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

**FORM 10-Q**

**QUARTERLY REPORT UNDER SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**  
**For the Quarter Ended June 30, 2008**

**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**  
(State or other jurisdiction of  
incorporation or organization)

**Not Applicable**  
(I.R.S. Employer  
Identification No.)

**120 Prosperous Place, Suite 201**  
**Lexington, Kentucky**  
(Address of principal executive offices)

**40509-1844**  
(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 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**  
**Common Stock**

**Outstanding at August 4, 2008**  
**26,483,646**

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# NGAS RESOURCES, INC.

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## ADDITIONAL INFORMATION

We file annual, quarterly and other reports and information with the Securities Exchange Commission. Promptly after their filing, we provide access to these reports without charge on our website at [www.ngas.com](http://www.ngas.com). Our headquarters are located in Lexington, Kentucky, and our common stock is traded on the Nasdaq Global Select Market under the symbol NGAS. Unless otherwise indicated, references in this report to *we*, *our* or *us* include NGAS Resources, Inc., our direct and indirect wholly owned subsidiaries and our interests in sponsored drilling programs. As used in this report, *Dth* means decatherm, *Mcf* means thousand cubic feet, *Bcf* means billion cubic feet, *Mcfe* means thousand cubic feet of gas equivalents and *Bcfe* means billion cubic feet of gas equivalents.

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# NGAS RESOURCES, INC.

## CONDENSED CONSOLIDATED BALANCE SHEETS

	<u>June 30, 2008</u>	<u>December 31, 2007</u>
<b>ASSETS</b>		
Current assets:	(Unaudited)	
Cash .....	\$ 1,637,832	\$ 2,816,678
Accounts receivable.....	11,646,423	7,909,943
Prepaid expenses and other current assets .....	388,164	505,778
Loans to related parties.....	<u>7,750</u>	<u>7,654</u>
Total current assets .....	13,680,169	11,240,053
Bonds and deposits .....	570,945	535,445
Oil and gas properties .....	204,718,859	183,823,702
Property and equipment .....	3,531,425	3,689,636
Loans to related parties .....	246,637	249,410
Deferred financing costs .....	1,571,810	1,706,852
Other non-current assets.....	--	3,242,790
Goodwill .....	<u>313,177</u>	<u>313,177</u>
Total assets .....	<u>\$ 224,633,022</u>	<u>\$ 204,801,065</u>
<b>LIABILITIES</b>		
Current liabilities:		
Accounts payable .....	\$ 7,354,493	\$ 6,649,809
Accrued liabilities.....	3,863,302	3,655,684
Customer drilling deposits.....	1,630,304	2,857,806
Deferred compensation.....	2,165,696	--
Long term debt, current portion.....	<u>24,000</u>	<u>388,856</u>
Total current liabilities .....	15,037,795	13,552,155
Deferred income taxes .....	11,454,793	9,218,770
Long term debt.....	95,416,022	80,160,915
Deferred compensation .....	<u>--</u>	<u>1,960,020</u>
Total liabilities.....	<u>121,908,610</u>	<u>104,891,860</u>
<b>SHAREHOLDERS' EQUITY</b>		
Capital stock		
<i>Authorized:</i>		
5,000,000 Preferred shares		
100,000,000 Common shares		
<i>Issued:</i>		
26,480,646 Common shares (2007 – 26,136,064) .....	110,301,403	108,842,526
21,100 Common shares held in treasury, at cost.....	(23,630)	(23,630)
Paid-in capital – options and warrants .....	3,332,453	3,484,148
<i>Contributed surplus</i> .....	866,796	1,043,222
<i>To be issued:</i>		
9,185 Common shares.....	<u>45,925</u>	<u>45,925</u>
	114,522,947	113,392,191
Deficit .....	<u>(11,798,535)</u>	<u>(13,482,986)</u>
Total shareholders' equity .....	<u>102,724,412</u>	<u>99,909,205</u>
Total liabilities and shareholders' equity .....	<u>\$ 224,633,022</u>	<u>\$ 204,801,065</u>

See accompanying notes.

# NGAS RESOURCES, INC.

## CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS

(Unaudited)

	Three Months Ended		Six Months Ended	
	June 30,		June 30,	
	2008	2007	2008	2007
<b>REVENUE</b>				
Contract drilling.....	\$ 7,625,356	\$ 7,459,704	\$ 14,227,474	\$ 16,704,923
Oil and gas production .....	11,179,620	6,730,947	19,669,054	13,483,179
Gas transmission, compression and processing.....	2,536,560	1,887,039	5,094,652	3,834,980
Total revenue .....	21,341,536	16,077,690	38,991,180	34,023,082
<b>DIRECT EXPENSES</b>				
Contract drilling .....	5,756,997	5,919,020	10,876,846	13,099,737
Oil and gas production .....	3,107,095	1,799,186	5,872,050	3,482,200
Gas transmission, compression and processing.....	957,548	779,843	2,047,794	1,879,436
Impairment of oil and gas assets .....	--	964,000	--	964,000
Total direct expenses .....	9,821,640	9,462,049	18,796,690	19,425,373
<b>OTHER EXPENSES (INCOME)</b>				
Selling, general and administrative .....	3,442,094	3,042,364	6,730,577	7,064,246
Options, warrants and deferred compensation ..	234,803	329,177	372,482	670,300
Depreciation, depletion and amortization .....	3,261,192	2,361,176	6,132,952	4,667,646
Bad debt expense .....	59,000	--	406,840	--
Interest expense.....	1,355,643	1,534,216	2,681,613	2,758,972
Interest income.....	(9,093)	(49,689)	(78,803)	(133,743)
Other, net.....	34,632	45,156	28,355	137,905
Total other expenses .....	8,378,271	7,262,400	16,274,016	15,165,326
<b>INCOME (LOSS) BEFORE INCOME TAXES .....</b>	<b>3,141,625</b>	<b>(646,759)</b>	<b>3,920,474</b>	<b>(567,617)</b>
<b>INCOME TAX EXPENSE.....</b>	<b>1,620,363</b>	<b>113,665</b>	<b>2,236,023</b>	<b>447,071</b>
<b>NET INCOME (LOSS) .....</b>	<b>\$ 1,521,262</b>	<b>\$ (760,424)</b>	<b>\$ 1,684,451</b>	<b>\$ (1,014,688)</b>
<b>NET INCOME (LOSS) PER SHARE</b>				
Basic .....	\$ 0.06	\$ (0.03)	\$ 0.06	\$ (0.05)
Diluted .....	\$ 0.06	\$ (0.03)	\$ 0.06	\$ (0.05)
<b>WEIGHTED AVERAGE COMMON SHARES OUTSTANDING:</b>				
Basic.....	26,346,506	21,798,607	26,291,159	21,794,843
Diluted .....	27,344,529	21,798,607	27,015,161	21,794,843

*See accompanying notes.*

# NGAS RESOURCES, INC.

## CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

(Unaudited)

	Three Months Ended		Six Months Ended	
	June 30,		June 30,	
	2008	2007	2008	2007
<b>OPERATING ACTIVITIES</b>				
Net income (loss) .....	\$ 1,521,262	\$ (760,424)	\$ 1,684,451	\$ (1,014,688)
Adjustments to reconcile net income to net cash used in operating activities:				
Incentive bonus paid in common shares .....	--	3,010	31,570	3,010
Compensation from options and warrants .....	234,803	329,177	372,482	670,300
Depreciation, depletion and amortization .....	3,261,192	2,361,176	6,132,952	4,667,646
Bad debt expense .....	59,000	--	406,840	--
Impairment of oil and gas assets .....	--	964,000	--	964,000
Gain (loss) on sale of assets .....	981	84,061	(355)	78,141
Deferred income taxes .....	1,620,363	113,665	2,236,023	447,071
Changes in assets and liabilities				
Accounts receivable .....	(2,987,214)	(1,488,709)	(4,143,320)	1,143,657
Prepaid expenses and other current assets ..	574,348	209,907	117,614	242,620
Other non-current assets .....	--	(340,696)	3,242,790	(867,958)
Accounts payable .....	(1,633,082)	427,672	704,684	(2,627,850)
Accrued liabilities .....	78,814	183,012	207,618	(479,161)
Customers' drilling deposits .....	(1,396,787)	(1,072,504)	(1,227,502)	(7,305,772)
Net cash provided by operating activities .....	<u>1,333,680</u>	<u>1,013,347</u>	<u>9,765,847</u>	<u>(4,078,984)</u>
<b>INVESTING ACTIVITIES</b>				
Proceeds from sale of assets .....	26,500	7,500	38,700	34,700
Purchase of property and equipment .....	(149,214)	(476,103)	(304,501)	(986,504)
Change in bonds and deposits .....	39,500	(12,000)	(35,500)	(37,000)
Additions to oil and gas properties, net .....	(13,228,191)	(14,708,038)	(26,325,157)	(25,524,179)
Net cash used in investing activities .....	<u>(13,311,405)</u>	<u>(15,188,641)</u>	<u>(26,626,458)</u>	<u>(26,512,983)</u>
<b>FINANCING ACTIVITIES</b>				
Decrease in loans to related parties .....	739	1,867	2,677	3,710
Proceeds from issuance of common shares .....	1,006,806	--	1,108,806	40,300
Payments of deferred financing costs .....	(29,250)	--	(143,543)	--
Proceeds from issuance of long term debt .....	11,000,000	15,000,000	16,740,000	19,000,000
Payments of long term debt .....	(6,000)	(6,000)	(2,026,175)	(12,000)
Net cash provided by financing activities .....	<u>11,972,295</u>	<u>14,995,867</u>	<u>15,681,765</u>	<u>19,032,010</u>
Change in cash .....	(5,430)	820,573	(1,178,846)	(11,559,957)
Cash, beginning of period .....	<u>1,643,262</u>	<u>2,051,447</u>	<u>2,816,678</u>	<u>14,431,977</u>
Cash, end of period .....	<u>\$ 1,637,832</u>	<u>\$ 2,872,020</u>	<u>\$ 1,637,832</u>	<u>\$ 2,872,020</u>
<b>SUPPLEMENTAL DISCLOSURE</b>				
Interest paid .....	\$ 1,353,635	\$ 1,526,408	\$ 2,681,318	\$ 2,757,452
Income taxes paid .....	--	--	--	--

*See accompanying notes.*

# NGAS RESOURCES, INC.

## 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, 2007. 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 but reflect all normal recurring adjustments that, in the opinion of our management, are necessary to fairly present our financial position at June 30, 2008 and results of operations and cash flows for the three months and six months ended June 30, 2008 and 2007.

(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. 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 June 30, 2008 and December 31, 2007 are summarized below.

	<b>June 30, 2008</b>	<b>December 31, 2007</b>
Proved oil and gas properties.....	\$168,091,230	\$148,981,923
Unproved oil and gas properties .....	4,416,921	3,876,721
Gathering facilities and well equipment .....	62,046,645	55,370,995
	234,554,796	208,229,639
Accumulated DD&A .....	(29,835,937)	(24,405,937)
Net oil and gas properties and equipment .....	<b>\$204,718,859</b>	<b>\$183,823,702</b>

(b) *Suspended Well Costs.* We adopted FSP No. 19-1, *Accounting for Suspended Well Costs*, effective January 1, 2005. Based on our evaluation at the time of adoption, we had found proved reserves for all our exploratory wells within one year after completion of drilling. We added suspended well costs late in 2005 and

during 2006 for an exploratory program to test the New Albany shale formation on the eastern rim of the Illinois Basin in western Kentucky. Based on the criteria of FSP No. 19-1, we expensed suspended well costs of \$178,700 for the first three wells in that program during 2006 and \$964,000 for the remaining 27 wells in the program during the second quarter of 2007. As of June 30, 2008, 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 3. Property and Equipment**

The following table presents the capitalized costs and accumulated depreciation for our other property and equipment as of June 30, 2008 and December 31, 2007.

	<u>June 30, 2008</u>	<u>December 31, 2007</u>
Land.....	\$ 12,908	\$ 12,908
Building improvements .....	60,340	58,051
Machinery and equipment .....	3,275,162	3,170,601
Office furniture and fixtures .....	173,275	168,217
Computer and office equipment .....	612,670	578,317
Vehicles.....	<u>1,925,073</u>	<u>1,869,551</u>
	6,059,428	5,857,645
Accumulated depreciation .....	<u>(2,528,003)</u>	<u>(2,168,009)</u>
Net other property and equipment.....	<u>\$ 3,531,425</u>	<u>\$ 3,689,636</u>

**Note 4. 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 7 – 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 \$1,571,810 at June 30, 2008 and \$1,706,852 at December 31, 2007, net of accumulated amortization totaling \$1,758,079 and \$1,479,494, respectively.

**Note 5. 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 June 30, 2008 and December 31, 2007, with unamortized goodwill of \$313,177.

**Note 6. 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. Customer drilling deposits aggregated \$1,630,304 at June 30, 2008 and \$2,857,806 at December 31, 2007, representing unapplied drilling contract payments for wells that were not yet drilled as of the balance sheet dates.

**Note 7. 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, reflecting an antidilution adjustment from the issuance of 4.2 million shares of our common stock in November 2007, based on our net proceeds of approximately \$23.7 million. See Note 8 – Capital Stock. 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. 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. Alternatively, we may elect Eurodollar based pricing from 1.5% to 3.0% above quoted LIBOR rates. We are also responsible for commitment fees at rates ranging from 0.375% to 0.5% of the unused borrowing base. In May 2008, we amended the facility to add to the collateral package and increase the borrowing base from \$65 million to \$75 million, which was subsequently increased to \$90 million. See Note 13 – Subsequent Event. As of June 30, 2008, outstanding borrowings under the facility aggregated \$59 million, with \$2 million in letters of credit. 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) *Equipment Loan.* We obtained a term loan of \$2.1 million in September 2007 from Central Bank & Trust Co. to finance two previously purchased drilling rigs that we leased to one of our drilling contractors. The loan was repayable in monthly installments over a five-year term, bearing interest at 8% per annum, and was prepaid without penalty during the first quarter of 2008.

(d) *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 \$306,818 at June 30, 2008.

(e) *Total Long Term Debt and Maturities.* The following tables summarize our total long term debt at June 30, 2008 and December 31, 2007 and the principal payments due each year through 2012 and thereafter.

	<u>Principal Amount Outstanding</u>	
	<u>June 30, 2008</u>	<u>December 31, 2007</u>
Total long term debt (including current portion) <sup>(1)</sup> .....	\$ 95,440,022	\$ 80,549,771
Less current portion .....	24,000	388,856
Total long term debt <sup>(1)</sup> .....	<u>\$ 95,416,022</u>	<u>\$ 80,160,915</u>

**Maturities of Debt**

Remainder of 2008 .....	\$ 12,000
2009 .....	24,000
2010 .....	36,157,204 <sup>(1)</sup>
2011 .....	59,024,000
2012 and thereafter .....	222,818

(1) Excludes allocations of \$866,796 at June 30, 2008 and \$1,043,222 at December 31, 2007 from our 6% convertible notes in the principal amount of \$37,000,000 based on equity components of their conversion features and related warrants, which expired unexercised in 2006.

***Note 8. Capital Stock***

(a) *Preferred Shares.* We have 5,000,000 authorized shares of preferred stock, none of which were outstanding at June 30, 2008 or December 31, 2007.

(b) *Common Shares.* We have 100,000,000 authorized shares of common stock. The following table reflects transactions in our common stock during the reported periods, including a direct placement of 4.2 million common shares at \$6.00 per share completed in November 2007 under our existing shelf registration statement.

<b><u>Common Shares Issued</u></b>	<b><u>Number of Shares</u></b>	<b><u>Amount</u></b>
Balance, December 31, 2006 .....	21,788,551	\$ 84,531,832
Issued in registered direct placement.....	4,200,000	23,687,955
Issued as stock awards under incentive plan.....	10,430	61,010
Issued upon exercise of stock options and warrants .....	<u>137,083</u>	<u>561,729</u>
Balance, December 31, 2007 .....	<u>26,136,064</u>	<u>108,842,526</u>
Issued to employees as incentive bonus .....	7,000	31,570
Issued upon exercise of stock options.....	<u>337,582</u>	<u>1,427,307</u>
Balance, June 30, 2008 .....	<u>26,480,646</u>	<u>\$110,301,403</u>
<b><u>Paid In Capital – Options and Warrants</u></b>		
Balance, December 31, 2006 .....		\$ 3,073,287
Recognized .....		529,062
Exercised .....		<u>(118,201)</u>
Balance, December 31, 2007 .....		3,484,148
Recognized .....		166,806
Exercised .....		<u>(318,501)</u>
Balance, June 30, 2008 .....		<u>\$ 3,332,453</u>
<b><u>Contributed Surplus</u></b>		
Balance, December 31, 2006 .....		\$ 1,396,074
Accreted <sup>(1)</sup> .....		<u>(352,852)</u>
Balance, December 31, 2007 .....		1,043,222
Accreted <sup>(1)</sup> .....		<u>(176,426)</u>
Balance, June 30, 2008 .....		<u>\$ 866,796</u>
<b><u>Common Shares to be Issued</u></b>		
Balance, June 30, 2008 and December 31, 2007.....	<u>9,185</u>	<u>\$ 45,925</u>

(1) Reflects accretion of the equity components allocated to our 6% convertible notes and related warrants issued in 2005.

(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 were made under the third plan for 10,430 shares during 2007 and 7,000 shares during the first six months of 2008, along with stock option grants for 640,000 shares at \$6.51 per share during the interim period. The following table shows transactions in stock options under the plans during the reported periods.

<b><u>Stock Options</u></b>	<b><u>Issued</u></b>	<b><u>Exercisable</u></b>	<b><u>Weighted Average Exercise Price</u></b>
Balance, December 31, 2006 .....	2,815,000	945,833	\$ 4.68
Vested.....	--	920,833	6.03
Exercised .....	(127,083)	(127,083)	3.17
Forfeited .....	<u>(6,667)</u>	<u>--</u>	6.02
Balance, December 31, 2007 .....	2,681,250	1,739,583	4.75
Granted .....	640,000	--	6.51
Exercised .....	<u>(337,582)</u>	<u>(337,582)</u>	3.28
Balance, June 30, 2008 .....	<u>2,983,668</u>	<u>1,402,001</u>	5.29

At June 30, 2008, the exercise prices of options outstanding under our equity plans ranged from \$4.03 to \$7.04 per share, and their weighted average remaining contractual life was 2.05 years. The following table provides additional information on the terms of stock options outstanding at June 30, 2008.

Exercise Price or Range	Number	Options Outstanding		Options Exercisable	
		Weighted Average Remaining Life (years)	Weighted Average Exercise Price	Number	Weighted Average Exercise Price
\$ 4.03 - 4.09	1,560,000	1.31	\$ 4.05	760,000	\$ 4.06
6.02 - 7.04	<u>1,423,668</u>	2.85	6.66	<u>642,001</u>	6.94
	<u>2,983,668</u>			<u>1,402,001</u>	

In accounting for stock options, we apply the fair value recognition provisions of SFAS No. 123(R), *Share-Based Payment*, which we adopted retroactively in 2004. 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 4.5% to 6%, no dividend yield, a theoretical volatility ranging from 0.30 to 0.85 and an expected life ranging from six months to five years based on the option's vesting provisions. This resulted in non-cash charges for options and warrants of \$529,062 in 2007 and \$166,806 in the first six months of 2008.

(d) *Common Stock Purchase Warrants.* We have issued common stock purchase warrants in various financing transactions. We had warrants for the purchase of 10,000 common shares at \$4.03 per share outstanding at December 31, 2006, which were fully exercised in the first quarter of 2007.

#### Note 9. Income (Loss) Per Share

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

Numerator:	Three Months Ended June 30,		Six Months Ended June 30,	
	2008	2007	2008	2007
Net income (loss) as reported for basic EPS.....	\$ 1,521,262	\$ (760,424)	\$ 1,684,451	\$ (1,014,688)
Adjustments to income for diluted EPS.....	--	--	--	--
Net income (loss) for diluted EPS.....	<u>\$ 1,521,262</u>	<u>\$ (760,424)</u>	<u>\$ 1,684,451</u>	<u>\$ (1,014,688)</u>
<b>Denominator:</b>				
Weighted average shares for basic EPS.....	26,346,506	21,798,607	26,291,159	21,794,843
Effect of dilutive securities – stock options.....	998,023	--	724,002	--
Adjusted weighted average shares and assumed conversions for diluted EPS .....	<u>27,344,529</u>	<u>21,798,607</u>	<u>27,015,161</u>	<u>21,794,843</u>
Basic EPS.....	<u>\$ 0.06</u>	<u>\$ (0.03)</u>	<u>\$ 0.06</u>	<u>\$ (0.05)</u>
Diluted EPS .....	<u>\$ 0.06</u>	<u>\$ (0.03)</u>	<u>\$ 0.06</u>	<u>\$ (0.05)</u>

#### Note 10. 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 11. Commitments

We incurred operating lease expenses of \$2,317,526 in 2007 and \$1,268,028 in the first six months of 2008. As of June 30, 2008, we had future obligations under operating leases and other commercial commitments in the amounts listed below.

<u>Year</u>	<u>Operating Leases</u>	<u>Other Commitments<sup>(1)</sup></u>	<u>Total</u>
Remainder of 2008.....	\$ 1,165,555	\$ 340,000	\$ 1,505,555
2009 .....	2,250,846	2,045,000	4,295,846
2010 .....	2,182,717	--	2,182,717
2011 .....	1,976,039	--	1,976,039
2012 and thereafter.....	<u>920,725</u>	<u>--</u>	<u>920,725</u>
Total .....	<u>\$ 8,495,882</u>	<u>\$ 2,385,000</u>	<u>\$10,880,882</u>

(1) Reflects (i) obligations of \$240,000 under a guaranty secured by a certificate of deposit provided for bank debt of a limited liability company in which DPI previously held an interest and (ii) commitments under a purchase contract for an airplane.

### Note 12. Recent Accounting Standards

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 statement will be effective 60 days after the SEC approves the Public Company Accounting Oversight Board's amendments to AU Section 411, *The Meaning of Present Fairly in Conformity With Generally Accepted Accounting Principles*. We do not expect the adoption of SFAS 162 to have an 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. We do expect SFAS No. 161 to affect 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. We will adopt these deferred provision on January 1, 2009 and do not expect them to have a material impact on our consolidated financial position or results of operations.

SFAS No. 160. In December 2007, the FASB issued SFAS No. 160, *Noncontrolling Interests in Consolidated Financial Statements*, which establishes accounting and reporting standards for noncontrolling or minority interests in a subsidiary, including changes in a parent's ownership interest in a subsidiary. Under the new standard, noncontrolling interests in subsidiaries must be classified as a separate component of equity, and net income for both the parent and the noncontrolling interest must be disclosed on the consolidated statement of operations. SFAS No. 160 is effective for fiscal years and interim periods beginning after December 15, 2008, and its disclosure requirements will then apply retrospectively for all prior periods presented. We are assessing the affect its adoption may have on our consolidated financial statements.

SFAS No. 141(R). In December 2007, the FASB issued SFAS No. 141(R), *Business Combinations*. This statement provides revised guidance for recognizing and measuring assets acquired and liabilities assumed in a business combination. It also requires transactions costs for a business combination to be expensed as incurred. SFAS No. 141(R) will impact our accounting for any business acquisition we complete after 2008.

EITF 07-1. In December 2007, the FASB ratified the consensus reached by the Emerging Issues Task Force (EITF) in EITF Issue No. 07-1, *Accounting for Collaborative Arrangements*. The consensus requires costs incurred and revenues generated from transactions with third parties in collaborative arrangements to be reported on separate line items in the income statement pursuant to EITF Issue No. 99-19, *Reporting Revenue Gross as a*

*Principal Versus Net as an Agent.* The consensus also provides that income statement characterization of payments between the participants in a collaborative arrangement should be based on existing authoritative pronouncements or a reasonable, rational and consistently applied accounting policy election. EITF Issue No. 07-1 is effective for fiscal years beginning after December 15, 2008 and must be applied retrospectively for collaborative arrangements existing on the date of adoption. We are currently evaluating the affect of this consensus but do not anticipate any material impact on our consolidated results of operations or financial condition.

***Note 13. Subsequent Event***

In August 2008, our credit facility was expanded to increase the borrowing base from \$75 million to \$90 million.

# NGAS RESOURCES, INC.

## 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 also control the gas gathering facilities for our core Appalachian properties, which spanned a total of 636 miles as of June 30, 2008, providing deliverability directly from the wellhead to interstate pipelines serving major east coast natural gas markets. We believe our extensive experience in this region, coupled with our midstream assets, gas gathering infrastructure and relationships with partners, suppliers and mineral interest owners, gives us competitive advantages in developing these resources to achieve annual volumetric growth and strong financial returns on a long term basis.

#### *Strategy*

Our business is structured to achieve capital appreciation through growth in our natural gas production and reserves. During the second quarter of 2008, our production increased to 950.3 Mmcfe, up 8% from the preceding quarter and 23% from the second quarter of 2007. This contributed to record production revenues of \$11.2 million in the 2008 second quarter. We began 2008 with estimated proved reserves of 105.2 Bcfe, of which 46% were proved developed. Our undeveloped acreage position provides us with a multi-year inventory of drilling locations for future growth, which may be accelerated by emerging horizontal shale plays in our operating areas. Our strategy for capitalizing on these opportunities emphasizes several components.

- *Growth through the Drillbit.* Development drilling is our mainstay for production and reserve growth. During the first six months of 2008, we participated in 110 gross (55.2 net) wells, compared to 106 gross (45.5 net) wells in the same period last year. This reflects the evolution of our business model for accelerating organic growth by retaining all of our available working interest in wells drilled on operated properties in the Appalachian and Illinois Basins, which averaged 95% in the first half of 2008, compared to 56% for the prior year. We implemented this shift in our development strategy late in 2007, and most of our higher net interest wells were awaiting connection at year end. Our growth strategy during 2008 is focused on increasing our acreage position in targeted areas and taking advantage of horizontal drilling opportunities on core properties. To capitalize on those opportunities, we have a 2008 capital budget of \$50 million for drilling initiatives and related infrastructure build-outs.
- *Horizontal Drilling Initiatives.* The value proposition for many of our Appalachian properties may be enhanced by horizontal drilling. While substantially more expensive, horizontal drilling may improve overall returns on investment 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. We have focused these initiatives in our Leatherwood field, where we completed five horizontal wells in the first half of 2008, with an additional four wells at various stages of completion through the date of this report. Each of our horizontal wells has a single lateral leg up to 3,500 feet through the lower Huron section of the Devonian shale, which is present throughout most of our operating areas. For the first month in production, the five completed wells had an average flow rate 351 Mcf per day. We are encouraged by these results and plan to drill a total of twenty horizontal wells by year end, including our first New Albany shale horizontal well in our Haley's Mill field.
- *Enhancement of Field-Wide Infrastructure.* We construct and operate field-wide gas gathering facilities to provide compression, connection and local distribution capabilities for most of our Appalachian production. Because we control third-party access to these facilities, they provide us with competitive advantages in acquiring and developing nearby acreage. We continually upgrade this infrastructure to keep pace with our expanding production base. Recent additions include 43 miles of gathering lines installed during the first half of 2008, including infrastructure for producing our New Albany shale project in western Kentucky, which is scheduled to go on line in August 2008. We also completed facilities to provide deliverability from our Fonde field through a 14-mile, six-inch steel line

to our midstream system. Historically, production in Fonde had been limited by pipeline capacity constraints. Completion of our new facilities has enabled us to begin connecting a backlog of wells drilled in Fonde over the last several years and open nearly 50,000 acres for future development in this field.

- *Investment in Midstream Assets.* We own and operate a strategically located open-access gas gathering system spanning 116 miles in southeastern Kentucky and southwestern Virginia. We acquired this midstream system in 2006 through our NGAS Gathering subsidiary and augmented the system through two high-pressure lateral upgrades for connections to our field-wide gathering facilities, plus a recently completed processing plant for liquids extraction. We currently deliver all our production from the Leatherwood, Straight Creek, Fonde and SME fields to the interstate pipeline network through the NGAS Gathering system. As of June 30, 2008, the system had daily gross throughput of over 21,300 Dth, including third-party deliveries. In addition to generating gas transmission and processing revenues from third-party throughput and cost savings for our own Appalachian production, ownership of these midstream assets gives us control over gas flow from our connected fields and enhances our competitive position in the region.
- *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, we are aggressively developing our New Albany shale play in the Haley's Mill field, which is situated within the southcentral portion of the Illinois Basin in western Kentucky. We have also begun drilling operations on our Licking River prospect, where we have development rights and a 50% interest in currently constrained gathering infrastructure for a project spanning six counties in eastern Kentucky. Through the date of this report, we have drilled six wells in Licking River and a total of 33 wells in Haley's Mill, including the top hole section of our first horizontal well in this field. We plan to continue developing these prospects and evaluating other opportunities to assemble or participate in similar unconventional plays with significant reserve potential.
- *Purchase of Producing Properties.* The purchase of third-party production offers a means in addition to drilling for capitalizing on our operating experience and accelerating our growth. Our acquisition criteria for producing properties include reserve life, profit enhancement potential, existing infrastructure, geographic concentration and working interest levels permitting operation of acquired properties. Based on those criteria, we believe our mature drilling programs present attractive acquisition candidates, providing opportunities to increase our interest in producing wells that we operate for sponsored programs on our core Appalachian properties, while also generating administrative efficiencies and simplifying our capital structure. Beginning in June 2008, we launched a project to purchase the interests of outside investors in the assets of targeted programs in all-cash transactions based on independent reserve estimates that give effect to our working interests and reversionary interests in the properties.

### ***Drilling Operations***

*General.* As of June 30, 2008, we had interests in a total of 1,341 wells, concentrated on Appalachian properties that we operate and control through our gas gathering infrastructure. We believe our long and successful operating history in the southern portion of the Appalachian Basin and proven ability to drill a large number of wells year after year have positioned us as a leading player in this region. Historically, we conducted most of our drilling operations through sponsored drilling programs. Our combined interest as both general partner and an investor in these programs ranges from 12.5% to 75%, with additional reversionary interests after distribution thresholds are reached. Beginning in the second half of 2007, we changed our business model to accelerate organic growth by limiting our use of future drilling programs to participation in our non-operated initiatives, retaining all of our available working interest in wells drilled on operated properties.

*Geological Factors.* Most of our Appalachian wells are drilled to relatively shallow total depths up to 5,000 feet, generally encountering several predictable natural gas pay zones. The primary pay zone throughout this region 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. Typically, vertical gas wells in this part of Appalachia recover between 100 to 450 Mmcf of reserves per drilling unit. While these unconventional shale plays are characterized by modest initial volumes and pressures, their geological features also account for the

low annual decline rates demonstrated by vertical wells in the region, many of which are expected to produce for 25 years or more.

***Drilling Results.*** The following table shows the number of gross and net development and exploratory wells we drilled during 2007 and the first six months of 2008. Drilling results shown in the table for 2007 include 89 gross (39.54 net) wells that were drilled by year end but were awaiting installation of gathering lines or extensions prior to completion. Gross wells are the total number of wells in which we have a working interest. Net wells reflect our working interests in wells, without giving effect to any reversionary interest we may subsequently earn in wells drilled through our drilling programs.

	Development Wells			Exploratory Wells		
	Productive		Dry	Productive		Dry
	Gross	Net	Gross	Gross	Net	Gross
Year ended December 31, 2007.....	211	76.1508	--	6	6.0000	--
Six months ended						
June 30, 2008 .....	104	49.4104	--	6	5.8125	--

The exploratory wells listed for the interim period in 2008 reflect our first initiatives in our Licking River project in eastern Kentucky, where an additional four wells are planned by year end. The other exploratory wells shown in the table are part of a project started late in 2006 to test the New Albany shale in the southcentral portion of the Illinois Basin on our acquired Haley's Mill acreage. Results in Haley's Mill have been promising, and we are continuing to aggressively develop this play, including additions to our lease position and infrastructure. We also plan to drill four exploratory wells later this year to test the New Albany shale in western Kentucky outside our Haley's Mill field.

***Participation Rights.*** The interests in some of our operated properties in the Appalachian Basin, primarily our Leatherwood field, are subject to participation rights retained by the mineral interest owners for up to 50% of the working interest in wells drilled on the covered acreage. During the first six months of 2008, we had third-party participation in Leatherwood for average working interests of 14.3% in our vertical wells and 27.5% in our horizontal wells.

### ***Producing Activities***

***Regional Advantages.*** Our proved reserves, both developed and undeveloped, are concentrated in the southern portion of the Appalachian Basin. 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. 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. 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 a joint venture partner in Rogersville, Tennessee for liquids extraction from our Appalachian production delivered through the NGAS Gathering system. The plant was brought on line in January 2008, ensuring our compliance with the new energy content standard. During the first six months of 2008, our sales of extracted liquids have substantially offset the reduction in energy-related yields from our Appalachian gas production.

***Oil and Gas Production.*** The following table shows our total production volumes and average sales prices for natural gas, oil and natural gas liquids during the three months and six months ended June 30, 2008 and 2007 and for the year ended December 31, 2007.

	<b>Three Months Ended June 30, 2008</b>		<b>Six Months Ended June 30,</b>		<b>Year Ended December 31,</b>
	<b>2008</b>	<b>2007</b>	<b>2008</b>	<b>2007</b>	<b>2007</b>
<b>Production volumes:</b>					
Natural gas (Mcf).....	764,530	675,001	1,508,528	1,359,650	2,950,690
Oil (Bbl).....	14,994	15,731	28,482	31,341	57,738
Natural gas liquids (gallons).....	1,094,547	54,506	1,728,682	95,839	154,797
Equivalents (Mcf).....	950,268	774,155	1,830,682	1,556,084	3,310,665
<b>Average sales prices:</b>					
Natural gas (per Mcf) .....	\$ 9.88	\$ 8.54	\$ 9.21	\$ 8.58	\$ 8.19
Oil (per Bbl) .....	115.54	56.44	103.67	53.95	64.97
Natural gas liquids (per gallon) .....	1.73	1.43	1.64	1.28	1.41

### **Results of Operations – Three Months Ended June 30, 2008 and 2007**

*Revenues.* The following table shows the components of our revenues for the three months ended June 30, 2008 and 2007, together with their percentages of total revenue in the current period and percentage change on a period-over-period basis.

<b>Revenue:</b>	<b>Three Months Ended June 30,</b>			
	<b>2008</b>	<b>% of Revenue</b>	<b>2007</b>	<b>% Change</b>
Contract drilling.....	\$ 7,625,356	36%	\$ 7,459,704	2%
Oil and gas production.....	11,179,620	52	6,730,947	66
Gas transmission, compression and processing .....	2,536,560	12	1,887,039	34
Total .....	<u>\$21,341,536</u>	<u>100%</u>	<u>\$16,077,690</u>	33

Our revenue mix for the second quarter of 2008 reflects our ongoing strategy for transitioning to a more production based business, with oil and gas sales accounting for 52% of total revenues, compared to 42% of total revenues for the second quarter of 2007 and 40% for the year as a whole. We expect to sustain this trend as we continue to execute our initiatives for expanding our infrastructure, acreage position and working interests in core fields.

Contract drilling revenues reflect the size and timing of our drilling program initiatives, as well our ownership interest in sponsored programs. Although we receive the proceeds from private placements in sponsored programs 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. We are currently sponsoring a program for participation in up to 150 wells on non-operated properties known as the HRE fields spanning six counties in West Virginia and Virginia, where our investors will have a 75% program interest. Our contract drilling revenues in the current quarter reflect the commencement of operations for this program and the substantial completion of last year's HRE program.

The growth in our production revenues in the 2008 second quarter reflects a 23% increase in production output to 950.3 Mmcfe, compared to 774.2 Mmcfe in the same quarter last year. We anticipate ongoing production gains as we continue to upgrade our infrastructure and bring completed wells on stream, including high output horizontal wells in our Leatherwood field. Principal purchasers of our production are gas marketing intermediaries. Approximately 55% 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 averaged \$10.39 per Mcf for our Appalachian production and \$9.88 per Mcf overall during the current quarter, compared to an average overall realization of \$8.54 per Mcf in the second quarter of 2007.

Gas transmission, compression and processing revenues were driven by fees totaling \$1,397,182 for moving third-party gas through our NGAS Gathering system and \$92,712 in related processing fees for liquids extraction through our Rogersville plant. This component of revenues also includes our drilling program investors' share of gathering and compression fees for moving gas through our field-wide facilities, together with contributions of \$69,213 from gas utility sales and \$99,447 from our interest in the gathering system that services a non-operated

coalbed methane project in the Arkoma Basin.

*Expenses.* The following table shows the components of our direct and other expenses for the three months ended June 30, 2008 and 2007. Percentages listed in the table reflect margins for each component of direct expenses and percentages of total revenue for each component of other expenses.

<b><u>Direct Expenses:</u></b>	<b>Three Months Ended June 30,</b>			
	<b><u>2008</u></b>	<b><u>Margin</u></b>	<b><u>2007</u></b>	<b><u>Margin</u></b>
Contract drilling.....	\$ 5,756,997	25%	\$ 5,919,020	21%
Oil and gas production.....	3,107,095	72	1,799,186	73
Gas transmission, compression and processing.....	957,548	62	779,843	59
Impairment of oil and gas assets.....	--	--	964,000	N/A
Total direct expenses.....	<u>9,821,640</u>	54	<u>9,462,049</u>	41
<b><u>Other Expenses:</u></b>		<b><u>% Revenue</u></b>		<b><u>% Revenue</u></b>
Selling, general and administrative.....	3,442,094	16%	3,042,364	19%
Options, warrants and deferred compensation.....	234,803	1	329,177	2
Depreciation, depletion and amortization.....	3,261,192	15	2,361,176	15
Bad debt expense.....	59,000	--	--	N/A
Interest expense, net of interest income.....	1,346,550	6	1,484,527	9
Other, net.....	<u>34,632</u>	--	<u>45,156</u>	--
Total other expenses.....	<u>\$ 8,378,271</u>		<u>\$ 7,262,400</u>	

Contract drilling expenses reflect the level of drilling initiatives conducted through our sponsored programs. These expenses decreased by 3% on a period-over-period basis and represented 75% of contract drilling revenues in current period, compared to 79% in the year-earlier period. The contraction in this part of our business reflects a planned phase-out of drilling program participation in developing our operated Appalachian properties. 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 for the current quarter were consistent with our volumetric growth. In addition to lifting costs, production expenses include field operating and maintenance costs, related overhead, severance and other production taxes, third-party transportation fees, processing costs and lease operating expenses. 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. As a percentage of oil and gas production revenues, our production expenses were 28% in the 2008 second quarter, compared to 27% in the year-earlier period.

Gas transmission, compression and processing expenses in the second quarter of 2008 were 38% of associated revenues, compared to 41% 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 two years ago. Our gas transmission, compression and processing expenses do not include capitalized costs of approximately \$3.3 million 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.

In the second quarter of 2007, we expensed all of the suspended exploratory well costs for the remaining 27 wells in a 30-well program we began late in 2005 to test the New Albany shale formation on the eastern rim of the Illinois basin in western Kentucky. This resulted in an impairment charge of \$964,000 in the carrying value of our position during the second quarter last year, in addition to a charge of \$178,700 recognized for the first three wells in that program during 2006.

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 increased by 13% from the same period last year, primarily reflecting sales costs for a program launched in April 2008 for participation in up to 150 wells on non-operated properties in West Virginia and Virginia, along with overhead costs for supporting our expanded operations as a whole. As a percentage of revenues, SG&A expenses decreased from 19% in the 2007 second quarter to 16% in the current quarter.

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 \$102,838 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 \$59,000 in the 2008 second quarter for a non-performing loan to a regional operator on a three-well project in Texas prior to its filing for liquidation under the bankruptcy laws. See “Critical Accounting Policies and Estimates – Allowance for Doubtful Accounts.”

Interest expense for the 2008 second quarter decreased from lower variable rates under our revolving credit facility. Draws under the credit facility were used primarily to support our ongoing drilling initiatives and enhancements of our field-wide gas gathering systems.

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.

*Net Income and EPS.* We realized a net income of \$1,521,262 in the second quarter of 2008, compared to a net loss of \$760,424 recognized in the same quarter last year, reflecting the foregoing factors. Basic earnings per share (*EPS*) was \$0.06 based on 26,346,506 weighted average common shares outstanding in the current quarter, compared to *EPS* of \$(0.03) based on 21,798,607 weighted average common shares outstanding in the second quarter of 2007.

***Results of Operations – Six Months Ended June 30, 2008 and 2007***

*Revenues.* The following table shows the components of our revenues for the six months ended June 30, 2008 and 2007, together with their percentages of total revenue in the current period and percentage change on a period-over-period basis.

<b><u>Revenue:</u></b>	<b><u>Six Months Ended June 30,</u></b>			
	<b><u>2008</u></b>	<b><u>% of Revenue</u></b>	<b><u>2007</u></b>	<b><u>% Change</u></b>
Contract drilling.....	\$ 14,227,474	37%	16,704,923	(15)%
Oil and gas production.....	19,669,054	50	13,483,179	46
Gas transmission, compression and processing .....	<u>5,094,652</u>	<u>13</u>	<u>3,834,980</u>	33
Total .....	<u>\$ 38,991,180</u>	<u>100%</u>	<u>\$ 34,023,082</u>	15

Contract drilling revenues reflect the size and timing of our drilling program initiatives, as well our ownership interest in sponsored programs. The contraction in our contract drilling revenues for the current period reflects the shift in our business model to retain all of our available working interest in new wells drilled on operated properties, limiting our use of sponsored programs to participation in our non-operated initiatives. Drilling operations for our 2007 year-end program were substantially completed during the first two quarters this year and began for our current drilling program in the second quarter. Investors in our 2008 program will have a 75% interest, and our contract drilling revenues for the balance of the year will be driven by the size of the program, which will participate in up to 150 wells on non-operated HRE properties in West Virginia and Virginia.

The growth in our production revenues in the first half of 2008 reflects a 18% increase in production output to 1,830.7 Mmcfe, compared to 1,556.1 Mmcfe in the same period last year. Our volumetric growth was driven by added production from wells brought on line in the last twelve months. We anticipate ongoing production gains as we continue to upgrade our infrastructure and bring completed wells on stream, including substantial contributions

from our horizontal drilling project in Leatherwood and our infrastructure upgrade in Fonde. Realized natural gas prices averaged \$9.79 per Mcf for our Appalachian production and \$9.21 per Mcf overall during the current period, compared to an average overall realization of \$8.58 per Mcf in the year-earlier period. Approximately 50% of our natural gas production in the first half of 2008 was sold under fixed-price contracts, and the balance primarily at prices determined monthly under formulas based on prevailing market indices.

Gas transmission, compression and processing revenues were driven by fees totaling \$2,480,664 for moving third-party gas through our NGAS Gathering system and \$296,250 in related processing fees for liquids extraction through our Rogersville plant. This component of revenues also includes our drilling program investors' share of gathering and compression fees for moving gas through our field-wide facilities, together with contributions of \$334,316 from gas utility sales and \$208,040 from our interest in the gathering system that services a non-operated coalbed methane project in the Arkoma Basin.

*Expenses.* The following table shows the components of our direct and other expenses for the six months ended June 30, 2008 and 2007. Percentages listed in the table reflect margins for each component of direct expenses and percentages of total revenue for each component of other expenses.

	<b>Six Months Ended June 30,</b>			
	<b>2008</b>	<b>Margin</b>	<b>2007</b>	<b>Margin</b>
<b>Direct Expenses:</b>				
Contract drilling.....	\$10,876,846	24%	13,099,737	22%
Oil and gas production.....	5,872,050	70	3,482,200	74
Gas transmission, compression and processing.....	2,047,794	60	1,879,436	51
Impairment of oil and gas assets.....	--		<u>964,000</u>	N/A
Total direct expenses.....	<u>18,796,690</u>	52	<u>19,425,373</u>	43
<b>Other Expenses:</b>				
		<b>% Revenue</b>		<b>% Revenue</b>
Selling, general and administrative.....	6,730,577	17	7,064,246	21%
Options, warrants and deferred compensation.....	372,482	1	670,300	2
Depreciation, depletion and amortization.....	6,132,952	16	4,667,646	14
Bad debt expense.....	406,840	1	--	N/A
Interest expense, net of interest income.....	2,602,810	7	2,625,229	8
Other, net.....	<u>28,355</u>	--	<u>137,905</u>	--
Total other expenses.....	<u>\$16,274,016</u>		<u>\$15,165,326</u>	

Contract drilling expenses reflect the level of drilling initiatives conducted through our sponsored programs. These expenses decreased by 17% on a period-over-period basis and represented 76% of contract drilling revenues in current period, compared to 78% in the year-earlier period. The contraction in this part of our business reflects a planned phase-out of drilling programs to participate in developing our operated properties in the Appalachian Basin. 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 for the first half of 2008 were consistent with our volumetric growth. Our margins in both reported 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 Appalachian production delivered through the system. As a percentage of oil and gas production revenues, our production expenses were 30% in the first six months of 2008, compared to 26% in the year-earlier period, primarily reflecting start-up costs for bringing our Rogersville processing plant and Fonde system on line.

Gas transmission, compression and processing expenses in the first half of 2008 were 40% of associated revenues, compared to 49% in the same period last year. The margins for this part of our business have benefited from third-party fees generated by the NGAS Gathering system acquired two years ago. Our gas transmission, compression and processing expenses do not include capitalized costs of approximately \$6.9 million in the current period for extensions of our field-wide gas gathering systems and additions to dehydration and compression capacity required to bring new wells on line.

SG&A expenses in the first six months of 2008 decreased by 5% year-over-year, reflecting the reduced

level of drilling program sales. This component of SG&A is subject to considerable fluctuation based on the timing of drilling program sales, which are generally higher in the second half of the year. As a percentage of revenues, SG&A expenses decreased from 21% in the first half of 2007 to 17% in the current period.

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 \$205,676 for deferred compensation cost.

The increase in DD&A charges for the current period reflects substantial additions to our oil and gas properties, gas gathering systems and related equipment. We recognize DD&A 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.

We recognized a bad debt expense of \$347,840 in the first quarter of 2008 and \$59,000 in the 2008 second quarter. The first quarter charge, coupled with a prior period reserve, represents the entire amount due for oil sales to a regional refinery prior to its filing for reorganization under the bankruptcy laws last year. The second quarter charge reflects a writeoff of a non-performing loan to a regional operator on a three-well project in Texas. See “Critical Accounting Policies and Estimates – Allowance for Doubtful Accounts.”

Interest expense for the first half of 2008 decreased from lower variable rates under our revolving credit facility. Draws under the credit facility were used primarily to support our ongoing drilling initiatives and enhancements of our field-wide gas gathering systems.

We recognize deferred income tax expense based on 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.

*Net Income and EPS.* We realized a net income of \$1,684,451 in the first six months of 2008, compared to a net loss of \$1,014,688 recognized in the same period last year, reflecting the foregoing factors. Basic EPS was \$0.06 based on 26,291,159 weighted average common shares outstanding in the current period, compared to EPS of \$(0.05) based on 21,794,843 weighted average common shares outstanding in year-earlier period.

The results of operations for the three months and six months ended June 30, 2008 are not necessarily indicative of results to be expected for the full year.

### ***Liquidity and Capital Resources***

*Liquidity.* Net cash of \$9,765,847 was provided by operating activities for the first six months of 2008. During the period, we used \$26,626,458 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 \$15,681,765 from financing activities. As a result of these activities, net cash decreased from \$2,816,678 at the end of last year to \$1,637,832 at June 30, 2008.

As of June 30, 2008, we had a working capital deficit of \$1,357,626. 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. Our working capital position at the end of the second quarter this year is not expected to have an adverse effect on our financial condition or results of operations in future periods.

*Capital Resources.* 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. Our long term performance and profitability is dependent not only on recovery of existing oil and gas reserves, but also on our ability to find or acquire additional reserves and provide the infrastructure to support their development on terms that are economically and operationally advantageous. Historically, 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

ongoing reserve and infrastructure development and acquisition activities, as well as participation in our drilling initiatives by outside investors in our sponsored programs. With the evolution of our business model for accelerating organic growth by retaining all of our available working interest in wells drilled on operated properties, we have limited our use of future drilling programs to participation in our non-operated initiatives. This may increase our dependence on the credit and capital markets to meet our ongoing development objectives.

We have a senior secured revolving credit facility maintained by our U.S. operating subsidiary, Daugherty Petroleum, Inc. (*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 increase the borrowing base from \$65 million to \$75 million. 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. Alternatively, we may elect Eurodollar based pricing from 1.5% to 3.0% above quoted LIBOR rates. 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 proved oil and gas properties and open-access gathering facilities. As of June 30, 2008, outstanding borrowings under the facility aggregated \$59 million, and the interest rate amounted to 5.75%, reflecting our election for prime-based pricing during the first half of 2008. In August 2008, the credit facility was expanded to increase the borrowing base from \$75 million to \$90 million.

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. We will likely be dependent on additional financings to repay our outstanding long term debt at maturity. 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 program capital for participation in our non-operated initiatives. The market price for natural gas is subject to wide fluctuations in response to relatively minor changes in supply and demand, market uncertainty and a variety of other factors that are beyond our control.

We expect our cash reserves, cash flows from operations and anticipated borrowing base availability under our credit facility to provide adequate working capital to meet our short-term capital expenditure objectives. To fully realize our long-term goals for growth in revenues and reserves, we will continue to be dependent on the credit and capital markets or other financing alternatives.

### ***Forward Looking Statements and Risk Factors***

Some statements in this report are prospective and constitute forward-looking statements within the meaning of Section 21E of the Securities Exchange Act. 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. They include subsurface risks on the recoverability of hydrocarbons, operating risks involving logistical, infrastructure and regulatory issues and commercial risks stemming from the volatility of natural gas prices. A discussion of these risk factors is included in our annual report on Form 10-K for the year ended December 31, 2007. There were no material changes in these risk factors during the interim periods covered by this report.

### ***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 annual commitments under these instruments at June 30, 2008.

<b><u>Year</u></b>	<b><u>Operating Leases</u></b>			<b><u>Other Commitments</u></b> <sup>(1)</sup>	<b><u>Long Term Debt</u></b>
	<b><u>Equipment</u></b>	<b><u>Premises</u></b>	<b><u>Total</u></b>		
Remainder of 2008 .....	\$ 1,043,169	\$ 122,386	\$ 1,165,555	\$ 340,000	\$ 12,000
2009 .....	2,003,982	246,864	2,250,846	2,045,000	24,000
2010 .....	1,934,902	247,815	2,182,717	--	36,157,204 <sup>(2)</sup>
2011 .....	1,723,650	252,389	1,976,039	--	59,024,000
2012 and thereafter .....	<u>643,397</u>	<u>277,329</u>	<u>920,725</u>	<u>--</u>	<u>222,818</u>
Total .....	<u>\$ 7,349,099</u>	<u>\$ 1,146,783</u>	<u>\$ 8,495,882</u>	<u>\$ 2,385,000</u>	<u>\$ 95,440,022</u>

- (1) Reflects (i) obligations of \$240,000 under a guaranty secured by a certificate of deposit provided for bank debt of a limited liability company in which we previously held an interest and (ii) commitments under a purchase contract for an airplane.
- (2) Excludes an allocation of \$866,796 from our 6% convertible notes in the principal amount of \$37,000,000 based on equity components of their conversion features.

### ***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 in Note 1 to the consolidated financial statements included in our 2007 annual report on Form 10-K. 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 and 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 impairment 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 amounts 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. For the remaining six months of 2008, we have contracts in place for approximately 80% of our gas production from operated properties at a weighted average sales price of \$9.45 per Mcf.

#### ***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 June 30, 2008, 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 June 30, 2008 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 June 30, 2008.

#### ***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. OTHER INFORMATION

### Item 4. Submission of Matters to a Vote of Security Holders

Our annual meeting of shareholders was held on June 26, 2008. The following incumbent directors were reelected, based on the voting results set forth below:

<u>Nominee</u>	<u>Votes For</u>	<u>Votes Withheld</u>
William S. Daugherty.....	19,237,447	1,847,471
James K. Klyman .....	19,107,072	1,977,846
Thomas F. Miller.....	19,204,193	1,880,725

Our shareholders also voted at the meeting to ratify the board's appointment of Hall, Kistler & Company LLP as our auditors for 2008 and to approve a proposal for fixing the size of our board of directors at three members, based on the number of incumbent directors at the time we issued our proxy statement for the meeting. The number of votes cast for and against each of these proposals is set forth below.

<u>Proposal</u>	<u>Votes For</u>	<u>Votes Against</u>
Ratification of independent auditors .....	19,313,533	1,771,385
Fixing the size of the board .....	18,139,804	2,945,114

At the annual meeting of our board of directors held in conjunction with the shareholders meeting, the board confirmed its appointment of Steve U. Morgan as a director and member of the audit committee and compensation committee on June 18, 2008, filling a vacancy in those positions following the death of one of our independent directors late last year. Although the appointment was not completed in time to include Mr. Morgan among the incumbent members of our board standing for reelection at the shareholders meeting, his appointment enables us to maintain our compliance with Nasdaq audit committee composition requirements.

### Item 6. Exhibits

<u>Exhibit Number</u>	<u>Description of Exhibit</u>
3.1	Notice of Articles, certified on June 3, 2004 by the Registrar of Corporations under the British Columbia Business Corporations Act (incorporated by reference to Exhibit 3.1 to Current Report on Form 8-K [File No. 0-12185], filed June 29, 2004).
3.2	Alteration to Notice of Articles, certified on June 25, 2004 by the Registrar of Corporations under the British Columbia Business Corporations Act (incorporated by reference to Exhibit 3.2 to Current Report on Form 8-K [File No. 0-12185], filed June 29, 2004).
3.3	Articles dated June 25, 2004, as amended and restated for corporate transition under the British Columbia Business Corporations Act (incorporated by reference to Exhibit 3.3 to Current Report on Form 8-K [File No. 0-12185], filed June 29, 2004).
10.1	1997 Stock Option Plan (incorporated by reference to Exhibit 10[a] to Annual Report on Form 10-KSB [File No. 0-12185] for the year ended December 31, 2002).
10.2	2001 Stock Option Plan (incorporated by reference to Exhibit 10[b] to Annual Report on Form 10-KSB [File No. 0-12185] for the year ended December 31, 2002).
10.3	2003 Incentive Stock and Stock Option Plan (incorporated by reference to Exhibit 10.3 to Quarterly Report on Form 10-QSB [File No. 0-12185] for the quarter ended June 31, 2004).
10.4	Asset Purchase and Sale Agreement dated as of January 17, 2006 among Duke Energy Gas Services, LLC, NGAS Gathering, LLC and Daugherty Resources, Inc. (incorporated by reference to Exhibit 10.1 to current report on Form 8-K [File No. 0-12185] dated January 19, 2006).

- 10.5 Form of 6% convertible notes issued pursuant to the Securities Purchase Agreement dated as of December 13, 2005 among NGAS Resources, Inc. and the investors named therein (incorporated by reference to Exhibit 10.2 to current report on Form 8-K [File No. 0-12185] dated December 14, 2005).
- 10.6 Amended and Restated Credit Agreement dated as of May 30, 2008 among NGAS Resources, Inc., Daugherty Petroleum, Inc. and KeyBank National Association, as agent for the lenders named therein.
- 10.6 Amended and Restated Credit Agreement dated as of May 30, 2008 among NGAS Resources, Inc., Daugherty Petroleum, Inc. and KeyBank National Association, as agent for the lenders named therein.
- 10.7 Amendment No. 1 dated as of August \_\_, 2008 to Amended and Restated Credit Agreement dated as of May 30, 2008 among NGAS Resources, Inc., Daugherty Petroleum, Inc. and KeyBank National Association, as agent for the lenders named therein.
- 10.8 Form of Change of Control Agreement dated as of February 25, 2004 (incorporated by reference to Exhibit 10.9 to quarterly report on Form 10-QSB [File No. 0-12185] for the quarter ended June 31, 2004).
- 10.9 Form of Indemnification Agreement dated as of February 25, 2004 (incorporated by reference to Exhibit 10.10 to quarterly report on Form 10-QSB [File No. 0-12185] for the quarter ended June 31, 2004).
- 10.10 Form of Long Term Incentive Agreement dated as of February 25, 2004 (incorporated by reference to Exhibit 10.11 to quarterly report on Form 10-QSB [File No. 0-12185] for the quarter ended June 31, 2004).
- 10.11 Form of general partnership agreement with sponsored drilling programs (incorporated by reference to Exhibit 10.11 to amended annual report on Form 10-K/A [File No. 0-12185] for the year ended December 31, 2006).
- 10.12 Form of limited partnership agreement with sponsored investment partnerships (incorporated by reference to Exhibit 10.12 to amended annual report on Form 10-K/A [File No. 0-12185] for the year ended December 31, 2006).
- 10.13 Form of assignment of drilling rights with sponsored drilling programs (incorporated by reference to Exhibit 10.13 to amended annual report on Form 10-K/A [File No. 0-12185] for the year ended December 31, 2006).
- 10.14 Form of drilling and operating agreement with sponsored drilling programs (incorporated by reference to Exhibit 10.14 to amended annual report on Form 10-K/A [File No. 0-12185] for the year ended December 31, 2006).
- 11.1 Computation of Earnings Per Share (included in Note 9 to the accompanying consolidated financial statements)
- 21.0 Subsidiaries (incorporated by reference to Exhibit 21.1 to annual report on Form 10-K [File No. 0-12185] for the year ended December 31, 2006).
- 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 report to be signed on its behalf by the undersigned thereunto duly authorized.

**NGAS RESOURCES, INC.**

Date: August 7, 2008

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

**AMENDED AND RESTATED CREDIT AGREEMENT**

**AMENDMENT NO. 1 TO  
AMENDED AND RESTATED CREDIT AGREEMENT**

**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 quarterly report of NGAS Resources, Inc. on Form 10-Q for the quarter ended June 30, 2008, 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 quarterly report on Form 10-Q 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  
August 7, 2008

**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 quarterly report of NGAS Resources, Inc. on Form 10-Q for the quarter ended June 30, 2008, 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 quarterly report on Form 10-Q 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  
August 7, 2008

**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 quarterly report of NGAS Resources, Inc. on Form 10-Q for the quarter ended June 30, 2008, 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  
August 7, 2008

**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 quarterly report of NGAS Resources, Inc. on Form 10-Q for the quarter ended June 30, 2008, 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  
August 7, 2008