horizontal drilling and completion technology have enhanced the value proposition for our operated properties by substantially increasing our recovery volumes and rates at dramatically lower finding costs. Horizontal drilling also gives us access to areas where natural gas development would otherwise be delayed or constrained by coal mining activity or challenging terrain. We focused these initiatives during 2008 in our Leatherwood field, where we completed 20 horizontal wells last year. Each well has a single lateral leg up to 3,500 feet through the Devonian shale formation, which is present throughout our Appalachian operating areas. Initial 30-day flow rates for our Leatherwood horizontals averaged 309Mcf per day. We achieved comparable results for our first two New Albany shale horizontals drilled late in 2008 on our Illinois Basin acreage and our initial Devonian shale horizontals completed during the first quarter of 2009 in each of our Straight Creek, Fonde and Martin's Fork fields. We plan to continue this transition throughout our operated properties, with up to 53 horizontals planned for our 2009 drilling partnership.

- *Advantages from Restructured Infrastructure Position*. The gas gathering facilities covered by our APA with Seminole span approximately 485 miles through parts of southeastern Kentucky, eastern Tennessee and western Virginia, providing deliverability from 90% of our Appalachian properties directly from the wellhead to the interstate pipeline network serving major east coast natural gas markets. The facilities include an open-access system we purchased in March 2006 from Duke Energy Gas Services, LLC. This midstream system spans 116 miles, with a connection to Duke Energy's East Tennessee pipeline. We upgraded our midstream system during 2007 with a liquids extraction plant co-owned and operated by an affiliate of Seminole. The system has a current daily gross throughput of approximately 20,000 Dth, including third-party deliveries. Although our pending sale of a half interest in our Appalachian system will eliminate the closed-access status of our field-wide infrastructure, our capacity rights following the sale will have an evergreen term and will ensure continued deliverability from our operated Appalachian properties serviced by these facilities. Our capacity rights should also preserve our competitive advantages from control of regional gas flow, enhancing our opportunities to acquire undeveloped acreage near our core producing fields upon completion of coal mining activities.

- *Development of Additional Drilling Prospects*. We follow a disciplined capital allocation process in selecting opportunities to expand our substantial inventory of drilling prospects that meet our criteria for predictable, long-lived reserves. Our goal is to consolidate our position in the Appalachian Basin, while diversifying our asset base with similar unconventional plays outside the basin. As part of this strategy, in addition to the recent expansion of our Devonian shale play through our Chesapeake farmout, we are developing our New Albany shale play within the southcentral portion of the Illinois Basin in western Kentucky. We began producing this project to sales in September 2008, with a total of 30 wells on line at March 31, 2009. Based on encouraging results from our New Albany shale horizontals, we have expanded our lease position and plan to drill up to five horizontal wells on this acreage during 2009. See "Recent Developments."

Drilling Operations

General. As of March 31, 2009, we had interests in a total of 1,397 wells, concentrated on Appalachian properties. We believe our long and successful operating history and proven ability to drill a large number of wells year after year have positioned us as a leading producer in this region. Historically, we conducted most of our drilling operations through sponsored drilling partnerships with outside investors, enabling us to assemble our acreage positions on the strength of our drilling commitments, while also funding infrastructure development on acquired acreage for our own account. Beginning in the second half of 2007, with our core Appalachian infrastructure in place, we changed our business model to limit our use of drilling partnerships to participation in non-operated plays, retaining all of our available working interest in wells drilled on operated properties through the end of 2008. To address part of the capital requirements for meeting this year's drilling commitments and objectives, we are sponsoring a drilling partnership for up to $53.1 million to participate in our horizontal wells.

Geological Factors. Although mineral development in Appalachia has historically been dominated by coal mining interests, it is also one of the oldest and most prolific natural gas producing areas in the United States. Most of our vertical wells in this region were drilled to relatively shallow total depths averaging 4,500 feet, generally encountering several predictable natural gas pay zones. The primary pay zone throughout our Appalachian acreage is the Devonian shale formation. This is considered an unconventional target due to its low permeability, requiring effective treatment to enhance natural fracturing in these reservoirs. Estimated ultimately recoverable volumes (*EUR*s) of natural gas reported for vertical gas wells in this part of Appalachia range between 100 to 450 Mmcf, with modest initial volumes offset by low annual decline rates, resulting in a reserve life index of over 25 years. Our New Albany shale play in the Illinois Basin has similar geological, production and reserve characteristics.

Horizontal Drilling. Air-driven horizontal drilling advances and staged completion technology optimized for our operating areas have dramatically improved the economics of our shale plays in the Appalachian and Illinois Basins. In general, our horizontal wells use directional air drilling to create a lateral leg up to 3,500 feet through the target formation. This allows the well bore to stay in contact with the reservoir longer and to intersect more fractures in the formation than conventional vertical wells. While up to four times more expensive than vertical wells, horizontal drilling is improving overall performance by increasing recovery volumes and rates, limiting the number of wells necessary to develop an area through conventional drilling and reducing the costs and surface disturbances of multiple vertical wells. Typically, one horizontal well replaces between three to four vertical locations, reducing the total footprint of the drill site. Additional economies can be achieved by drilling multiple horizontal wells on a single drilling location. In addition to these operational advantages, the initial recovery rates for these horizontals are averaging six to ten times the rates for our vertical Devonian shale wells in the same fields. Although not fully reflected in our 2008 year-end reserve estimates, we anticipate substantial upside in both production and EURs from our ongoing transition to horizontal drilling.

Air Drilling Technology. Our horizontal wells are drilled in separate sections. The initial section is identical to our standard vertical well, with 7-inch casing set approximately 600 feet above the target formation and cemented in place. After drilling about 30 feet below the casing, we begin drilling a curve that generally takes approximately 500 feet of additional vertical depth to achieve a position 90 degrees from the vertical well bore. At that point, the well bore is near the base of the target zone, 500 feet away from the original location, at the proper angle to drill the horizontal leg. The lateral leg is then drilled approximately 3,000 feet through the target formation at a slight angle to allow the well bore to cross from the bottom to the top of the formation, guided by real-time data on the drill bit location. Upon completion of drilling, 4.5-inch casing and packers are run to the end of the horizontal leg, and the packers are set at intervals, allowing the well to be completed in up to eight separate stages within the horizontal leg.

Staged Completion Technology. A staged treatment process is performed on our horizontal wells to enhance natural fracturing with large volumes of nitrogen, generally one-million standard cubic feet. After the well is blown back for approximately seven days, it is connected to our existing field-wide gathering facilities to commence gas sales. We have not completed any of our horizontal wells in up-hole zones to avoid the risk of fluid production from those zones.

Drilling Results. The following table shows the number of gross and net development and exploratory wells we drilled during 2008 and the first quarter of 2009. Drilling results shown in the table for 2008 include 55 gross (24.18 net) wells that were drilled by year-end but were awaiting installation of gathering lines or extensions prior to completion, primarily on non-operated properties. Gross wells are the total number of wells in which we have a working interest. Net wells reflect our working interests, without giving effect to any reversionary interest we may subsequently earn in wells drilled through our sponsored drilling programs.

	Development Wells			Exploratory Wells		
	Productive		Dry	Productive		Dry
Year Ended December 31, 2008	Gross	Net	Gross	Gross	Net	Gross
Vertical	137	58.8522	—	9	8.8125	—
Horizontal	47	15.7254	—	—	—	—
Total	184	74.5776	—	9	8.8125	—
Quarter Ended March 31, 2009						
Vertical	4	0.7972	—	—	—	—
Horizontal	8	4.1588	—	—	—	—
Total	12	4.9560	—		—	—

Producing Activities

Regional Advantages. Our proved reserves, both developed and undeveloped, are concentrated in the southern portion of the Appalachian Basin. The proximity of this region to major east coast gas markets generates realization premiums above Henry Hub spot prices, contributing to long term returns on investment. Our Appalachian gas production also has the advantage of a high energy content (Dth), ranging from 1.1 to 1.3 Dth per Mcf. Historically, because our gas sales contracts yield upward adjustments from index based pricing for throughput with an energy content above 1 Dth per Mcf, this resulted in realized premiums averaging 17% over normal pipeline quality gas.

Liquids Extraction. During 2007, in response to regulatory initiatives limiting the upward range of pipeline throughput to 1.1 Dth per Mcf, we constructed a processing plant with Seminole in Rogersville, Tennessee for liquids extraction from our Appalachian production delivered through the NGAS Gathering system. See "Recent Developments." The plant was brought on line in February 2008, ensuring our compliance with the new energy content standard. During the first three months of 2009, our sales of extracted liquids have partially offset the reduction in energy-related yields from our Appalachian gas production.

Oil and Gas Production. Our production revenues and estimated oil and gas reserves are substantially dependent on prevailing market prices for natural gas, which comprised 78% of our proved reserves on an energy equivalent basis at the end of 2008. The following table shows the average sales prices for our oil and gas production during the three months ended March 31, 2009 and 2008 and for the year ended December 31, 2008, along with our average lifting costs and transmission, compression and processing costs in each of the reported periods.

	Three Months Ended March 31,		Year Ended December 31,
Production volumes:	**2009**	**2008**	**2008**
Natural gas (Mcf)	868,548	743,998	3,087,596
Oil (Bbl)	17,277	13,488	57,291
Natural gas liquids (gallons)	1,201,181	634,135	3,895,649
Equivalents (Mcfe)	1,038,297	880,414	3,745,124
Average sales prices and costs:			
Natural gas (per Mcf)	$ 6.74	$ 8.51	$ 8.89
Oil (per Bbl)	33.09	90.48	95.07
Natural gas liquids (per gallon)	0.64	1.48	1.41

Future Gas Sales Contracts. We use fixed-price, fixed-volume physical delivery contracts that cover portions of our natural gas production at specified prices during varying periods of time to address commodity price volatility. Our physical delivery contracts are not treated as financial hedging activities and are not subject to mark-to-market accounting. The financial impact of these contracts is included in our oil and gas revenues at the time of settlement. As of the date of this report, we have contracts in place for the following portions of our anticipated 2009 natural gas production.

FIXED-PRICE CONTRACTS FOR NATURAL GAS PRODUCTION

	2009		
	Q2	**Q3**	**Q4**
Average price per Dth	$ 8.47	$ 8.20	$ 8.00
Average price per Mcf	9.35	9.04	8.83
Percent of DPI gas contracted	46%	33%	28%

Results of Operations – Three Months Ended March 31, 2009 and 2008

Revenues. The following table shows the components of our revenues for the three months ended March 31, 2009 and 2008, together with their percentages of total revenue in the current period and percentage change on a period-over-period basis.

	Three Months Ended March 31,			
Revenue:	**2009**	**% of Revenue**	**2008**	**% Change**
Contract drilling	$ 7,323,752	43%	$ 6,602,118	11%
Oil and gas production	7,067,219	41	8,489,434	(17)
Gas transmission, compression and processing	2,804,982	16	2,558,092	10
Total	$ 17,195,953	100%	$ 17,649,644	(3)

Our revenue mix for the first quarter of 2009 reflects the impact of declining commodity prices and reduced drilling activity on our strategy for transitioning to a more production based business, with oil and gas sales accounting for 41% of total revenues, compared to 48% of total revenues for the first quarter of 2008 and 46% for the year as a whole. Despite our planned reduction in capital expenditures for 2009, we expect this trend to reverse on a long-term basis as we expand our horizontal drilling initiatives and acreage position in our core operating areas and commodity prices eventually recover.

Contract drilling revenues reflect the size and timing of our drilling partnership initiatives, as well our ownership interest in sponsored programs. Although we receive the proceeds from private placements in sponsored partnerships as customers' drilling deposits under our program drilling contracts, we recognize revenues from the interests of outside investors in these programs on the completed contract method as the wells are drilled, rather than when funds are received. During 2008, we sponsored a program for participation in 89 wells on non-operated properties known as the HRE fields, spanning six counties in West Virginia and Virginia. Our contract drilling revenues in the first quarter of 2009 reflect the substantial completion of drilling operations for that program. We retained an interest of 25% before payout of that program and 35% after payout.

Production revenues for the first quarter of 2009 reflect an 18% increase in production output to 1,038 Mmcfe, compared to 880 Mmcfe in the year-earlier period, offset by a 21% decline in natural gas prices, 65% in oil prices and 57% for sales of natural gas liquids. Our volumetric growth reflects strong performance from our horizontal wells and the commencement of production from our Haley's Mill field in August 2008. We anticipate continued production growth driven by these ongoing initiatives. Most of our production is sold through gas marketing intermediaries. Approximately 58% of our natural gas production in the current quarter was sold under fixed-price contracts, and the balance primarily at prices determined monthly under formulas based on prevailing market indices. Realized natural gas prices in the 2009 first quarter averaged $8.10 per Mcf for our Appalachian production and $6.74 per Mcf overall, compared to an average overall realization of $8.51 per Mcf in the first quarter of 2008.

Gas transmission, compression and processing revenues for the current quarter were driven by fees totaling $429,453 for moving third-party gas through our NGAS Gathering system and $108,565 in related processing fees for liquids extraction through our Rogersville plant. This component of revenues also includes gathering and compression fees of $836,611 for moving our drilling program investors' share of gas through our field-wide facilities, together with contributions of $256,926 from gas utility sales.

Expenses. The following table shows the components of our direct and other expenses for the three months ended March 31, 2009 and 2008. Percentages listed in the table reflect margins for each component of direct expenses and percentages of total revenue for each component of other expenses. Certain non-cash expenses for the 2009 interim period reflect adjustments for the adoption of derivative fair value accounting for our 6% convertible notes as of January 1, 2009. The impact of these adjustments is discussed below and in Note 2 to the accompanying condensed consolidated financial statements.

	Three Months Ended March 31,			
Direct Expenses:	**2009**	**Margin**	**2008**	**Margin**
Contract drilling	$ 5,541,426	24%	$ 5,119,849	22%
Oil and gas production	2,324,965	67	2,764,955	67
Gas transmission, compression and processing	968,917	65	1,090,246	57
Total direct expenses	8,835,308	49	8,975,050	49
Other Expenses:	**(Restated)**	**% Revenue**		**% Revenue**
Selling, general and administrative	3,250,265	19%	3,288,483	19%
Options, warrants and deferred compensation	418,273	2	137,679	1
Depreciation, depletion and amortization	3,618,870	21	2,871,760	16
Bad debt expense	—	N/A	347,840	2
Interest expense, net of interest income	2,272,192	13	1,256,260	7
Fair value gain on derivative financial instrument	(14,319)	N/A	—	N/A
Other, net	79,541	—	(6,277)	N/A
Total other expenses	$ 9,624,822		$ 7,895,745	

Contract drilling expenses reflect the level of drilling initiatives conducted through our sponsored programs. These expenses increased by 8% on a period-over-period basis and represented 76% of contract drilling revenues in the current period, compared to 78% in the year-earlier period. All of our contract drilling activities in the current quarter were conducted on non-operated HRE properties in West Virginia and Virginia. Margins for contract drilling operations reflect our cost-plus pricing model, which we adopted in 2006 to address price volatility for drilling services, equipment and steel casing requirements.

Production expenses represent lifting costs, field operating and maintenance expenses, related overhead, severance and other production taxes, third-party transportation fees and processing costs. The decrease in production expenses on a period-over-period basis primarily reflects recent declines in drilling costs from the industry-wide contraction of drilling activity. We also benefited from lower hauling costs for natural gas liquids through recently implemented rail shipping arrangements. Our margins in both periods reflect cost savings realized from ownership of the NGAS Gathering system acquired in March 2006, eliminating transportation and processing fees for our share of Leatherwood, Straight Creek, Fonde and SME production delivered through the system. Following the pending sale of a 50% interest in our Appalachian gathering system under our APA with Seminole, we expect part of these savings to be eliminated, with higher transportation fees impacting our overall production expenses . See “Recent Developments – Pending Sale of Interest in Gathering System.”

Gas transmission, compression and processing expenses in the first quarter of 2009 were 35% of associated revenues, compared to 43% in the same quarter last year. The margins for this part of our business have benefited from third-party fees generated by the NGAS Gathering system acquired in 2006. Our gas transmission, compression and processing expenses do not include capitalized costs of approximately $810,000 in the current quarter for extensions of our field-wide gas gathering systems and additions to dehydration and compression capacity required to bring new wells on line.

Selling, general and administrative (*SG&A*) expenses are comprised primarily of selling and promotional costs for our sponsored drilling programs and general overhead costs. Our SG&A expenses in the current quarter decreased nominally from the same period last year and represented 19% of revenues in the first quarters of both 2009 and 2008.

Non-cash charges for options, warrants and deferred compensation reflect the fair value method of accounting for employee stock options. Under this method, employee stock options are valued at the grant date using the Black-Scholes valuation model, and the compensation cost is recognized ratably over the vesting period. We also recognized an accrual of $153,637 for deferred compensation cost in the current quarter.

Depreciation, depletion and amortization (*DD&A*) is recognized under the units-of-production method, based on the estimated proved developed reserves of the underlying oil and gas properties, and on a straight-line basis over the useful life of other property and equipment. The increase in DD&A charges reflects substantial additions to our oil and gas properties, gas gathering systems and related equipment.

We recognized a bad debt expense of $347,840 in the first quarter of 2008. Coupled with existing reserves from prior periods, this represents the entire amount due for oil sales to a regional refinery prior to its filing for reorganization under the bankruptcy laws last year. See “Critical Accounting Policies and Estimates – Allowance for Doubtful Accounts."

Cash interest expense for the 2009 first quarter increased nominally from the year-earlier period, reflecting lower variable rates under our revolving credit facility on higher debt levels under our revolving credit facility. Draws under the facility were used primarily to support our ongoing drilling initiatives and enhancements of our field-wide gas gathering systems. Non-cash interest expense of $908,967 for the first quarter of 2009 reflects the application of the effective interest method for accretion of the debt discount attributable to the embedded conversion feature of our 6% notes, which have of face amount of $37,000,000. See "Liquidity and Capital Resources."

Deferred income tax expense recognized in both reported periods represents future tax liability at the operating company level. Although we have no current tax liability due to the utilization of intangible drilling costs, our consolidated income tax expense is negatively impacted by the non-recognition of tax benefits at the parent company level.

<u>*Net Income and EPS*</u>. We recognized a net loss of $1,431,339 in the first quarter of 2009, as restated, compared to net income of $163,189 realized in the same quarter last year, reflecting the foregoing factors. Basic earnings (loss) per share (*EPS*) was $(0.05) based on 26,671,146 weighted average common shares outstanding in the current quarter, compared to EPS of $0.01 based on 26,235,811 weighted average common shares outstanding in the first quarter of 2008. Adjustments for derivative treatment of our 6% convertible notes accounted for $894,648 of our restated net loss, or $(0.03) per share, for the first quarter of 2009.

The results of operations for the three months ended March 31, 2009 are not necessarily indicative of results to be expected for the full year.

Liquidity and Capital Resources

<u>*Liquidity*</u>. Net cash of $1,003,658 was provided by operating activities in the first quarter of 2009. During the quarter, we used $6,232,172 in investing activities, most of which reflects net additions to our oil and gas properties and gathering systems. These investments were funded in part with net cash of $5,494,681 from financing activities, primarily consisting of advances under our revolving credit facility. As a result of these activities, cash increased from $981,899 at December 31, 2008 to $1,248,066 at March 31, 2009.

As of March 31, 2009, we had a working capital deficit of $2,041,944. This reflects wide fluctuations in our current assets and liabilities from the timing of customer deposits and expenditures under drilling contracts with our sponsored programs. Since these fluctuations are normalized over relatively short time periods, we do not consider working capital to be a reliable measure of liquidity. The working capital deficit at the end of 2008 is not expected to have an adverse effect on our financial condition or results of operations in future periods.

<u>*Capital Resources*</u>. Our business involves significant capital requirements. The rate of production from oil and gas properties declines as reserves are depleted. Without successful development activities, our proved reserves would decline as oil and gas is produced from our proved developed reserves. We also have substantial annual drilling commitments under various leases and farmouts for our Appalachian properties, including an annual 25-well commitment for our Leatherwood field. Our long-term performance and profitability is dependent not only on meeting these commitments and recovering existing oil and gas reserves, but also on our ability to find or acquire additional reserves and fund related infrastructure build-outs on terms that are economically and operationally advantageous.

We have relied on a combination of cash flows from operations, bank borrowings and private placements of our convertible notes and equity securities to fund our reserve and infrastructure development and acquisition activities. Historically, we also relied on participation in our operated drilling initiatives by outside investors in our sponsored partnerships. For 2008, we changed our business model to accelerate organic growth by retaining all of our available working interest in wells drilled on operated properties, with a view to limiting our use of drilling partnerships to non-operated initiatives.

While we are committed to continue expanding our reserves and production through the drillbit, we have addressed the challenging conditions in our industry by reducing our 2009 capital spending budget to $15 million, allocated 80% to drilling and the balance to infrastructure and lease acquisition projects. This is in line with our anticipated cash flow from operations and may be adjusted during the year in response to market developments. To meet our 2009 drilling commitments and objectives with limited reliance on additional draws under our credit facility, we are returning to our established partnership structure and sales network, which raised over $34 million for a non-operated program last year. We expect to maintain a 20% interest in this year's program, which will increase to 35% after program payout. With our critical infrastructure in place to provide deliverability for our production at a low cash cost, this will allow us to continue delivering organic growth, although at lower rates than we could achieve with access to the capital markets. If market conditions improve, we would expect to raise additional capital to accelerate drilling and meet our long-term resource development objectives.

We have a senior secured revolving credit facility maintained by DPI with KeyBank National Association, as agent and primary lender. The facility provides for revolving term loans and letters of credit in an aggregate amount up to $125 million, with a scheduled maturity in September 2011. We amended the facility in May 2008 to add to the collateral package and in August 2008 to increase the borrowing base from $75 million to $90 million. The borrowing base was lowered to $80 million at year end to reflect the downturn in the energy and credit markets. Outstanding borrowings under the facility bear interest at fluctuating rates ranging from the agent's prime rate to 1.0% above that rate, depending on the amount of borrowing base utilization. We are also responsible for commitment fees at rates ranging from 0.375% to 0.5% of the unused borrowing base. The facility is guaranteed by NGAS and is secured by liens on DPI's oil and gas properties and gathering facilities. As of March 31, 2009, outstanding borrowings under the facility aggregated $77.5 million, and the interest rate amounted to 4.25%. We are in compliance with our financial and other covenants under the credit facility at March 31, 2009.

As a condition to the closing under our APA with Seminole, we will be required to obtain an amendment to our credit facility permitting the sale of interests in our core Appalachian gathering system, which is currently part of the collateral securing the facility. See "Recent Developments – Pending Sale of Interest in Gathering System." To reflect the release of the collateral as well as the decrease in our 2008 reserve estimates from lower year-end commodity prices and higher drilling costs, we anticipate an significant reduction in our current $80 million borrowing base at the semi-annual redetermination scheduled by the end of June 2009. The APA requires a borrowing base of not less than $55 million at the time of the closing when our gathering facilities will be eliminated from the collateral pool. At that reduced level, the reduction of our currently outstanding debt by $28 million from sale proceeds upon closing under the APA would leave approximately $5 million of unused borrowing base commitments under the facility. The APA also requires us to obtain a waiver of the current ratio financial covenant under our credit facility as of June 30, 2009 and adjustments to the other financial covenants through December 31, 2010. We are currently in compliance with our financial and other covenants under the credit facility and expect to be able to meet these and other customary closing conditions under the APA within the next 30 days.

We have an outstanding series of 6% convertible notes due December 15, 2010 in the aggregate principal amount of $37 million. The notes are convertible into our common shares at a conversion price of $12.94, reflecting an antidilution adjustment based on the pricing of a registered direct equity placement of our common stock at $6.00 per share in November 2007. We will be entitled to redeem the notes at their face amount plus accrued interest if the prevailing market price of our common stock exceeds 160% of the note conversion price for specified periods. In the event of a default under the notes or any change of control, the holders may require us to redeem the notes at a default rate equal to 125% of their principal amount or a change of control rate equal to the greater of 110% of their principal amount or the consideration that would be received by the holders for the underlying shares in the change of control transaction. Any notes that are neither redeemed nor converted prior to maturity will be repayable in cash or in common shares, valued for that purpose at 92.5% of their prevailing market price.

Our ability to repay our revolving credit and convertible debt will be subject to our future performance and prospects as well as market and general economic conditions. Our future revenues, profitability and rate of growth will continue to be substantially dependent on the demand and market price for natural gas. Future market prices for natural gas will also have a significant impact on our ability to maintain or increase our borrowing capacity, to obtain additional capital on acceptable terms and to attract drilling partnership capital. While we have been able to mitigate some of the steep decline in natural gas prices with fixed-price, fixed-volume physical delivery contracts that cover portions of our natural gas production, we are exposed to price volatility for future production not covered by these arrangements. See "Quantitative and Qualitative Disclosures about Market Risk."

We have addressed the general economic downturn and current unsettled conditions in natural gas markets by reducing our capital expenditure budget and returning to our established drilling partnership structure for participation in our development initiatives. To realize our long-term goals for growth in revenues and reserves, however, we will continue to dependent on the credit and capital markets or other financing alternatives. Any prolonged constriction in the capital markets could require us to sell assets or pursue other financing or strategic arrangements to meet those objectives and to repay or refinance our long-term debt at maturity.

Forward Looking Statements

Some statements made by us in this report are prospective and constitute forward-looking statements within the meaning of Section 21E of the Securities Exchange Act and Section 27A of the Securities Act of 1933. Other than statements of historical fact, all statements that address future activities, outcomes and other matters we plan, expect, budget, intend or estimate, and other similar expressions, are forward-looking statements. These forward-looking statements involve known and unknown risks, uncertainties and other factors, many of which are beyond our control. Among other things, these include:

- uncertainty about estimates of future natural gas production and required capital expenditures;
- commodity price volatility;
- increases in the cost of drilling, completion, gas gathering and processing or other costs of developing and producing our reserves;
- unavailability of drilling rigs and services;
- drilling, operational and environmental risks;
- regulatory changes and litigation risks; and
- uncertainties in estimating proved oil and gas reserves, projecting future rates of production and timing of development and remedial expenditures.

If the assumptions we use in making forward-looking statements prove incorrect or the risks described in this report occur, our actual results could differ materially from future results expressed or implied by the forward-looking statements.

Contractual Obligations and Commercial Commitments

We are parties to leases for office facilities and various types of equipment. We are also obligated to make payments at specified times and amounts under instruments governing our long-term debt and other commercial commitments. The following table lists our minimum annual commitments as of March 31, 2009 under these instruments.

	Operating Leases			Other	Long-Term
Year	**Equipment**	**Premises**	**Total**	**Commitments**	**Debt**
Remainder of 2009	$1,566,929	$ 185,290	$1,752,219	$2,343,000[1]	$ 18,000
2010	2,020,158	247,815	2,267,973	—	29,451,922[2]
2011	1,794,697	252,389	2,047,086	—	77,524,000
2012	591,469	255,973	847,442	—	24,000
2013 and thereafter	51,929	21,355	73,284	—	198,818
Total	$6,025,182	$ 962,822	$6,988,004	$2,343,000	$107,216,740[2]

(1) Reflects commitments under a purchase contract for an airplane.
(2) Excludes the unamortized debt discount of $7,572,078 at March 31, 2009 attributable to the embedded conversion feature of our 6% convertible notes in the principal amount of $37,000,000.

Related Party Transactions

Because we operate through subsidiaries and affiliated drilling partnerships, our corporate structure causes various agreements and transactions in the normal course of business to be treated as related party transactions. Our policy to structure any transactions with related parties only on terms that are no less favorable to the Company than could be obtained on an arm's length basis from unrelated parties. Significant related party transactions are summarized in Notes 5 and 14 to the consolidated financial statements and related disclosure included elsewhere in this report.

Critical Accounting Policies and Estimates

General. The preparation of financial statements requires management to utilize estimates and make judgments that affect the reported amounts of assets, liabilities, revenues and expenses and related disclosure of contingent assets and liabilities. These estimates are based on historical experience and on various other assumptions that management believes to be reasonable under the circumstances. The estimates are evaluated by management on an ongoing basis, and the results of these evaluations form a basis for making decisions about the carrying value of assets and liabilities that are not readily apparent from other sources. Although actual results may differ from these estimates under different assumptions or conditions, management believes that the estimates used in the preparation of our financial statements are reasonable. The critical accounting policies affecting these aspects of our financial reporting are summarized or referenced in Notes 1and 2 to the consolidated financial statements included in this 10-Q/A. Policies involving the more significant judgments and estimates used in the preparation of our consolidated financial statements are summarized below.

Estimates of Proved Reserves and Future Net Cash Flows. Estimates of our proved oil and gas reserves and related future net cash flows are used in impairment tests of goodwill and other long-lived assets. These estimates are prepared as of year end by our independent petroleum engineers and are updated internally at mid-year. There are many uncertainties inherent in estimating quantities of proved reserves and in projecting future rates of production and timing of development expenditures. The accuracy of any reserve estimate is dependent on the quality of available data and is subject to engineering and geological interpretation and judgment. Results of our drilling, testing and production after the date of these estimates may require future revisions, and actual results could differ materially from the estimates.

Impairment of Long-Lived Assets. Our long-lived assets include property, equipment and goodwill. Long-lived assets with an indefinite life are reviewed at least annually for impairment, while other long-lived assets are reviewed whenever events or changes in circumstances indicate that carrying values of these assets are not recoverable. During 2007, we recognized an impartment charge of $964,000 for exploratory well costs that had been capitalized for less than one year pending our assessment of reserves for the project.

Allowance for Doubtful Accounts. We maintain an allowance for doubtful accounts when deemed appropriate to reflect losses that could result from failures by customers or other parties to make payments on our trade receivables. The estimates of this allowance, when maintained, are based on a number of factors, including historical experience, aging of the trade accounts receivable, specific information obtained on the financial condition of customers and specific agreements or negotiated settlements with customers.

Item 3. Quantitative and Qualitative Disclosures about Market Risk

Commodity Price Risk

Our major market risk exposure is the pricing of natural gas production, which has been highly volatile and unpredictable during the last several years. While we do not use financial hedging instruments to manage our exposure to these fluctuations or for speculative trading purposes, we do use fixed-price, fixed-volume physical delivery contracts that cover portions of our natural gas production at specified prices during varying periods of time up to two years from the contract date. Because these physical delivery contracts qualify for the normal purchase and sale exception under SFAS No. 133, they are not treated as financial hedging activities and are not subject to mark-to-market accounting. The financial impact of physical delivery contracts is included in our oil and gas revenues at the time of settlement, which in turn affects our average realized natural gas prices. As of March 31, 2009, we have contracts in place for approximately 85% of our gas production from operated Appalachian properties at a weighted average sales price of $9.53 per Mcf during the remaining nine months of 2009 and for approximately 80% of our that production at a weighted average sales price of $9.53 per Mcf during the first six months of 2009.

Financial Market Risks

Interest Rate Risk. Borrowings under our secured credit facility bear interest at fluctuating market-based rates. Accordingly, our interest expenses are sensitive to market changes, which exposes us to interest rate risk on current and future borrowings under the facility.

Foreign Market Risk. We sell our products and services exclusively in the United States and receive payment solely in United States dollars. As a result, our financial results are unlikely to be affected by factors such as changes in foreign currency exchange rates or weak economic conditions in foreign markets, except to the extent they affect domestic natural gas markets.

Item 4. Controls and Procedures

Management's Responsibility for Financial Statements

Our management is responsible for the integrity and objectivity of all information presented in this report. The consolidated financial statements included in this report have been prepared in accordance with U.S. GAAP and reflect management's judgments and estimates on the effect of the reported events and transactions.

Disclosure Controls and Procedures

Our management, with the participation of our chief executive officer and chief financial officer, evaluated the effectiveness of our disclosure controls and procedures, as defined in Rule 13a-15(e) under the Exchange Act, as of the end of the period covered by this report. Based on management's evaluation as of March 31, 2009 and as of December 31, 2009 in connection with the filing of this 10-Q/A, our chief executive officer and chief financial officer have concluded that our disclosure controls and procedures are effective to ensure that material information about our business and operations is recorded, processed, summarized and publicly reported within the time periods required under the Exchange Act, and that this information is accumulated and communicated to our management to allow timely decisions about required disclosures.

Management's Report on Internal Control over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as defined in Rule 13a-15(f) under the Exchange Act. Management assessed the effectiveness of our internal control over financial reporting as of March 31, 2009 and as of December 31, 2009 in connection with the filing of this 10-Q/A, using the criteria established under *Internal Control – Integrated Framework,* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on that assessment, management concluded that our internal control over financial reporting was effective based on those criteria as of March 31, 2009 and December 31, 2009.

Changes in Internal Control over Financial Reporting

We regularly review our system of internal control over financial reporting to ensure the maintenance of an effective internal control environment. There were no changes in our internal control over financial reporting during the period covered by this report that have materially affected or are reasonably likely to materially affect our internal control over financial reporting.

Part II -- Item 6

Exhibit Number	***Description of Exhibit***
31.1	Certification of Chief Executive Officer pursuant to Exchange Act Rule 13a-14(a), as adopted under Section 302 of the Sarbanes-Oxley Act of 2002.
31.2	Certification of Chief Financial Officer pursuant to Exchange Act Rule 13a-14(a), as adopted under Section 302 of the Sarbanes-Oxley Act of 2002.
32.1	Certification of Chief Executive Officer pursuant to Exchange Act Rule 13a-14(b), as adopted under Section 906 of the Sarbanes-Oxley Act of 2002.
32.2	Certification of Chief Financial Officer pursuant to Exchange Act Rule 13a-14(b), as adopted under Section 906 of the Sarbanes-Oxley Act of 2002.

SIGNATURES

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

NGAS RESOURCES, INC.

Date: December 31, 2009

By: */s/ WILLIAM S. DAUGHERTY*
William S. Daugherty
Chief Executive Officer
(Duly Authorized Officer)
(Principal Executive Officer)

Exhibit 31.1

CERTIFICATION OF CHIEF EXECUTIVE OFFICER
PURSUANT TO RULE 13A-14(A) OR 15D-14(A) UNDER THE SECURITIES EXCHANGE ACT OF 1934

In connection with the amended quarterly report of NGAS Resources, Inc. on Form 10-Q/A for the quarter ended March 31, 2009, as filed with the Securities Exchange Commission on the date hereof under the Securities Exchange Act of 1934, the undersigned certifies pursuant to Rule 13a-14(a) or 15d-14(a) under the Exchange Act that:

1. I have reviewed this amended quarterly report on Form 10-Q/A of NGAS Resources, Inc.

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 consolidated 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 and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rule 13a-15(e) and 15d-15(e)) for the registrant and internal control over financial reporting (as defined in Exchange Act Rule 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 controls over financial reporting, or caused such internal controls 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 reported fiscal quarter 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 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 the registrant's board of directors:

(a) all significant deficiencies and material weaknesses in the design or operation of internal controls 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.

/s/ *WILLIAM S. DAUGHERTY*

William S. Daugherty
Chairman, Chief Executive Officer and President
December 31, 2009

Exhibit 31.2

CERTIFICATION OF CHIEF FINANCIAL OFFICER
PURSUANT TO RULE 13A-14(A) OR 15D-14(A) UNDER THE SECURITIES EXCHANGE ACT OF 1934

In connection with the amended quarterly report of NGAS Resources, Inc. on Form 10-Q/A for the quarter ended March 31, 2009, as filed with the Securities Exchange Commission on the date hereof under the Securities Exchange Act of 1934, the undersigned certifies pursuant to Rule 13a-14(a) or 15d-14(a) under the Exchange Act that:

1. I have reviewed this amended quarterly report on Form 10-Q/A of NGAS Resources, Inc.

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 consolidated 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 reported in this report.

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

(a) designed such disclosure controls and procedures, or caused such disclosure control 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 controls over financial reporting, or caused such disclosure control and procedures to be designed under our supervision, to provide reasonable assurances 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 those disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) disclosed in the report any change in the registrant's internal control over financial reporting that occurred during the reported fiscal quarter 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 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 the registrant's board of directors:

(a) all significant deficiencies and material weaknesses in the design or operation of internal controls 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.

/s/ *MICHAEL P. WINDISCH*

Michael P. Windisch
Chief Financial Officer
December 31, 2009

Exhibit 32.1

CERTIFICATION OF CHIEF EXECUTIVE OFFICER
PURSUANT TO RULE 13A-14(B) OR 15D-14(B) UNDER THE SECURITIES EXCHANGE ACT OF 1934

In connection with the amended quarterly report of NGAS Resources, Inc. on Form 10-Q/A for the quarter ended March 31, 2009, as filed with the Securities Exchange Commission on the date hereof under the Securities Exchange Act of 1934, the undersigned, William S. Daugherty, certifies pursuant to Rule 13a-14(b) or 15d-14(b) under the Exchange Act that:

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

2. The information contained in the report fairly presents, in all material respects, the financial condition and results of operations of NGAS Resources, Inc. as of the date and for the periods reported therein.

/s/ *WILLIAM S. DAUGHERTY*

William S. Daugherty
Chairman, Chief Executive Officer and President
December 31, 2009

Exhibit 32.2

CERTIFICATION OF CHIEF FINANCIAL OFFICER
PURSUANT TO RULE 13A-14(B) OR 15D-14(B) UNDER THE SECURITIES EXCHANGE ACT OF 1934

In connection with the amended quarterly report of NGAS Resources, Inc. on Form 10-Q/A for the quarter ended March 31, 2009, as filed with the Securities Exchange Commission on the date hereof under the Securities Exchange Act of 1934, the undersigned, Michael P. Windisch, certifies pursuant to Rule 13a-14(b) or 15d-14(b) under the Exchange Act that:

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

2. The information contained in the report fairly presents, in all material respects, the financial condition and results of operations of NGAS Resources, Inc. as of the date and for the periods reported therein.

/s/ *MICHAEL P. WINDISCH*

Michael P. Windisch
Chief Financial Officer
December 31, 2009