KGen Power Corporation

Report to Shareholders

for

Quarter Ended March 31, 2010

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KGen Power Corporation

Condensed Consolidated Balance Sheets

(in thousands, except per share amounts)

	March 31, 2010 (unaudited)	June 30, 2009
Assets		
Current assets:		
Cash and cash equivalents	**$ 53,724**	$ 40,663
Restricted cash and cash equivalents	**11,343**	32,943
Accounts receivable	**4,873**	22,815
Spare parts inventories	**8,786**	7,232
Prepaid expenses and other current assets	**2,706**	1,336
Total current assets	**81,432**	104,989
Property, plant, and equipment	**707,565**	705,711
Less: accumulated depreciation	**75,730**	57,501
Net property, plant, and equipment	**631,835**	648,210
Contract-based intangibles (net of $33,490 and $25,498 of accumulated amortization, respectively)	**50,052**	58,044
Deferred charge	**2,762**	2,769
Deferred financing fees (net of $2,809 and $2,138 of accumulated amortization, respectively)	**3,455**	4,126
Other noncurrent assets	**382**	325
Total assets	**$ 769,918**	$ 818,463
Liabilities and stockholders' equity		
Current liabilities:		
Accounts payable and accrued liabilities	**$ 14,325**	$ 19,078
Current portion of long-term debt	**2,000**	2,000
Total current liabilities	**16,325**	21,078
Long-term debt	**201,500**	203,000
Contract-based intangibles (net of $4,611 and $3,604 of accumulated amortization, respectively)	**15,557**	16,564
Other noncurrent liabilities	**2,745**	4,119
Commitments and contingencies (Note 6)	**—**	—
Stockholders' equity:		
Common stock (par value $.01; 150,000 shares authorized; 55,968 shares issued and outstanding at both March 31, 2010 and June 30, 2009)	**560**	560
Additional paid in capital	**742,469**	741,602
Accumulated deficit	**(209,238)**	(168,460)
Total stockholders' equity	**533,791**	573,702
Total liabilities and stockholders' equity	**$ 769,918**	$ 818,463

The accompanying notes are an integral part of these condensed consolidated financial statements.

KGen Power Corporation

Condensed Consolidated Statements of Operations

(in thousands, except per share amounts)

(unaudited)

	For the Three Months Ended March 31, 2010	For the Three Months Ended March 31, 2009	For the Nine Months Ended March 31, 2010	For the Nine Months Ended March 31, 2009
Revenues:				
Energy sales	**$ 21,676**	$ 19,307	**$ 99,091**	$ 153,683
Capacity sales	**6,115**	5,659	**38,494**	42,153
Total revenues	**27,791**	24,966	**137,585**	195,836
Operating expenses:				
Cost of fuel	**21,369**	18,196	**84,538**	130,875
Operating and maintenance	**21,700**	6,398	**32,791**	35,233
Gas transportation	**3,684**	3,675	**12,119**	11,971
Selling, general, and administrative	**3,250**	4,674	**9,198**	12,363
Depreciation	**6,009**	5,989	**18,264**	18,206
Auxiliary power	**2,148**	1,950	**6,331**	6,475
Insurance	**905**	937	**2,687**	2,741
Total operating expenses	**59,065**	41,819	**165,928**	217,864
Operating loss	**(31,274)**	(16,853)	**(28,343)**	(22,028)
Other income (expenses):				
Interest expense	**(2,994)**	(2,546)	**(9,182)**	(9,668)
Taxes, other than income taxes	**(1,113)**	(1,041)	**(3,076)**	(3,238)
Net interest income	**—**	(81)	**—**	221
Other	**(57)**	1,097	**(177)**	(7,182)
Total other expenses	**(4,164)**	(2,571)	**(12,435)**	(19,867)
Net loss before taxes	**(35,438)**	(19,424)	**(40,778)**	(41,895)
Income tax benefit	**—**	—	**—**	—
Net loss after taxes	**$ (35,438)**	$ (19,424)	**$ (40,778)**	$ (41,895)
Net loss per share—basic and diluted	**$ (0.63)**	$ (0.35)	**$ (0.73)**	$ (0.75)
Weighted average shares outstanding—basic and diluted	**55,968**	55,967	**55,968**	55,967

The accompanying notes are an integral part of these condensed consolidated financial statements.

KGen Power Corporation

Condensed Consolidated Statements of Cash Flows

(in thousands)

(unaudited)

	For the Nine Months Ended March 31, 2010	For the Nine Months Ended March 31, 2009
Cash flows from operating activities		
Net loss	**$ (40,778)**	$ (41,895)
Adjustments to reconcile net loss to net cash used in operating activities:		
Depreciation	**18,264**	18,206
Amortization of deferred financing fees	**671**	671
Amortization of contract-based intangibles	**6,985**	6,966
Valuation of derivative instruments	**3,236**	7,177
Stock-based compensation	**867**	2,411
Payments from settlement of derivative instruments	**(4,772)**	(4,108)
Changes in operating assets and liabilities:		
Accounts receivable	**17,942**	31,347
Spare parts inventories	**(1,554)**	183
Prepaid expenses and other current assets	**(1,370)**	(595)
Deferred charge	**7**	(638)
Accounts payable and accrued liabilities	**(5,308)**	(23,394)
Other noncurrent assets	**(57)**	—
Other noncurrent liabilities	**(5)**	(5)
Net cash used in operating activities	**(5,872)**	(3,674)
Cash flows from investing activities		
Purchases of property, plant, and equipment	**(1,167)**	(1,267)
Short-term investments	**—**	1,614
Use of (investment in) restricted cash and cash equivalents	**21,600**	(8,541)
Net cash provided by (used in) investing activities	**20,433**	(8,194)
Cash flows from financing activities		
Repayment of debt	**(1,500)**	(1,500)
Borrowings from working capital revolver	**—**	10,000
Net cash (used in) provided by financing activities	**(1,500)**	8,500
Increase (decrease) in cash and cash equivalents	**13,061**	(3,368)
Cash and cash equivalents at beginning of period	**40,663**	51,493
Cash and cash equivalents at end of period	**53,724**	$ 48,125
Cash paid for		
Interest	**$ 5,237**	$ 8,985
Noncash transactions		
Grant of shares for Board fees	**$ —**	$ 116
Accounts payable related to purchases of property, plant, and equipment	**$ 687**	**$ —**

The accompanying notes are an integral part of these condensed consolidated financial statements.

KGen Power Corporation

Notes to Unaudited Condensed Consolidated Financial Statements

1. Nature of Business and Significant Accounting Policies

Operations—KGen Power Corporation (the "Company") was incorporated in Delaware on December 4, 2006, which is the date of its inception. The Company owns and operates electric power generation plants and sells electricity and electrical generation capacity in the United States to wholesale purchasers such as retail electric providers, power trading organizations, municipal utilities, electric power cooperatives, and other power generation companies. The portfolio of facilities consists of five operational and fully permitted power plants (the "Plants") located in the southeastern United States with gas turbines having an aggregate capacity of 3,030 megawatts ("MW"). The Plants include four combined-cycle plants (Murray I, Murray II, Hot Spring, and Hinds) and one simple-cycle plant (Sandersville). The Plants were acquired from an affiliate of MatlinPatterson Global Advisors LLC on February 8, 2007.

Interim Financial Statements—The accompanying condensed consolidated financial statements have been prepared in accordance with the regulations regarding interim financial reporting. Certain information and footnote disclosures normally included in financial statements prepared in accordance with accounting principles generally accepted in the United States of America ("GAAP") have been condensed or omitted. In the opinion of management, all adjustments (consisting of normal recurring accruals, except as noted in Note 6—Commitments and Contingencies) considered necessary for a fair presentation have been included. The balance sheet at June 30, 2009 is derived from the June 30, 2009 audited consolidated financial statements. These condensed consolidated financial statements included herein should be read in conjunction with the Consolidated Financial Statements and Notes included in the Company's Annual Report for the year ended June 30, 2009.

Use of Estimates—The preparation of the condensed consolidated financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the amounts reported in the condensed consolidated financial statements and accompanying notes. Such estimates include the fair value of acquired assets, estimated asset lives, recovery of investments in long-lived assets, utilization of deferred tax assets, and fair value determination of financial instruments and share-based compensation. Actual results could differ from these estimates.

Principles of Consolidation—The condensed consolidated financial statements include the accounts of the Company and those of KGen Partners LLC, KGen Power Management Inc., KGen LLC, KGen Murray LLC, KGen Murray I and II LLC, KGen Hot Spring LLC, KGen Hinds LLC, KGen Sandersville LLC, KGen Acquisition I LLC, all direct or indirect 100% owned subsidiaries, as well as any variable interest entities for which the Company is the primary beneficiary. All significant intercompany balances and transactions have been eliminated in consolidation.

Effects of Seasonality—The electric power industry is highly seasonal. In the summer months, especially in the southeastern United States, demand for electricity is usually much higher as a result of increased use of air conditioning. The Company's results of operations are subject to seasonal variations since demand for electricity, and thus production varies with weather conditions. Four of the plants currently operate on a merchant basis without long-term purchase agreements, and therefore are exposed to significant volatility in prices and generation demand. The Company earns the majority of its annual revenues in the five summer months, May through September. The shoulder periods, months other than the peak summer months, historically have not been profitable for the Company and are typically the months during which the Company seeks to perform scheduled maintenance-related activities.

Recently Issued Accounting Standards— In February 2010, an update was issued to FASB ASC 855 *Subsequent Events*, effective for the Company for interim periods ending June 2010. FASB ASC 855 establishes general standards of accounting for and disclosure of events that occur after the balance sheet date but before financial statements are issued or are available to be issued. The Company does not expect the adoption of this guidance to have a material impact on either its financial position or results of operations.

In March 2010, an update was issued to FASB ASC 740 *Income Taxes*. FASB ASC 740 establishes financial accounting and reporting standards for the effects of income taxes that result from an enterprise's activities during the current and preceding years. The Company does not expect the adoption of this guidance to have a material impact on either its financial position or results of operations.

2. Property, Plant, and Equipment

Property, plant, and equipment consists of the following (in thousands of dollars):

	Estimated Useful Life	March 31, 2010	June 30, 2009
Land	—	$ 4,201	$ 4,201
Buildings	40 years	29,382	28,612
Gas and steam turbines	30 years	236,450	235,985
Steam generators and auxiliaries	30 years	48,959	48,402
Transmission and fuel gas pipelines	30 years	57,344	57,191
Systems and equipment	5 - 30 years	124,819	122,616
Other plant	3 - 30 years	206,410	208,704
Total property, plant, and equipment		707,565	705,711
Less: accumulated depreciation		75,730	57,501
Net property, plant, and equipment		$ 631,835	$ 648,210

3. Contract-Based Intangibles

Contract-based intangibles, net of accumulated amortization, consist of the following (in thousands of dollars):

	Term	March 31, 2010	June 30, 2009
Assets			
Murray I Georgia Power contract	May 31, 2012	$ 17,770	$ 23,854
Murray firm transportation contracts	Various	32,282	34,190
Total assets		$ 50,052	$ 58,044
Liabilities			
Hinds firm transportation contract	March 31, 2012	$ 107	$ 147
Murray firm transportation contract	November 30, 2016	432	481
Hot Spring firm transportation contracts	Various	15,018	15,936
Total liabilities		$ 15,557	$ 16,564

For the three months ended March 31, 2010 and 2009, amortization of contract-based power sales rights and obligations was 2.0 million. For the nine months ended March 31, 2010 and 2009, amortization of contract-based power sales rights and obligations was $6.1 million. These amortization amounts were recorded as a reduction of energy sales on the condensed consolidated statements of operations.

For the three months ended March 31, 2010 and 2009, amortization of contract-based natural gas transportation rights and obligations was $0.3 million. For the nine months ended March 31, 2010 and 2009, amortization of contract-based natural gas transportation rights and obligations was $0.9 million. These amortization amounts were recorded as an increase of gas transportation expenses on the condensed consolidated statements of operations.

4. Long-Term Debt

Long-term debt is summarized as follows (in thousands of dollars):

	Interest Rate	Maturity	March 31, 2010	June 30, 2009
Term debt	Variable	February 8, 2014	$ 193,500	$ 195,000
Working capital facility	Variable	February 8, 2012	10,000	10,000
Total debt outstanding			203,500	205,000
Less: current portion			2,000	2,000
Total long-term debt			$ 201,500	$ 203,000

On February 8, 2007, KGen LLC, a wholly owned subsidiary of the Company, entered into a credit agreement with Morgan Stanley (the "Credit Agreement") and related security deposit agreement (the "Security Deposit Agreement") with Union Bank, N.A., as collateral agent, and The Bank of New York, as depository agent, to provide term debt in the amount of $200.0 million. The term debt bears interest at an adjusted rate based on the London Interbank Offered Rate ("LIBOR") plus 175 basis points, has a term of seven years and requires a $2.0 million principal payment per year made in quarterly installments. KGen LLC's obligations and indebtedness under the Credit Agreement are secured by a security interest in all of the assets and all of the membership interests of KGen LLC and its subsidiaries. The interest rate on the term debt was 2.0% and 2.1% at March 31, 2010 and June 30, 2009, respectively.

KGen LLC also entered into an $80.0 million working capital facility for other liquidity needs and a $120.0 million synthetic letter of credit facility to support the collateral requirements at the project level. The working capital facility charges a 200 basis point fee for outstanding letters of credit, bears interest at LIBOR plus 200 basis points for outstanding draws, and has a 50 basis point commitment fee for any unused portion. It has a five-year term expiring on February 8, 2012. On March 20, 2009, KGen LLC drew $10.0 million under the working capital facility. The proceeds of the drawdown continue to be used for working capital purposes. There were $8.0 million of outstanding letters of credit issued under the working capital facility as of March 31, 2010 and June 30, 2009. KGen LLC pays a fee of 191 basis points on the $120.0 million synthetic letter of credit facility. The synthetic letter of credit facility has a seven-year term expiring on February 8, 2014. At both March 31, 2010 and June 30, 2009, a letter of credit, supporting the power sales contract with GPC, with a current outstanding amount of $100.0 million, and $19.9 million of other letters of credit were outstanding under the synthetic letter of credit facility.

The remaining future minimum principal payments under the term debt and the working capital facility subsequent to March 31, 2010 are as follows (in thousands of dollars):

2010	500
2011	2,000
2012	12,000
2013	2,000
Thereafter	187,000
Total	$ 203,500

The Credit Agreement and related financing documents contain various affirmative and negative covenants, including (a) financial covenants, (b) limitations on KGen LLC's ability to pay dividends, (c) restrictions on the use of available cash for operations, except as required for debt service payments and (d) an event of default in the event of a change in control of KGen. At March 31, 2010, KGen LLC was in compliance with these covenants.

Under the terms of the Credit Agreement, KGen LLC is restricted from making dividend payments, loans or advances to the Company. These restrictions resulted in restricted net assets of the Company's subsidiaries exceeding 25% of the consolidated net assets of the Company and its subsidiaries. The amount of restricted net assets was $493.9 million at March 31, 2010, of which $26.0 million was restricted net current assets.

5. Restricted Cash and Cash Equivalents

The Credit Agreement requires KGen LLC to maintain six months of principal and interest payments reserve in cash. At both March 31, 2010 and June 30, 2009, the restricted balance, in accordance with this requirement, was $5.8 million.

Additionally, the Security Deposit Agreement requires KGen LLC to reserve quarterly the amount of major maintenance expenditures expected to be incurred during the following 12 months. At March 31, 2010 and June 30, 2009, the restricted balance, in accordance with this requirement, was $5.5 million and $27.1 million, respectively.

6. Commitments and Contingencies

Litigation—The Company is party to various legal and regulatory actions arising in the normal course of business. Matters that are probable of unfavorable outcome to the Company and which can be reasonably estimated are accrued.

Commitments—The Company enters into long-term contractual arrangements for power purchases and capacity sales and to procure fuel and transportation services. There have not been significant changes to these commitments as discussed in Note 6—Commitments in the Notes to Consolidated Financial Statements contained in the Annual Report for the year ended June 30, 2009.

NERC Violations—On September 23, 2009, KGen Hot Spring LLC ("Hot Spring"), a 100% owned subsidiary of the Company, self-reported to the SERC Reliability Corporation ("SERC"), that it failed to include certain protection system components in its maintenance and testing program which may constitute a violation of one of the North American Electric Reliability Corporation Reliability Standards ("NERC Standards"). On December 7, 2009, SERC notified Hot Spring that it had completed its assessment to determine Hot Spring's compliance with the NERC Standards, for which Hot Spring self-reported, and concluded that insufficient basis existed to allege a violation or noncompliance of said NERC Standards and requirements.

On September 29, 2009, SERC conducted its regularly scheduled audit of all of the Company's facilities and found a possible violation by Hot Spring of the NERC Standards. On March 11, 2010, SERC notified Hot Spring that it had completed its assessment to determine Hot Spring's compliance with the NERC Standards in connection with the possible violation and concluded that insufficient basis existed to allege a violation or noncompliance of said NERC Standards and requirements.

On January 15, 2010, SERC notified Hot Spring of a possible separate violation of the NERC Standards resulting from its review of Hot Spring's previous self report on September 23, 2009. On March 18, 2010, Hot Spring made a request to SERC to enter into settlement negotiations in connection with the potential violation cited by SERC on January 15, 2010. In the event that it is determined that there has been a violation of the NERC Standards, Hot Spring may be subject to penalties. The ultimate outcome of these matters remains uncertain, but the Company does not believe an unfavorable outcome would result in a material impact to its consolidated financial statements. No loss contingency has been accrued; however should any such financial penalties be imposed on us, it is our estimate such penalties would be in the range of $0 to $250,000.

7. Derivatives

The Company recognizes all derivatives as either assets or liabilities on the balance sheet and measures those instruments at fair value. The ongoing effects are dependent on future market conditions.

On May 4, 2007, KGen LLC entered into six interest rate swap agreements ("Swaps") for the purpose of reducing exposure to interest rate fluctuations as required under credit agreement terms. Each of the six individual Swaps has a notional amount of $33.0 million and has a term that expires in each consecutive year, beginning on March 31, 2008 continuing through March 31, 2013. The average interest rate payable by KGen LLC, under the Swaps, was 5.0% at March 31, 2010. During the year ended June 30, 2009, the Company and its counterparty amended the Swaps to reduce the Company's fixed rate payments component and change the basis of the counterparty's floating rate payments.

7. Derivatives (Continued)

The short-term portion of the Swaps as of March 31, 2010 and June 30, 2009 was $3.8 million and $3.9 million, respectively, and was recorded in accounts payable and accrued liabilities. The long-term portion of the Swaps as of March 31, 2010 and June 30, 2009 was $2.7 million and $4.1 million, respectively, and was recorded in other noncurrent liabilities.

The Swaps are not accounted for utilizing hedge accounting, they are marked to market with gains and losses shown on the condensed consolidated statements of operations as follows (in thousands of dollars):

	Location of Gain (Loss) in Statement of Operations	Gain (Loss) on Derivatives	
For the three months ended March 31, 2010	Interest expense	$	(1,044)
For the three months ended March 31, 2009	Other income (expenses)	$	1,098
For the nine months ended March 31, 2010	Interest expense	$	(3,236)
For the nine months ended March 31, 2009	Other income (expenses)	$	(7,177)

The Company evaluated the requirements of FASB ASC 820, *Fair Value Measurement and Disclosures* ("FASB ASC 820") and believes the Swaps are valued using Level 2 fair value measurements. Under FASB ASC 820, instruments valued using Level 2 measurements are valued based on either quoted prices for similar instruments in active markets, quoted prices for identical or similar instruments in markets that are not active, and/or model-based valuations whose inputs are observable or whose significant value drivers are observable.

The three levels of the fair value hierarchy are:

Level 1—Unadjusted quoted prices in active markets that are accessible at the measurement date for identical assets and liabilities;

Level 2—Pricing inputs include quote prices for similar assets and liabilities in active markets and inputs that are observable for the asset or liability, either directly or indirectly, for substantially the full term of the financial instrument; and

Level 3—Prices or valuations that require inputs that are both significant to the fair value measurements and unobservable.

8. Net Loss per Share

Basic loss per share is calculated by dividing net loss by the weighted average number of shares of common stock outstanding during the period. For both the three and nine months ended March 31, 2010 and 2009, diluted loss per share was computed on the same basis as basic loss per share as the inclusion of any other potential shares outstanding would be anti-dilutive. There were no unexercised in-the-money stock options to purchase shares of common stock for the three and nine months ended March 31, 2010 and 2009. Had the Company recognized net income for the three and nine months ended March 31, 2010 and 2009, incremental shares attributable to restricted stock awards would have increased diluted shares outstanding by 12,567 shares for the three and nine months ended March 31, 2010 and 603 shares for the three and nine months ended March 31, 2009. Amounts shown below are in thousands, except per share amounts.

8. Net Loss per Share (Continued)

	For the Three Months Ended March 31, 2010	For the Three Months Ended March 31, 2009	For the Nine Months Ended March 31, 2010	For the Nine Months Ended March 31, 2009
Numerator:				
Net loss	$ (35,438)	$ (19,424)	$ (40,778)	$ (41,895)
Denominator:				
Weighted average shares outstanding—basic and diluted	55,968	55,967	55,968	55,967
Net loss per share—basic and diluted	$ (0.63)	$ (0.35)	$ (0.73)	$ (0.75)

9. Share-Based Payments

This footnote should be read in conjunction with Note 9—Share-Based Payments of the Notes to Consolidated Financial Statements contained in the Annual Report for the year ended June 30, 2009.

The Company recorded compensation expense of $0.1 million and $0.9 million for the three and nine months ended March 31, 2010, respectively, and $1.1 million and $2.3 million for the three and nine months ended March 31, 2009, respectively, related to stock options and awards outstanding. As of March 31, 2010, all options were vested and there was no unrecognized compensation expense remaining on the options, however, there was approximately $45,000 of total unrecognized compensation expense related to unvested awards. As of March 31, 2009, there was $1.4 million of total unrecognized compensation expense related to unvested options. For both the three and nine months ended March 31, 2010 and 2009, no options were granted or exercised.

10. Income Taxes

For the three and nine months ended March 31, 2010 and 2009, there were no current or deferred income tax provision (benefits) included in the net loss.

The Company's provision for income taxes differed from that determined by applying the federal income tax rate (statutory rate) to loss before income taxes, as follows (in thousands of dollars):

	For the Three Months Ended March 31, 2010	For the Three Months Ended March 31, 2009	For the Nine Months Ended March 31, 2010	For the Nine Months Ended March 31, 2009
Statutory rate	35%	35%	35%	35%
Tax at statutory rate	$ (12,404)	$ (6,798)	$ (14,272)	$ (14,663)
Increase (decrease) due to:				
Nondeductible meals and entertainment	1	(4)	6	(1)
State tax benefit	(1,380)	(742)	(1,652)	(1,925)
Return to provision				
Adjustment to valuation allowance	13,783	7,544	15,918	16,589
Total provision	$ —	$ —	$ —	$ —

10. Income Taxes (Continued)

Temporary differences and carryforwards which gave rise to deferred tax assets and liabilities were as follows (in thousands of dollars):

	March 31, 2010	June 30, 2009
Deferred tax assets:		
Interest rate derivatives	$ 2,529	$ 3,124
Contract-based intangible assets	14,164	11,329
Nonqualified stock options expense	5,372	5,036
Accrued expenses	123	258
Net operating loss	78,892	60,493
Contribution carryforward	14	—
Net deferred tax assets	101,094	80,240
Deferred tax liabilities:		
Property, plant, and equipment	17,876	13,886
Prepaid expenses	850	294
Contract-based intangible liabilities	3,878	3,488
Net deferred tax liability	22,604	17,668
Valuation allowance	78,490	62,572
Deferred tax asset (liabilities), net	$ —	$ —

At March 31, 2010, the Company had a federal net operating loss carryforward of $203.5 million which will expire between 2027 and 2030. The amount of taxable income that the Company can offset with this carryforward is subject to limitations under Section 382 of the Internal Revenue Code, which is applicable to corporations in certain instances following an ownership change (as such term is defined for income tax purposes).

Management has determined that valuation allowances are necessary as of March 31, 2010 and June 30, 2009, as the future tax benefits relating to all deferred income tax assets are not expected to be fully realized when measured against a more likely than not standard. There were no unrecognized tax benefits that if recognized would affect the tax rate. No interest or penalties were recognized as of March 31, 2010.

The Company filed income tax returns in the United States federal jurisdiction and in various U.S. states. In all material respects, the Company will not be subject to United States federal, state and local income tax examination by tax authorities for fiscal years ended before 2005.

11. Subsequent Events

Hot Spring Lateral Pipeline-—On April 1, 2010, KGen Hot Spring entered into a Precedent Agreement with Texas Eastern Transmission, LP (“TETCO” and “TETCO PA”), a subsidiary of Spectra Energy Transmission Services, LLC, for the construction of an 8.5 mile pipeline lateral and for firm transportation services on TETCO’s 24-inch line, subject to certain approvals including the Federal Energy Regulatory Commission. This lateral pipeline is being constructed in order for Hot Spring to access the operational flexibility on TETCO’s system. The pipeline is expected to be in service by summer 2011 with financial incentives of up to $0.8 million payable to TETCO if the pipeline is completed before July 1, 2011. The Company is required to post collateral to support construction of the pipeline and as of April 7, 2010 posted a $6.0 million letter of credit. The Company’s collateral requirements will increase during the construction process and will be approximately $39.0 million upon the in-service date of the pipeline lateral. Additionally, once the pipeline is operational, there will be annual fixed transportation fees of approximately $6.7 million associated with the new firm transportation agreements for the 20-year term. The collateral requirements will decrease proportionally over the 20-year term.

11. Subsequent Events (Continued)

Hinds Firm Transportation Contract Extension—On April 1, 2010, the Company extended the long-term gas transportation contract with TETCO to deliver gas to the Hinds facility through March 2022, under substantially similar terms.

Sandersville Purchase & Sale Agreement—On May 6, 2010, the Company executed a definitive agreement for the sale of the Company's Sandersville power generation facility to AL Sandersville Holdings, LLC, an entity formed by ArcLight Energy Partners Fund III, L.P., for a cash purchase price of $130.0 million, subject to a customary working capital adjustment. A subsidiary of ArcLight Energy Partners Fund IV, L.P. is a shareholder of the Company. The transaction will be implemented by means of a sale of 100% of the ownership interests in KGen Sandersville LLC, the project entity that owns the Sandersville facility. The transaction is conditioned upon the receipt of approval of the Federal Energy Regulatory Commission, the expiration or termination of the waiting period under the Hart-Scott-Rodino Antitrust Improvements Act of 1976, certain third-party consents, the receipt by the purchaser of debt financing for a substantial portion of the purchase price (which also includes a letter of credit facility) that has been committed to by certain strategic lenders experienced in the power project financing market, and certain customary closing conditions. Assuming the satisfaction of these conditions, the transaction is expected to close in the summer of 2010. The equity portion of the purchase price has been committed by ArcLight Energy Partners Fund III, L.P. The Company expects to use a portion of its existing tax new operating loss (NOLs) to offset all of the taxable gain resulting from the sale of the Sandersville facility. Pursuant to the Company's credit facility, the Company is required to use a portion of the net proceeds of the sale to prepay a portion of its existing debt.

Subsequent events were analyzed and considered through May 14, 2010, the issuance date of the report.

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

The following discussion is intended to assist you in understanding our business and results of operations together with our present financial condition. This section should be read in conjunction with our Condensed Consolidated Financial Statements and the accompanying notes included in this Quarterly Report, as well as our Annual Report for the fiscal year ended June 30, 2009. Unless the context otherwise requires or indicates, references to "KGen," "Company," "we," "our," and "us" refer to KGen Power Corporation and its subsidiaries. Statements in our discussion may be forward-looking. These forward-looking statements involve risk and uncertainties. We caution that a number of factors could cause future results to differ materially from our expectations. Please see "Number 1A. *Risk Factors*" of Part I of our Annual Report for the fiscal year ended June 30, 2009 and "Number 1A. *Risk Factors and Forward-Looking Statements*" of Part II of this Quarterly Report regarding certain risk factors related to the Company.

Business Overview

We own and operate electric power generation plants and sell electricity and electrical generation capacity in the United States. We sell power and related products to wholesale purchasers such as retail electric providers, power trading organizations, municipal utilities, electric power cooperatives and other power generation companies. Our portfolio of facilities consists of five operational and fully permitted power plants, or the Plants, located in the southeastern United States with General Electric 7FA and 7EA gas turbines. The Plants have an aggregate capacity of 3,030 megawatts, or MW. The Plants include four combined cycle plants (Murray I, Murray II, Hot Spring and Hinds) and one simple cycle plant (Sandersville). We acquired the Plants from an affiliate of MatlinPatterson Global Advisors LLC on February 8, 2007.

Four of the Plants currently operate as merchant power providers. The remaining plant, the Murray I combined cycle plant, benefits from a fixed price long-term power purchase agreement, or the GPC PPA, for all of its 630 MW of capacity with Georgia Power, a subsidiary of Southern Company. The GPC PPA, which continues through May 2012, provides for fixed capacity payments that provide stable cash flow. The Company recognized \$5.7 million and \$37.6 million related to capacity sales on the GPC PPA for the three and nine months ended March 31, 2010. The Company recognized \$5.6 million and \$36.8 million related to capacity sales on the GPC PPA for the three and nine months ended March 31, 2009. On June 6, 2008, the Sandersville simple cycle plant entered into a power purchase agreement, or the Sandersville PPA, for a unit contingent 250 to 280 MW of capacity and associated energy with Southern Power Company. The Sandersville PPA commences on June 1, 2011 and continues through December 31, 2015.

As part of our strategy, we continue to explore and review credible alternatives that may become available to us to enhance shareholder value.

Recent Events

Operating and Maintenance Service Provider—On October 16, 2009, the Company notified Duke Energy Generation Services, or DEGS, that it was exercising its rights to terminate the operating and maintenance agreements between DEGS and KGen Hinds LLC, KGen Hot Spring LLC, and KGen Sandersville LLC, the 100% owned subsidiaries of the Company that, respectively, own the Hinds, Hot Spring, and Sandersville plants. The termination was effective for the Sandersville plant on February 1, 2010 and was effective for the Hinds and Hot Spring plants on February 15, 2010. The Company paid DEGS approximately \$420,000, in the aggregate, in connection with the termination of all of the agreements. KGen Hinds LLC, KGen Hot Spring LLC, and KGen Sandersville LLC executed new operating agreements with NAES Corporation, or NAES, a third party operations and maintenance provider that replaced DEGS as the service provider for such facilities.

Hot Spring Lateral Pipeline—On April 1, 2010, KGen Hot Spring entered into a Precedent Agreement with Texas Eastern Transmission, LP, or TETCO and TETCO PA, a subsidiary of Spectra Energy Transmission Services, LLC, for the construction of an 8.5 mile pipeline lateral and for firm transportation services on TETCO's 24-inch line, subject to certain approvals including the Federal Energy Regulatory Commission. This lateral pipeline is being constructed in order for Hot Spring to access the operational flexibility on TETCO's system. The pipeline is expected to be in service by summer 2011 with financial incentives of up to $0.8 million payable to TETCO if the pipeline is completed before July 1, 2011. We are required to post collateral to support construction of the pipeline and as of April 7, 2010 posted a $6.0 million letter of credit. Our collateral requirements will increase during the construction process and will be approximately $39.0 million upon the in-service date of the pipeline lateral. Additionally, once the pipeline is operational, there will be annual fixed transportation fees of approximately $6.7 million associated with the new firm transportation agreements for the 20-year term. The collateral requirements will decrease proportionally over the 20-year term.

Hinds Firm Transportation Contract Extension—On April 1, 2010, the Company extended the long-term gas transportation contract with TETCO to deliver gas to the Hinds facility through March 2022, under substantially similar terms.

Sandersville Purchase & Sale Agreement—On May 6, 2010, the Company executed a definitive agreement for the sale of the Company's Sandersville power generation facility to AL Sandersville Holdings, LLC, an entity formed by ArcLight Energy Partners Fund III, L.P., for a cash purchase price of $130.0 million, subject to a customary working capital adjustment. A subsidiary of ArcLight Energy Partners Fund IV, L.P. is a shareholder of the Company. The transaction will be implemented by means of a sale of 100% of the ownership interests in KGen Sandersville LLC, the project entity that owns the Sandersville facility. The transaction is conditioned upon the receipt of approval of the Federal Energy Regulatory Commission, the expiration or termination of the waiting period under the Hart-Scott-Rodino Antitrust Improvements Act of 1976, certain third-party consents, the receipt by the purchaser of debt financing for a substantial portion of the purchase price (which also includes a letter of credit facility) that has been committed to by certain strategic lenders experienced in the power project financing market, and certain customary closing conditions. Assuming the satisfaction of these conditions, the transaction is expected to close in the summer of 2010. The equity portion of the purchase price has been committed by ArcLight Energy Partners Fund III, L.P. The Company expects to use a portion of its existing tax net operating loss (NOLs) to offset all the taxable gain resulting from the sale of the Sandersville facility. Pursuant to the Company's credit facility, the Company is required to use a portion of the net proceeds of the sale to prepay a portion of its existing debt.

Results of Operations

Our results of operations are subject to seasonal variations since demand for electricity, and thus, production capacity, varies with weather conditions. For our merchant plants, we earn the majority of our revenues in the months of May through September. Months other than the peak summer months historically have not been profitable for KGen and are the months during which we typically seek to perform scheduled maintenance-related activities.

Consolidated Results of Operations of KGen for the Three Months Ended March 31, 2010 compared to the Three Months Ended March 31, 2009.

The following table sets forth our results of operations for the three months ended March 31, 2010 and 2009, expressed in thousands of dollars:

	For the Three Months Ended March 31, 2010	For the Three Months Ended March 31, 2009	Favorable/ (Unfavorable) Change	% Change
Revenues:				
Energy sales	$ 21,676	$ 19,307	$ 2,369	12%
Capacity sales	6,115	5,659	456	8%
Total revenues	27,791	24,966	2,825	11%
Operating expenses:				
Cost of fuel	21,369	18,196	(3,173)	(17)%
Operating and maintenance	21,700	6,398	(15,302)	(239)%
Gas transportation	3,684	3,675	(9)	(0)%
Selling, general, and administrative	3,250	4,674	1,424	30%
Depreciation	6,009	5,989	(20)	(0)%
Auxiliary power	2,148	1,950	(198)	(10)%
Insurance	905	937	32	3%
Total operating expenses	59,065	41,819	(17,246)	(41)%
Operating loss	(31,274)	(16,853)	(14,421)	(86)%
Other income (expenses):				
Interest expense	(2,994)	(2,546)	(448)	(18)%
Taxes, other than income taxes	(1,113)	(1,041)	(72)	(7)%
Net interest income	—	(81)	81	100%
Other	(57)	1097	(1,154)	(105)%
Total other expenses	(4,164)	(2,571)	(1,593)	(62)%
Net loss before taxes	(35,438)	(19,424)	(16,014)	(82)%
Income tax benefit	—	—	—	0%
Net loss after taxes	$ (35,438)	$ (19,424)	$ (16,014)	(82)%

Operating and Business Metrics We Use to Analyze the Company's Performance for the Three Months Ended March 31, 2010 and March 31, 2009

In addition to the foregoing results of operations presented in accordance with GAAP, we utilize various non-GAAP operating and business metrics to analyze the Company's performance. We believe these metrics provide useful insight into the Company's performance, assist us in identifying trends in our business, and better allow us to compare our performance to others in our industry. We describe below these various non-GAAP metrics and provide a reconciliation of these metrics for the three months ended March 31, 2010 and 2009, to the most directly comparable GAAP measures for those periods. See the reconciliation of net loss to adjusted EBITDA on page 20. This presentation may not include all of the disclosure that SEC regulations would require a company that files periodic reports with the SEC to make, with respect to non-GAAP financial measures.

Merchant Margin, Adjusted Contracted Margin, and Total Adjusted Margin

We separate merchant margin and adjusted contracted margin because the distinction helps us analyze the certainty of future cash flows of the Company and the underlying commodity value of the Company's assets.

Merchant margin is equal to the sum of merchant energy margin and merchant capacity sales. Merchant energy margin is defined as energy sales less the related cost of fuel pursuant to arrangements having an original delivery term of less than one year. Merchant capacity sales is defined as capacity sales pursuant to arrangements having an original delivery term of less than one year. We currently consider Hinds, Hot Spring, Murray II and Sandersville to be merchant plants because they are currently not selling their energy output and capacity pursuant to long-term sales agreements.

	For the Three Months Ended March 31, 2010	For the Three Months Ended March 31, 2009
Energy sales	$ 21,676	$ 19,307
Less: Cost of fuel	(21,369)	(18,196)
Less: Contracted energy sales	(9,484)	(4,495)
Add: Contracted cost of fuel	10,452	6,045
Merchant energy margin	1,275	2,661
Capacity sales	6,115	5,659
Less: Contracted capacity sales	(5,673)	(5,659)
Merchant capacity sales	$ 442	$ —
Merchant margin	$ 1,717	$ 2,661

Adjusted contracted margin is equal to the sum of adjusted contracted energy margin and adjusted contracted capacity sales. Adjusted contracted energy margin is defined as energy sales less the related cost of fuel pursuant to arrangements having an original delivery term of one year or greater, adjusted to remove the income effects of noncash amortization of contract-based intangibles. Adjusted contracted capacity sales is defined as capacity sales pursuant to arrangements having an original delivery term of one year or greater, adjusted to remove the income effects of noncash deferred capacity revenue to levelize the capacity sales over the term of the agreement as required by GAAP. We believe that the foregoing adjustments are helpful in understanding the commercial results of our contractual arrangements without the impact of noncash accounting adjustments. We currently consider Murray I to be contracted, because it is selling its energy output and capacity pursuant to the long-term GPC PPA.

	For the Three Months Ended March 31, 2010	For the Three Months Ended March 31, 2009
Energy sales	$ 21,676	$ 19,307
Less: Merchant sales	(12,192)	(14,812)
Contracted energy sales	9,484	4,495
Less: Contracted cost of fuel	(10,452)	(6,045)
Add: Power sales rights and obligations amortization	2,028	2,028
Adjusted contracted energy margin	1,060	478
Contracted capacity sales	5,673	5,659
Add (Less): Noncash deferred capacity revenue	56	(41)
Adjusted contracted capacity sales	$ 5,729	$ 5,618
Adjusted contracted margin	$ 6,789	$ 6,096

Total adjusted margin is equal to the sum of merchant margin and adjusted contracted margin.

	For the Three Months Ended March 31, 2010	For the Three Months Ended March 31, 2009
Merchant margin	$ 1,717	$ 2,661
Adjusted contracted margin	6,789	6,096
Total adjusted margin	$ 8,506	$ 8,757

Adjusted Plant Expense and Adjusted Corporate Expense

Adjusted plant expenses is defined as total operating expenses adjusted for the removal of (a) cost of fuel captured in merchant energy margin and adjusted contracted energy margin, (b) major maintenance expense, (c) the income effects of noncash amortization of contract-based intangibles of gas transportation expense, (d) all selling, general, and administrative expense, part of which is captured in adjusted corporate expenses (defined below), (e) any nonrecurring items such as contract termination fees and transition costs, (f) depreciation, (g) director and officer insurance expense captured in adjusted corporate expenses (defined below); and the addition of taxes, other than income taxes, as it largely represents plant property taxes and payments in lieu of taxes.

	For the Three Months Ended March 31, 2010	For the Three Months Ended March 31, 2009
Total operating expenses	$ 59,065	$ 41,819
Less: Cost of fuel	(21,369)	(18,196)
Less: Major maintenance expense	(15,110)	(755)
Less: Gas transportation noncash amortization	(301)	(294)
Less: Selling, general, and administrative expense	(3,238)	(4,674)
Less: Termination and transition costs	(580)	—
Less: Depreciation	(6,009)	(5,989)
Less: D&O insurance expense	(45)	(99)
Add: Taxes, other than income taxes	1,113	1,041
Adjusted plant expenses	$ 13,526	$ 12,853

Adjusted corporate expenses is defined as selling, general, and administrative expense adjusted for (a) the removal of noncash employee options/awards expense and reorganization items such as employee severance and (b) the addition of director and officer insurance expense.

	For the Three Months Ended March 31, 2010	For the Three Months Ended March 31, 2009
Selling, general, and administrative expense	$ 3,238	$ 4,674
Less: Noncash employee options/awards expense	(111)	(1,115)
Less: Employee severance expense	—	(460)
Add: D&O insurance expense	45	99
Adjusted corporate expenses	$ 3,172	$ 3,198

Adjusted Plant EBITDA and Adjusted EBITDA

Adjusted plant EBITDA is defined as total adjusted margin less adjusted plant expenses. Adjusted EBITDA is defined as adjusted plant EBITDA less adjusted corporate expenses.

	For the Three Months Ended March 31, 2010	For the Three Months Ended March 31, 2009	Favorable/ (Unfavorable)	
			Change	% Change
Merchant energy margin	$ 1,275	$ 2,661	$ (1,386)	(52)%
Merchant capacity sales	442	—	442	100%
Merchant margin	1,717	2,661	(944)	(35)%
Adjusted contracted energy margin	1,060	478	582	122%
Adjusted contracted capacity sales	5,729	5,618	111	2%
Adjusted contracted margin	6,789	6,096	693	11%
Total adjusted margin	8,506	8,757	(251)	(3)%
Adjusted plant expenses	13,526	12,853	(673)	(5)%
Adjusted plant EBITDA	(5,020)	(4,096)	(924)	(23)%
Adjusted corporate expenses	3,172	3,198	26	1%
Adjusted EBITDA	$ (8,192)	$ (7,294)	$ (898)	(12)%

Selected Operating and Business Metrics

	For the Three Months Ended March 31, 2010	For the Three Months Ended March 31, 2009	Favorable/ (Unfavorable) Change	% Change
Selected Financial and Operating Data				
Total generation (GWh)	487	574	(87)	(15)%
Merchant generation (GWh)	272	436	(164)	(38)%
Merchant margin/merchant generation ($/MWh)	$ 6.31	$ 6.10	$ 0.21	3%

Selected Market and Weather Data

	For the Three Months Ended March 31, 2010	For the Three Months Ended March 31, 2009	Change	% Change
Selected Market Data(1)				
Average on-peak market power price—Entergy ($/MWh)	$ 42.04	$ 35.79	$ 6.25	17%
Average on-peak market power price—Southern ($/MWh)	$ 43.84	$ 39.40	$ 4.44	11%
Average Henry Hub gas price ($/MMbtu)	$ 5.14	$ 4.58	$ 0.56	12%
Selected Weather Data				
Actual HDDs(2)	5,860	4,304	1,556	36%
Normal HDDs	4,828	4,828	—	0%

Notes:

(1) Data from Platt's Megawatt Daily and Gas Daily publications.

(2) HDD, or heating degree days, represents the number of degrees that the mean temperature for a particular day is below 65 degrees Fahrenheit. The HDDs are then accumulated for a given period. The cumulative heating degree days are calculated using current weather data obtained from online weather data services such as Weather Channel and Accuweather compared to the 30-year NOAA National Weather Service archive database.

Historical Results of Operations of KGen for the Three Months Ended March 31, 2010 compared to the Three Months Ended March 31, 2009.

Total adjusted margin decreased $0.2 million, or 3%, to $8.5 million for the three months ended March 31, 2010 compared to the same period in the previous year as a result of a $0.9 million decrease in merchant margin offset by a $0.7 million increase in adjusted contracted margin. The $8.5 million in total adjusted margin was comprised of $1.7 million in merchant margin and $6.8 million in adjusted contracted margin.

Merchant margin decreased $0.9 million, or 35%, to $1.7 million for the three months ended March 31, 2010. The $0.9 million decrease was made up of a $1.4 million decrease in merchant energy margin, offset by a $0.5 million increase in merchant capacity sales. The $1.4 million decrease in merchant energy margin was principally related to a decrease in merchant generation of 38% from 436 GWh to 272 GWh. This volatility in generation is not uncommon in the shoulder months when our total generation is relatively low compared to our summer months. The $0.5 million increase in merchant capacity sales was attributable to capacity sales at the Hinds plant in February and March 2010. When compared to the previous year, the implied merchant spark spread, or merchant margin divided by merchant generation, increased from $6.10 per MWh to $6.31 per MWh for the three months ended March 31, 2010.

Adjusted contracted margin increased $0.7 million, 11% for the three months ended March 31, 2010. The $0.7 million increase was made up of a $0.6 million increase in adjusted contracted energy margin and a $0.1 million increase in adjusted contracted capacity sales. The $0.6 million increase in adjusted contracted energy margin was largely attributable to higher revenues from the GPC PPA as a result of higher natural gas prices and increased generation due to colder weather. The $0.1 million increase in adjusted contracted capacity sales was a result of the escalation of the pricing under the GPC PPA.

Adjusted plant expenses increased by $0.7 million, or 5%, to $13.5 million for the three months ended March 31, 2010. The increase primarily related to a $0.5 million increase in the LTSA bonus paid during the three months ended March 31, 2010.

As a result of the foregoing changes in total adjusted margin and adjusted plant expenses, adjusted plant EBITDA decreased by $0.9 million to a $5.0 million loss for the three months ended March 31, 2010.

Adjusted corporate expenses decreased by $26,000 to $3.2 million for the three months ended March 31, 2010.

As a result of the foregoing, adjusted EBITDA decreased by $0.9 million to an $8.2 million loss for the three months ended March 31, 2010.

GAAP to Non-GAAP Adjusted EBITDA Reconciliation

Following is an alternative calculation of adjusted EBITDA and adjusted plant EBITDA starting from net loss after taxes. EBITDA is equal to net loss after taxes adjusted for interest expenses, income taxes, depreciation, and amortization. Adjusted EBITDA is equal to EBITDA minus certain other items (such as major maintenance and other non-recurring expenses). Adjusted plant EBITDA is equal to total adjusted EBITDA less certain corporate expenses.

	For the Three Months Ended March 31, 2010	For the Three Months Ended March 31, 2009
Net loss after taxes	$ (35,438)	$ (19,424)
Add: Interest expense	2,994	2,546
Less: Net interest income	—	81
Add: Depreciation	6,009	5,989
Add: Power sales rights and obligations amortization	2,028	2,028
Add: Gas transportation noncash amortization	301	294
Less: Noncash deferred capacity revenue	56	(41)
Add: Other expenses	57	(1,097)
EBITDA	(23,993)	(9,624)
Add: Major maintenance expense	15,110	755
Add: Termination and transition costs	580	—
Add: Noncash employee options/awards expense	111	1,115
Add: Employee severance expense	—	460
Adjusted EBITDA	(8,192)	(7,294)
Add: Selling, general, and administrative expense	3,238	4,674
Less: Noncash employee options/awards expense	(111)	(1,115)
Less: Employee severance expense	—	(460)
Add: D&O insurance expense	45	99
Adjusted plant EBITDA	$ (5,020)	$ (4,096)

The following describes changes to specified financial measures of our performance. As indicated above, in calculating our adjusted EBITDA, we make adjustments to our net loss after taxes using these financial measures for the three months ended March 31, 2010 compared to the three months ended March 31, 2009.

- Interest expense for the three months ended March 31, 2010 was $3.0 million compared to $2.5 million for the same period in 2009. In order to more accurately reflect our financing costs for the three months ended March 31, 2010, we have elected to move gains and losses on derivatives from the other expense line and reflect them in the interest expense line of our condensed consolidated statement of operations. The $0.5 million decrease was made up of a $0.5 million decrease in interest expense due to a reduction in interest rates and outstanding debt compared to the same period in the previous year, offset by $1.0 million in losses on derivatives associated with our interest rate hedging and cash payments on our Swaps.

- Interest income was offset by banking fees for the three months ended March 31, 2010 and was $0.1 million for the three months ended March 31, 2009. The decrease in interest income was related to lower interest rates for the three months ended March 31, 2010, when compared to the same period in the previous year.

- Depreciation, for both three month periods, was $6.0 million.

- Amortization of contract-based power sales rights and obligations, for both three month periods, was $2.0 million and was recorded as a reduction of energy sales.

- Amortization of contract-based natural gas transportation rights and obligations, for both three month periods, was $0.3 million and was recorded as an increase of gas transportation expense.

- Noncash deferred capacity revenue, which represents the levelization of capacity sales over the GPC PPA term, was approximately $56,000 of expense for the three months ended March 31, 2010 and approximately $41,000 of income for the three months ended March 31, 2009 and was recorded in capacity sales.

- Other income (expense) for the three months ended March 31, 2010 and 2009 was expense of $0.1 million and income of $1.1 million, respectively. The $0.1 related to various financing fees and the $1.1 million related to gains on derivatives associated with our interest rate hedging due to cash payments on and a change in valuation of our Swaps. For the three months ended March 31, 2010, the losses on derivatives were reflected in the interest expense line of our condensed consolidated statement of operations.

- Major maintenance expense for the three months ended March 31, 2010 and 2009 was $15.1 million and $0.8 million, respectively. The $15.1 million expense related to a hot gas path inspection at the Hinds plant. The $0.8 million expense in the prior year primarily related to $0.7 million of major maintenance expenses at the Murray facilities and $0.1 million of major maintenance expenses at the Hot Spring plant.

- Termination and transition costs for the three months ended March 31, 2010 and 2009 were $0.6 million and zero, respectively. The $0.6 million expense related to a $0.4 million one-time termination fee paid to DEGS and $0.2 million in transition costs related to the change in operating and maintenance providers.

- Noncash employee options/awards expense for the three months ended March 31, 2010 and 2009 was $0.1 million and $1.1 million, respectively, and was recorded as an increase of selling, general, and administrative expense.

- Selling, general, and administrative expense was $3.2 million and $4.7 million for the three months ended March 31, 2010 and 2009, respectively. This decrease was primarily related to a $1.0 million decrease in noncash employee options/awards expense and a $0.5 million decrease in payroll expenses, offset by $0.3 million increase in legal and professional service expenses.

Consolidated Results of Operations of KGen for the Nine Months Ended March 31, 2010 compared to the Nine Months Ended March 31, 2009.

The following table sets forth our results of operations for the nine months ended March 31, 2010 and 2009, expressed in thousands of dollars:

	For the Nine Months Ended March 31, 2010	For the Nine Months Ended March 31, 2009	Favorable/ (Unfavorable) Change	% Change
Revenues:				
Energy sales	$ 99,091	$ 153,683	$ (54,592)	(36)%
Capacity sales	38,494	42,153	(3,659)	(9)%
Total revenues	137,585	195,836	(58,251)	(30)%
Operating expenses:				
Cost of fuel	84,538	130,875	46,337	35%
Operating and maintenance	32,791	35,233	2,442	7%
Gas transportation	12,119	11,971	(148)	(1)%
Selling, general, and administrative	9,198	12,363	3,165	26%
Depreciation	18,264	18,206	(58)	(0)%
Auxiliary power	6,331	6,475	144	2%
Insurance	2,687	2,741	54	2%
Total operating expenses	165,928	217,864	51,936	24%
Operating loss	(28,343)	(22,028)	(6,315)	(29)%
Other income (expenses):				
Interest expense	(9,182)	(9,668)	486	5%
Taxes, other than income taxes	(3,076)	(3,238)	162	5%
Net interest income	—	221	(221)	(100)%
Other	(177)	(7,182)	7,005	98%
Total other expenses	(12,435)	(19,867)	7,432	37%
Net loss before taxes	(40,778)	(41,895)	1,117	3%
Income tax benefit	—	—	—	0%
Net loss after taxes	$ (40,778)	$ (41,895)	$ 1,117	3%

Operating and Business Metrics We Use to Analyze the Company's Performance for the Nine Months Ended March 31, 2010 and March 31, 2009

As indicated above, in addition to the foregoing results of operations presented in accordance with GAAP, we utilize various non-GAAP operating and business metrics to analyze the Company's performance. We believe these metrics provide useful insight into the Company's performance, assist us in identifying trends in our business, and better allow us to compare our performance to others in our industry. We describe below these various non-GAAP metrics and provide a reconciliation of these metrics for the nine months ended March 31, 2010 and 2009, to the most directly comparable GAAP measures for those periods. See the reconciliation of net loss to adjusted EBITDA on page 26. This presentation may not include all of the disclosure that SEC regulations would require a company that files periodic reports with the SEC to make, with respect to non-GAAP financial measures.

Merchant Margin, Adjusted Contracted Margin, and Total Adjusted Margin

We separate merchant margin and adjusted contracted margin because the distinction helps us analyze the certainty of future cash flows of the Company and the underlying commodity value of the Company's assets.

Merchant margin is equal to the sum of merchant energy margin and merchant capacity sales. Merchant energy margin is defined as energy sales less the related cost of fuel pursuant to arrangements having an original delivery term of less than one year. Merchant capacity sales is defined as capacity sales pursuant to arrangements having an original delivery term of less than one year. We currently consider Hinds, Hot Spring, Murray II and Sandersville to be merchant plants because they are currently not selling their energy output and capacity pursuant to long-term sales agreements.

	For the Nine Months Ended March 31, 2010	For the Nine Months Ended March 31, 2009
Energy sales	$ 99,091	$ 153,683
Less: Cost of fuel	(84,538)	(130,875)
Less: Contracted energy sales	(22,655)	(33,438)
Add: Contracted cost of fuel	23,568	33,716
Merchant energy margin	15,466	23,086
Capacity sales	38,494	42,153
Less: Contracted capacity sales	(37,555)	(37,462)
Merchant capacity sales	$ 939	$ 4,691
Merchant margin	$ 16,405	$ 27,777

Adjusted contracted margin is equal to the sum of adjusted contracted energy margin and adjusted contracted capacity sales. Adjusted contracted energy margin is defined as energy sales less the related cost of fuel pursuant to arrangements having an original delivery term of one year or greater, adjusted to remove the income effects of noncash amortization of contract-based intangibles. Adjusted contracted capacity sales is defined as capacity sales pursuant to arrangements having an original delivery term of one year or greater, adjusted to remove the income effects of noncash deferred capacity revenue to levelize the capacity sales over the term of the agreement as required by GAAP. We believe that the foregoing adjustments are helpful in understanding the commercial results of our contractual arrangements without the impact of noncash accounting adjustments. We currently consider Murray I to be contracted, because it is selling its energy output and capacity pursuant to the long-term GPC PPA.

	For the Nine Months Ended March 31, 2010	For the Nine Months Ended March 31, 2009
Energy sales	$ 99,091	$ 153,683
Less: Merchant sales	(76,436)	(120,245)
Contracted energy sales	22,655	33,438
Less: Contracted cost of fuel	(23,568)	(33,716)
Add: Power sales rights and obligations amortization	6,084	6,084
Adjusted contracted energy margin	5,171	5,806
Contracted capacity sales	37,555	37,462
Add (Less): Noncash deferred capacity revenue	7	(638)
Adjusted contracted capacity sales	$ 37,562	$ 36,824
Adjusted contracted margin	$ 42,733	$ 42,630

Total adjusted margin is equal to the sum of merchant margin and adjusted contracted margin.

	For the Nine Months Ended March 31, 2010	For the Nine Months Ended March 31, 2009
Merchant margin	$ 16,405	$ 27,777
Adjusted contracted margin	42,733	42,630
Total adjusted margin	$ 59,138	$ 70,407

Adjusted Plant Expense and Adjusted Corporate Expense

Adjusted plant expenses is defined as total operating expenses adjusted for the removal of (a) cost of fuel captured in merchant energy margin and adjusted contracted energy margin, (b) major maintenance expense, (c) the income effects of noncash amortization of contract-based intangibles of gas transportation expense, (d) all selling, general, and administrative expense, part of which is captured in adjusted corporate expenses (defined below), (e) any nonrecurring items such as contract termination fees and transition costs, (f) depreciation, (g) director and officer insurance expense captured in adjusted corporate expenses (defined below); and the addition of taxes, other than income taxes, as it largely represents plant property taxes and payments in lieu of taxes.

	For the Nine Months Ended March 31, 2010	For the Nine Months Ended March 31, 2009
Total operating expenses	$ 165,928	$ 217,864
Less: Cost of fuel	(84,538)	(130,875)
Less: Major maintenance expense	(14,115)	(19,368)
Less: Gas transportation noncash amortization	(902)	(882)
Less: Selling, general, and administrative expense	(9,175)	(12,363)
Less: Termination and transition costs	(612)	—
Less: Depreciation	(18,264)	(18,206)
Less: D&O insurance expense	(137)	(302)
Add: Taxes, other than income taxes	3,076	3,238
Adjusted plant expenses	$ 41,261	$ 39,106

Adjusted corporate expenses is defined as selling, general, and administrative expense adjusted for (a) the removal of noncash employee options/awards expense and reorganization items such as employee severance and (b) the addition of director and officer insurance expense.

	For the Nine Months Ended March 31, 2010	For the Nine Months Ended March 31, 2009
Selling, general, and administrative expense	$ 9,175	$ 12,363
Less: Noncash employee options/awards expense	(866)	(2,294)
Less: Employee severance expense	(1)	(460)
Add: D&O insurance expense	137	302
Adjusted corporate expenses	$ 8,445	$ 9,911

Adjusted Plant EBITDA and Adjusted EBITDA

Adjusted plant EBITDA is defined as total adjusted margin less adjusted plant expenses. Adjusted EBITDA is defined as adjusted plant EBITDA less adjusted corporate expenses.

	For the Nine Months Ended March 31, 2010	For the Nine Months Ended March 31, 2009	Favorable/ (Unfavorable) Change	Favorable/ (Unfavorable) % Change
Merchant energy margin	$ 15,466	$ 23,086	$ (7,620)	(33)%
Merchant capacity sales	939	4,691	(3,752)	(80)%
Merchant margin	16,405	27,777	(11,372)	(41)%
Adjusted contracted energy margin	5,171	5,806	(635)	(11)%
Adjusted contracted capacity sales	37,562	36,824	738	2%
Adjusted contracted margin	42,733	42,630	103	0%
Total adjusted margin	59,138	70,407	(11,269)	(16)%
Adjusted plant expenses	41,261	39,106	(2,155)	(6)%
Adjusted plant EBITDA	17,877	31,301	(13,424)	(43)%
Adjusted corporate expenses	8,445	9,911	1,466	15%
Adjusted EBITDA	$ 9,432	$ 21,390	$ (11,958)	(56)%

Selected Operating and Business Metrics

	For the Nine Months Ended March 31, 2010	For the Nine Months Ended March 31, 2009	Favorable/ (Unfavorable) Change	% Change
Selected Financial and Operating Data				
Total generation (GWh)	2,843	2,324	519	22%
Merchant generation (GWh)	2,183	1,833	350	19%
Merchant margin/merchant generation ($/MWh)	$ 7.51	$ 15.15	$ (7.64)	(50)%

Selected Market and Weather Data

	For the Nine Months Ended March 31, 2010	For the Nine Months Ended March 31, 2009	Change	% Change
Selected Market Data(1)				
Average on-peak market power price— Entergy ($/MWh)	$ 34.97	$ 50.77	$ (15.80)	(31)%
Average on-peak market power price— Southern ($/MWh)	$ 37.31	$ 55.65	$ (18.34)	(33)%
Average Henry Hub gas price ($/MMbtu)	$ 4.19	$ 6.70	$ (2.51)	(37)%
Selected Weather Data				
Actual CDDs(2)	3,710	3,974	(264)	(7)%
Normal CDDs	3,761	3,761	—	0%
Actual HDDs(3)	8,926	7,363	1,563	21%
Normal HDDs	7,915	7,915	—	0%

Notes:

(1) Data from Platt's Megawatt Daily and Gas Daily publications.

(2) CDD, or cooling degree days, represents the number of degrees that the mean temperature for a particular day is above 65 degrees Fahrenheit. The CDDs are then accumulated for a given period. The cumulative cooling degree days are calculated using current weather data obtained from online weather data services such as Weather Channel and Accuweather compared to the 30 year NOAA National Weather Service archive database.

(3) HDD, or heating degree days, represents the number of degrees that the mean temperature for a particular day is below 65 degrees Fahrenheit. The HDDs are then accumulated for a given period. The cumulative heating degree days are calculated using current weather data obtained from online weather data services such as Weather Channel and Accuweather compared to the 30 year NOAA National Weather Service archive database.

Historical Results of Operations of KGen for the Nine Months Ended March 31, 2010 compared to the Nine Months Ended March 31, 2009.

Total adjusted margin decreased $11.3 million, or 16%, to $59.1 million for the nine months ended March 31, 2010 compared to the same period in the previous year as a result of an $11.4 million decrease in merchant margin offset a $0.1 million increase in adjusted contracted margin. The $59.1 million in total adjusted margin was comprised of $16.4 million in merchant margin and $42.7 million in adjusted contracted margin.

Merchant margin decreased $11.4 million, or 41%, to $16.4 million for the nine months ended March 31, 2010. The $11.4 million decrease was made up of a $7.6 million decrease in merchant energy margin and a $3.8 million decrease in merchant capacity sales. The $7.6 million decrease in merchant energy margin related primarily to the decrease in natural gas prices, as evidenced by the 37% decrease in the average Henry Hub gas price from $6.70 per MMbtu to $4.19 per MMbtu for the nine months ended March 31, 2010 as compared to the previous year, the absence of favorable gas basis differentials at Hot Spring in the 2009 and 2010 period compared to 2008, and the pipeline operational constraints that developed in 2009 that have limited Hot Spring to selling longer schedules which generally have lower financial value. In our markets, merchant energy margins are in part a function of natural gas prices and the market heat rates. Thus, lower gas prices at the same level of market heat rates will yield lower merchant energy margins. There was an increase in merchant generation of 19% from 1,833 GWh to 2,183 GWh which was a result of additional “must run” and 24 hour monthly block sales as compared to the nine months ended March 31, 2009. We believe that lower natural gas prices were in part a factor in the increased monthly sales opportunities for our plants and that such prices enabled our combined cycle plants to displace more expensive generation sources in the market. The $3.8 million decrease in merchant capacity sales was attributable to $4.7 million in merchant capacity sales from a portion of the Murray II plant in the prior year, offset by merchant capacity sales from the Hinds plant in the current year in the amount of $0.9 million. The implied merchant spark spread, or merchant margin divided by merchant generation, decreased from $15.15 per MWh to $7.51 per MWh, largely due to the decrease in merchant capacity sales, the effects of generally lower market gas prices and the absence of favorable gas basis differentials at Hot Spring in the 2009 and 2010 period compared to 2008.

Adjusted contracted margin increased $0.1 million to $42.7 million for the nine months ended March 31, 2010, which was comprised of $5.2 million in adjusted contracted energy margin and $37.6 million in adjusted contracted capacity sales. The $0.1 million increase was made up of a $0.7 million increase in adjusted contracted capacity sales offset by a $0.6 million decrease in adjusted contracted energy margin. The $0.7 million increase in adjusted contracted capacity sales was a result of the escalation of the pricing under the GPC PPA. The $0.6 million decrease in adjusted contracted energy margin was largely attributable to lower revenues from the GPC PPA as a result of lower natural gas prices and was also offset by the reduction of costs of replacement power purchased in connection with the GPC PPA for the nine months ended March 31, 2010 as compared to the previous year.

Adjusted plant expenses increased by $2.2 million, or 6%, to $41.3 million for the nine months ended March 31, 2010. The increase primarily related to $1.0 million associated with the performance of certain non-critical maintenance during the nine months ended March 31, 2010 that was deferred from the previous year, a $0.5 million increase in the LTSA bonus paid and $0.3 million in costs related to the impact of freezing weather on operations at the Murray facility.

As a result of the foregoing changes in total adjusted margin and adjusted plant expenses, adjusted plant EBITDA decreased by $13.4 million to $17.9 million for the nine months ended March 31, 2010.

Adjusted corporate expenses decreased by $1.5 million, or 15%, to $8.4 million for the nine months ended March 31, 2010. This decrease was primarily related to a $0.9 million decrease in payroll expenses, a $0.6 million decrease in commercial marketing fees, and a $0.2 million decrease in legal and professional service expenses.

As a result of the foregoing, adjusted EBITDA decreased by $12.0 million to $9.4 million for the nine months ended March 31, 2010.

GAAP to Non-GAAP Adjusted EBITDA Reconciliation

Following is an alternative calculation of adjusted EBITDA and adjusted plant EBITDA starting from net loss after taxes. EBITDA is equal to net loss after taxes adjusted for interest expenses, income taxes, depreciation, and amortization. Adjusted EBITDA is equal to EBITDA minus certain other items (such as major maintenance and other non-recurring expenses). Adjusted plant EBITDA is equal to total adjusted EBITDA less certain corporate expenses.

	For the Nine Months Ended March 31, 2010	For the Nine Months Ended March 31, 2009
Net loss after taxes	$ (40,778)	$ (41,895)
Add: Interest expense	9,182	9,668
Less: Net interest income	—	(221)
Add: Depreciation	18,264	18,206
Add: Power sales rights and obligations amortization	6,084	6,084
Add: Gas transportation noncash amortization	902	882
Less: Noncash deferred capacity revenue	7	(638)
Add: Other expenses	177	7,182
EBITDA	(6,162)	(732)
Add: Major maintenance expense	14,115	19,368
Add: Termination and transition costs	612	—
Add: Noncash employee options/awards expense	866	2,294
Add: Employee severance expense	1	460
Adjusted EBITDA	9,432	21,390
Add: Selling, general, and administrative expense	9,175	12,363
Less: Noncash employee options/awards expense	(866)	(2,294)
Less: Employee severance expense	(1)	(460)
Add: D&O insurance expense	137	302
Adjusted plant EBITDA	$ 17,877	$ 31,301

The following describes changes to specified financial measures of our performance. As indicated above, in calculating our adjusted EBITDA, we make adjustments to our net loss after taxes using these financial measures for the nine months ended March 31, 2010 compared to the nine months ended March 31, 2009.

- Interest expense for the nine months ended March 31, 2010 was $9.2 million compared to $9.7 million for the same period in 2009. In order to more accurately reflect our financing costs for the nine months ended March 31, 2010, we elected to move gains and losses on derivatives from the other expense line and reflect them in the interest expense line of our condensed consolidated statement of operations. The $0.5 million decrease was made up of a $3.7 million decrease in interest expense due to a reduction in interest rates and outstanding debt compared to the same period in the previous year, offset by $3.2 million in losses on derivatives associated with our interest rate hedging and cash payments on our Swaps.

- Interest income was offset by banking fees for the nine months ended March 31, 2010. Interest income was $0.2 million for the nine months ended March 31, 2009. The decrease in interest income was related to lower interest rates when compared to the same period in the previous year.

- Depreciation was $18.3 million and $18.2 million for the nine months ended March 31, 2010 and 2009.

- Amortization of contract-based power sales rights and obligations, for both nine month periods, was $6.1 million and was recorded as a reduction of energy sales.

- Amortization of contract-based natural gas transportation rights and obligations, for both nine month periods, was $0.9 million and was recorded as an increase of gas transportation expense.

- Noncash deferred capacity revenue, which represents the levelization of capacity sales over the GPC PPA term, of approximately $7,000 of expense and $0.6 million of revenue for the nine months ended March 31, 2010 and 2009, respectively, and was recorded as capacity sales.

- Other expense for the nine months ended March 31, 2010 and 2009 was $0.2 million and $7.2 million, respectively. The $0.2 related to various financing fees and the $7.2 million in the prior year was primarily related to losses on derivatives associated with our interest rate hedging due to cash payments on and a change in valuation of our Swaps. For the nine months ended March 31, 2010, the losses on derivatives were reflected in the interest expense line of our condensed consolidated statement of operations.

- Major maintenance expense for the nine months ended March 31, 2010 and 2009 was $14.1 million and $19.4 million, respectively. The $14.1 million expense primarily related to $15.1 million in connection with the spring 2010 hot gas path inspection performed at the Hinds plant offset by income related to a credit from GE for repair work at Murray I of $1.0 million. The $19.4 million expense in fiscal 2009 primarily related to $18.9 million in connection with the fall 2008 hot gas path inspection performed at Murray II and $0.5 million in other major maintenance expenses at the Hot Spring plant.

- Termination and transition costs for the nine months ended March 31, 2010 and 2009 were $0.6 million and zero, respectively. The $0.6 million expense related to a $0.4 million one-time termination fee paid to DEGS and $0.2 million in transition costs related to the change in operating and maintenance providers.

- Noncash employee options/awards expense for the nine months ended March 31, 2010 and 2009 as $0.9 million and $2.3 million, respectively, and was recorded as an increase of selling, general, and administrative expense.

- Selling, general, and administrative expense was $9.2 million and $12.4 million for the nine months ended March 31, 2010 and 2009, respectively. This decrease was primarily related to a $1.4 million decrease in noncash employee options/awards expense, a $0.9 million decrease in payroll expenses, a $0.6 million decrease in commercial marketing fees, and a $0.2 million decrease in legal and professional service expenses.

Liquidity and Capital Resources

Liquidity Position

We expect that cash on hand, cash flow provided by operations, and cash available under our Credit Facility will satisfy our short-term liquidity needs with respect to our current portfolio of working capital assets over the next 12 months. Our liquidity was comprised of the following at March 31, 2010 (in thousands of dollars):

Unrestricted cash and cash equivalents	$ 53,724
Working capital revolver and synthetic letter of credit facility (net of letters of credit issued and cash draws thereunder)	62,126
Total	$ 115,850

Our principal sources of funds are cash flows from operations and borrowings under our Credit Facility. Our principal use of funds consists of operating expenditures, payments of principal and interest on our Credit Facility, and capital expenditures. On March 31, 2010, we had $62.1 million available under our Credit Facility, of which $62.0 million was under the working capital revolver and $0.1 million was under the synthetic letter of credit facility, for activities related to our plants. We had cash on hand of $53.7 million, of which $29.3 million was cash at the parent level and not subject to the lien of the Credit Agreement at March 31, 2010. Similarly, $32.0 million was the balance at the parent level not subject to the credit agreement at June 30, 2009. Management believes that cash on hand, amounts available under our Credit Facility, and cash flows from operations will be adequate to finance capital expenditures and other liquidity commitments over the next 12 months.

Debt and Credit Facility

Our only debt for borrowed money is evidenced by our Credit Facility, which consists of:

- a $200.0 million term loan facility, or the Term Loan Facility;

- an $80.0 million working capital facility for letters of credit and other liquidity needs, or the Working Capital Facility; and

- a $120.0 million synthetic letter of credit facility to support the collateral requirements under the project documents related to the facilities, or the Collateral Credit Facility.

Borrowings under the Term Loan Facility were made in 2007 by KGen LLC, our subsidiary, and were used to refinance existing indebtedness of KGen LLC, pay fees and expenses relating to the Credit Facility, and fund required reserves. Future borrowings under the Credit Facility are subject to the satisfaction of customary conditions.

On March 20, 2009, KGen LLC drew $10.0 million under the working capital facility. The proceeds of the drawdown continue to be used for working capital purposes. Total letters of credits outstanding under the Working Capital Facility were $8.0 million as of March 31, 2010. Total letters of credit outstanding under the Collateral Credit Facility were $119.9 million as of March 31, 2010.

Interest Rate. Borrowings under the Credit Facility bear interest at a spread above LIBOR-based loans. The $200.0 million Term Loan Facility bears interest at LIBOR plus 175 basis points. Please refer to "Number 3. *Quantitative and Qualitative Disclosures About Market Risk*." Amounts borrowed under the $80.0 million Working Capital Facility bear interest at LIBOR plus 200 basis points.

Fees. We pay a 50 basis point fee on the unused portion of commitments and all undrawn letters of credit under the Working Capital Facility, a 200 basis point fee on drawn letters of credit under the Working Capital Facility, and a 191 basis point fee on the $120.0 million of the Collateral Credit Facility.

Maturity Date. The maturity date of the Credit Facility is February 8, 2014, except that the maturity date of the Working Capital Facility is February 8, 2012.

Security. Borrowings under the Credit Facility are secured by substantially all of the assets of our subsidiaries, which constitute all of our operating assets and generate substantially all of our operating cash flows. Our only significant asset not subject to the lien of the Credit Agreement was a cash balance of $29.3 million at March 31, 2010 that was held at our parent company level.

The Credit Facility and related financing documents contain various affirmative and negative covenants, including (a) financial covenants, (b) limitations on KGen LLC's ability to pay dividends, (c) restrictions on the use of available cash for operations, except as required for debt service payments and, (d) an event of default in the event of a change in control of KGen. At March 31, 2010, we were in compliance with the covenants contained within our Credit Facility.

Capital Expenditures and Major Maintenance

Total capital expenditures for the three and nine months ended March 31, 2010 were $0.4 million and $1.9 million, respectively. Total capital expenditures for the three and nine months ended March 31, 2009 were $0.2 million and $1.3 million, respectively.

Major maintenance was $15.1 million and $0.8 million for the three months ended March 31, 2010 and 2009, respectively. The $15.1 million expense related to a hot gas path inspection at the Hinds plant. The $0.8 million expense in the prior year primarily related to $0.7 million of major maintenance expenses at the Murray facilities and $0.1 million of major maintenance expenses at the Hot Spring plant. Major maintenance expense was $14.1 million and $19.4 million for the nine months ended March 31, 2010 and 2009, respectively. The $14.1 million expense primarily related to $15.1 million in connection with the spring 2010 hot gas path inspection performed at the Hinds plant offset by income related to a credit from GE for repair work at Murray I of $1.0 million. The $19.4 million expense primarily related to $18.9 million in connection with the fall 2008 hot gas path inspection performed at Murray II and $0.5 million in other major maintenance expenses at the Hot Spring plant.

We incur costs for major maintenance on the Plants which is expensed in the period incurred. We expect to incur additional major maintenance expenses of $3.0 million for the remainder of fiscal 2010.

Cash Flow Analysis

The following table summarizes our changes in cash (in thousands of dollars):

	For the Nine Months Ended March 31, 2010	For the Nine Months Ended March 31, 2009
Statement of Cash Flow Data:		
Cash flows provided by (used in):		
Operating activities	$ (5,872)	$ (3,674)
Investing activities	20,433	(8,194)
Financing activities	(1,500)	8,500
Increase (decrease) in cash and cash equivalents	13,061	(3,368)
Cash and cash equivalents at beginning of period	40,663	51,493
Cash and cash equivalents at end of period	$ 53,724	$ 48,125

Cash Flows from Operating Activities. Our cash flows used in operations were $5.9 million for the nine months ended March 31, 2010, primarily related to a $40.8 million net loss, payments from settlement of derivative instruments of $4.8 million, a $1.6 million decrease in spare parts inventory, a $1.4 million decrease in prepaid expenses and other current assets, and a $5.3 million decrease in accounts payable and liabilities, which was offset primarily by depreciation expense of $18.3 million, amortization expense of $7.0 million, valuation of derivative instruments of $3.2 million, and collections of accounts receivable of $17.9 million. We also incurred $5.2 million of cash interest expense during the period under our outstanding Credit Facility.

Cash Flows from Investing Activities. Our cash flows provided by investing activities for the nine months ended March 31, 2010 were $20.4 million and related primarily to $21.6 million use of restricted cash and cash equivalents offset by $1.2 million in purchases of property, plant, and equipment.

Cash Flows from Financing Activities. Our cash flows used in financing activities for the nine months ended March 31, 2010 were $1.5 million and represented $1.5 million in principal payments of long-term debt as required by the Credit Facility.

Number 3. Quantitative and Qualitative Disclosures about Market Risk

Interest Rate Risks

Our primary market risk is the potential impact of changes in interest rates on our variable rate borrowings. The terms of our Credit Facility require us to maintain interest hedge arrangements through the third anniversary of the closing date of our Credit Facility, or February 8, 2010, on at least fifty percent of our outstanding term debt balance to reduce our exposure to market risk from changes in the interest rate. As a result, we have entered into interest rate swaps in order to mitigate the risk associated with the variable rate borrowings.

KGen LLC has three current interest rate swap agreements, or Swaps. These Swaps are intended to hedge the risk associated with variable interest rates. For each of the Swaps, the Company has historically paid its counterparty the equivalent of a fixed interest payment on a predetermined notional value, and we received the equivalent of a floating interest payment based on three-month LIBOR rate calculated on the same notional value. These payments were made on a quarterly basis. During the year ended June 30, 2009, the Company and its counterparty amended the Swaps to reduce the Company's fixed rate payment component and change the basis of the counterparty's floating rate payments. We now receive the equivalent of a floating interest payment based on a one-month LIBOR rate calculated on the same notional value. These payments are made on a monthly basis. While the notional value of each of the Swaps does not vary over time, the Swaps are designed to mature sequentially. The total notional amount of the Swaps as of March 31, 2010 was $99.0 million with an average interest rate payable by KGen LLC of 5.0%. The following is a summary of the Swaps:

	Maturity Date	Notional Amount	March 31, 2010 Fair Value	March 31, 2010 Fixed Rate	June 30, 2009 Fair Value	June 30, 2009 Fixed Rate
		(in millions)	(in thousands)		(in thousands)	
Contract #1	Expired	$ —	$ —	—	$ —	—
Contract #2	Expired	$ —	$ —	—	$ —	—
Contract #3	Expired	$ —	$ —	—	$ (922)	4.9%
Contract #4	3-31-2011	$ 33.0	$ (1,242)	5.0%	$ (1,869)	5.0%
Contract #5	3-31-2012	$ 33.0	$ (2,338)	5.0%	$ (2,455)	5.0%
Contract #6	3-31-2013	$ 33.0	$ (2,909)	5.1%	$ (2,778)	5.1%

As of March 31, 2010, the majority of our exposure to variation in interest costs associated with our term debt due to changes in the LIBOR rate has been hedged through the Swaps. We are exposed to credit related losses in the event of non-performance by the counterparty to the Swaps, however our counterparty is a major financial institution and we consider such risk of loss to be minimal. We will continue to monitor the creditworthiness of our counterparty.

PART II—OTHER INFORMATION

Number 1A. Risk Factors and Forward-Looking Statements

Risk Factors

The following risk factor below updates Part I. "Number 1A. *Risk Factors*" of our Annual Report for the year ended June 30, 2009.

We rely extensively on third party service providers for the operation and maintenance of the Plants and for certain marketing of our electricity, and if such service providers cease to perform such services or fail to perform such services adequately or on the same terms, it could adversely affect our results of operations and cash flows.

We currently have few employees of our own and are dependent on contractual arrangements with third parties for the operation and maintenance of our Plants. Our Murray I and Murray II Plants are operated by DEGS, and our Hinds, Hot Spring, and Sandersville Plants are operated by NAES, under operating and maintenance agreements. In addition, GEI provides maintenance services to our combined-cycle plants under LTSAs. BNP Paribas Energy Trading GP, or BNP, formerly Fortis Energy Marketing & Trading GP, acts as commercial marketer for the power produced by four of the Plants other than the Murray I plant. Procurement of fuel for the Plants, except for sales under the GPC PPA for Murray I and natural gas supply from Sequent for Murray I, is provided by BNP. Currently, BNP and Sequent provide significant credit to us which allows us to transact without providing additional financial collateral. In the event that their credit policies toward us change or these agreements terminate, we may be unable to obtain an agreement with another energy service provider on similarly favorable terms and this could have a significant impact on our ability to procure fuel and meet our power generation targets. While we believe that such contractual arrangements allow us to leverage our management team and have allowed us to operate more effectively and efficiently, in the event we have a significant disagreement with DEGS, NAES, GEI, Sequent or BNP that interrupts one of their services or one of these providers experiences financial difficulties that adversely affect their ability to provide services, our results of operations, financial condition and cash flows may be adversely affected. In this regard, DEGS and BNP both have the right to terminate their agreements with us at their convenience. In addition, although we seek to align our interests contractually, there may be conflicts of interest and one of these parties may take actions that are not in our best interests. We do not have the internal operating capability to perform the services that we outsource, and to develop such capabilities would be time consuming and expensive. However, based upon discussions with potential alternative providers, we believe that multiple options for a replacement energy management service provider and a replacement operations and maintenance service provider are available to KGen. However, we cannot be certain that these providers will deliver their services to us on the same terms as our current providers.

It is our intent that BNP passes through the actual price of power and costs of fuel that it receives from its counterparties through mirroring back-to-back transactions and not make any additional revenues by inserting an additional margin on these transactions. However, not all transactions are totally transparent (particularly when sales or purchases are made to and from BNP's own trading book), and although we have the ultimate authority for all transactions, the possibility exists that our future sales margins may be materially reduced by BNP's pricing.

Forward-Looking Statements

The discussion in this report contains certain forward-looking statements that involve risks and uncertainties. We have based these forward-looking statements on our current expectations and assumptions about future events. In some cases, you can identify forward-looking statements by terminology, such as "may," "should," "could," "predict," "potential," "continue," "expect," "anticipate," "future," "intend," "plan," "believe," "estimate," "forecast" and similar expressions (or the negative of such expressions.) Forward-looking statements include statements concerning known and unknown risks, uncertainties and other important factors that could cause actual results, performance or achievements of KGen and its subsidiaries to differ materially from any future results, performance or achievements expressed or implied by such forward-looking statements. Forward-looking statements are based on our beliefs as well as assumptions based on information currently available to us, including financial and operational information, the volatility of our stock price, current competitive conditions, and anticipated demand for electricity. As a result, these statements are subject to various risks and uncertainties. For a discussion of material risks and uncertainties that the Company faces, see the discussion above and the "Cautionary Statement concerning Forward-Looking Statements" and Part I. "Number 1A. *Risk Factors*" in our Annual Report for the fiscal year ended June 30, 2009.