KGEN POWER CORPORATION

ANNUAL REPORT

For the Fiscal Year Ended June 30, 2011

Four Oaks Place
1330 Post Oak Boulevard, Suite 1500
Houston, Texas 77056

Investor Relations
713-979-1990

TABLE OF CONTENTS

CAUTIONARY STATEMENT CONCERNING 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 Power Corporation 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, 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 "Number 1A. Risk Factors" in this Annual Report. Important factors that could cause actual results to differ materially include, but are not limited to, the following:

- the occurrence of any event, change, or other circumstance that could give rise to the termination of the agreements for the sale of our facilities;
- our inability to complete the sale transactions due to the failure to satisfy conditions to completion of the transactions, including receipt of stockholder or required regulatory approvals;
- the failure of the transactions to sell our facilities to close for any other reason;
- in connection with the sale of our facilities, the possibility that we may be required to make indemnification payments out of, or in excess of, the purchase price that has been placed into escrow to secure post-closing indemnification obligations;
- as a result of the transactions to sell our facilities, the potential difficulties in the retention of executive management and other key employees;
- limitations on our ability to utilize our net operation loss carryforwards to offset taxable gains from the sales transactions;
- the expenses related to the winding down of the Company may be greater than anticipated;
- our remaining power generation plants are expected to be free cash flow negative for the foreseeable future and, if only one or both of the transactions for the sale of our facilities fails to close, we may not generate sufficient cash or otherwise have sufficient liquidity to operate those plants.
- the timing and extent of changes in commodity prices, particularly natural gas;
- the liquidity and competitiveness of wholesale markets for electricity;
- economic slowdowns and cooler-than-expected weather during our peak operating months that can adversely affect consumption of electricity by businesses and consumers;
- uncertainties that actual costs may be higher than estimated;
- uncertainties that our actual cash generation may be lower and our actual need for cash may be higher than estimated;
- refusal by or inability of our current or potential counterparties or vendors to enter into transactions with us or fulfill their obligations to us;
- effectiveness of our risk management policies and procedures;

- present and possible future claims, litigation, and enforcement actions;
- effects of the application of regulations, including changes in regulations or the interpretation thereof;
- disruptions in the transmission and distribution of power;
- availability of fuel and fuel transportation; and
- catastrophic events such as fires, hurricanes, explosions, floods, lightning strikes, terrorist attacks, or other similar occurrences to our facilities or to facilities upon which we depend.

We undertake no duty or obligation to revise or update these forward-looking statements.

Part I

Number 1. *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 two operational and fully permitted combined-cycle power plants (Hot Spring and Hinds), or the Plants, located in the southeastern United States with General Electric 7FA gas turbines. Our combined-cycle plants have an aggregate capacity of 1,140 megawatts, or MW. On July 9, 2010, we completed the sale of our Sandersville power plant, a 640 MW simple-cycle plant, for which we received $129.3 million in cash sales proceeds. On April 8, 2011, we completed the sale of our Murray I and Murray II combined-cycle power plants having an aggregate nominal capacity of 1,250 MW, for which we received $530.3 million in cash sales proceeds. On April 28, 2011, we executed separate definitive sales agreements with subsidiaries of Entergy Corporation for the sale of our Hinds and Hot Spring combined-cycle power plants having an aggregate nominal capacity of 1,140 MW. The terms of these agreements are described on page 20 and in our proxy statement, dated May 16, 2011, relating to our special meeting of stockholders held on June 13, 2011, or the 2011 Special Meeting Proxy Statement. A copy of our 2011 Special Meeting Proxy Statement is available on our website at *www.kgenpower.com*.

Our two Plants currently operate, and historically our previously-divested Sandersville and Murray II power plants operated, as merchant power providers. Our previously-divested Murray I combined-cycle plant, benefited 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.

Our Strategy

Our strategy includes the following elements:

- ***Focus on completion of Hinds and Hot Spring divestitures and maximizing cash available for distribution.*** As indicated above, on April 28, 2011, we executed separate definitive sales agreements with subsidiaries of Entergy Corporation for the divestiture of our Hinds and Hot Spring combined-cycle power plants, our last remaining power plant assets. We are focused on working with Entergy to obtain necessary regulatory approvals and satisfy the other conditions to complete these transactions as soon as possible. Our objective is to maximize the cash available for distribution to our stockholders. Accordingly, we are committed to controlling the costs and expenses at our corporate and plant levels.
- ***Disciplined and opportunistic commercial strategy.*** Until we complete the sale of our Hinds and Hot Spring facilities, we will seek to sell energy and capacity from those facilities into markets when

pricing is most attractive. We currently sell and deliver our merchant energy primarily in the short-term, day-ahead, month ahead, or real-time markets to maintain our flexibility.

- ***Focus on operational efficiency and excellence.*** Until we complete the sale of our Hinds and Hot Spring facilities, we will focus on maintaining and enhancing our plant availability and operational reliability to take advantage of market opportunities. We are committed to operating our Hinds and Hot Spring plants in a safe, reliable, and environmentally-compliant manner. We maintain lean staffing at our corporate and plant levels and employ strategic outsource partners to enhance our energy marketing, gas supply, plant operations and maintenance functions, and to increase the economic efficiency of our operations.

Our Remaining Combined-Cycle Power Plants

Plant	Location	Turbines	Heat Rate(1)	Total Capacity (MW)(2)	Commercial Operation Date
Hot Spring	Hot Spring County, Arkansas	7FA	7,150	620	June 2002
Hinds	Hinds County, Mississippi	7FA	7,000	520	May 2001
Total				1,140	

(1) Approximate heat rate at full-load summer operation without supplemental firing.

(2) Nominal operating capacity.

Our Operations

Our management includes a core group of industry veterans. We have leveraged the capabilities of this core team by using third-party outsource providers to manage and maintain our facilities.

Our Hot Spring and Hinds Plants are operated pursuant to operation and maintenance agreements with NAES Corporation, or NAES. NAES provides operations, certain accounting, human resources, engineering, environmental, health and safety compliance, and other services to the Plants for which it is the operation and maintenance provider. NAES utilizes their own personnel, supplemented by outside contractors on an as-needed basis, to perform such services. NAES also provides, when requested, technical and commercial services, health and safety services, and human resources support for plant employees.

The energy management services for the power and capacity of our Plants have been provided by BNP Paribas Energy Trading GP, or BNP, formerly Fortis Energy Marketing & Trading GP. The services provided by BNP include seeking purchasers for our merchant power sales and handling our natural gas purchases to meet operating needs for electricity placed through BNP and providing administrative services for the tracking of power sales and gas purchases. Under our energy management arrangements with BNP, we benefit from BNP's credit and use BNP's balance sheet to transact with other counterparties which streamlines our sales process and allows us to enter into transactions that we might not otherwise be able to enter. On July 21, 2011 the Company was notified by BNP that they are terminating the contract to provide energy management services. On September 26, 2011, we retained Twin Eagle Resource Management, LLC, or Twin Eagle, as our new energy management services provider with services commencing on October 1, 2011. Twin Eagle does not have an investment grade rating. Accordingly, under the Company's agreements with Twin Eagle, Twin Eagle is required to post collateral in the form of letters of credit or cash in the event our exposure to Twin Eagle exceeds certain specified thresholds.

Our Hinds Plant began operations in May 2001 and our Hot Spring Plant began operations in June 2002. Since inception our Plants have been maintained pursuant to long-term service agreements, or LTSA's, with General Electric International, or GEI. Average availability at the Plants was 84.6% for the year ended June 30, 2011, or 98.2% excluding major maintenance. Our Plants are fully operational with all required permits, transmission interconnections, and gas transportation access. In addition, the use of standardized equipment in the Plants creates economies of scale with respect to operations and maintenance, spare parts, and capital equipment inventory.

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 than in other months as a result of increased use of air conditioning. Our results of operations are subject to seasonal variations since demand for electricity and production capacity varies with weather conditions. Our Plants currently operate on a merchant basis without long-term purchase agreements, and therefore are exposed to significant volatility in prices and generation demand. We earn the majority of our 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 us and are typically the months during which we seek to perform scheduled maintenance-related activities.

Principal Customers

Historically, Georgia Power was our most significant customer, with payments by it under the GPC PPA accounting for approximately 34.1% and 41.9% of our revenues for the years ended June 30, 2011 and 2010, respectively. Most of our remaining sales are merchant sales that we have made through BNP who simultaneously sells the power to other counterparties under an identical sales arrangement "back-to-back basis", which are approved by us.

Power Transmission

Our Hinds facility is interconnected to Entergy Services' transmission system at the 230 kV Lakeover substation pursuant to a long-term interconnection agreement with Entergy Mississippi.

Our Hot Spring facility is interconnected to Entergy Services' transmission system at the 500 kV Etta substation pursuant to a long-term interconnection agreement with Entergy Arkansas.

Gas Supply

Our source of fuel to generate electricity is natural gas and we purchase gas generally on a short-term basis. When we enter into longer-term electricity transactions, we enter into gas purchase agreements that are consistent with our electricity pricing exposure. Natural gas is delivered to our Hinds facility through a 2.5-mile pipeline interconnected to Texas Eastern Transmission, LP, or TETCO. The firm transport contract provides firm capacity of 80,000 decatherms per day, or Dth/day, in our summer peak period and lesser amounts in the other parts of the year. On April 10, 2010, we extended the long-term gas transportation contract with TETCO to deliver gas to the Hinds facility through March 2022.

At our Hot Spring facility, natural gas is delivered through either of two pipeline systems to which the plant is interconnected. We have long-term pipeline transport contracts with CenterPoint Inc., or Centerpoint, that provide firm capacity of 98,000 Dth/day in our summer peak period and 50,000 Dth/day in the other parts of the year.

On April 1, 2010, we entered into a Precedent Agreement with TETCO, 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. This lateral pipeline was constructed in order for Hot Spring to access increased scheduling flexibility on TETCO's system. The FERC filing was made on July 15, 2010 and the pipeline was completed and in service in June 2011 with financial incentives of $0.2 million paid to TETCO since the pipeline was completed before July 1, 2011. We were required to post collateral to support construction of the pipeline and as of June 30, 2011 posted a $39.0 million letter of credit. Now that 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, which provide 112,000 Dth/day of firm capacity. The collateral requirements will decrease proportionally over the 20-year term.

Competition

Our Plants currently operate on a merchant basis. As a result, we face competition from the power generation plants operated by Entergy Services, other utilities, and from other merchant generators within the SERC region and outside the SERC region for electricity orders. Furthermore, competitive conditions may be substantially affected by various forms of energy legislation and/or regulation considered from time to time by the government of the United States or the states in which our Plants reside. At this time, it is not possible to predict the nature of any such legislation or regulation that may ultimately be adopted or its effects upon our future operations.

Employees

As of June 30, 2011, we employed 17 people all of whom are located at our corporate office in Houston, Texas.

Regulatory Matters

Overview

We are subject to U.S. federal, state, and local energy and environmental laws and regulations applicable to the development, ownership and operation of our Plants. Federal laws and regulations govern, among other things, types of fuel used, the type of energy produced, power plant ownership, the rates, terms and conditions of wholesale electricity sales, and corporate transactions involving entities that engage in wholesale sales and interstate transmission of electricity. State energy laws govern, among other things, retail utility rates, terms of retail sales, determinations of need for new facilities, land use, and local permitting. Power projects also are subject to laws and regulations governing environmental emissions and other substances produced by a plant, along with the geographical location, zoning, land use, and operation of a plant. Applicable federal environmental laws typically have state and local enforcement and implementation provisions. These environmental laws and regulations generally require that a wide variety of permits and other approvals be obtained before construction or operation of a power plant commences and that the facility operate in compliance therewith.

Federal Regulation and the Federal Energy Regulatory Commission

The FERC is an independent regulatory commission within the Department of Energy that, among other things, regulates the transmission and wholesale sale of electricity in interstate commerce under the authority of the Federal Power Act, or FPA. Each of our subsidiary generating companies makes wholesale sales of electricity and is a "public utility" under the FPA, subject to regulation by the FERC. In addition, FERC determines whether a company that owns or operates a generation facility qualifies for Exempt Wholesale Generator, or EWG, status under the Public Utility Holding Company Act of 2005, or PUHCA of 2005. Each of our Plants is owned through subsidiaries that have been determined to be EWGs. This permits us to be exempt from most regulation as a holding company under PUHCA of 2005.

Federal Power Act. The FPA gives FERC exclusive rate-making jurisdiction over wholesale sales of electricity and transmission of electricity in interstate commerce. Under the FPA, FERC, with certain exceptions, regulates entities that engage in wholesale sales of electricity and transmission of electricity in interstate commerce as "public utilities." Public utilities under the FPA are required to obtain FERC's acceptance, pursuant to Section 205 of the FPA, of their rate schedules and tariffs under which they sell electricity at wholesale. FERC has granted each of our generating companies the authority to sell electricity at market-based rates. FERC's orders that grant our generating companies market-based rate authority reserve the right to revoke or revise that authority if FERC subsequently determines that we can exercise undue market power in transmission or generation, create barriers to entry or engage in abusive affiliate transactions. As a condition to the orders granting our generating companies market-based rate authority, we are required every three years to file a market power update to show that our generating companies and other generating assets that are considered to be under common control with us continue to meet FERC's standards with respect to generation market power and other criteria used to evaluate whether entities qualify for market-based rates. Our generating companies will be filing their next market power update with FERC in December 2011. We are also required to report to FERC any material change in status that would reflect a departure from the characteristics that FERC relied upon when it granted our various generating companies' market-based rates. When determining whether market power issues exist, FERC aggregates our generating assets with other generating assets owned or controlled by any of our shareholders that own ten percent or more of the Company's voting securities. Thus, to the extent one of our existing ten percent shareholders directly or indirectly owns or acquires ten percent or more of the voting securities of new generating assets, or an existing or new shareholder that acquires ten percent or more of our stock also owns or acquires ten percent or more of the voting securities of other generating assets, either directly or indirectly, our generating companies may be required to make a change of status filing with FERC, and the aggregation of such additional generating assets with ours could cause market power issues that could cause the generating companies to lose or restrict their market-based rate authority.

The market-based rate sales made by our generating companies are subject to certain market manipulation prohibitions that make it unlawful for any entity involved directly or indirectly in a FERC jurisdictional transaction to intentionally defraud, make untrue statements or omit material facts. If any of our generating companies were deemed to have violated one of those rules or any other FPA provision or rules or orders issued thereunder, they could be subject to potential civil or criminal penalties, disgorgement of profits associated with the violation and/or suspension or revocation of their market-based rate authority.

If our generating companies were to lose their market-based rate authority, such companies would be required to obtain FERC's acceptance to sell power at cost-based rates. Our company then would become subject to the accounting, record-keeping and reporting requirements that are imposed on utilities with cost-based rate schedules. Also, the loss of market-based rate authority could cause an event of default under our credit agreement.

In addition, Section 204 of the FPA gives FERC jurisdiction over a public utility's issuance of securities or assumption of liabilities. However, FERC typically grants blanket approval for future securities issuances or assumptions of liabilities to entities with market-based rate authority. FERC granted such blanket authority to our generating companies. In the event that one of our public utility generating companies were to lose its market-based rate authority, such company's future securities issuances or assumptions of liabilities could require prior approval of the FERC.

The FPA also gives FERC jurisdiction to review certain corporate transactions and numerous other activities of public utilities, including mergers or consolidations involving public utilities, certain transfers of public utility and electric generation facilities, certain purchases by a public utility of the securities of another public utility, and certain public utility holding company purchases of securities and direct or indirect mergers and consolidations. FERC will grant approval under FPA Section 203 if it finds that the proposed transaction will be consistent with the public interest and does not raise concerns with respect to cross-subsidization involving a traditional public utility that has captive customers which receive services at cost-based rates.

In compliance with Section 215 of the EPAct, FERC has approved the North American Electric Reliability Corporation, or NERC, as the national Electric Reliability Organization, or ERO. As the ERO, NERC is responsible for the development and enforcement of mandatory electric reliability standards for the wholesale electric power system. Our subsidiary generating companies are responsible for complying with the standards applicable to Generator Owners. The ERO can assess civil penalties for non-compliance with the standards.

Public Utility Holding Company Act of 2005. The PUHCA of 2005 gives FERC access to the books and records of holding companies if necessary for determining jurisdictional rates. FERC has also implemented the PUHCA of 2005 rules governing accounting, record retention and reporting, as required by EPAct. Because we are a holding company under the PUHCA of 2005 solely as the result of owning one or more EWGs, we and our subsidiary generating companies are exempt from FERC access to books and records under the PUHCA of 2005. However, FERC has asserted independent authority under the FPA granting it access to the books and records of public utilities and holding companies. Moreover, the PUHCA of 2005 also gives state regulatory authorities access to books and records of holding companies if necessary for determining jurisdictional rates. Our subsidiary companies' EWG status does not exempt them or us from such state authority.

The Dodd-Frank Wall Street Reform and Consumer Protection Act of 2010. On July 21, 2010 the President signed into law H.R. 4173, the Dodd-Frank Wall Street Reform and Consumer Protection Act, the Dodd-Frank Act, or the Act, the most comprehensive restructuring of the banking and financial sectors in many decades. The Dodd-Frank Act authorizes the Commodity Futures Trading Commission, or CFTC, to regulate trading in derivatives in energy and energy-related commodities, including electricity, natural gas, oil, renewable energy credits, and greenhouse gas allowances and offset credits. Prior to enactment of the Act, derivatives and other financial transactions in energy and energy-related commodities, which are widely used by energy companies to manage and hedge commercial risks, had largely been exempt from CFTC regulation. The Act repeals this exemption.

Under the Dodd-Frank Act, trading of certain energy and energy-related derivatives, commonly referred to as "swaps", will be subject to clearing requirements, under which trading in swaps that had heretofore been conducted in bilateral, over-the-counter transactions must be traded on or processed by a registered clearing house organization, such as NYMEX. Mandatory clearing will be accompanied by capital and margin requirements, collateral posting requirements, position limits and reporting requirements, and the use of standardized contracts. The capital and margin requirements, in particular, could impose substantial new costs on energy companies trading derivatives, i.e., swaps, for risk-management purposes.

The Dodd-Frank Act includes an exemption from the general clearing requirements for swaps in which at least one party is not a defined financial entity, known as a "major swap participant", and whose purpose is to hedge that entity's commercial risks. The precise scope of this "end-user's" exemption is a subject of much controversy and will be determined by new CFTC rulemakings. The CFTC issued an initial set of proposed regulations on May 23, 2011, which would define key terms pertinent to the possible scope of the end-user's exemption. The CFTC has not indicated when it expects to issue further proposed or final regulations affecting energy-related swaps.

Even if an end-user's exemption from clearing requirements were to apply to certain energy and energy-related derivative trading, the Dodd-Frank Act creates substantial uncertainty for the energy industry as it authorizes the CFTC to impose special capital and margin requirements that would apply even to over-the-counter swaps of energy and energy-related commodities that are used for commercial hedging and that are not required to be traded on a registered clearing house. Again, the CFTC, which is given considerable discretion under the Act, must establish by rulemakings the scope of these requirements. At this time, it is not known whether final CFTC regulations will impose burdensome capital and margin requirements on trading in swaps used by an electric or gas utility that purchases or sells fuel or electricity to manage the commercial risks of the utility's business.

Environmental Regulation

The construction and operation of power projects are subject to extensive environmental protection and land use laws and regulations in the United States. Environmental laws and regulations that apply to us primarily involve emissions into the air, discharges to surface waters and the use of water, but often also include wetlands preservation, endangered species preservation, waste disposal and noise abatement. These laws and regulations often require us to follow lengthy and complex procedures to obtain licenses, permits and approvals for the Plants and their operations from federal, state and local agencies.

Since the Clean Air Act of 1970 was enacted, the air emissions of power plants such as our Plants have been comprehensively regulated by the United States Environmental Protection Agency, or EPA, and/or EPA-authorized States. New power plants are required to include either Best Available Control Technology, or BACT, for the control of various regulated emissions, including nitrogen oxides, or NO_x, sulfur dioxide, or SO_2, volatile organic compounds, or VOCs, and particulate matter. If located in a nonattainment area for a specific pollutant, the plant must achieve the Lowest Achievable Emission Rate, or LAER for that pollutant. In addition, operating power plants can become subject to new BACT and LAER provisions if they undergo "major modification," thereby rendering them subject to current BACT/LAER requirements rather than the BACT/LAER requirements in effect when the Plant was originally built. Finally, operating plants generally are not exempt or otherwise grandfathered from subsequent changes in environmental law, either federal or state. For this reason, for example, the greenhouse gas, or GHG, emissions of our Plants could become subject to federal and/or state regulation, and the current regulatory requirements governing the Plant's NO_x, SO_2, VOC, and particulate matter emissions could be increased.

Based on current trends, we expect that environmental and land use laws and regulations will continue to change and indeed to become more stringent with time. If such laws and regulations or the terms of our licenses, permits or approvals are changed and our facilities are not grandfathered or excluded from these changes, we may need to make significant capital expenditures for modifications to project technologies and facilities to maintain compliance in order to continue operation. We do not anticipate incurring material capital expenditures related to environmental compliance in the near term.

Clean Air Act. There are three parts of the Clean Air Act that are particularly relevant to electricity generation facilities: Title I—National Ambient Air Quality Standards; Title IV—Acid Deposition Control; and Title V—The Clean Air Act Permit Program. Most of the permit and regulatory requirements that apply to the Plants arise under Titles IV and V. Title IV affects all fossil fuel-fired generation facilities and requires covered sources to generate or obtain annual credits for SO_2, emissions. Title V affects all emission sources, including gas-fired electricity generation facilities. Title V requires that we obtain comprehensive air emission control permits for the Plants that are classified as major sources under the Clean Air Act. All of our Plants are major sources, and we have applied for and obtained the required Title V permits.

Under Title I of the federal Clean Air Act, if National Ambient Air Quality Standards, or NAAQS, are violated in a region, that area is designated as a non-attainment area by the EPA, and is given a deadline for reaching compliance. The relevant state is required to submit a state implementation plan, or SIP, detailing how regional attainment will be achieved within the prescribed time limit, including a requirement for new and modified stationary sources to obtain emissions offsets for their No_x, VOC, and particulate matter emissions where certain emission thresholds are triggered. All of the Plants are located in areas presently in attainment of NAAQS.

Proposed and Recently Adopted Air Quality Regulations. During 2005, the EPA adopted the Clean Air Interstate Rule, or CAIR, which expands the NO_x and SO_2 "cap and trade" programs established for states in the eastern and southeastern United States, including Arkansas and Mississippi.

On July 6, 2011, the EPA issued a Final Cross-State Air Pollution Rule ("Cross-State Rule"), which replaced CAIR. Under the Cross-State Rule, the EPA adopted federal implementation plans, or FIPs, for each of the states covered by the rule. The FIP is only operative until individual states submit revised SIPs implementing the Cross-State Rule to the EPA for approval. Like CAIR, the Cross-State Rule is a two phase program with declining compliance caps for SO_2 and NO_x by January 1, 2012 with a second phase of SO_2 reductions by January 1, 2014. Additionally, twenty states, including Arkansas and Mississippi, are required to reduce NO_x emissions during the ozone season (May through September) by May 1, 2012 in order to decrease the emissions transported to downwind states. Under the Cross-State Rule, plants in Mississippi and Arkansas are only subject to the ozone season NO_x reduction requirements and not the general SO_2 and NO_x phased reductions. The Cross-State Rule allows emission allowance trading among covered sources, utilizing an allowance market infrastructure based on existing, successful allowance trading programs. Sources can trade emissions allowances with other sources within the ozone season NO_x program in the same or different states. Legislative efforts are underway to delay implementation of the Cross-State Rule. On July 12, 2011, the House Energy and Commerce Committee passed the Transparency in Regulatory Analysis of Impacts on the Nation Act of 2011 (the "TRAIN Act") (H.R. 2401), which included an amendment to delay implementation of the Cross-State Rule. The TRAIN Act and its amendment are waiting for a full vote in the House.

As the allowable caps on ozone season NO_x emissions decreases, we anticipate that the cost to acquire emission credits will increase. If we are unable to satisfy some or all of our environmental commitments with emissions allowances, either because of regulatory changes or an inability to obtain emissions allowances, we could be required to take alternative actions, which may include reduced plant operation or shutdown or additional capital expenditures to comply with the Clean Air Act.

Proposed Climate Change Legislation and Regulations. There is a growing popular consensus in the U.S. and globally that GHG emissions are linked to global climate change; this consensus may lead to more stringent regulation of GHG emissions in the future. Increased public concern and mounting political pressure may result in state, regional, and/or federal requirements to reduce or mitigate the effects of GHG emissions, in particular from power plants.

In *Massachusetts v EPA*, 549 U.S. 497 (2007), the United States Supreme Court determined that the EPA has authority under existing law to regulate GHG emissions pursuant to its authority to set emission standards for "any air pollutant" which in the EPA Administrator's judgment "cause[s], or contribute[s] to, air pollution which may reasonably be anticipated to endanger public health or welfare." In a related action, on April 24, 2009, the EPA issued a proposed finding that carbon dioxide, or CO_2, and other GHGs endanger public health and welfare, which could require the EPA to issue emissions limits for GHG emissions from motor vehicles. This so-called "endangerment finding," if affirmed in court, would establish the EPA's authority to set emission standards for GHGs. On May 13, 2010, the EPA issued a final rule (Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule, or Tailoring Rule) adopting a phased-in approach to address six GHG emissions from stationary sources, including power plants, which began in January 2011. A number of industry groups, environmental organizations and states challenged the final rule before the United States Court of Appeals for the District of Columbia Circuit (*Sierra Club v. EPA*, Case No. 09-1018, *et al*) and the case is still pending.

While the Tailoring Rule would only apply to new and modified facilities, the EPA entered into two proposed settlement agreements, under which it will issue rules that will address GHG emissions from existing fossil fuel-fired power plants, as well as new and modified sources. The rules would establish new source performance standards for new and modified plants and emissions guidelines for existing plants. The federal emissions guidelines will be translated by states into enforceable performance standards. It is unclear at this time what form the standards will take; much of the debate likely will center around the flexibility of the federal guidelines and how the states exercise their discretion in implementing the standards. The EPA committed to issuing the proposed regulations by July 26, 2011 and final regulations by May 26, 2012, but in June the EPA announced that it was delaying the issuance of the proposed rule by two months. Based on the current delay any federal requirements likely would not take effect until late 2012 or early 2013.

While a comprehensive energy and environmental bill establishing a "cap and trade" system for targeted reductions of GHG emissions passed the U.S. House of Representatives two years ago, further action was not taken on this bill and additional climate change bills have not been passed by the House or

Senate. With the 112th Congress now in its last few months, it is highly unlikely that a climate change bill, or even a pared-down energy bill, will reach the President's desk this year.

EPA rulemakings to regulate GHG emissions are expected to continue despite the absence of a new, comprehensive federal statutory scheme to address the issue, but since the mid-term elections the EPA has been reconsidering and delaying its efforts. While new GHG rules, once finalized, are expected to be challenged in the courts and by Congress through attempts to delay, defund, or deauthorize the EPA's regulation of GHG emissions, it is likely that the current Administration will continue this regulatory exercise in the near term, or at least until a consensus emerges on possible GHG legislation. In addition, states and regions seeking to control the GHG emissions of their power plants are expected to continue. Regulation of CO_2 emissions at the federal level or in the states or regions where we operate could impact our operations by requiring us to obtain allowances for each ton of CO_2 produced. It is uncertain whether existing emitters will be awarded allowances or be required to purchase allowances under federal regulatory framework. Our power generation operations primarily use natural gas and therefore emit less CO_2 than coal-fired generation facilities. Natural-gas fired combined cycle facilities emit 50% to 60% less CO_2 per kW-hr compared to conventional coal-fired generation facilities.

Site Remediation Liability. Certain federal and state environmental laws impose joint and several liability without regard to fault for costs required to clean up and restore sites where hazardous substances have been or could be released. We could be responsible under these laws for liabilities associated with the environmental condition of power generation plants that we own or operate or locations where we have arranged for the disposal of hazardous substances. We are also subject to environmental laws and regulations that require us to report and respond to spills and releases that may occur as a result of our operations. We are not currently subject to material liabilities or obligations to investigate, clean-up, or monitor on-site or off-site environmental contamination under these environmental laws.

Insurance

We carry insurance coverage consistent with companies engaged in similar commercial operations with similar properties, including business interruption insurance for our combined-cycle facilities. However, our insurance policies are subject to certain limits and deductibles as well as policy exclusions. Adequate insurance coverage in the future may be more expensive or may not be available on commercially reasonable terms. Also, the insurance proceeds received for any loss of or any damage to any of our generation facilities may not be sufficient to restore the loss or damage without negative impact on our financial condition, results of operations, or cash flows.

Available Information

Our principal offices are at Four Oaks Place, 1330 Post Oak Blvd., Suite 1500, Houston, TX 77056. Our phone number is (713) 979-1900. Our investor relations department will provide without charge, upon the written request of a holder of our common stock or a prospective investor, our annual reports, quarterly reports, and any amendments to these reports. Certain of these reports and other communication are also available on our website at *www.kgenpower.com*. We are not an SEC registrant and therefore none of these reports have been filed with the Securities and Exchange Commission.

Number 1A. ***Risk Factors***

Risks Related to Our Business

The Company has entered into agreements for the sale of its remaining facilities, and upon consummation of those sales, the Company will have no remaining operations and will be wound down.

Upon the consummation of the Hinds and Hot Spring transactions, the Company will have sold all of its remaining operating assets. As the Company will cease to own any operating assets upon the consummation of the Hinds and Hot Spring transactions, the Board expects to distribute to our stockholders substantially all of the net after-tax proceeds of these sales as they are received after taking into account the anticipated expenses of winding down the Company. If expenses related to the winding down of the Company are greater than anticipated, there will be less net after-tax proceeds from the sales available for distribution to our stockholders.

The sales of the Company's remaining facilities are subject to a number of closing conditions, a number of which are beyond our control, which if not satisfied could prevent one or both of the sales from being consummated, and as a result there would be no distribution of the expected net after-tax sale proceeds from such sale or sales to our stockholders.

The Hinds and Hot Spring transactions are each conditioned upon the receipt of approval of the Federal Energy Regulatory Commission, approval of applicable state public service commissions, clearance under the Hart-Scott-Rodino Antitrust Improvements Act of 1976, certain third-party consents and certain other closing conditions. The transactions, which are not subject to any financing condition, are each expected to close in the middle of calendar year 2012, but may close before or after such time, or not at all. Neither the Hinds transaction nor the Hot Spring transaction is conditioned on the closing of the other, thus the transactions may close at different times and one transaction may be completed and not the other.

In addition, the occurrence of certain events, changes, or other circumstances that are beyond our control could give rise to the termination of one or both of the agreements for the sale of our facilities.

If either or both of the Hinds or Hot Spring transactions fail to close, the net after-tax sale proceeds from such sale or sales would not be available for distribution to our stockholders.

The Company has certain indemnity obligations under the agreements for the sale of the Hinds and Hot Spring facilities as well as under the agreements for the sale of the Company's legacy facilities which have already been consummated. Any indemnification payments required to be made by the Company under those agreements would reduce the net after-tax sale proceeds available for distribution to our stockholders.

In order to secure the Company's post-closing indemnification obligations under the agreements for the sale of the Hinds and Hot Spring facilities as well as under the agreements for the sale of the Company's Murray facilities which have already been consummated, a portion of the purchase price for the Murray transaction has been, and in the case of the Hinds and Hot Spring facilities, will be, placed into escrow. It is possible that the Company may be required to make indemnification payments out of, or in excess of, the portion of the amounts that have been, and will be, placed into escrow. To the extent indemnification payments are required to be made by the Company under those agreements, whether out of or in excess of the respective escrowed amounts, those payments would reduce the available net after-tax sale proceeds available for distribution to our stockholders.

Until the consummation of the sale of our facilities, the failure to achieve favorable operating results could have an effect on our financial condition.

Our inability to operate the Plants efficiently, manage capital expenditures and costs, and generate earnings and cash flow from our asset-based businesses in relation to our obligations could have a material adverse effect on our results of operations, financial condition, or cash flows.

We expect both our Hinds and Hot Spring facilities to be free cash flow negative for the foreseeable future and, if only one or both of the sales fails to close, we may not generate sufficient cash or otherwise have sufficient liquidity to continue to operate our facilities.

Both of our Plants currently operate without long-term power purchase agreements and if we are unable to find purchasers for our power or capacity or to find purchasers at attractive pricing, it would have a material adverse effect on our financial condition and cash flows.

Our Plants currently operate as merchant facilities without long-term power purchase agreements, and therefore are exposed to significant price volatility from the supply and demand imbalances in the day-ahead and spot markets. Without the benefit of long-term power purchase agreements for these assets, we cannot be sure that we will be able to sell any or all of the capacity available or power generated by these facilities at commercially attractive rates or that these facilities will be able to generate revenues or operate profitably.

We rely on a power transmission facility that we do not own or control and are subject to transmission constraints within our core region. If this facility fails to provide us with adequate transmission capacity, we may be restricted in our ability to deliver wholesale electric power to our customers and we may either incur additional costs or forego revenues.

We depend on a transmission facility owned and operated by others to deliver the wholesale power we sell from the Plants to our customers. Entergy Services controls the transmission infrastructure in our primary region of operations within SERC.

Additionally, if transmission is unavailable or disrupted, or if the transmission capacity infrastructure is inadequate, our ability to sell and deliver wholesale power may be adversely impacted. If a region's power transmission infrastructure is inadequate, our recovery of wholesale costs and profits may be limited.

Until the consummation of the sale of our facilities, our costs, results of operations, financial condition, and cash flows could be adversely impacted by disruption of our fuel supplies.

We rely on natural gas to fuel our Plants. Delivery of fuel to our Plants is dependent upon the continuing financial viability of contractual counterparties as well as upon the infrastructure (particularly natural gas pipelines) available to serve each plant. As a result, we are subject to the risks of disruptions or curtailments in the production of power at the Plants if a counter party fails to perform or if there is a disruption in the fuel delivery infrastructure.

We buy significant amounts of fuel on a short-term or spot market basis. Prices for our fuel fluctuate, sometimes rising or falling significantly over a short period. The price we can obtain for the sale of electric energy may not rise at the same rate, or may not rise at all, to match a rise in fuel or fuel delivery costs. This may have a material adverse effect on our financial performance. Changes in market prices for natural gas may result from the following:

- weather conditions;
- seasonality;
- demand for energy commodities and general economic conditions;
- disruption of gas transportation, infrastructure, or other constraints or inefficiencies;
- changes in FERC-approved gas transport tariff rates;
- additional generation capacity;
- outages resulting from maintenance;

- availability of competitively priced alternative energy sources;
- availability and levels of storage and inventory for fuel stocks;
- natural gas production levels;
- the creditworthiness or bankruptcy or other financial distress of market participants;
- changes in market liquidity;
- natural disasters, wars, embargoes, acts of terrorism, and other catastrophic events; and
- federal, state, and foreign governmental regulation and legislation.

We obtain supplies of natural gas through firm and interruptible pipeline transport agreements. The transport prices we pay are regulated under tariffs approved by FERC. Certain tariffs apply to gas supplies taken over a fixed period of time. As the Plants are generally dispatched intermittently, we do not need gas at a steady rate over a long period of time but in compressed periods. Unless the gas transporter has flexible operations or cooperates with us, a requirement to take a minimum amount of gas over an extended period or face penalties related to the pressure in the pipeline and other contract requirements can make it uneconomical to operate a plant under certain conditions.

As a result of the transactions to sell our facilities, we face potential difficulties in the retention of executive management and other employees.

Our ability to successfully consummate the sale of our facilities will depend in part on the skills, experience and efforts of our senior management and certain key personnel with critical skills. While our Chief Executive Officer and certain other members of our management are subject to employment agreements, these employment agreements may be terminated at will by the employees and the loss of the services of any such individual or other key personnel could have a material adverse impact upon on our business and results of operations. The Company's entry into agreements for the sale of its remaining facilities may negatively impact our ability to retain our senior management team and certain other key personnel.

We have only one significant customer with which we have a direct contractual relationship for our power so our credit risk is concentrated. This customer does not have an investment grade credit rating. If our customer was to experience financial difficulties, we could be subject to a material and adverse effect on our financial condition and results of operations.

Commencing October 1, 2011, our only significant customer with which we will have a direct contractual relationship with is Twin Eagle. We will benefit from credit sleeving with Twin Eagle through back-to-back sales of merchant power and capacity to our ultimate customers. Changes in economic, regulatory, or other factors could have a significant effect on these customers or our contractual relationships. Twin Eagle does not have an investment grade credit rating. If Twin Eagle failed to pay us or was delayed in their payments under our contracts, we would be adversely affected to the extent that we were unable to find other customers at the same level of contract profitability.

Risks Related to Our Industry

Until the consummation of the sale of our facilities, the operation of power generation plants involves significant risks that could result in unplanned power outages or reduced output, which would adversely affect our results of operations, financial condition or cash flows.

We are subject to significant risks associated with operating power generation plants, any of which could adversely affect our revenues, costs, results of operations, financial condition or cash flows. These risks include:

- operating performance below expected levels of output or efficiency;
- failure of equipment or processes, operator or maintenance errors, or other events resulting in power outages or reduced output;
- availability of fuel and fuel transportation;
- disruptions in the transmission or distribution of power; and
- catastrophic events such as fires, hurricanes, explosions, floods, lightning strikes, terrorist attacks, or other similar occurrences to our facilities or to facilities upon which we depend.

Unplanned outages of generation units, including extensions of scheduled outages due to mechanical failures or other problems occur from time to time and are an inherent risk of our business. Unplanned outages typically increase our operating and maintenance expenses. In addition, an unplanned outage may reduce our revenues as a result of selling fewer megawatt hour, or MWh, or require us to incur significant additional costs as a result of running one of our higher cost units or obtaining replacement power from third parties in the open market to satisfy our power sales obligations. As a result, if any one unit were to experience an unexpected failure or unplanned outage, especially during our peak summer season, it may have a material adverse effect on our revenues from operations or our costs of operations.

The cost of repairing damage to our Plants due to storms, lightning strikes, natural disasters, and other catastrophic events may adversely affect our results of operations, financial condition, or cash flows. These events and future events of this kind could damage our Plants and disrupt our fuel supply and transmission capability. Such events could also result in adverse changes in the insurance markets or other operating costs and disruptions of power and fuel markets. In addition, our power generation plants, fuel supply, fuel transport, and transmission capability could be directly or indirectly harmed by future terrorist activity or acts of war. Strategic targets, such as energy-related facilities, may be at greater risk of future terrorist activities than other domestic targets. The occurrence or risk of occurrence of future terrorist attacks or related acts of war could result in increased securities and insurance costs, adversely affect the U.S. economy or otherwise impact our results of operations and financial condition in unpredictable ways.

Our operations are subject to hazards customary to the power generation industry. We may not have adequate insurance to cover all of these hazards.

Power generation involves hazardous activities, including acquiring, transporting and unloading fuel, operating large pieces of rotating equipment, and delivering electricity to transmission and distribution systems. In addition to natural risks such as earthquake, flood, lightning strikes, hurricane and wind, other hazards, such as fire, explosion, structural collapse, and machinery failure are inherent risks in our operations. These and other hazards can cause significant personal injury or loss of life, severe damage to and destruction of property, plant and equipment, contamination of, or damage to, the environment, and suspension of operations. The occurrence of any one of these events may result in our being named as a defendant in lawsuits asserting claims for substantial damages, including for environmental cleanup costs, personal injury and property damage, and fines and/or penalties. We maintain an amount of insurance protection that we consider adequate, but we cannot make assurances that our insurance will be sufficient or effective under all circumstances and against all hazards or liabilities to which we may be subject. A successful claim for which we are not fully insured could hurt our financial results and materially harm our financial condition. Further, due to rising insurance costs and changes in the insurance markets, we cannot make assurances that insurance coverage will continue to be available at all or at rates or on terms similar to those presently available to us. Any losses not covered by insurance could have a material adverse effect on our financial condition, results of operations, or cash flows.

Until the consummation of the sale of our facilities, our revenues and results of operations from the sale of electric power and generation capacity may be adversely impacted by market risks that are beyond our control.

We have not sought FERC approval to sell electric energy and capacity from our generation facilities at cost-based rates. Rather, we sell electric generation capacity and energy on a merchant basis to wholesale purchasers at prices determined by the market. As a result, we are not guaranteed any rate of return on our capital investments through mandated rates, and our revenues and results of operations depend upon current and forward market prices for power. Unlike most other commodities, large quantities of electricity cannot be economically stored and therefore must be produced concurrently with its use. As a result, wholesale power markets are subject to significant price volatility from supply and demand imbalances, especially in the day-ahead and spot markets. Long-term and short-term power prices may also fluctuate substantially due to other factors outside of our control, including:

- oversupply or undersupply of generation capacity;
- changes in power transmission or fuel transportation capacity constraints or inefficiencies;
- electric supply disruptions, including plant outages and transmission disruptions;
- seasonality;
- demand changes due to changes in the macro-economic environment;
- weather conditions;
- availability and market prices for natural gas;
- changes in demand for power or patterns of power usage;
- additional supplies of power from existing competitors or new market entrants as a result of the development of new generation plants, expansion of existing plants, the revitalization of non-operating plants, or additional transmission capacity;
- development of new fuels and new technologies for the production of power;
- availability of competitively priced alternative power sources;
- changes in the relationship between the prices of natural gas and coal;
- natural disasters, wars, embargoes, terrorist attacks, and other catastrophic events;
- regulations and actions of regulatory bodies; and
- federal and state power market and environmental regulation and legislation.

Until the consummation of the sale of our facilities, our business will be subject to substantial governmental regulation and may be adversely affected by liability under, or any future inability to comply with, existing or future regulations or requirements.

Our business is subject to extensive federal, state, and local laws and regulation. Compliance with the requirements under these various regulatory regimes may cause us to incur significant additional costs and failure to comply with such requirements could result in the shutdown of the non-complying facility, the imposition of liens, fines, and/or civil or criminal liability. We are also affected by changes to market rules, tariffs, changes in market structures, changes in administrative fee allocations, and changes in market bidding rules.

Until the consummation of the sale of our facilities, we will be subject to environmental laws and regulations that impose extensive and increasingly stringent requirements and liabilities on our operations that could adversely impact our results of operations, financial condition, and cash flows.

Our business is subject to the environmental laws and regulations of federal, state, and local authorities. We must comply with these laws and regulations and obtain numerous governmental permits and approvals to operate our power projects. If we fail to comply with environmental requirements applicable to our operations, we could be subject to administrative, civil and/or criminal liability and fines, and regulatory agencies could take other actions to limit or curtail our operations. We are also subject to liability for environmental contamination at our operating facilities or third-party locations where our operations have sent wastes. In addition, new environmental requirements that take effect or changes to or reinterpretation of existing environmental requirements or enforcement policies could adversely affect our business, results of operations, financial condition, and cash flows. See "Number 1. *Business—Regulatory Matters—Environmental Regulation*."

Until the consummation of the sale of our facilities, competition in wholesale power markets may have a material adverse effect on our results of operations, cash flows, and the market value of our assets.

We have numerous competitors in all aspects of our business, and additional competitors may enter the industry. Other companies with which we compete may have greater liquidity, access to credit and other financial resources, lower cost structures, more effective risk management policies and procedures, greater ability to incur losses, longer standing relationships with customers, greater potential for profitability from ancillary services, or greater flexibility in the timing of their sale of generation capacity and ancillary services than we do.

Other Risks

We rely extensively on third party service providers for the operation and maintenance of our 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 business results of operations and cash flows.

We currently rely on contractual arrangements with third parties for the operation and maintenance of our Plants and for the marketing of our Plants' output. Our Hinds and Hot Spring plants are operated by NAES, under operating and maintenance agreements. Commencing October 1, 2011, Twin Eagle will provide energy management services. In addition, GEI provides maintenance services to our combined-cycle plants under LTSAs. 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 our third party service providers 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, NAES and Twin Eagle 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 operations and maintenance service provider and a replacement energy management provider are available to KGen. However, we cannot be certain that such replacement providers will deliver their services to us on the same terms as our current providers.

There has been only limited trading in our common stock, so our stockholders may find it difficult to dispose of their investment.

Our common stock is not traded on any established trading market. Although institutional investors do occasionally trade our common stock, this trading activity is limited and may not occur on a regular basis. As such, investors who own or purchase our common stock will find that the liquidity or transferability of the common stock is limited. Accordingly, stockholders may find it difficult to dispose of, or obtain accurate quotations as to the market value, of our common stock.

Number 2. *Properties*

Our corporate headquarters are located in Houston, Texas. As of June 30, 2011, we leased approximately 20,200 square feet of office space of which approximately 6,318 square feet of corporate office space is currently subleased. The commencement date of the sublease was December 17, 2009. Sublease payments began on February 17, 2010.

In addition, we own and lease various real property and facilities relating to our power generation business. We believe we have satisfactory title to our Plants and our facilities in accordance with standards generally accepted in the electric power industry, subject to exceptions that, in our opinion, should not have a material adverse effect on the use or value of our portfolio. Our properties are as follows:

Site Name	Location	Owned/Leased
Corporate Office	Houston, TX	Leased
Hinds	Jackson, MS	Owned
Hot Spring	Malvern, AR	Leased(1)

(1) Generation assets and real property are leased in relation to the Industrial Revenue Bonds mentioned in Note 7 to our audited financial statements. There is a bargain purchase option whereby we can acquire the asset at the end of the lease for a nominal price.

Number 3. *Legal Proceedings*

The Company could be 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.

Part II

Number 4. ***Market for the Company's Common Equity, Related Stockholder Matters and Company Purchases of Equity Securities***

Our common stock shares are not traded on any securities exchange. On June 24, 2011, we paid a partial liquidating distribution to the holders of common stock of the Company in an amount of $5.00 per share, or $281,119,885 in the aggregate, including amounts being reserved in respect of unvested restricted stock units.

Number 5. ***Selected Financial Data***

	Year Ended June 30, 2011	Year Ended June 30, 2010	Year Ended June 30, 2009	Year Ended June 30, 2008	Period December 4, 2006 through June 30, 2007	Predecessor Period July 1, 2006 through February 7, 2007
	(in thousands)	(in thousands)	(in thousands)	(in thousands)	(in thousands)	(in thousands)
Operating Results Data:						
Revenues:						
Energy sales	$170,253	$155,389	$206,674	$ 308,605	$ 87,396	$141,080
Capacity sales	42,594	52,033	54,666	51,416	15,737	34,501
Total revenues	212,847	207,422	261,340	360,021	103,133	175,581
Operating expenses:						
Cost of fuel	143,326	131,898	174,392	268,978	78,127	115,076
Operating and maintenance	32,972	39,636	40,733	52,065	9,722	11,549
Gas transportation	15,519	16,569	16,438	16,382	6,279	9,674
Selling, general, and administrative	13,258	11,689	15,422	29,418	11,777	10,436
Acquisition contract termination loss	—	—	—	37,190	—	—
Depreciation	15,534	23,978	24,272	24,068	9,164	7,614
Auxiliary power	7,240	8,532	8,784	8,437	2,649	4,187
Insurance	2,417	3,466	3,605	3,177	1,531	2,039
Total operating expenses	230,266	235,768	283,646	439,715	119,249	160,575
Operating (loss) profit	(17,419)	(28,346)	(22,306)	(79,694)	(16,116)	15,006
Other income (expenses):						
Interest expense	(9,782)	(12,226)	(11,770)	(16,513)	(7,153)	(30,231)
Gain on sale of assets	240,517	—	—	—	—	110,109
Taxes, other than income taxes	(4,511)	(4,134)	(4,355)	(3,457)	(1,161)	(3,106)
Interest income	—	—	147	2,796	879	3,834
Other	(375)	(230)	(7,206)	(7,065)	912	(3,536)
Total other income (expenses)	225,849	(16,590)	(23,184)	(24,239)	(6,523)	77,070
Net income (loss) before income taxes	208,430	(44,936)	(45,490)	(103,933)	(22,639)	92,076
Income tax (expense) benefit	(830)	—	—	—	3,602	—
Net income (loss) after income taxes	$207,600	$(44,936)	$(45,490)	$(103,933)	$(19,037)	$ 92,076
Net loss per share—basic and diluted(1)	$ 3.70	$ (0.80)	$ (0.81)	$ (1.86)	$ (0.39)	N/A
Weighted average shares outstanding—basic(1)	56,027	55,969	55,968	55,949	48,603	N/A
Weighted average shares outstanding—diluted(1)	56,118	55,969	55,968	55,949	48,603	N/A
Balance Sheet Data:						
Total property, plant, and equipment, net	$ 990	$563,525	$648,210	$ 671,114	$693,295	$336,935
Total assets	480,823	772,254	818,463	870,722	948,767	560,211
Total current liabilities	22,750	23,767	21,078	39,457	20,589	12,492
Long-term debt	—	201,000	203,000	195,000	197,000	409,327
Stockholders'/Member's equity	$458,060	$529,641	$573,702	$ 615,805	$711,741	$119,695

(1) KGen Power Corporation was formed December 4, 2006. Its predecessor was a partnership; therefore there is no common stock issuance to account for in the predecessor periods.

Number 6. *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 the results of operations together with our present financial condition. This section should be read in conjunction with our Consolidated Financial Statements and the accompanying notes included in this Annual Report for the fiscal year ended June 30, 2011. 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, 2011 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 two operational and fully permitted combined-cycle power plants (Hot Spring and Hinds), located in the southeastern United States with General Electric (GE) 7FA gas turbines. Our combined-cycle Plants have an aggregate nominal capacity of 1,140 MW. On July 9, 2010, we completed the sale of our Sandersville power plant, a 640 MW simple-cycle plant, for which we received $129.3 million in cash sales proceeds. On April 8, 2011, we completed the sale of our Murray I and Murray II combined-cycle power plants having an aggregate nominal capacity of 1,250 MW, for which we received $530.3 million in cash sales proceeds. On April 28, 2011, we executed separate definitive sales agreements for the sale of our Hinds and Hot Spring combined-cycle power plants having an aggregate nominal capacity of 1,140 MW.

Our two Plants currently operate, and historically the Sandersville and Murray II power plants operated, as merchant power providers. Our Murray I combined-cycle plant, benefited 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 provided for fixed capacity payments that provided stable cash flow. The Company recognized $37.6 million and $50.1 million related to capacity sales on the GPC PPA for the year ended June 30, 2011 and 2010, related to capacity sales on the GPC PPA, respectively.

Recent Events

Hinds Asset Purchase Agreement—On April 28, 2011, the Company executed a definitive agreement for the sale of the Company's Hinds power generation facility to Entergy Mississippi, Inc. for a cash purchase price of $206.0 million, subject to certain adjustments. The Company received approval from a majority of the Company's shareholders for the sale of this facility. The transaction is conditioned on the satisfaction of various regulatory approvals and other conditions described in our 2011 Special Meeting Proxy Statement. One of these conditions is that Entergy is to receive a study for network transmission service for the Hinds facility that does not reflect aggregate costs in excess of $10.0 million for the supplemental upgrades required to provide network transmission service for the Hinds facility. In June 2011, Entergy received a study that reflected costs in excess of $10.0 million; however, Entergy continues to examine issues associated with such costs. The transaction is conditioned upon the receipt of various regulatory approvals and clearances including approval of the FERC, clearance under the Hart-Scott-Rodino Antitrust Improvements Act of 1976, or the HSR Act, and approval of the Mississippi Public Service Commission. On July 15, 2011, Entergy filed an application to approve the transaction with the Mississippi Public Service Commission. On July 27, 2011, the Company and Entergy filed notification and report forms under the HSR Act with the U.S. Federal Trade Commission, or the FTC, and the Antitrust Division of the U.S. Department of Justice, or the DOJ, with respect to the sale of the Hinds facility. On

August 26, 2011, the DOJ issued to the Company and Entergy a Request for Additional Information and Documentary Material prior to the expiration of the waiting period. After the parties have substantially complied with the request for information, the parties must observe a 30 calendar day waiting period before closing is permitted, unless the waiting period is terminated earlier or extended with the consent of the parties. On August 31, 2011, the parties filed a joint application with FERC seeking authorizations pursuant to Section 203 of the Federal Power Act. We continue to expect that the Hinds transaction will close in the middle of calendar 2012, but may close before or after such time. Under the terms of the transaction agreement, $30.0 million of the purchase price will be held in escrow to secure customary post-closing indemnification obligations. An escrow amount of $10.0 million is subject to release 12 months after closing, an additional $10.0 million is subject to release 18 months after closing, and the remaining balance will be subject to release 42 months after closing.

Hot Spring Asset Purchase Agreement—On April 28, 2011, the Company executed a definitive agreement for the sale of the Company's Hot Spring power generation facility to Entergy Arkansas, Inc. for a cash purchase price of $253.0 million, subject to certain adjustments. The Company received approval from a majority of the Company's shareholders for the sale of this facility. The transaction is conditioned on the satisfaction of various regulatory approvals and other conditions described in our 2011 Special Meeting Proxy Statement. One of these conditions is that Entergy is to receive a study for network transmission service for the Hot Spring facility that does not reflect aggregate costs in excess of $40.0 million for the supplemental upgrades required to provide network transmission service for the Hot Spring facility. In June 2011, Entergy received a study that reflected costs in excess of $40.0 million; however, Entergy continues to examine issues associated with such costs. The transaction is conditioned upon the receipt of various regulatory approvals and clearances including approval of the FERC, clearance under the HSR Act, and approval of the Arkansas Public Service Commission. On July 15, 2011, Entergy filed an application to approve the transaction with the Arkansas Public Service Commission. On July 27, 2011, the Company and Entergy filed notification and report forms under the HSR Act with the FTC and the DOJ, with respect to the sale of the Hot Spring facility. On August 26, 2011, the DOJ issued to the Company and Entergy a Request for Additional Information and Documentary Material prior to the expiration of the waiting period. After the parties have substantially complied with the request for information, the parties must observe a 30 calendar day waiting period before closing is permitted, unless the waiting period is terminated earlier or extended with the consent of the parties. On August 31, 2011, the parties filed a joint application with FERC seeking authorizations pursuant to Section 203 of the Federal Power Act. We continue to expect that the Hot Spring transaction will close in the middle of calendar 2012, but may close before or after such time. Under the terms of the transaction agreement, $38.0 million of the purchase price will be held in escrow to secure customary post-closing indemnification obligations. An escrow amount of $12.0 million is subject to release 12 months after closing, an additional $13.8 million is subject to release 18 months after closing, and the remaining balance will be subject to release 42 months after closing.

Murray Purchase & Sale Agreement—On January 31, 2011, we executed a definitive agreement for the sale of our Murray I and II electric generation facilities to Oglethorpe Power Corporation, or OPC. The transaction was implemented by means of a sale of 100% of the ownership interests in KGen Murray I and II LLC, the entity that owns the Murray facilities on April 8, 2011. We received cash consideration of $530.3 million inclusive of working capital and inventory adjustments. These facilities, located in Murray County, Georgia, are comprised of two natural gas-fired combined cycle power generation plants with a combined nominal capacity of 1,250 MW. We used tax net operating losses, or NOLs, to offset all but approximately $36.1 million of the taxable gain resulting from the sale. In connection with the closing of the transaction, our credit, working capital, and synthetic letter of credit facilities were terminated and the related interest rate swaps were unwound. The Company used $138.0 million of the net proceeds of the sale to repay outstanding debt under these facilities and satisfy related obligations. In connection with the termination of these facilities, the restricted cash and cash equivalents associated with these facilities was released. The Company transferred the Industrial Revenue Bonds associated with Murray I and II to OPC.

Additionally, all contractual commitments associated with Murray I and II were transferred in connection with the sale. Restricted stock units of 106,769 vested upon the consummation of the sale of Murray I and II power generation facilities. Under the terms of the transaction agreement, $79.7 million of the purchase price was placed in escrow for a period of 18 months after closing to secure customary post-closing indemnification obligations. The Board of Directors made a distribution of $5.00 per share to shareholders out of the net proceeds of the sale of KGen Murray I and II LLC.

Results of Operations

Our results of operations are subject to seasonal variations since demand for electricity and 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. The discussion below includes the results from our Sandersville plant, which we sold on July 9, 2010. For the year ended June 30, 2011, KGen Sandersville LLC's adjusted EBITDA, a non-GAAP financial measure, was a loss of $49.0 thousand. The discussion below also includes the results from our Murray I and II plants, which we sold on April 8, 2011. For the year ended June 30, 2011, KGen Murray I and II LLC's adjusted EBITDA, a non-GAAP financial measure, was income of $25.9 million. Accordingly, these results may not be indicative of future results of the Company.

Consolidated Results of Operations of KGen for the Year Ended June 30, 2011 compared to the Year Ended June 30, 2010.

The following table sets forth our results of operations for the years ended June 30, 2011 and 2010, expressed in thousands of dollars.

	For the Year Ended June 30, 2011	For the Year Ended June 30, 2010	Favorable/ (Unfavorable) Change	% Change
Revenues:				
Energy sales	$170,253	$155,389	$ 14,864	10%
Capacity sales	42,594	52,033	(9,439)	(18)%
Total revenues	212,847	207,422	5,425	3%
Operating expenses:				
Cost of fuel	143,326	131,898	(11,428)	(9)%
Operating and maintenance	32,972	39,636	6,664	17%
Gas transportation	15,519	16,569	1,050	6%
Selling, general, and administrative	13,258	11,689	(1,569)	(13)%
Depreciation	15,534	23,978	8,444	35%
Auxiliary power	7,240	8,532	1,292	15%
Insurance	2,417	3,466	1,049	30%
Total operating expenses	230,266	235,768	5,502	2%
Operating loss	(17,419)	(28,346)	10,927	39%
Other income (expenses):				
Net gain on sale of assets	240,517	—	240,517	100%
Interest expense	(9,782)	(12,226)	2,444	20%
Taxes, other than income taxes	(4,511)	(4,134)	(377)	(9)%
Other	(375)	(230)	(145)	(63)%
Total other income (expenses)	225,849	(16,590)	1,922	12%
Net income (loss) before taxes	$208,430	$(44,936)	$253,366	564%

GAAP to Non-GAAP Consolidated Results of Operations Reconciliation

	For the Year Ended June 30, 2011			For the Year Ended June 30, 2010		
	Continuing Operations	Discontinued Operations	Results of Operations	Continuing Operations	Discontinued Operations	Results of Operations
Revenues:						
Energy sales	$ 97,422	$ 72,831	**$170,253**	$ 66,263	$ 89,126	$155,389
Capacity sales	4,999	37,595	**42,594**	1,932	50,101	52,033
Total revenues	102,421	110,426	**212,847**	68,195	139,227	207,422
Operating expenses:						
Cost of fuel	80,843	62,483	**143,326**	55,403	76,495	131,898
Operating and maintenance	19,478	13,494	**32,972**	28,369	11,267	39,636
Gas transportation	5,926	9,593	**15,519**	3,333	13,236	16,569
Selling, general, and administrative	12,322	936	**13,258**	10,613	1,076	11,689
Depreciation	8,629	6,905	**15,534**	10,242	13,736	23,978
Auxiliary power	2,953	4,287	**7,240**	2,696	5,836	8,532
Insurance	1,575	842	**2,417**	1,791	1,675	3,466
Total operating expenses	131,726	98,540	**230,266**	112,447	123,321	235,768
Operating (loss) income	(29,305)	11,886	**(17,419)**	(44,252)	15,906	(28,346)
Other (expenses) income:						
Net gain on sale of assets	—	240,517	**240,517**	—	—	—
Interest expense	(9,782)	—	**(9,782)**	(12,226)	—	(12,226)
Taxes, other than income taxes	(3,813)	(698)	**(4,511)**	(2,101)	(2,033)	(4,134)
Other	(375)	—	**(375)**	(230)	—	(230)
Total other (expenses) income	(13,970)	239,819	**225,849**	(14,557)	(2,033)	(16,590)
Net (loss) income before taxes	$(43,275)	$251,705	**$208,430**	$(58,809)	$ 13,873	$(44,936)

Operating and Business Metrics We Use to Analyze the Company's Performance for the Years Ended June 30, 2011 and June 30, 2010

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 years ended June 30, 2011 and 2010, to the most directly comparable GAAP measures for those periods. See the reconciliation of net income to adjusted EBITDA on page 29. The results reflected and discussed below include both those from continuing operations and discontinued operations (the Murray and Sandersville facilities which were sold). In order to provide additional analysis on our continuing operations, we have presented those separate metrics on page 31. 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 consider our Hinds and Hot Spring plants, and considered our former Murray II and Sandersville plants to be merchant plants because they did not sell their energy output and capacity pursuant to long-term sales agreements during these reporting periods.

	For the Year Ended June 30, 2011	For the Year Ended June 30, 2010
Energy sales	$ 170,253	$ 155,389
Less: Cost of fuel	(143,326)	(131,898)
Less: Contracted energy sales	(34,929)	(36,802)
Add: Contracted cost of fuel	35,558	37,387
Merchant energy margin	27,556	24,076
Capacity sales	42,594	52,033
Less: Contracted capacity sales	(37,595)	(50,101)
Merchant capacity sales	$ 4,999	$ 1,932
Merchant margin	$ 32,555	$ 26,008

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 considered Murray I to be contracted, because it sold its energy output and capacity pursuant to the long-term GPC PPA.

	For the Year Ended June 30, 2011	For the Year Ended June 30, 2010
Energy sales	$ 170,253	$ 155,389
Less: Merchant sales	(135,324)	(118,587)
Contracted energy sales	34,929	36,802
Less: Contracted cost of fuel	(35,558)	(37,387)
Add: Power sales rights and obligations amortization	4,732	8,112
Adjusted contracted energy margin	4,103	7,527
Contracted capacity sales	37,595	50,101
Add: Noncash deferred capacity revenue	673	194
Adjusted contracted capacity sales	$ 38,268	$ 50,295
Adjusted contracted margin	$ 42,371	$ 57,822

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

	For the Year Ended June 30, 2011	For the Year Ended June 30, 2010
Merchant margin	$32,555	$26,008
Adjusted contracted margin	42,371	57,822
Total adjusted margin	$74,926	$83,830

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 and transition costs, (f) depreciation, (g) director and officer insurance expense captured in adjusted corporate expenses (defined below); and (h) the addition of taxes, other than income taxes, as it largely represents plant property taxes and payments in lieu of taxes.

	For the Year Ended June 30, 2011	For the Year Ended June 30, 2010
Total operating expenses	$ 230,266	$ 235,768
Less: Cost of fuel	(143,326)	(131,898)
Less: Major maintenance expense	(5,311)	(15,175)
Less: Gas transportation noncash amortization	(434)	(1,109)
Less: Selling, general, and administrative expense	(13,258)	(11,666)
Less: Termination and transition costs	—	(684)
Less: Depreciation	(15,534)	(23,978)
Less: D&O insurance expense	(168)	(179)
Add: Taxes, other than income taxes	4,511	4,134
Adjusted plant expenses	$ 56,746	$ 55,213

Adjusted corporate expenses is defined as selling, general, and administrative expense adjusted for (a) the removal of noncash stock compensation expense and reorganization items such as employee severance, (b) any nonrecurring items such as expenses associated with plant sales and (c) the addition of director and officer insurance expense.

	For the Year Ended June 30, 2011	For the Year Ended June 30, 2010
Selling, general, and administrative expense	$13,258	$11,666
Less: Noncash employee options/awards expense	(1,601)	(875)
Add (Less): Employee severance expenses	6	(1)
Less: Sale of plant expense	(1,618)	(788)
Add: D&O insurance expense	168	179
Adjusted corporate expenses	$10,213	$10,181

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 Year Ended June 30, 2011	For the Year Ended June 30, 2010	Favorable/ (Unfavorable)	
			Change	% Change
Merchant energy margin	$27,556	$24,076	$ 3,480	14%
Merchant capacity sales	4,999	1,932	3,067	159%
Merchant margin	32,555	26,008	6,547	25%
Adjusted contracted energy margin	4,103	7,527	(3,424)	(45)%
Adjusted contracted capacity sales	38,268	50,295	(12,027)	(24)%
Adjusted contracted margin	42,371	57,822	(15,451)	(27)%
Total adjusted margin	74,926	83,830	(8,904)	(11)%
Adjusted plant expenses	56,746	55,213	(1,533)	(3)%
Adjusted plant EBITDA	18,180	28,617	(10,437)	(36)%
Adjusted corporate expenses	10,213	10,181	(32)	(0)%
Adjusted EBITDA	$ 7,967	$18,436	$(10,469)	(57)%

Selected Operating and Business Metrics

	Year Ended June 30, 2011	Year Ended June 30, 2010	Favorable/ (Unfavorable)	
			Change	% Change
Selected Financial and Operating Data				
Total generation (GWh)	4,213	4,133	80	2%
Merchant generation (GWh)	3,229	3,124	105	3%
Merchant margin/merchant generation ($/MWh)	$10.08	$ 8.33	$1.75	21%

Selected Market and Weather Data

	For the Year Ended June 30, 2011	For the Year Ended June 30, 2010	Change	% Change
Selected Market Data(1)				
Average on-peak market power price—Entergy ($/MWh)	$37.66	$35.57	$ 2.09	6%
Average on-peak market power price—Southern ($/MWh)	$40.95	$37.88	$ 3.07	8%
Average Henry Hub gas price ($/MMbtu)	$ 4.15	$ 4.21	$(0.06)	(1)%
Selected Weather Data				
Actual CDDs(2)	7,500	6,348	1,152	18%
Normal CDDs	5,282	5,283	(1)	(0)%
Actual HDDs(3)	7,939	8,927	(988)	(11)%
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 during April through October that the mean temperature for a particular day is above 65 degrees Fahrenheit. The CDDs are then accumulated for a given period.

(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.

Historical Results of Operations of KGen for the Year Ended June 30, 2011 compared to the Year Ended June 30, 2010.

Total adjusted margin decreased $8.9 million, or 11%, to $74.9 million for the year ended June 30, 2011 compared to the same period in the previous year as a result of a $6.5 million increase in merchant margin offset by a $15.4 million decrease in adjusted contracted margin. The $74.9 million in total adjusted margin was comprised of $32.5 million in merchant margin and $42.4 million in adjusted contracted margin.

Merchant margin increased $6.5 million, or 25%, to $32.5 million for the year ended June 30, 2011, which was comprised of $27.5 million in merchant energy margin and $5.0 million in merchant capacity sales. The $6.5 million increase was made up of a $3.5 million increase in merchant energy margin and a $3.0 million increase in merchant capacity sales. The $3.5 million increase in merchant energy margin related primarily to warmer weather as evidenced by an 18% increase in CDDs. Merchant generation increased by 3% from 3,124 GWh to 3,229 GWh for the year ended June 30, 2011 as compared to the previous year. The implied merchant spark spread, or merchant margin divided by merchant generation, increased from $8.33 per MWh to $10.08 per MWh, largely due to the increase in merchant capacity sales and warmer weather. Merchant margin was also impacted by operational issues associated with the Hot Spring facility. See additional discussion in the Adjusted Plant EBITDA for Continuing Operations section on page 31.

Adjusted contracted margin decreased $15.5 million, or 27%, to $42.4 million for the year ended June 30, 2011, which was comprised of $4.1 million in adjusted contracted energy margin and $38.3 million in adjusted contracted capacity sales. The $15.5 million decrease was made up of a $3.5 million decrease in the adjusted contracted energy margin and a $12.0 million decrease in the adjusted contracted capacity sales. The $12.0 million decrease in adjusted contracted capacity sales was primarily a result of the sale of the Murray power generation facility in April 2011. During November and December 2010, an extended outage occurred at our Murray power generation facility to repair the high pressure piping at Murray I and II, the Murray II steam turbine generator rotor, and other related items resulting in costs of approximately $2.7 million. During the outage, we provided replacement power at a cost of approximately $1.5 million from other sources to Georgia Power in accordance with the GPC PPA. The cost of the replacement power negatively impacted our adjusted contracted capacity sales by $0.5 million and our adjusted contracted energy margin by $1.0 million.

Adjusted plant expenses increased by $1.5 million, or 3%, to $56.7 million for the year ended June 30, 2011. The increase related primarily to a $3.8 million increase in operating and maintenance expenses caused primarily by repairs at Hot Spring. See additional discussion in the Adjusted Plant EBITDA for Continuing Operations section on page 31. This was offset by a $0.6 million decrease in gas transportation, a $0.6 million decrease in insurance expense, and a $1.4 million decrease in auxiliary power, all primarily related to the sale of the Murray power generation facility in April 2011.

As a result of the foregoing changes in total adjusted margin and adjusted plant expenses, adjusted plant EBITDA decreased by $10.4 million to $18.2 million for the year ended June 30, 2011.

Adjusted corporate expenses increased by $32.0 thousand, or 0%, to $10.2 million for the year ended June 30, 2011.

As a result of the foregoing, adjusted EBITDA decreased by $10.5 million to $8.0 million for the year ended June 30, 2011.

GAAP to Non-GAAP Adjusted EBITDA Reconciliation for Consolidated Results of Operations

Following is an alternative calculation of adjusted EBITDA and adjusted plant EBITDA starting from net loss after taxes. EBITDA is equal to net income (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 nonrecurring expenses). Adjusted plant EBITDA is equal to total adjusted EBITDA less certain corporate expenses.

	For the Year Ended June 30, 2011	For the Year Ended June 30, 2010
Net income (loss) before taxes	$ 208,430	$(44,936)
Add: Interest expense	9,782	12,226
Add: Depreciation	15,534	23,978
Add: Power sales rights and obligations amortization	4,732	8,112
Add: Gas transportation noncash amortization	434	1,109
Add: Noncash deferred capacity revenue	673	194
Add: Other expense	375	230
EBITDA	239,960	913
Less: Net gain on sale of assets	(240,517)	—
Add: Major maintenance expense	5,311	15,175
Add: Termination and transition costs	—	684
Add: Noncash employee options/awards expense	1,601	875
Add (Less): Employee severance expense	(6)	1
Add: Sale of plant expense	1,618	788
Adjusted EBITDA	7,967	18,436
Add: Selling, general, and administrative expense	13,258	11,666
Less: Noncash employee options/awards expense	(1,601)	(875)
Add (Less): Employee severance expense	6	(1)
Less: Sale of plant expense	(1,618)	(788)
Add: D&O insurance expense	168	179
Adjusted plant EBITDA	$ 18,180	$ 28,617

The following describes changes to specified financial measures of our performance. As indicated above, in calculating our adjusted EBITDA, we made adjustments to our net income after taxes using these financial measures for the year ended June 30, 2011 compared to the year ended June 30, 2010.

- Interest expense for the year ended June 30, 2011 was $9.8 million compared to $12.2 million for the same period in 2010. The $2.4 million decrease was mainly due to the April 2011 repayment of all of the outstanding debt under the Credit Facility and the termination of the related Swaps, in connection with the sale of the Murray power generation facility.

- Depreciation was $15.5 million and $24.0 million for years ended June 30, 2011 and 2010, respectively. The $8.5 million decrease was due to the suspension of depreciation related to the Sandersville, Murray, Hinds, and Hot Spring plants in the amounts of $2.0 million, $4.8 million, $0.5 million, and $1.1 million, respectively.

- Amortization of contract-based power sales rights and obligations was $4.7 million and $8.1 million for the years ended June 30, 2011 and 2010, respectively, and was recorded as a reduction of energy sales. The $3.4 million decrease was due to suspension of amortization on the Murray intangibles due to its January 2011 held for sale status.

- Amortization of contract-based natural gas transportation rights and obligations was $0.4 million and $1.1 million for years ended June 30, 2011 and 2010, respectively, and was recorded as an increase of gas transportation expense. The $0.7 million decrease was due to suspension of amortization on the Murray and Hot Spring intangibles due to their held for sale status in January 2011 and April 2011, respectively.

- Noncash deferred capacity revenue, which represents the levelization of capacity sales over the GPC PPA term, of $0.7 million and $0.2 million for the years ended June 30, 2011 and 2010, respectively, was recorded as capacity sales.
- Other expense was $0.4 million and $0.2 million for the years ended June 30, 2011 and 2010, respectively.
- Net gain on sale of assets was $240.5 million and zero for the years ended June 30, 2011 and 2010, respectively. Of this amount, $65.0 million of the net gain on sale of assets is related to the sale of the Sandersville facility on July 9, 2010 and $175.5 million is related to the sale of the Murray facility on April 8, 2011.
- Major maintenance expense for the years ended June 30, 2011 and 2010 was $5.3 million and $15.2 million, respectively. The $5.3 million expense primarily related to $2.4 million of major maintenance at the Hot Spring plant, a $1.7 million payment to GE as a result of restructuring the long-term service agreements with GE, $0.9 million of major maintenance performed at the Murray facility, and $0.4 million performed at the Hinds facility. The $15.2 million expense primarily related to $15.8 million in connection with the spring 2010 hot gas path inspection and $0.4 million in other major maintenance performed at the Hinds plant, offset by $1.0 million of income related to a credit from GE for repair work at Murray I.
- Noncash employee options/awards expense for the years ended June 30, 2011 and 2010 was $1.6 million and $0.9 million, respectively, and was recorded as an increase of selling, general, and administrative expense.
- Sale of plant expenses for the years ended June 30, 2011 and 2010 were $1.6 million and $0.8 million, respectively, and were recorded as an increase of selling, general, and administrative expense.
- Selling, general, and administrative expense was $13.3 million and $11.7 million for the years ended June 30, 2011 and 2010, respectively. The $1.6 million increase was primarily related to a $0.9 million of increased legal expenses related to our sales transactions and $0.7 million increase in noncash employee options/awards expenses.

Adjusted Plant EBITDA for Continuing Operations: (includes only our Hinds and Hot Spring Facilities)

	For the Year Ended June 30, 2011	For the Year Ended June 30, 2010	Favorable/ (Unfavorable) Change	Favorable/ (Unfavorable) % Change
Merchant energy margin	$16,579	$10,860	$ 5,719	53%
Merchant capacity sales	4,999	1,932	3,067	159%
Merchant margin	21,578	12,792	8,786	69%
Adjusted contracted energy margin	—	—	—	0%
Adjusted contracted capacity sales	—	—	—	0%
Adjusted contracted margin	—	—	—	0%
Total adjusted margin	21,578	12,792	8,786	69%
Adjusted plant expenses	29,519	22,090	(7,429)	(34)%
Adjusted plant EBITDA	$(7,941)	$(9,298)	$ 1,357	15%

Selected Operating and Business Metrics for Continuing Operations

	For the Year Ended June 30, 2011	For the Year Ended June 30, 2010	Favorable/ (Unfavorable) Change	% Change
Selected Financial and Operating Data				
Total generation (GWh)	2,493	1,863	630	34%
Merchant generation (GWh)	2,493	1,863	630	34%
Merchant margin/merchant generation ($/MWh)	$ 8.66	$ 6.87	$1.79	26%

Selected Market and Weather Data for Continuing Operations

	For the Year Ended June 30, 2011	For the Year Ended June 30, 2010	Change	% Change
Selected Market Data(1)				
Average on-peak market power price—Entergy ($/MWh)	$37.66	$35.57	$ 2.09	6%
Average Henry Hub gas price ($/MMbtu)	$ 4.15	$ 4.21	$(0.06)	(1)%
Selected Weather Data				
Actual CDDs(2)	5,194	4,427	767	17%
Normal CDDs	3,799	3,798	1	0%
Actual HDDs(3)	4,958	5,668	(710)	(13)%
Normal HDDs	4,950	4,950	—	0%

Notes:

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

(2) CDD, or cooling degree days, represents the number of degrees during April through October that the mean temperature for a particular day is above 65 degrees Fahrenheit. The CDDs are then accumulated for a given period.

(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.

Historical Results of Continuing Operations of KGen for the Year Ended June 30, 2011 compared to the Year Ended June 30, 2010.

Total adjusted margin for continuing operations increased $8.8 million, or 69%, to $21.6 million for the year ended June 30, 2011 compared to the same period in the previous year as a result of an $8.8 million increase in merchant margin. The $21.6 million in total adjusted margin was comprised of $21.6 million in merchant margin and zero in adjusted contracted margin, as these results represent the continuing operations of our Hinds and Hot Spring merchant power generation facilities.

Merchant margin increased $8.8 million, or 69%, to $21.6 million for the year ended June 30, 2011, which was comprised of $16.6 million in merchant energy margin and $5.0 million in merchant capacity sales. The $8.8 million increase was made up of a $5.7 million increase in merchant energy margin and a $3.1 million increase in merchant capacity sales. The $5.7 million increase in merchant energy margin related primarily to warmer weather as evidenced by a 17% increase in CDDs. Merchant generation increased by 34% from 1,863 GWh to 2,493 GWh for the year ended June 30, 2011 as compared to the previous year. The implied merchant spark spread, or merchant margin divided by merchant generation, increased from $6.87 per MWh to $8.66 per MWh, largely due to the increase in merchant capacity sales and warmer weather. Merchant margin for the year ended June 30, 2011 was also impacted by operational issues associated with the Hot Spring facility's inlet chiller system. These issues were repaired at the facility's spring 2011 outage and an insurance claim was filed in connection therewith.

Adjusted contracted margin was zero as these results represent the continuing operations of our Hinds and Hot Spring merchant power generation facilities.

Adjusted plant expenses increased by $7.4 million, or 34%, to $29.5 million for the year ended June 30, 2011. The increase related primarily to a $3.8 million increase in operating and maintenance expenses caused primarily by repairs to the inlet chiller system and one of the gas turbine compressors at Hot Spring, for which an insurance claim was filed in connection therewith, a $2.3 million increase in gas transportation associated with enhanced firm transportation purchased from Centerpoint, and $1.6 million in increased property taxes at Hinds due to the expiration of the payments in lieu of taxes agreement.

As a result of the foregoing changes in total adjusted margin and adjusted plant expenses, adjusted plant EBITDA from continuing operations increased by $1.4 million to $7.9 million loss for the year ended June 30, 2011.

Liquidity and Capital Resources

Liquidity Position

Our current cash on hand consists of $89.4 million of unrestricted cash, $43.4 million of restricted cash, and short-term investments of $4.0 million. We anticipate that our cash on hand and cash flow provided by operations will satisfy our short term liquidity needs with respect to our current portfolio of assets. Historically, our principal sources of funds were cash flows from operations and borrowings under our Credit Facility. Our principal use of funds consisted of operating expenditures and capital expenditures.

In addition, in connection with the sale of the Murray I and II combined-cycle power generation facilities, $79.7 million was placed in escrow for a period of 18 months after closing to secure customary post-closing indemnification obligations. This escrow balance was recorded in restricted cash in escrow.

Subsequent to the repayment of all outstanding debt under the Credit Agreement, a $75.0 million cash collateralized replacement letter of credit facility was entered into on April 8, 2011 of which $43.4 million of letters of credit have been issued. The $43.4 million of cash collateral supporting this letter of credit facility was recorded in restricted cash and cash equivalents. The letters of credit issued under this facility support obligations associated with ongoing long-term gas transportation contracts at the Hinds and Hot Spring facilities. Fees related to this letter of credit facility were $0.1 million and were expensed as incurred.

Contractual Obligations

Our contractual obligations consist primarily of obligations under firm gas transportation agreements, minimum LTSA payments, and leasehold payments. We intend to fund our contractual obligations through our internally generated cash flows from operations and asset sales. We believe that our sources of liquidity will be sufficient to meet our contractual obligations.

The following table sets forth our contractual obligations as of June 30, 2011 (in thousands of dollars):

	Total	Less than 1 year	1 - 3 years	3 - 5 years	More than 5 years
Pipeline payments	$174,832	$10,450	$31,351	$31,351	$101,680
LTSA	30,606	1,067	3,398	3,713	22,428
Other(1)	3,941	743	1,813	1,385	—
Total	$209,379	$12,260	$36,562	$36,449	$124,108

(1) Minimum lease rental payments have not been reduced by minimum sublease rentals of $1.2 million due in the future under noncancelable subleases.

Capital Expenditures and Major Maintenance

Total capital expenditures for the years ended June 30, 2011 and 2010 were $3.0 and $2.2 million, respectively. We expect to incur approximately $7.0 million in capital expenditures during fiscal 2012, primarily to implement a drainage/soils master plan for the Hinds facility, which is required by the asset purchase agreement with Entergy Mississippi, Inc.

Major maintenance expense was $5.3 million and $15.2 million for the years ended June 30, 2011 and 2010, respectively. The $5.3 million expense primarily related to $2.4 million of major maintenance at the Hot Spring plant, a $1.7 million payment to GE as a result of restructuring the long-term service agreements with GE, $0.9 million of major maintenance performed at the Murray facility and $0.4 million performed at the Hinds facility. The $15.2 million expense for the year ended June 30, 2010 primarily related to $15.8 million in connection with the spring 2010 hot gas path inspection and $0.4 million in other major maintenance expenses 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 timing of major maintenance expenditures is uncertain and can be delayed or accelerated depending on many factors including plant utilization, unexpected plant shut-downs for other reasons, and unanticipated dispatch schedules. We budget anticipated major maintenance costs by using our estimate of future anticipated run time at each facility. This schedule can change based upon changes to actual run time.

We incur costs for major maintenance on the Plants which are expensed in the period incurred. We expect to incur $1.0 million in major maintenance expenses in fiscal 2012.

Cash Flow Analysis

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

	For the Year Ended June 30, 2011	For the Year Ended June 30, 2010
Statements of Cash Flows Data:		
Cash flows provided by (used in):		
Operating activities	$ (4,555)	$(14,980)
Investing activities	529,432	24,494
Financing activities	(483,612)	(2,000)
Increase in cash and cash equivalents	41,265	7,514
Cash and cash equivalents at beginning of period	48,177	40,663
Cash and cash equivalents at end of period	$ 89,442	$ 48,177

Cash Flows from Operating Activities. Our cash flows used in operations were $4.6 million for the year ended June 30, 2011, primarily related to a net income of $207.6 million, depreciation expense of $15.5 million, amortization expense of $8.4 million, valuation of derivative instruments of $1.7 million, stock-based compensation of $1.4 million, an increase in accounts receivable of $16.8 million, and an increase in deferred charge of $0.7 million, which was offset primarily by a net gain on sale of assets of $240.5 million, payments from settlement of derivative instruments of $8.1 million, a $0.1 million decrease in spare parts inventories, a decrease in prepaid expenses and other current assets of $4.8 million, a decrease in other noncurrent assets of $0.7 million, and a decrease in accounts payable and accrued liabilities of $2.5 million. We also incurred $4.8 million of cash interest during the period under our previously outstanding Credit Facility.

Cash Flows from Investing Activities. Our cash flows provided by investing activities for the year ended June 30, 2011 were $529.4 million and related to a sale of assets of $651.6 million, offset by purchases of $4.0 million in short-term investments, $2.2 million in purchases of property, plant, and equipment, $36.2 million in investments of restricted cash and cash equivalents, and $79.7 million in investments in restricted cash in escrow.

Cash Flows from Financing Activities. Our cash flows used in financing activities for the year ended June 30, 2011 were $483.6 million and represented the repayment of debt of $203.0 million and the distribution to stockholders of $280.6 million.

Off-Balance Sheet Arrangements

The Company did not participate in or have any off-balance sheet arrangements for the years ended June 30, 2011 and 2010, respectively.

Discussion of Critical Accounting Policies

In preparing our consolidated financial statements in accordance with accounting principles generally accepted in the United States, KGen is required to use its judgment in making estimates and assumptions that affect the amounts reported in its financial statements and related notes. Management bases its estimates on historical experience and on various other assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making judgments about the carrying value of assets and liabilities that are not readily apparent from other sources. Many of our critical accounting policies are those subject to significant judgments and uncertainties which could potentially result in materially different results under different conditions and assumptions. Future events rarely develop exactly as forecast, and the best estimates routinely require adjustment.

Submission of Matters to a Vote of Security Holders

On June 13, 2011, we held a special meeting of shareholders. At the meeting, the following proposals were voted upon and approved:

Other Matters

	For	Against	Abstain	Broker Non-Votes
Approval of the sale of our 520 megawatt combined-cycle power generation facility located in Hinds County, Mississippi and other assets of our subsidiary KGen Hinds LLC to Entergy Mississippi, Inc.	47,233,986	—	46,338	—
Approval of the sale of our 620 megawatt combined-cycle power generation facility located in Hot Spring County, Arkansas and other assets of our subsidiary KGen Hot Spring LLC to Entergy Arkansas, Inc.	47,233,986	—	46,338	—

Number 7. ***Financial Statements and Supplementary Data***

KGen Power Corporation

Consolidated Financial Statements

For the Years Ended June 30, 2011 and 2010

Contents

INDEPENDENT AUDITORS' REPORT

To the Board of Directors and Stockholders of
KGen Power Corporation
Houston, Texas

We have audited the accompanying consolidated balance sheets of KGen Power Corporation and subsidiaries (the "Company") as of June 30, 2011 and 2010, and the related consolidated statements of operations, stockholders' equity, and cash flows for the year then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of the Company as of June 30, 2011 and 2010, and the results of its operations and its cash flows for the year then ended in conformity with accounting principles generally accepted in the United States of America.

/s/ DELOITTE & TOUCHE LLP

Houston, Texas
September 27, 2011

KGen Power Corporation

Consolidated Balance Sheets

(in thousands, except per share amounts)

	June 30, 2011	June 30, 2010
Assets		
Current assets:		
Cash and cash equivalents	**$ 89,442**	$ 48,177
Restricted cash and cash equivalents	**43,384**	7,167
Short-term investments	**4,005**	—
Accounts receivable	**994**	26,329
Spare parts inventories	**—**	8,009
Prepaid expenses and other current assets	**6,731**	1,947
Assets held for sale	**254,901**	63,580
Total current assets	**399,457**	155,209
Property, plant, and equipment	**3,488**	637,344
Less: accumulated depreciation	**2,498**	73,819
Net property, plant, and equipment	**990**	563,525
Contract-based intangibles (net of $0 and $36,154 of accumulated amortization, respectively)	**—**	47,388
Deferred charge	**—**	2,575
Deferred financing fees (net of $0 and $3,032 of accumulated amortization, respectively)	**—**	3,232
Restricted cash in escrow	**79,688**	—
Other noncurrent assets	**688**	325
Total assets	**$480,823**	$ 772,254
Liabilities and stockholders' equity		
Current liabilities:		
Accounts payable and accrued liabilities	**$ 2,571**	$ 20,983
Current portion of long-term debt	**—**	2,000
Liabilities associated with assets held for sale	**20,179**	784
Total current liabilities	**22,750**	23,767
Long-term debt	**—**	201,000
Contract-based intangibles (net of $0 and $4,370 of accumulated amortization, respectively)	**—**	15,129
Other noncurrent liabilities	**13**	2,717
Commitments and contingencies (Note 6)		
Stockholders' equity:		
Common stock (par value $.01; 150,000 shares authorized; 56,122 and 55,974 shares issued and outstanding at June 30, 2011 and June 30, 2010, respectively)	**561**	560
Additional paid in capital	**463,295**	742,477
Accumulated deficit	**(5,796)**	(213,396)
Total stockholders' equity	**458,060**	529,641
Total liabilities and stockholders' equity	**$480,823**	$ 772,254

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

KGen Power Corporation

Consolidated Statements of Operations

(in thousands, except per share amounts)

	For the Year Ended June 30, 2011	For the Year Ended June 30, 2010
Revenues:		
Energy sales	**$ 97,422**	$ 66,263
Capacity sales	**4,999**	1,932
Total revenues	**102,421**	68,195
Operating expenses:		
Cost of fuel	**80,843**	55,403
Operating and maintenance	**19,478**	28,369
Gas transportation	**5,926**	3,333
Selling, general, and administrative	**12,322**	10,613
Depreciation	**8,629**	10,242
Auxiliary power	**2,953**	2,696
Insurance	**1,575**	1,791
Total operating expenses	**131,726**	112,447
Operating loss	**(29,305)**	(44,252)
Other expenses		
Interest expense	**(9,782)**	(12,226)
Taxes, other than income taxes	**(3,813)**	(2,101)
Other	**(375)**	(230)
Total other expenses	**(13,970)**	(14,557)
Net loss from continuing operations before taxes	**(43,275)**	(58,809)
Income tax benefit from continuing operations	**16,489**	—
Net loss from continuing operations after taxes	**$ (26,786)**	$ (58,809)
Net income from discontinued operations, net of tax	**$234,386**	$ 13,873
Net income (loss)	**$207,600**	$ (44,936)
Net (loss) income per share—basic and diluted		
Continuing operations	**$ (0.48)**	$ (1.05)
Discontinued operations	**$ 4.18**	$ 0.25
Total	**$ 3.70**	$ (0.80)
Weighted average shares outstanding—basic	**56,027**	55,969
Weighted average shares outstanding—diluted	**56,118**	55,969

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

KGen Power Corporation

Consolidated Statements of Stockholders' Equity

(in thousands)

For the Years Ended June 30, 2011 and 2010

	Common Stock		Additional	Accumulated	
	Shares	Amount	Paid in Capital	Deficit	Total
Balance at June 30, 2009	55,968	$560	$ 741,602	$(168,460)	$ 573,702
Stock-based compensation	6	—	875	—	875
Net loss	—	—	—	(44,936)	(44,936)
Balance at June 30, 2010	55,974	$560	$ 742,477	$(213,396)	$ 529,641
Stock-based compensation	**148**	**1**	**1,430**	**—**	**1,431**
Net income	**—**	**—**	**—**	**207,600**	**207,600**
Distribution to stockholders	**—**	**—**	**(280,612)**	**—**	**(280,612)**
Balance at June 30, 2011	**56,122**	**$561**	**$ 463,295**	**$ (5,796)**	**$ 458,060**

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

KGen Power Corporation

Consolidated Statements of Cash Flows

(in thousands)

	For the Year Ended June 30, 2011	For the Year Ended June 30, 2010
Cash flows from operating activities		
Net income (loss)	**$ 207,600**	$(44,936)
Adjustments to reconcile net income (loss) to net cash used in operating activities:		
Net gain on sale of assets	**(240,517)**	—
Depreciation	**15,535**	23,978
Amortization of deferred financing fees	**3,232**	894
Amortization of contract-based intangibles	**5,164**	9,221
Valuation of derivative instruments	**1,720**	4,276
Stock-based compensation	**1,431**	875
Payments from settlement of derivative instruments	**(8,065)**	(5,957)
Changes in operating assets and liabilities:		
Accounts receivable	**16,791**	(3,514)
Spare parts inventories	**(116)**	(1,418)
Prepaid expenses and other current assets	**(4,784)**	(611)
Deferred charge	**674**	194
Other noncurrent assets	**(688)**	(56)
Accounts payable and accrued liabilities	**(2,525)**	2,081
Other noncurrent liabilities	**(7)**	(7)
Net cash used in operating activities	**(4,555)**	(14,980)
Cash flows from investing activities		
Purchases of property, plant, and equipment	**(2,245)**	(1,282)
Sale of assets	**651,587**	—
Short-term investments	**(4,005)**	—
(Investment in) use of restricted cash and cash equivalents	**(36,217)**	25,776
Investment in restricted cash in escrow	**(79,688)**	—
Net cash provided by investing activities	**529,432**	24,494
Cash flows from financing activities		
Repayment of debt	**(203,000)**	(2,000)
Distribution to stockholders	**(280,612)**	—
Net cash used in financing activities	**(483,612)**	(2,000)
Increase in cash and cash equivalents	**41,265**	7,514
Cash and cash equivalents at beginning of period	**48,177**	40,663
Cash and cash equivalents at end of period	**89,442**	48,177
Cash paid for		
Interest	**$ 4,829**	$ 7,079
Taxes	**$ 5,347**	$ —
Noncash transactions		
Grant of shares to Director	**$ —**	$ 40
Accounts payable related to purchases of property, plant, and equipment	**$ 470**	$ 858

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

KGen Power Corporation

Notes to Consolidated Financial Statements

For the Years ended June 30, 2011 and 2010

1. Nature of Business and Significant Accounting Policies

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. As of June 30, 2011, the Company's portfolio of facilities consisted of two operational and fully permitted combined-cycle power plants (Hot Spring and Hinds), or (the "Plants"), located in the southeastern United States with an aggregate capacity of 1140 megawatts ("MW").

On July 9, 2010, the Company completed the sale of its Sandersville power plant, a 640 MW simple-cycle plant and on April 8, 2011, the Company completed the sale of its Murray I and Murray II combined-cycle power plants having an aggregate capacity of 1250 MW. The results of operations for Sandersville and Murray I and II are reported in discontinued operations for all periods presented herein.

On April 28, 2011, the Company executed separate definitive agreements for the sale of its Hinds and Hot Spring combined-cycle power plants having an aggregate capacity of 1140 MW. Assets held for sale and liabilities associated with the assets held for sale related to the Hinds and Hot Spring power generation facilities were recorded as current assets and current liabilities as of June 30, 2011. Assets held for sale and liabilities associated with the assets held for sale related to the Sandersville power generation facility were recorded as current assets and current liabilities as of June 30, 2010 (See Note 11).

Principles of Consolidation

The 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, and KGen Acquisition I LLC, all direct or indirect 100% owned subsidiaries of the Company, 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.

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 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.

Revenue Recognition

Revenues derived from electric power energy sales are recognized as power is delivered. Revenues derived from long-term capacity sales contracts are recognized based on the monthly minimum commitment component adjusted for seasonal and other factors as appropriate on a straight-line basis over the terms of the contracts.

1. Nature of Business and Significant Accounting Policies (Continued)

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 production varies with weather conditions. The Hinds and Hot Spring plants operate, and historically the Sandersville power plant and the Murray II power plant operated 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.

Cash and Cash Equivalents and Restricted Cash and Cash Equivalents

Short-term investments, consisting of money market instruments with original maturities of three months or less, are considered to be cash equivalents and are recorded at cost, which approximates current market value.

Cash and cash equivalents that are contractually restricted for specific purposes are classified as restricted on the balance sheet. Such restricted funds are classified as current and noncurrent based upon the nature of the purpose for which the funds can be used and the expected timing of use of such funds.

Short-Term Investments

Short-term investments, consisting of money market instruments with original maturities of less than twelve months but more than three months, are considered to be short-term investments and are recorded at cost, which approximates current market value.

Spare Parts Inventories

Inventories consist primarily of various consumable spare parts and tools, which are valued at the weighted-average cost method, and are stated at the lower of cost or market.

Contract-Based Intangibles

Contract-based intangibles consist of the estimated fair value of contractual rights and obligations related to power purchase agreements and firm transportation contracts. The intangibles are being amortized using the straight-line method over the life of the specific contracts, and such amortization is reflected as an adjustment to the associated revenue or expense item. The contract-based intangibles are reviewed annually for impairment. No impairment was indicated at June 30, 2011 or 2010.

Property, Plant, and Equipment

Property, plant, and equipment is recorded at cost and is depreciated on a straight-line basis over the estimated useful life of the various classes of assets.

1. Nature of Business and Significant Accounting Policies (Continued)

Long-Lived Assets

Assets held for use are carried at cost less accumulated depreciation, unless recognition of impairment is necessary. For the years ended June 30, 2011 and 2010, no events or changes in circumstances indicated the carrying value of long-lived assets held for use might not be fully recoverable.

Deferred Financing Fees

Included in deferred financing fees were capitalized costs associated with debt issuance. Costs incurred to secure debt were capitalized and were being amortized over the life of the borrowing.

Fair Value of Financial Instruments

The Company's financial instruments consisted primarily of cash and cash equivalents, restricted cash and cash equivalents, short-term investments, accounts receivable, accounts payable, debt instruments, and interest rate derivatives. The carrying values of the cash and cash equivalents, restricted cash and cash equivalents, short-term investments, accounts receivable, and accounts payable are representative of their respective fair value due to the short-term nature of these instruments. The carrying value of interest rate derivative instruments represented the fair value, which was based on estimates using standard pricing models that took into account the present value of future cash flows as of the consolidated balance sheet date. Based on the borrowing rates currently available to the Company for bank loans with similar terms and average maturities, the fair value of term debt was $184.7 million at June 30, 2010. The Company no longer held the interest rate derivative instruments or the term debt at June 30, 2011 (See Note 4).

Concentration of Credit Risk

The Company's only major customer at June 30, 2011 was BNP Paribas Energy Trading GP ("BNP"). As of June 30, 2010, the Company had two major customers, Georgia Power Company ("GPC") and BNP. The Company does not believe BNP represents a significant credit risk. However, changes in economic, regulatory, or other factors could have a significant impact on the Company's contractual relationships (See Note 6). Operations of the facilities are dependent on the continued performance by customers and suppliers of their obligations under the relevant power sales contracts and operation and maintenance agreements. The Company does not believe this customer represents a significant credit risk due to its payment history and, therefore, does not require collateral for accounts receivable. However, the contract does provide for the customers to post collateral upon certain defined credit-related events.

Repair and Maintenance

Costs incurred to repair and maintain the power plants, including major maintenance costs, are expensed as incurred.

Contingencies

The Company, in the course of its operations, is subject to claims, lawsuits, and contingencies. Accruals are made in specific instances where it is probable that liabilities will be incurred and where such liabilities can be reasonably estimated.

1. Nature of Business and Significant Accounting Policies (Continued)

Income Taxes

The Company accounts for income taxes using the asset and liability method. The asset and liability method requires the recognition of deferred tax assets and liabilities for the expected future tax consequences of (i) temporary differences between financial statement carrying amounts of assets and liabilities and the basis of these assets and liabilities for tax purposes and (ii) operating loss and tax credit carry-forwards for tax purposes. Deferred tax assets are reduced by a valuation allowance when management concludes that it is more likely than not that a portion of the deferred tax assets will not be realized in a future period.

Net Earnings (Loss) per Share

Basic earnings (loss) per share is calculated by dividing net income (loss) by the weighted average number of shares of common stock outstanding during the period. Due to the net loss from continuing operations for the years ended June 30, 2011 and 2010, diluted earnings per share was calculated on the same basis as basic loss per share as the inclusion of any other potential shares outstanding would be anti-dilutive. Due to the net income from discontinued operations for the years ended June 30, 2011 and 2010, diluted earnings per share was calculated by adjusting the weighted average number of shares of common stock outstanding by the dilutive effect of incremental shares attributable to unvested restricted stock units and unexercised in-the-money stock options of 91,710 and 7,420 shares for the years ended June 30, 2011 and 2010, respectively. Unexercised out-of-the-money stock options to purchase a weighted average of 507,300 shares and 1,473,936 shares of common stock for the years ended June 30, 2011 and 2010, respectively, were not considered in the earnings (loss) per share calculation as the impact of such inclusion would have been anti-dilutive. Amounts shown below are in thousands, except per share amounts.

	For the Year Ended June 30, 2011	For the Year Ended June 30, 2010
Numerator:		
Net loss from continuing operations after taxes	$(26,786)	$(58,809)
Net income from discontinued operations after taxes	234,386	13,873
Net income (loss)	$207,600	$(44,936)
Denominator:		
Weighted average shares outstanding—basic	56,027	55,969
Weighted average shares outstanding—diluted	56,118	55,969
Net loss per share from continuing operations—basic and diluted	$ (0.48)	$ (1.05)
Net income per share from discontinued operations—basic and diluted	4.18	0.25
Total	$ 3.70	$ (0.80)

Other Comprehensive Income

The Company has no comprehensive income or loss other than net loss.

2. Property, Plant, and Equipment

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

	Estimated Useful Life	June 30, 2011	June 30, 2010
Land	—	$ —	$ 3,312
Buildings	40 years	—	26,382
Gas and steam turbines	30 years	—	181,733
Steam generators and auxiliaries	30 years	—	48,959
Transmission and fuel gas pipelines	30 years	—	51,038
Systems and equipment	5 - 30 years	3,488	120,210
Other plant	3 - 30 years	—	205,710
Total property, plant, and equipment		3,488	637,344
Less: accumulated depreciation		2,498	73,819
Net property, plant, and equipment		$ 990	$563,525

During the year ended June 30, 2011, the companies that own the assets of the Sandersville simple-cycle power generation facility and the Murray I and II combined-cycle power generation facilities were sold. In addition, on April 28, 2011, the assets of the Hinds and Hot Spring combined-cycle power generation facilities were classified as held for sale (See Note 11).

3. Contract-Based Intangibles

Contract-based intangibles consist of the following (in thousands of dollars):

	Term	Original Cost	Accumulated Amortization	June 30, 2010
Assets				
Murray I Georgia Power contract	May 31, 2012	$43,265	$(27,523)	$15,742
Murray firm transportation contracts	Various	40,277	(8,631)	31,646
Total assets		$83,542	$(36,154)	$47,388
Liabilities				
Murray firm transportation contract	November 30, 2016	638	(222)	416
Hot Spring firm transportation contracts	Various	18,861	(4,148)	14,713
Total liabilities		$19,499	$ (4,370)	$15,129

For the years ended June 30, 2011 and 2010, amortization of contract-based natural gas transportation rights and obligations for continuing operations was $1.0 million and $1.3 million, respectively. These amortization amounts were recorded as an increase of gas transportation expenses on the consolidated statements of operations.

For the years ended June 30, 2011 and 2010, amortization of contract-based natural gas transportation rights and obligations for discontinued operations was $1.5 million and $2.5 million, respectively. These

3. Contract-Based Intangibles (Continued)

amortization amounts were included in discontinued operations on the consolidated statements of operations.

For the years ended June 30, 2011 and 2010, amortization of contract-based power sales rights and obligations was $4.7 million and $8.1 million, respectively. These amortization amounts were included in discontinued operations on the consolidated statements of operations.

During the year ended June 30, 2011, the companies that own the assets of the Sandersville simple-cycle power generation facility and the Murray I and II combined-cycle power generation facilities were sold. In addition, on April 28, 2011, the assets of the Hinds and Hot Spring combined-cycle power generation facilities were classified as held for sale (See Note 11).

4. Long-Term Debt

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

	Interest Rate	Maturity	June 30, 2011	June 30, 2010
Term debt	Variable	February 8, 2014	$—	$193,000
Working capital facility	Variable	February 8, 2012	—	10,000
Total debt outstanding			—	203,000
Less: current portion			—	2,000
Total long-term debt			$—	$201,000

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 bore interest at an adjusted rate based on the London Interbank Offered Rate ("LIBOR") plus 175 basis points, had a term of seven years, and required a $2.0 million principal payment per year made in quarterly installments. KGen LLC's obligations and indebtedness under the Credit Agreement were 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 2.1% at June 30, 2010.

The Credit Agreement included an $80.0 million working capital facility for 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 charged a 200 basis point fee for outstanding letters of credit, bore interest at LIBOR plus 200 basis points for outstanding draws, and had a 50 basis point commitment fee for any unused portion. It had a five-year term expiring on February 8, 2012. KGen LLC paid a fee of 191 basis points on the $120.0 million synthetic letter of credit facility. It had a seven-year term expiring on February 8, 2014.

There were $14.0 million of outstanding letters of credit issued under the working capital facility as of June 30, 2010. At June 30, 2010, a letter of credit, supporting the power sales contract with GPC, in the amount of $80.0 million was outstanding under the synthetic letter of credit facility. There were

4. Long-Term Debt (Continued)

$19.9 million of other outstanding letters of credit under the synthetic letter of credit facility as of June 30, 2010.

On August 18, 2010, the Company prepaid $58.5 million of its outstanding term debt and $10.0 million of its outstanding working capital facility using a portion of the proceeds received from the sale of 100% of the ownership interests in KGen Sandersville LLC, the entity that owned the Sandersville power generation facility (See Note 11). In connection with this prepayment, the Company reduced its principal payment requirement of $2.0 million per year to $1.4 million per year with quarterly installments beginning September 30, 2010. In addition, there were $0.5 million of outstanding letters of credit issued under the working capital facility and $14.4 million of outstanding letters of credit issued under the synthetic letter of credit facility that related to Sandersville and were cancelled following the sale of 100% of the ownership interests in KGen Sandersville LLC.

On April 8, 2011, the Company repaid $133.4 million of the remaining outstanding term debt using a portion of the proceeds received from the sale of the assets of the Murray I and II power generation facilities (See Note 11). In connection with the term debt repayment, the Company's working capital and synthetic letter of credit facilities were terminated and a $75.0 million cash collateralized replacement letter of credit facility was entered into on April 8, 2011. There have been $43.4 million of letters of credit issued against the $75.0 million facility. The cash collateral supporting this letter of credit facility was recorded to restricted cash and cash equivalents (See Note 5).

5. Restricted Cash and Cash Equivalents and Restricted Cash in Escrow

Subsequent to the repayment of all outstanding debt under the Credit Agreement, a $75.0 million cash collateralized replacement letter of credit facility was entered into on April 8, 2011 of which $43.4 million of letters of credit have been issued. The $43.4 million of cash collateral supporting this letter of credit facility was recorded in restricted cash and cash equivalents. The letters of credit issued under this facility support obligations associated with ongoing long-term gas transportation contracts at the Hinds and Hot Spring facilities. Fees related to this letter of credit facility were $0.1 million and were expensed as incurred.

In addition, in connection with the sale of the Murray I and II combined-cycle power generation facilities, $79.7 million was placed in escrow for a period of 18 months after closing to secure customary post-closing indemnification obligations. This escrow balance was recorded in restricted cash in escrow.

Prior to the April 8, 2011 debt repayment, the Credit Agreement required KGen LLC to maintain six months of principal and interest payments reserve in cash. At June 30, 2010, the restricted balance, in accordance with this requirement, was $4.7 million. Additionally, the Security Deposit Agreement required KGen LLC to reserve, on a quarterly basis, the amount of major maintenance expenditures expected to be incurred during the following 12 months. At June 30, 2010, the restricted balance, in accordance with this requirement, was $2.5 million.

6. Commitments and Contingencies

Litigation—The Company may be a 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.

6. Commitments and Contingencies (Continued)

Commitments—BNP is the commercial marketer for all of the Company's facilities. The Company compensates BNP based on a percentage of gross margin not to be less than a minimum management fee. For the years ended June 30, 2011 and 2010, the Company paid BNP $5.6 million and $0.6 million, respectively, for energy management related expenses.

The Company has long-term gas transportation contracts with Texas Eastern Transmission, LP ("TETCO") to deliver gas to the Hinds facility. The contract provides firm capacity of 80,000 Dth/day in the summer peak period and lesser amounts in the other parts of the year. 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.

The Company has long-term gas transportation contracts with a subsidiary of CenterPoint Energy, Inc. ("CenterPoint") to deliver gas to the Hot Spring facility. The contracts provide firm capacity of 98,000 Dth/day in the summer peak period and 50,000 Dth/day in the other parts of the year. The transporation contracts with CenterPoint to deliver gas to the Hot Spring facility continue through October 2022.

The Company entered into long-term service agreements with General Electric International ("GE") to provide maintenance services at the Hinds and Hot Spring facilities. All maintenance costs paid to GE are expensed as incurred. The term of each agreement ends following completion of the fourth hot gas path cycle which is determined based on attainment of specified aggregate factored hours or starts and performance of the attendant planned maintenance activities. Payments to GE are variable based on parts and work required, plant run time, or equivalent starts and stops.

On October 16, 2009, the Company notified Duke Energy Generation Services ("DEGS") that it was exercising its rights to terminate the operating and maintenance agreements between DEGS and KGen Hinds LLC and KGen Hot Spring LLC, the 100% owned subsidiaries of the Company that, respectively, own the Hinds and Hot Spring plants. The termination was effective for the Hinds and Hot Spring plants on February 15, 2010. The Company was required to pay DEGS approximately $0.4 million, in the aggregate, in connection with the termination of the agreements. KGen Hinds LLC and KGen Hot Spring LLC executed new operating agreements with NAES Corporation ("NAES"), a third party operations and maintenance provider that replaced DEGS as the service provider for such facilities. The Company paid NAES $5.7 million and $1.9 million for the years ended June 30, 2011 and 2010, respectively, for operations and maintenance services. The Company paid DEGS zero and $8.7 million, respectively, for the years ended June 30, 2011 and 2010, for all operations and maintenance services and termination fees.

On April 1, 2010, KGen Hot Spring entered into a Precedent Agreement with TETCO, 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. This lateral pipeline was being constructed in order for Hot Spring to access the increased scheduling flexibility on TETCO's system. The pipeline was completed and in service by June 16, 2011 and financial incentives of $0.2 million payable were paid to TETCO according to the agreement. The Company also posted a $39.0 million letter of credit as collateral according to the agreement upon the in-service date of the pipeline lateral. Now that 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 which provide 112,000 Dth/day of firm capacity. The collateral requirements will decrease proportionally over the 20-year term.

6. Commitments and Contingencies (Continued)

Corporate Matters—The Company has a ten-year operating lease for its executive office space expiring December 31, 2017, which includes its current space of 20,200 square feet. Rent expense under this lease was $0.4 million and $0.5 million, respectively, for the years ended June 30, 2011 and 2010.

The Company entered into an agreement on September 29, 2009 to sublease approximately 6,318 square feet of corporate office space in exchange for monthly payments of $15,775. The commencement date of the sublease was December 17, 2009 and the expiration date is December 31, 2017. Sublease payments began on February 17, 2010.

The future minimums lease payments for the five years subsequent to June 30, 2011, and thereafter are as follows (in thousands of dollars):

2012	570
2013	570
2014	570
2015	570
2016	570
Thereafter	855
Total	$3,705

(1) Minimum lease rental payments have not been reduced by minimum sublease rentals of $1.2 million due in the future under noncancelable subleases.

As of June 30, 2011 and 2010, the Company employed 17 people.

The Company has adopted an Employee Performance Bonus and Retention Plan (the "Plan") for its employees. Payments under the Plan are based on the continued employment of the recipient and bonuses are triggered in connection with the consummation of any sale of a facility and/or a change in control, in each case in accordance with, and subject to the terms set forth in, the Plan. During the year ended June 30, 2011, the Company paid cash bonuses totaling $2.4 million in connection with the sales of Sandersville and Murray. As of June 30, 2011, the Company accrued $0.2 million for amounts held in escrow in connection with the sale of Murray.

During the year ended June 30, 2011, the companies that own the assets of the Sandersville simple-cycle power generation facility and the Murray I and II combined-cycle power generation facilities were sold. In addition, on April 28, 2011, the assets of the Hinds and Hot Spring combined-cycle power generation facilities were classified as held for sale (See Note 11).

7. Industrial Development Revenue Bonds

Construction of the Hot Spring, Murray, and Sandersville facilities was financed by various development authorities through the issuance of Industrial Development Revenue Bonds (the "Bonds"). Simultaneous with the Bonds' issuance, the facilities were leased to the project companies subsequently acquired by the Company by the development authority pursuant to either 20-year or 30-year lease agreements. As part of the bond agreements, the development authorities assigned the leases to the bond trustee to secure the Bonds in accordance with the terms of trust indentures. The lease payments are set exactly equal to the bond repayments and are the sole source of retirement for the Bonds. The Company was the sole holder of the Bonds.

The agreements executed in connection with the transfer of the Bonds permitted the limited liability companies to make payments to the Company in the form of intercompany book entries without the actual transfer of cash. At June 30, 2011, $10.0 million remained outstanding related to the Hot Spring project. At June 30, 2010, $775.4 million of the Bonds remained outstanding related to the Hot Spring, Sandersville, and Murray projects.

Upon expiration of the lease term or earlier termination of the lease by the repayment of the Bonds, the Company may purchase the Hot Spring property for a nominal amount.

Under the terms of the Bonds and the related trust indentures and agreements, the Company has constructive ownership of the facilities, which are included in property, plant, and equipment in the accompanying consolidated financial statements. As the Company has the unilateral right to terminate the lease and trust indentures by repaying the Bonds to itself, the principal balance of the Bonds and the lease obligation have been presented net in the accompanying consolidated balance sheets. Additionally, the lease payments and the bond interest income have been presented net in the accompanying consolidated statements of operations.

Following the sale of 100% of the ownership interests in KGen Sandersville LLC and KGen Murray I and II LLC, the Industrial Development Revenue Bonds related to Sandersville and Murray I and II were no longer held by the Company (See Note 11).

8. Derivatives and Investments

The Company recognized all derivatives and investments as either assets or liabilities on the balance sheet and measures those instruments at fair value. The ongoing effects were 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 swap agreements had a notional amount of $33.0 million and had a term that expired in each consecutive year, beginning on March 31, 2008 continuing through March 31, 2013.

The short-term portion of the Swaps as of June 30, 2011 and 2010 was zero and $3.6 million, respectively, and was recorded in accounts payable and accrued liabilities. The long-term portion of the Swaps as of June 30, 2011 and 2010 was zero and $2.7 million, respectively, and was recorded in other noncurrent liabilities.

8. Derivatives and Investments (Continued)

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

	Location of Gain (Loss) on Derivatives	Hierarchy	Gain (Loss) on Derivatives
For the year ended June 30, 2011	Interest expense	Level 2	$(1,720)
For the year ended June 30, 2010	Interest expense	Level 2	$(4,276)

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

In connection with the repayment of the term loan, the Company's interest rate swaps were terminated on April 8, 2011.

On December 9, 2010, the Company entered into short-term investments consisting of two cash collateralized letters of credit supported by certificates of deposit. The balance of the short-term investments was $4.0 million as of June 30, 2011. Short-term investment income is shown on the consolidated statements of operations as follows (in thousands of dollars):

	Location of Interest on Short-Term Investments	Hierarchy	Interest on Short-Term Investments
For the year ended June 30, 2011	Other	Level 1	$ 5
For the year ended June 30, 2010	Other	Level 1	$—

The Company evaluated the requirements of FASB ASC 820 and believes the short-term investments are valued using Level 1 fair value measurements. Under FASB ASC 820, instruments valued using Level 1 measurements are valued based on accessible quoted prices in active markets for identical instruments.

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 quoted 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.

During the year ended June 30, 2011, the companies that own the assets of the Sandersville simple-cycle power generation facility and the Murray I and II combined-cycle power generation facilities were sold. In addition, on April 28, 2011, the assets of the Hinds and Hot Spring combined-cycle power generation facilities were classified as held for sale (See Note 11).

9. Share-Based Payments

Effective January 1, 2007, the Company adopted the KGen Power Corporation 2006 Equity Incentive Plan (the "2006 Incentive Plan"). Under the 2006 Incentive Plan, 4,870,568 shares are currently authorized and reserved for equity awards.

On February 8, 2007, options were granted under the 2006 Incentive Plan to purchase 730,585 shares of common stock at an exercise price equal to $14.00 per share. On February 8, 2007, additional options were granted under the 2006 Incentive Plan to purchase 1,704,699 shares of common stock in four equal parts at four different exercise prices: (i) $14.00 per share, (ii) $15.40 per share, (iii) $16.80 per share (iv) $18.20 per share. Options from both grants have a ten-year term and will vest equally over three years from February 8, 2007. On May 28, 2008, options were granted under the KGen Power Corporation Chairman Stock Option Plan to purchase 100,000 shares of common stock at an exercise price equal to $19.50 per share. Options from this grant have a ten-year term and will vest one year from the date of issuance. The Company's policy is to recognize option awards subject to periodic vesting on a straight-line basis over the requisite service period for the entire award. No share-based compensation awards were awarded to employees prior to the February 8, 2007 grants.

On May 22, 2009, restricted stock awards were granted to an employee and director of the company at a fair value at grant date of $6.00 per share. On March 12, 2010, a corrective amendment was executed by the Board for awards to vest upon the first, second, and third anniversaries of March 13, 2009, the first day of employment. The restricted stock awards consisted of 20,000 restricted stock units ("RSUs") which vest according to the following schedule:

Date of Vest	# of Vested Units
March 13, 2010	6,667
March 13, 2011	6,667
March 13, 2012	6,666

Upon vesting, the RSUs will be granted as one share of common stock with a par value of $0.01 per share for each restricted stock unit granted. The RSUs will not have voting rights. Stock compensation expense related to the RSUs was $0.2 million and $0.1 million for the years ended June 30, 2011 and 2010. The RSUs will be recognized over a weighted average remaining recognition period of 0.70 years. These RSUs will vest upon the occurrence of a change in control.

The Company records compensation expense for the options granted under the 2006 Incentive Plan. In general, compensation expense will be determined at the date of grant based on the fair value of the options granted and amortized to compensation expense over the applicable vesting period.

9. Share-Based Payments (Continued)

The fair value of each stock option is estimated on the date of grant using a Black-Scholes option pricing model. The weighted average assumptions for the years ended June 30, 2011 and 2010 are noted in the following table:

	June 30, 2011	June 30, 2010
Risk-free interest rate	4.66%	4.66%
Expected volatility	32.26%	32.26%
Expected term in years	5.97	5.97
Expected dividends	—	—
Fair value (per option)	$ 5.33	$ 5.33

The risk-free rates of return were based on the U.S. Treasury yield curve in effect on the date of grant. As the Company has not had publicly traded stock, the expected volatilities were based on the average of the historical volatility of a group of companies that management believes is comparable to KGen Power Corporation. To the extent that the Company had sufficient information to develop reasonable expectations about future exercise patterns, the Company estimated the expected term of awards based on several factors, including vesting schedules, contractual terms, expected post-vesting termination behavior, and various factors surrounding the expected exercise behavior of employees. The "simplified" method for "plain vanilla" options as described in SEC Staff Accounting Bulletin No. 107 was used to estimate the expected term of certain options granted.

The following table summarizes incentive stock-based compensation activity for the year ended June 30, 2011:

	Shares Under Option	Weighted-Average Exercise Price Per Share	Weighted-Average Remaining Contractual Term (Years)	Aggregate Intrinsic Value
Outstanding June 30, 2010	796,297	$10.98	—	—
Granted				
Exercised				
Forfeited or expired	—	—	—	—
Outstanding June 30, 2011	796,297	$10.98	5.77	$—
Vested or expected to vest at June 30, 2011	796,297	$10.98	5.77	—
Exercisable at June 30, 2011	796,297	$10.98	5.77	—

The Company recorded compensation expense of zero and $0.8 million for the years ended June 30, 2011 and 2010, respectively, related to stock options outstanding. As of June 30, 2011 and 2010, all options were vested and there was no unrecognized compensation expense remaining on the options. For the years ended June 30, 2011 and 2010, no options were granted or exercised.

On June 24, 2011, the Company paid a cash liquidating distribution to the holders of common stock of the Company in an amount of $5.00 per share. As such, the exercise price applicable to each of the options outstanding under the 2006 Incentive Plan was reduced by $5.00 per share.

On August 13, 2010, the Board of Directors granted a total of 237,268 RSUs to senior employees and the Chairman of the Board of Directors pursuant to the KGen Power Corporation 2006 Equity Incentive

9. Share-Based Payments (Continued)

Plan ("the Plan"). Each RSU will entitle its holder to receive, upon vesting of the RSU, one share of common stock of the Company. Under the terms of the RSU awards, 35,592 RSUs vested immediately upon grant due to the completed sale of 100% of the ownership interests in KGen Sandersville LLC, the entity that owns the Sandersville power generation facility. Upon the consummation of the sale of the Murray I and II power generation facilities on April 8, 2011, 106,769 of the remaining RSU awards vested. Of the remaining unvested RSUs, 47,454 will vest upon the consummation of a sale of the Hot Spring power generation facility and 47,453 will vest upon the consummation of a sale of the Hinds power generation facility. The RSUs will be recognized over a weighted average remaining recognition period of 0.39 years. All unvested RSUs will vest upon the consummation of a change in control of the Company.

The Company recorded compensation expense of $1.4 million and zero for the years ended June 30, 2011 and 2010, respectively, related to the above outstanding RSUs. As of June 30, 2011 and 2010, there was $0.2 million and $37.0 thousand, respectively, of total unrecognized compensation expense related to the unvested RSUs.

On October 5, 2010, the Board of Directors granted 15,000 RSUs to the CEO of the company pursuant to the Plan. Each RSU entitled the CEO to receive, upon vesting of the RSU, one share of common stock of the Company. Under the terms of the RSU awards, all 15,000 shares vested immediately upon grant and the Company recorded the full compensation expense of $0.2 million during the year ended June 30, 2011.

During the year ended June 30, 2011, the companies that own the assets of the Sandersville simple-cycle power generation facility and the Murray I and II combined-cycle power generation facilities were sold. In addition, on April 28, 2011, the assets of the Hinds and Hot Spring combined-cycle power generation facilities were classified as held for sale (See Note 11).

10. Income Taxes

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

	For the Year Ended June 30, 2011	For the Year Ended June 30, 2010
Statutory rate	35%	35%
Tax at statutory rate	$(15,146)	$(20,583)
Increase (decrease) due to:		
Nondeductible meals and entertainment	8	7
State tax expense	(1,342)	(2,029)
Return to provision	(9)	(93)
Adjustment to valuation allowance	—	22,698
Total provision	$(16,489)	$ —

10. Income Taxes (Continued)

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

	June 30, 2011	June 30, 2010
Deferred tax assets:		
Interest rate derivatives	$ —	$ 2,472
Contract-based intangible assets	33	15,109
Nonqualified stock options expense	5,828	5,375
Accrued expenses	84	21
Net operating loss	437	81,113
Contribution carryforward	—	16
Net deferred tax assets	6,382	104,106
Deferred tax liabilities:		
Property, plant, and equipment	(557)	19,346
Prepaid expenses	542	613
Contract-based intangible liabilities	5,313	4,043
Net deferred tax liability	5,298	24,002
Valuation allowance	397	80,104
Deferred tax asset (liabilities), net	$ 687	$ —

The Company utilized the majority of its net operating loss carryforwards (“NOLs”) against federal and state taxable income generated during its fiscal year ended June 30, 2011. A portion of the Georgia net operating loss remains which is not expected to be utilized as the Company is not expected to owe Georgia tax in the future. A valuation allowance on this net operating loss remains. As the Company has determined that its deferred tax assets, with the exception of the Georgia net operating loss, now meet the more-likely-than-not recognition criteria, the Company has reversed all of its previously-recorded valuation allowance.

The Company recognizes interest and penalties related to unrecognized tax benefits within the provision for income taxes on continuing operations in the consolidated statements of operations. There are no unrecognized tax benefits as of the date of adoption. There are no unrecognized tax benefits that it recognized would affect the tax rate. There are no interest and penalties recognized as of the date of adoption or through June 30, 2011.

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. Asset Sales and Assets Held for Sale

KGen Sandersville LLC Sale

On May 6, 2010, it was determined that the assets held for sale criteria were met when the Company executed a definitive agreement for the sale of 100% of the ownership interests in KGen Sandersville LLC, the entity that owns the Sandersville power generation facility, to AL Sandersville Holdings, LLC, an entity formed by ArcLight Energy Partners Fund III, LP.

Assets held for sale and liabilities associated with the assets held for sale related to the Sandersville power generation facility were valued at the lower of historical book value or fair value less cost of disposal and were recorded as current assets and current liabilities as of June 30, 2010. The Company suspended related depreciation and amortization of these assets upon their classification of assets held for sale on May 6, 2010. They consisted of the following (in thousands of dollars):

	June 30, 2010
Spare parts inventories	$ 641
Property, plant, and equipment (net of $7,624 of accumulated depreciation)	62,883
Other assets	56
Assets held for sale	$63,580
Accounts payable and accrued liabilities	$ 784
Liabilities associated with assets held for sale	$ 784

The transaction between the Company and AL Sandersville Holdings, LLC, an entity formed by ArcLight Energy Partners Fund III, LP, to purchase 100% of the ownership interests in KGen Sandersville LLC, the entity that owns the Sandersville power generation facility closed on July 9, 2010. A subsidiary of ArcLight Energy Partners Fund IV, LLP, was a shareholder of the Company. The Company received $129.3 million in cash sales proceeds which represents a $130.0 million purchase price less a working capital adjustment. The net gain on the sale was $65.0 million and the Company prepaid $58.5 million of its outstanding term debt and $10.0 million of its outstanding working capital facility using a portion of the proceeds of this sale.

In addition, KGen LLC distributed $19.5 million of the cash sales proceeds received to its parent, KGen Power Corporation. The Company used a portion of its existing NOLs to offset all of the taxable gain resulting from this sale.

Commitments related to KGen Sandersville LLC—On October 16, 2009, the Company notified DEGS that it was exercising its rights to terminate the operating and maintenance agreements between DEGS and KGen Sandersville LLC, the 100% owned subsidiary of the Company that owns the Sandersville plant. The termination was effective for the Sandersville plant on February 1, 2010. The Company was required to pay DEGS approximately $20.0 thousand, in connection with the termination of this agreement. KGen Sandersville LLC executed a new operating agreement with NAES, a third party operations and maintenance provider that replaced DEGS as the service provider. The Company paid NAES $0.1 million and $0.2 million for the years ended June 30, 2011 and 2010, respectively, for operations and maintenance services. The Company paid DEGS zero and $1.0 million, respectively, for the years ended June 30, 2011 and 2010, for all operations and maintenance services and termination fees.

11. Asset Sales and Assets Held for Sale (Continued)

KGen Murray I & II LLC Sale

On January 31, 2011, it was determined that the assets held for sale criteria were met when the Company executed a definitive agreement for the sale of the Company's Murray I and II electric generation facilities to Oglethorpe Power Corporation ("OPC"). The sale closed on April 8, 2011. The Company received $530.3 million in cash sales proceeds and $79.7 million was placed in escrow for a period of 18 months after closing to secure customary post-closing indemnification obligations. The net gain on the sale was $175.5 million. The Company used a majority of its remaining tax NOLs to offset all but approximately $36.1 million of the taxable gain resulting from the sale. In connection with the closing of the transaction, the Company's credit, working capital, and synthetic letter of credit facilities were terminated and the related interest rate swaps were unwound. The Company used $138.0 million of the net proceeds of the sale to repay outstanding debt under these facilities and satisfy related obligations. In connection with the termination of these facilities, the restricted cash and cash equivalents associated with these facilities was released. The Company transferred the Industrial Revenue Bonds associated with Murray I and II to OPC. Additionally, all contractual commitments associated with Murray I and II were transferred in connection with the sale. RSUs of 106,769 vested upon the consummation of the sale of Murray I and II power generation facilities.

In addition, subsequent to the repayment of all outstanding debt under the Credit Agreement, a $75.0 million cash collateralized replacement letter of credit facility was entered into on April 8, 2011 of which $43.4 million of letters of credit have been issued. The $43.4 million of cash collateral supporting this letter of credit facility was recorded to restricted cash and cash equivalents. The letters of credit issued under this facility support obligations associated with ongoing long-term gas transportation contracts at the Hinds and Hot Spring facilities. Fees related to this letter of credit facility were $0.1 million and were expensed as incurred.

Commitments related to KGen Murray I & II LLC—KGen Murray I and II LLC had a power purchase agreement with GPC ("GPC PPA") expiring May 31, 2012. Under the terms of the GPC PPA, the Company sold a unit contingent 550 to 680 MW of capacity and associated energy to GPC. The capacity price under the GPC PPA escalated annually. The monthly minimum commitment of 550 MW was recognized separately for summer and non-summer months as capacity revenue on a straight-line basis over the remaining term of the GPC PPA. Actual capacity revenue recognized for the years ended June 30, 2011 and 2010 was based on a 630 MW designation, which was in excess of the monthly minimum commitment.

The Company recognized $37.6 million and $50.1 million, respectively, related to capacity sales on the GPC PPA for the years ended June 30, 2011 and 2010. The Company recognized expense of $0.7 million and recognized income of $0.2 million in deferred charges for the years ended June 30, 2011 and 2010, respectively, which consisted of the difference between the monthly minimum commitment calculated on a straight line-basis over the remaining term of the GPC PPA and actual minimum capacity sales payments due under the GPC PPA.

The price of the associated energy was calculated to approximate a pass-through of fuel and variable operations and maintenance costs. The Company recognized $43.9 million and $38.1 million, respectively, related to energy sales on the GPC PPA for the years ended June 30, 2011 and 2010.

11. Asset Sales and Assets Held for Sale (Continued)

The GPC PPA was subject to seasonal and monthly availability adjustments (positive or negative) if available capacity differs from a specified availability level. These adjustments were recognized as capacity sales revenue as associated capacity was provided.

The amount receivable from the GPC PPA was zero and $19.6 million at June 30, 2011 and 2010, respectively.

A letter of credit, issued pursuant to the synthetic letter of credit facility under the Credit Agreement, supported a performance guarantee under the GPC PPA of $120.0 million through May 2008, $100.0 million from June 2008 through May 2010, $80.0 million from June 2010 through May 2011, and $40.0 million from June 2011 through May 2012. This letter of credit was terminated upon the repayment of all obligations under the Credit Agreement on April 8, 2011.

The Company had a fuel supply agreement with Sequent Energy Management ("Sequent"), a subsidiary of AGL Resources, which supports the GPC PPA. This full requirement contract was for firm delivery of 85,106 decatherms per day ("Dth/day") and was to expire May 31, 2012, with evergreen annual renewals absent notice from either party. Sequent retained a continuing first priority lien on and security interest in the Company's energy payment receivables from GPC, to the extent of fuel costs owed. The fuel pricing was based on a combination of related gas price indices and other components similar to the pricing in the GPC PPA. Sequent delivered natural gas to several pipeline receipt points from which the Company had long-term gas transportation contracts with East Tennessee Natural Gas Company for 168,000 Dth/day of firm capacity.

The Company entered into long-term service agreements with GE to provide maintenance services at the Murray facilities. All maintenance costs paid to GE are expensed as incurred. The term of each agreement ends following completion of the fourth hot gas path cycle which is determined based on attainment of specified aggregate factored hours or starts and performance of the attendant planned maintenance activities. Payments to GE are variable based on parts and work required, plant run time, or equivalent starts and stops.

The operating and maintenance agreement between DEGS and KGen Murray I and II LLC remained in place through the date of the sale of the Murray facilities. The Company paid DEGS $3.7 million and $4.7 million, respectively, for the years ended June 30, 2011 and 2010, for all operations and maintenance services, and termination fees.

Discontinued Operations

The Company has determined it no longer has a presence in the Southern control area given the sale of KGen Sandersville LLC and the sale of KGen Murray I and II LLC and therefore has reflected the results of operations for KGen Sandersville LLC and KGen Murray I and II LLC as discontinued

11. Asset Sales and Assets Held for Sale (Continued)

operations for the years ended June 30, 2011 and 2010. The following table presents the results of discontinued operations for Sandersville and Murray I and II:

	For the Year Ended June 30, 2011	For the Year Ended June 30, 2010
Revenues:		
Energy sales	**$ 72,831**	$ 89,126
Capacity sales	**37,595**	50,101
Total revenues	**110,426**	139,227
Operating expenses:		
Cost of fuel	**62,483**	76,495
Operating and maintenance	**13,494**	11,267
Gas transportation	**9,593**	13,236
Selling, general, and administrative	**936**	1,076
Depreciation	**6,905**	13,736
Auxiliary power	**4,287**	5,836
Insurance	**842**	1,675
Total operating expenses	**98,540**	123,321
Operating income	**11,886**	15,906
Other income (expenses):		
Net gain on sale of assets	**240,517**	—
Taxes, other than income taxes	**(698)**	(2,033)
Total other income (expenses)	**239,819**	(2,033)
Net income before taxes	**251,705**	13,873
Income tax expense	**17,319**	—
Net income	**$234,386**	$ 13,873

KGen Hinds LLC and KGen Hot Spring LLC Held for Sale

On April 28, 2011, it was determined that the assets held for sale criteria were met when the Company executed a definitive agreement for the sale of the Company's Hinds power generation facility to Entergy Mississippi, Inc. for a cash purchase price of $206.0 million, subject to certain adjustments. The Company received approval from a majority of the Company's shareholders for the sale of this facility. The transaction is conditioned on the satisfaction of various regulatory approvals and other conditions described in our 2011 Special Meeting Proxy Statement. One of these conditions is that Entergy is to receive a study for network transmission service for the Hinds facility that does not reflect aggregate costs in excess of $10.0 million for the supplemental upgrades required to provide network transmission service for the Hinds facility. In June 2011, Entergy received a study that reflected costs in excess of $10.0 million; however, Entergy continues to examine issues associated with such costs. The transaction is conditioned upon the receipt of various regulatory approvals and clearances including approval of the FERC, clearance

11. Asset Sales and Assets Held for Sale (Continued)

under the Hart-Scott-Rodino Antitrust Improvements Act of 1976 ("the HSR Act") and approval of the Mississippi Public Service Commission. On July 15, 2011, Entergy filed an application to approve the transaction with the Mississippi Public Service Commission. On July 27, 2011, the Company and Entergy filed notification and report forms under the HSR Act with the U.S. Federal Trade Commission ("FTC"), and the Antitrust Division of the U.S. Department of Justice ("DOJ"), with respect to the sale of the Hinds facility. On August 26, 2011, the DOJ issued to the Company and Entergy a Request for Additional Information and Documentary Material prior to the expiration of the waiting period. After the parties have substantially complied with the request for information, the parties must observe a 30 calendar day waiting period before closing is permitted, unless the waiting period is terminated earlier or extended with the consent of the parties. On August 31, 2011, the parties filed a joint application with FERC seeking authorizations pursuant to Section 203 of the Federal Power Act. The Company expects the transaction to close in the middle of calendar 2012, but may close before or after such time. Under the terms of the transaction agreement, $30.0 million of the purchase price will be held in escrow to secure customary post-closing indemnification obligations. An escrow amount of $10.0 million is subject to release 12 months after closing, an additional $10.0 million is subject to release 18 months after closing, and the remaining balance will be subject to release 42 months after closing.

On April 28, 2011, it was determined that the assets held for sale criteria were met when the Company executed a definitive agreement for the sale of the Company's Hot Spring power generation facility to Entergy Arkansas, Inc. for a cash purchase price of $253.0 million, subject to certain adjustments. The Company received approval from a majority of the Company's shareholders for the sale of this facility. The transaction is conditioned on the satisfaction of various regulatory approvals and other conditions described in our 2011 Special Meeting Proxy Statement. One of these conditions is that Entergy is to receive a study for network transmission service for the Hot Spring facility that does not reflect aggregate costs in excess of $40.0 million for the supplemental upgrades required to provide network transmission service for the Hot Spring facility. In June 2011, Entergy received a study that reflected costs in excess of $40.0 million; however, Entergy continues to examine issues associated with such costs. The transaction is conditioned upon the receipt of various regulatory approvals and clearances including approval of the FERC, clearance under the HSR Act, and approval of the Arkansas Public Service Commission. On July 15, 2011, Entergy filed an application to approve the transaction with the Arkansas Public Service Commission. On July 27, 2011, the Company and Entergy filed notification and report forms under the HSR Act with the FTC and the DOJ, with respect to the sale of the Hot Spring facility. On August 26, 2011, the DOJ issued to the Company and Entergy a Request for Additional Information and Documentary Material prior to the expiration of the waiting period. After the parties have substantially complied with the request for information, the parties must observe a 30 calendar day waiting period before closing is permitted, unless the waiting period is terminated earlier or extended with the consent of the parties. On August 31, 2011, the parties filed a joint application with FERC seeking authorizations pursuant to Section 203 of the Federal Power Act. The Company expects the transaction to close in the middle of calendar 2012, but may close before or after such time. Under the terms of the transaction agreement, $38.0 million of the purchase price will be held in escrow to secure customary post-closing indemnification obligations. An escrow amount of $12.0 million is subject to release 12 months after closing, an additional $13.8 million is subject to release 18 months after closing, and the remaining balance will be subject to release 42 months after closing.

11. Asset Sales and Assets Held for Sale (Continued)

Under Delaware law, shareholder approval will be required for the ultimate dissolution of the Company. No such approval of the stockholders of the Company has yet been obtained.

Assets held for sale and liabilities associated with the assets held for sale related to the Hinds and Hot Spring power generation facilities were valued at the lower of historical book value or fair value less cost of disposal and were recorded as current assets and current liabilities as of June 30, 2011. The Company suspended related depreciation and amortization of these assets upon their classification of assets held for sale on April 28, 2011. Their combined total consisted of the following (in thousands of dollars):

	June 30, 2011
Accounts receivable	$ 4,000
Spare parts inventories	3,879
Property, plant, and equipment (net of $40,323 of accumulated depreciation)	246,777
Other assets	245
Assets held for sale	$254,901
Accounts payable and accrued liabilities	$ 6,479
Contract-based intangibles (net of $5,161 of accumulated amortization)	13,700
Liabilities associated with assets held for sale	$ 20,179

Contract-Based Intangibles related to the held for sale assets consist of the following (in thousands of dollars):

	Term	Original Cost	Accumulated Amortization	June 30, 2011
Hot Spring firm transportation contracts	Various	$18,861	$(5,161)	$13,700
Total liabilities		$18,861	$(5,161)	$13,700

12. Subsequent Events

On July 21, 2011 the Company was notified by BNP that they are terminating the contract to provide energy management services. On September 26, 2011, the Company retained Twin Eagle Resource Management, LLC ("Twin Eagle") as its new energy management services provider with services commencing on October 1, 2011. Twin Eagle does not have an investment grade rating. Accordingly, under the Company's agreements with Twin Eagle, Twin Eagle is required to post collateral in the form of letters of credit or cash in the event the Company's exposure to Twin Eagle exceeds certain specified thresholds.

Subsequent events were analyzed and considered through September 27, 2011, the date this report was available for issuance.

Part III

Number 8. ***Directors, Officers and Corporate Governance***

Directors and Officers

The following table sets forth certain information about the persons currently serving as our directors and officers as of June 30, 2011:

Name	Age	Position
Thomas B. White	55	President, Chief Executive Officer, and Director
James H. Sweeney	52	Executive Vice President, Energy Management
William R. Marlow	44	General Counsel and Secretary
Charles L. Holland	69	Executive Vice President, Operations
W. Kevin Redmond	46	Chief Accounting Officer and Controller
Tina C. Lee	40	Vice President, Energy Management
Stuart J. Prall	37	Vice President, Operations
Steven B. McDowell	36	Vice President, Mergers & Acquisitions and Finance
Daniel T. Hudson	45	Chairman of the Board
James P. Jenkins	63	Director
Gerald J. Stalun	52	Director

Officers

Thomas B. White

Mr. White became a director in April 2008 and was named President and Chief Executive Officer in March 2009. Prior to joining the management of KGen, Mr. White was employed as a director by Stark Investments, a multi-strategy asset management firm with over $14 billion in assets under management. At Stark, Mr. White was responsible for the identification, evaluation, and closing on private equity type investments in physical energy assets and businesses, as well as supporting asset management activities for investments made by Stark through the energy asset team and investments employed through other asset strategies including risk arbitrage and commodity hedging structures. From 2002 to 2006, Mr. White was employed by Marathon Capital, LLC, a boutique investment banking firm focusing on the power generation and renewable energy markets, where he was an officer and Managing Director from 2003 to 2006. At Marathon, Mr. White was the principal executive responsible for banking, origination and marketing activities which included the sourcing, evaluation, and closing of non-recourse financing structures for renewable and conventional energy assets and for managing financial consulting efforts with corporate clients in the acquisition and divestiture of energy assets and portfolios in these markets. From 1996 to 2002, Mr. White was employed by Duke Energy, where he was senior director, Development, for Duke Energy North America from 2001 to 2002 and Vice President, Industrial Services, for DukeSolutions, Inc. for 1997 to 2001. Mr. White received his Bachelor of Sciences in Mechanical Engineering from the University of Illinois and through 2010 was a Registered Professional Engineer in the State of Illinois. From 2004 to 2007, Mr. White was a Registered Representative and held Series 7 and Series 63 Licenses. Mr. White is currently a Director of Renewable Biofuels, a Houston-based biofuel production company.

James H. Sweeney

Mr. Sweeney is our Executive Vice President, Energy Management. Mr. Sweeney has been with KGen since our formation and held that position with our predecessor from June 2004. Prior to joining KGen, Mr. Sweeney was employed by American Electric Power as Vice President-M&A and Divestitures from 2002 to 2004, and as Vice President-Latin America from 1998 to 2002. From 1987 to 1998, Mr. Sweeney held various senior positions at LG&E Energy (formerly Hadson & Ultrasystems) including Vice

President-Latin American Development. Mr. Sweeney has a BS in electrical engineering from Worcester Polytechnic Institute and an ME in power systems from Rensselaer Polytechnic Institute.

William R. Marlow

Mr. Marlow has been our General Counsel and Secretary since our formation and held that position with our predecessor from March 2005. Mr. Marlow was an attorney at Bracewell & Patterson LLP from 1992 to 2005 where he left as a partner in the Real Estate, Energy, and Finance practice group. Mr. Marlow holds a BBA from the University of Houston and a JD from The University of Texas School of Law.

Charles L. Holland

Mr. Holland is our Executive Vice President, Operations. Mr. Holland joined our predecessor as Vice President, Operations in October 2004. He was previously employed with Duke Energy from 1995 to 2004. Initially in his career with Duke Energy he held the position of Vice President, Asia Pacific, and was responsible for the development of power projects in that region. Immediately prior to joining the Company he was a Managing Director in the North American merchant power business unit with responsibility for managing the plants that the Company acquired from Duke Energy. Prior to 1995, Mr. Holland held a number of officer-level positions with companies involved in the development, design, construction, and operation of power generating facilities. Mr. Holland holds a Bachelor of Science degree in nuclear engineering from North Carolina State University.

W. Kevin Redmond

Mr. Redmond has been our Chief Accounting Officer & Controller since our formation. Mr. Redmond joined our predecessor as Controller in March 2005. He began his career working as an internal auditor for a national printing company. He subsequently joined Ernst and Young, LLP, an international accounting firm and worked primarily in the Energy group focusing on power/energy clients during his four-year tenure. Mr. Redmond later joined Tractebel Power, Inc. (aka GDF Suez Energy North America) and ultimately became Vice President, Controller during his eight-year tenure from 1996 to 2004. He also worked with a local consulting firm, Sirius Solutions, from 2004 to 2005, providing Sarbanes Oxley implementation assistance to energy companies. Mr. Redmond has a BS degree from Texas A&M University and an MBA from University of Houston. He is a licensed Certified Public Accountant.

Tina C. Lee

Ms. Lee is our Vice President, Energy Management. She joined KGen in November 2004 as Director, Energy Management. Before KGen, Ms. Lee was a wholesale structurer at Reliant Energy from 1999 to 2003 and at RWE Energy Trading from 2003 to 2004. At Navigant Consulting in 2004, she worked on various advisory projects for energy clients. She began her energy career at Columbia Energy in 1997 where she worked in the natural gas pipeline and energy marketing groups as part of a MBA rotational program until 1999. Before getting her MBA from the Wharton Business School at the University of Pennsylvania, Ms. Lee was an investment banking analyst at Morgan Stanley where she worked on mergers and acquisitions and equity and debt financings for insurance companies. She has a BBA in finance honors and BA in liberal arts honors from The University of Texas at Austin.

Stuart J. Prall

Mr. Prall is our Vice President, Operations. Mr. Prall joined us in March 2007. He was previously employed with Duke Energy North America where he held several positions including; Director of Supply Chain Management, Manager of Engineering, and Manager of Valuation and Strategic Review. Mr. Prall was previously employed with TXU Electric as Plant Engineer and Operations Supervisor at a steam electric station. Mr. Prall received a Bachelors of Science in Mechanical Engineering from The University of Texas at Austin.

Steven B. McDowell

Mr. McDowell is our Vice President, Mergers & Acquisitions and Finance. Mr. McDowell joined our organization in April of 2007 as a Director, Strategic Planning. Prior to joining KGen, Mr. McDowell was employed by El Paso Corporation from 2004 to 2007. During that period he worked in a number of capacities in the Strategy & Planning group which included leading the creation of the corporate 5 year plan, M&A transaction review and long term treasury forecasts for over $15 billion of corporate debt. Prior to 2004, Mr. McDowell worked for Dynegy where he managed the analysis of M&A transactions and commercial development projects. During this time, he was also responsible for the forecasts of long term power curves used to value outstanding power contracts and M&A projects. Mr. McDowell holds a BA in Economics and an MBA, both from The University of Texas at Austin.

Directors

Daniel T. Hudson

Mr. Hudson became a director in February of 2008 and was elected Chairman of the Board in May 2008. Mr. Hudson is the president and CFO and a principal owner of Navasota Energy Services LLC and Montgomery Power Partners LP. He is responsible for M&A, capital formation/management from private equity, third-party debt, and equity-raising. Navasota Energy Services LLC is currently the Asset Manager for 1,000 MW Guadalupe Power Partners LP located in New Braunfels, Texas. Montgomery Power Partners LP is a majority owner in 600 MV Hartland Wind Farm LLC located in North Dakota. Until April, 2010, Mr. Hudson was a Director and CFO of Navasota Holdings Texas Partners LP, a 1,650 MW ERCOT portfolio. During 24 years of industry experience, Mr. Hudson has focused on wholesale electric and gas markets. His background includes asset acquisition and divestiture strategies, implementation, and financing at Navigant Consulting, Duke Energy North America, and NRG Energy. Prior to joining Navigant, Hudson served as Managing Director of Acquisitions and Divestitures for Duke where he led the company's acquisition and divestiture program. Mr. Hudson received a BS in Mechanical Engineering from the University of Minnesota and an MBA from the University of St. Thomas.

James P. Jenkins

Mr. Jenkins became a director in May 2008. Mr. Jenkins is a Managing Director, Transaction Development at King Street Capital Management, L.L.C. In this capacity, Mr. Jenkins utilizes his senior restructuring and investment banking skills in assisting the investing team particularly in special situations, distressed and event-driven investments and investment opportunities being considered. Mr. Jenkins joined King Street in April 2007 after five years at Mellon HBV Alternative Strategies, where he was a Portfolio Manager and head of the distressed investing group. At Mellon HBV, Mr. Jenkins served on several official and unofficial creditor or equity committees, including Adelphia, Advanced Lighting, Delta Air Lines, Impath, Ormet, Outsourcing Services Group, Peregrine Systems and Solutia. Prior to Mellon HBV, Mr. Jenkins spent his entire career in investment banking. He ran the Investment Banking and Capital Markets group at Advest for two years. Prior to that, Mr. Jenkins spent 12 years at CS First Boston where he was a Managing Director in the Reorganization Group and the Leveraged Finance Group, and where he advised numerous debtors and creditor groups, both in and out of bankruptcy, including AK Steel, CalFed, Charter Companies creditors, Cleveland-Cliffs, GlenFed, Harvard Industries, Imo Industries, LTV creditors, Mcorp, Midway Airlines, Presidio Oil, Spreckels Industries and Terex. Previously, Mr. Jenkins spent 12 years at Lehman Brothers in general corporate finance, sovereign debt restructuring and corporate reorganization. Mr. Jenkins was formerly a director of several companies, including Frederick's of Hollywood, Interboro Insurance Company (Chairman), Outsourcing Services

Group, Peregrine Systems (Chairman), The Robbins Company (Chairman) and Telespectrum Worldwide. Mr. Jenkins received both a BA in English in 1970 and an MBA in 1972 from Stanford University.

Gerald J. Stalun

Mr. Stalun became a director in May 2008. Mr. Stalun is a Managing Director and the global head of power at EIG Global Energy Partners, LLC, (EIG) formerly TCW Group, Inc's Energy & Infrastructure Group (TCW EIG). EIG currently has approximately $11 billion of energy and infrastructure investments under management. Mr. Stalun has more than 25 years of experience in the global power business, most recently as Head of Asset Based Investments for Arcapita, a leading private equity firm active in the sector. Previous positions in the industry include SVP of GE Energy Financial Services, Managing Director and Executive Vice President of Duke Capital Partners and Managing Director and Co-Head of Power Project Finance for Bank of America. He received a B.S. in Accounting from the University of Illinois and an MBA from the University of Chicago. Mr. Stalun previously practiced as a Certified Public Accountant in Illinois. Previous board memberships include Bosque Power, Falcon Gas Storage, as well as current board memberships of Kelson Energy, Inc. and Milford Holdings LLC.

Code of Ethics

We have adopted a code of conduct for each of our employees to follow. Our management insists on integrity, honesty and ethical behavior in the workplace and therefore, we requested that each employee affirm, via a written statement, that they are not aware of any code of conduct violation.

Number 9. ***Certain Relationships and Related Transactions, and Director Independence***

Independence of Directors

The Company has affirmatively determined that no member of the Board of Directors, other than Thomas B. White who is our President and Chief Executive Officer, has a relationship which, in the opinion of the Company, would interfere with the exercise of independent judgment in carrying out the responsibilities of a director of the Company. Based on this determination, the Board of Directors considers all of its members, other than Mr. White, to be "independent."