KGEN POWER CORPORATION

ANNUAL REPORT

For the Fiscal Year Ended June 30, 2010

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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 Company's non-investment grade credit rating;
- 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 actual sources may be lower and actual uses 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;
- our ability to obtain credit or capital in desired amounts and/or on favorable terms;
- our ability to operate our power plants efficiently, manage capital expenditures and costs tightly, and generate earnings and cash flow from our asset based businesses;
- the Company's exploration of value-enhancing alternatives;
- 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 four operational and fully permitted combined-cycle power plants (Murray I, Murray II, 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 2,390 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 sales proceeds. See discussion on page 25. We acquired our Plants from an affiliate of MatlinPatterson Global Advisors LLC, or MatlinPatterson, on February 8, 2007.

All of our Plants are located in the southeastern United States. Under the current market conditions in the southeastern United States region, where regional utilities control the dispatching order, our combined-cycle facilities historically have run between 10% and 35% annual capacity. The regional utilities have indicated that their electric demand is starting to grow again, after a decline due to the recent recession. We expect the electric power market in the southeastern United States region to return to equilibrium in the 2012-2016 timeframe as the electricity demand growth in the region continues. We believe this demand growth and the advent of more transparent and economic dispatch of regional system assets should result in increasing capacity demand, dispatch profile and improved profitability for the Plants.

Three of our four Plants currently operate as merchant power providers. The remaining plant, the Murray I combined-cycle plant, benefits from a fixed-price long-term power purchase agreement with Georgia Power, a subsidiary of Southern Company, or the GPC PPA, for all of its 630 MW of capacity. The GPC PPA, which continues through May 2012, provides for fixed capacity payments and is our most significant source of stable cash flow.

Our Strategy

Our strategy includes the following elements:

- ***Disciplined and opportunistic commercial strategy.*** We plan to sell energy and capacity 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 and to be able to participate in the anticipated continuing market recovery. We are pursuing potential transactions for longer terms in instances where the pricing of such transactions would enable us to increase the value of our assets and is consistent with our views of the anticipated market recovery.
- ***Focus on operational efficiency and excellence.*** We focus on maintaining and enhancing our plant availability and operational reliability to take advantage of market opportunities. We are committed to operating the 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 and benefit from our partners' scale, experience, and credibility. We seek to align the interests of our outsource partners through proper incentives.
- ***Explore credible value-enhancing alternatives.*** We explore credible alternatives for enhancing shareholder value that may become available to us, including but not limited to, sales of individual facilities, long-term power sale agreements, and potential business combinations. Our management

team's compensation package includes incentives payable upon successful facility sales or a change in control transaction.

Our Combined-Cycle Power Plants

Plant	Location	Turbines	Heat Rate(1)	Total Capacity (MW)(2)	Commercial Operation Date
Murray I	Murray County, Georgia	7FA	7,250	630	June 2002
Murray II	Murray County, Georgia	7FA	7,250	620	June 2002
Hot Spring	Hot Spring County, Arkansas	7FA	7,150	620	June 2002
Hinds	Hinds County, Mississippi	7FA	7,000	520	May 2001
Total				2,390	

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

(2) Nominal operating capacity.

Our Plants are strategically located within SERC Reliability Corporation's region, or SERC, such that, with a market recovery, they should be able to take advantage of their locations to generate attractive financial returns. They are also located with strategic access to the natural gas system, providing broad access to suppliers. In addition, our Plants have access, via wheeling, to other regional markets.

Our Operations

Our management includes a core group of industry veterans who direct and implement our strategy. We have leveraged the capabilities of this core team by using third-party outsource providers to manage and maintain our facilities and to assist in marketing our capacity and energy.

Our Murray Plants are operated pursuant to operation and maintenance agreements with Duke Energy Generation Services, or DEGS. Our Hot Spring and Hinds Plants are operated pursuant to operation and maintenance agreements with NAES Corporation, or NAES, which replaced DEGS as the operation and maintenance provider for those plants on February 15, 2010. DEGS and NAES each provide 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. DEGS and NAES utilize their own personnel, supplemented by outside contractors on an as-needed basis, to perform such services. DEGS and NAES also provide, 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 the Plants are 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. Our natural gas needs under the GPC PPA are arranged by Sequent Energy Management L.P., or Sequent, under a long-term agreement. 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.

All of the Plants began operations in May 2001 or June 2002. Since inception our combined-cycle 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 92.2% for the year ended June 30, 2010, or 97.7% 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. Three of our four 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

Currently, Georgia Power is our most significant customer, with payments by it under the GPC PPA accounting for approximately 41.9% and 36.0% of our revenues for the years ended June 30, 2010 and 2009, respectively. Most of our remaining sales are merchant sales 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. During the past year, BNP's regular counterparties purchasing the output from our Plants have broadened beyond just the regional utilities.

Power Transmission

Our Murray I facility is interconnected to the Georgia Integrated Transmission System, or GITS, at the Conasauga 500 kilovolt, or kV, substation pursuant to a long-term interconnection agreement with Georgia Power. Murray II interconnects at the 230 kV Loopers Farm switching station with (i) the GITS pursuant to a long-term interconnection agreement with Dalton Utilities and (ii) the Tennessee Valley Authority, or TVA, transmission system pursuant to a long-term interconnection agreement with TVA.

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.

The Entergy transmission system has had congestion issues which have impacted our ability to sell the output of our Hinds and Hot Spring facilities. In 2009, Entergy included many new transmission projects into its construction plan before the various state commissions which, when implemented over the coming years, should help alleviate the congestion that has impacted our facilities.

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. One major committed source of natural gas is an agreement with Sequent, which provides natural gas supplies to our Murray I plant and provides us the benefit of Sequent's credit in connection with such purchases. Our fuel supply agreement with Sequent has a term ending May 31, 2012, the date on which the GPC PPA terminates. To minimize risk, the gas price from Sequent is a day-ahead gas price calculated using an index formula similar in basis to gas pricing under the GPC PPA. Sequent provides firm gas supply sufficient to supply the requirements for Murray I.

Sequent delivers natural gas to a pipeline receipt point from which we have firm long-term contracts with East Tennessee Natural Gas Company sufficient for all deliveries from Sequent to Murray I.

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 a lateral pipeline interconnected to a subsidiary of CenterPoint Energy, Inc, or CenterPoint. We have long-term pipeline transport contracts with 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.

CenterPoint experienced several system issues in calendar year 2009, coupled with an increased utilization of their capacity and as a result began imposing limitations on flow flexibility consistent with their tariffs that do not allow for shorter dispatch schedules typical of power markets. Typically, we have schedules that are 12 to 16 hours and the standard peak power market product is a 16 hour schedule. The limitations imposed by CenterPoint require schedules that are at least 21 hours. In addition to sourcing longer scheduled sales when possible, we have been working with CenterPoint on various short-term alternatives such as purchasing a short-term flexibility tariff product for June through September 2010, which enabled us to run Hot Spring for shorter schedules.

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, subject to certain approvals including the Federal Energy Regulatory Commission, or FERC. This lateral pipeline is being 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 is expected to be in service by summer 2011 with financial incentives of up to $0.8 million payable to TETCO if the pipeline is completed before July 1, 2011. We are required to post collateral to support construction of the pipeline and as of April 7, 2010 posted a $6.0 million letter of credit. Our collateral requirements will increase during the construction process and will be approximately $39.0 million upon the in-service date of the pipeline lateral. Additionally, once the pipeline is operational, there will be annual fixed transportation fees of approximately $6.7 million associated with the new firm transportation agreements for the 20-year term. The collateral requirements will decrease proportionally over the 20-year term.

Competition

Since our Murray I plant is subject to a long-term unit contingent contract with Georgia Power and is a designated network resource to Georgia Power, we will not face substantial competition with respect to the sale of the Murray I plant's capacity until termination of the contract, or 2012. The remaining plants in our portfolio currently operate on a merchant basis. As a result, we face competition from the power generation plants operated by Southern Company, 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, 2010, 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. The scope of holding company regulation was changed by passage of the Energy Policy Act of 2005, or EPAct.

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 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, which will not be completed until 2011. To date, the CFTC has issued a public notice for comments, but it has not yet published proposed regulations defining key terms and clarifying new requirements.

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 the CFTC will propose 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, Georgia, and Mississippi. CAIR is a two-phase program with declining compliance caps for NO_x in 2009 and 2015 and for SO_2 in 2010 and 2015.

On April 28, 2006, the EPA published a Federal Implementation Plan, or FIP, to ensure that power generators affected by CAIR reduce emissions on schedule. The FIP is only operative until individual states submit revised SIPs implementing CAIR to the EPA for approval. Arkansas, Mississippi, and Georgia have received EPA approval for revised SIPs incorporating CAIR requirements.

On July 11, 2008, the U.S. Court of Appeals for the District of Columbia Circuit, or Court, issued an opinion in *North Carolina v. EPA* vacating CAIR and its associated FIP and remanding the rule to the EPA for further rulemaking. In response to a petition filed by the EPA on September 24, 2008, the Court decided on December 23, 2008, to remand without vacating CAIR, allowing the rule to remain in place until modifications are made. Because the Court chose not to vacate the rule, the Plants began complying with the current version of CAIR on January 1, 2009.

On July 6, 2010, the EPA proposed a new rule, the Proposed Transport Rule that, when final, will replace CAIR. Under the Proposed Transport Rule, the EPA is proposing to set a pollution limit (or budget) for each of the 31 states covered by the Proposed Transport Rule, which includes Georgia, Arkansas, and Mississippi, and is likely to allow limited interstate trading among power plants. The EPA is seeking comments on the rule and affected states must continue to comply with the vacated CAIR rule until the EPA finalizes the Proposed Transport Rule.

In a related action, on March 5, 2009, the Court issued a decision in *Sierra Club, et al. v. EPA* remanding the EPA's order denying the review of a Clean Air Act Section 126 petition submitted by the State of North Carolina. Under Section 126 of the Clean Air Act, states affected by migrating pollution can file a petition with the EPA if they believe pollutants from upwind states would prevent them from achieving or "attaining" their air quality standards. If the petition is approved, the EPA can require stricter pollution controls in upwind states. North Carolina's petition was denied by the EPA on the grounds that implementation of CAIR would address upwind emissions of fine particulates, or PM2.5, and that modeling indicated that North Carolina would attain and remain in attainment of ozone standards without additional reductions from other states. In light of the Court's decision to remand CAIR, the EPA requested remand of North Carolina's petition for further review. The Proposed Transport Rule notes that the EPA plans to propose a transport rule to address the ozone standard in 2011 and finalize it in 2012.

While we do not anticipate that compliance with CAIR in its current form will materially affect expenses in the near term, future costs of compliance with CAIR are unknown and will depend, in part, on further regulatory actions. Under the current program, as the allowable caps on NO_x and SO_2 emissions decrease, 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.

On June 4, 2010, the EPA issued proposed rules pursuant to Section 112(d) of the Clean Air Act, imposing emission standards for hazardous air pollutants, or HAPs, which include toxic air pollutants, such as mercury, other metals, and organic air toxics from a wide variety of major sources, including new and existing boilers used in electric generating facilities. These proposed rules have been issued by the EPA in response to a U.S. Court of Appeals decision that invalidated an earlier attempt by the EPA to implement Maximum Achievable Control Technology, or MACT, standards for boilers. Under this provision of the Clean Air Act, the EPA is required to set emission standards for each HAP based on MACT, which is supposed to reflect the actual emission performance of the best operating units of a given type of boiler. The methodology that the EPA has employed to establish MACT standards for boilers is highly controversial and has been widely challenged in public comments filed both by utilities and other industrial boiler operators. In particular, electric industry commentators have challenged the methods used by the EPA to identify the best operating units that set the MACT standards and the EPA's failure to properly account for emissions during periods of boiler malfunction, startup and shutdown. The comment period for the proposed rules closed in August 2010. The EPA may subsequently modify its proposed MACT standards and it is quite likely that any final rules that the EPA adopts will be challenged in court.

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." That decision, which addressed GHG emissions from automobile tailpipes, is assumed to apply also to GHG emissions from power plants.

The EPA issued an Advance Notice of Proposed Rulemaking on July 11, 2008 requesting public comment. 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 adopting a phased-in approach to address six GHG emissions from stationary sources, including power plants, which will begin in January 2011. On August 2, 2010, the Center for Biological Diversity and a number of industry groups challenged the final rule before the United States Court of Appeals for the District of Columbia Circuit.

While the EPA has taken initial steps toward regulating GHG emissions under the Clean Air Act, the Obama administration has repeatedly stated that it would prefer Congress to adopt comprehensive legislation to address climate change over regulatory action at the agency level. On June 26, 2009, the U.S. House of Representatives narrowly passed the American Clean Energy and Security Act of 2009 (H.R. 2454, known popularly as "Markey-Waxman"), a comprehensive energy and environmental bill, by a vote of 219 to 212. The bill would establish a "cap and trade" system for targeted reductions of GHG emissions (17% from 2005 levels by 2020 and 83% by 2050).

Since passage of the Markey-Waxman bill a year ago, the Senate Environment Committee has taken up a climate change bill and the Senate Energy Committee has taken up an energy bill, but no bills have been taken to the Senate floor for a vote. With the 111th 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. Future progress of these legislative proposals in the next Congress and beyond will depend on the outcome of the November elections.

EPA rulemakings to regulate GHG emissions are expected to continue despite the absence of a new, comprehensive federal statutory scheme to address the issue. An attempt to halt these rulemakings failed in the U.S. Senate earlier this year. While new GHG rules, once finalized, are expected to be challenged in the courts, 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.

In addition to direct regulation of GHGs, Congress is also considering legislation that would implement a national Renewable Portfolio Standard, or RPS, requiring load serving entities to purchase a portion of their electricity needs from renewable sources such as wind, solar, biomass, and some hydro power technologies. A federal RPS was included in the Markey-Waxman bill that passed the House of Representatives last year but, as previously noted, is unlikely to become federal law this year. However, at present, 29 states and the District of Columbia have enacted or promulgated RPS requirements, with portfolio requirements ranging from 5% to 33%. Even in the absence of a federal RPS, such RPS requirements in states or regions where the Plants operate could impact the demand for power from our facilities, since purchasers may be required to obtain that power from renewable resources. These state-level requirements are unlikely to be repealed, although they remain subject to change; in addition, RPS requirements are under consideration in several additional states that do not yet have them.

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 Industry

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. In particular, at times we have substituted power generated by our former Sandersville plant and our Murray II plant at significantly lower margins for power from Murray I that is supplied under the GPC PPA when Murray I has had an unplanned outage. Georgia Power, in each case, must agree to the replacement transmission delivery point. If Georgia Power does not approve the alternate delivery point, the revenues paid to us under the GPC PPA may be reduced. 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.

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.

Our business is 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. The EPAct is likely to have several long-term impacts on the energy sector. Among the impacts are strong financial incentives for investment in transmission and generation, federal pre-eminence over state authority, which may remove some obstacles to improved transmission, and changes to the Public Utility Regulatory Policies Act of 1978, or PURPA, that increase the importance of analyzing economic viability of certain merchant generation projects. Many of the provisions of the EPAct require implementation by FERC. FERC has not completed all of its rulemakings and certain of its regulations may face requests for rehearing, appeals or litigation. The effects on our business are uncertain and could adversely affect our business and financial results.

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. Although the Plants are not currently located within an Independent System Operator, or ISO, or Regional Transmission Operator, or RTO, we may in the future be subject to an ISO or RTO and we may sell some of our energy into ISOs or RTOs. The ISOs or RTOs that oversee most of the wholesale power markets impose, and in the future may continue to impose, price limitations, offer caps, and other mechanisms to address some of the volatility and the potential exercise of market power in these markets. These types of price limitations and other regulatory mechanisms may adversely affect the profitability of our generation facilities that sell energy and capacity into the wholesale power markets. In addition, the regulatory and legislative changes that have recently been enacted at the federal level and in a number of states in an effort to promote competition are novel and untested in many respects. These new approaches to the sale of electric power have very short operating histories, and it is not yet clear how they will operate in times of market stress or pressure, given the extreme volatility and lack of meaningful long-term price history in many of these markets and the imposition of price limitations by ISOs or RTOs. Additionally, Entergy Services, on behalf of various affiliated operating companies, has established the Independent Coordinator of Transmission, or ICT, to oversee its transmission system. The establishment of ICT is largely seen as a step towards improving transparency in granting transmission and non-discriminatory transmission access to Entergy Services' system. However, the introduction of the ICT into the Entergy sub-region may have a materially different impact from the impact of an ISO or RTO and may not be beneficial and therefore could have a material adverse effect on our operating results.

We are 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*."

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.

Our competitors may be able to respond more quickly to new laws or regulations or emerging technologies, or to devote greater resources to the construction, expansion, or refurbishment of their power generation facilities than we can. In addition, current and potential competitors may make strategic acquisitions or establish cooperative relationships among themselves or with third parties. Accordingly, it is possible that new competitors or alliances among current and new competitors may emerge and rapidly gain significant market share.

Our competitors include the power generation capabilities of Entergy Services, Southern Company, and TVA, utilities that have historically dominated their respective geographic regions in SERC and that have significant influence over the markets in which we compete and over the state regulatory bodies that regulate them. These utilities have the ability to charge rates based upon their cost of generation and thus may be able to dispatch their generation facilities instead of purchasing energy from merchant generators even though the price charged by the merchant generators may be lower than the utilities' cost of generation. Entergy Services has purchased merchant generation facilities and placed such facilities into its rate base. These purchases and any similar purchases in the future may significantly reduce the demand for energy and capacity from the Plants. In addition, Entergy Services and Southern Company are also our principal customers. There can be no assurance that we will be able to compete successfully against current and future competitors, and any failure to do so would have a material adverse effect on our business, financial condition, results of operations, and cash flows.

Changes in technology may impair the value of the Plants.

Research and development activities are ongoing to provide alternative and more efficient technologies to produce power, including fuel cells, clean coal and coal gasification, micro-turbines, photovoltaic (solar) cells, wind turbines, and improvements in traditional technologies and equipment, such as more efficient gas turbines, cleaner and safer nuclear or coal power plants, and coal-fired integrated gasification combined-cycle power plants, among others. Advances in these or other technologies could reduce the costs of power production to a level below what we have currently forecasted, which could adversely affect our revenues, results of operations or competitive position. Improvements in transmission technology may reduce transmission constraints but may also improve access of competitors to our markets. Renewable resource technologies receive assistance in commercial implementation through regulatory requirements, subsidies, and tax incentives that may adversely affect demand for the output of the Plants and their values.

Risks Related to Our Business

Three 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.

Three of 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. If long-term power purchase agreements at attractive prices become available, we may not have sufficient credit standing to take advantage of such opportunities.

Revenue may be reduced significantly upon expiration or termination of the GPC PPA.

The GPC PPA generates a substantial portion of our operating margin. The pricing of the GPC PPA exceeds current pricing structures for comparable facilities in our markets. The GPC PPA expires in May 2012 and contains termination provisions standard to contracts in our industry such as performance or payment default or prolonged events of force majeure. If we are not able to enter into an agreement or agreements with Georgia Power or other third parties with respect to the Murray I plant on similarly favorable terms to the GPC PPA upon its termination or expiration, it may have a material adverse effect on our results of operations, financial condition, and cash flows.

The development of nuclear and coal-fired generation facilities within the SERC region and the resulting production of electricity with lower marginal costs may adversely affect our revenues, results of operations, cash flow, or competitive position.

Nuclear and coal-fired generation facilities, which are generally used as base load power sources in an electric energy grid, which generally have lower fuel costs and as a result have lower marginal costs of power production as compared to our combined-cycle facilities, which are generally used in load-following roles, and our simple-cycle plant, which is generally used as a peaking power source. Proposed greenhouse gas limitations and the rising cost of construction have dampened the number of projects in various stages of development. In the southeastern United States region, coal-fired capacity is currently under construction or in various stages of development, and some capacity is projected to be operational by 2011. While a significant portion of this base load capacity will not be available in the near term, the expected increase in base load capacity could lower demand for load-following plants such as ours, which could adversely impact our revenues, results of operations, and cash flow. Several utilities in the southeastern

United States region have announced that they are considering the commissioning of new nuclear generation facilities. The construction of new nuclear generation facilities may have a similar impact on the markets as new base load coal-fired generation facilities.

We rely on power transmission facilities that we do not own or control and are subject to transmission constraints within our core regions. If these facilities fail 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 transmission facilities owned and operated by others to deliver the wholesale power we sell from the Plants to our customers. The Southern Company and Entergy Services control the transmission infrastructure in our primary regions 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. If restrictive transmission price regulation is imposed, the transmission companies may not have sufficient incentive to invest in expansion of transmission infrastructure. We also cannot predict whether transmission facilities will be expanded in specific markets to accommodate competitive access to those markets.

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. In particular, we obtain natural gas for our Hot Spring plant through CenterPoint, which has been enforcing its tariffs in a manner that has resulted in us not dispatching the Hot Spring plant even when such could be done at a positive margin. Failure to adopt flexible pipeline operations that recognize the needs of modern energy grids and merchant generation facilities may have an adverse affect on our revenues, results of operations, and cash flows.

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 debt and other obligations could have a material adverse effect on our results of operations, financial condition, or cash flows.

We depend on our management for our future success.

Our future success in operating our Plants is largely dependent 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.

Our exploration of value-enhancing strategic alternatives may not result in any transaction and may create uncertainties that could affect our business.

As part of our strategy, we explore and review credible alternatives for enhancing shareholder value that may become available to us. There are, however, various uncertainties and risks relating to our exploration of these alternatives, including:

- The exploration of alternatives may distract management and disrupt operations, which could have a material adverse effect on our operating results;
- We may not be able to successfully achieve the benefits of any alternative undertaken by us;
- The process of exploring alternatives may be time consuming and expensive; and
- Perceived uncertainties as to our future direction may result in the loss of employees or business opportunities or impact our relationship with third party service providers.

We have only two significant customers with which we have a direct contractual relationship for our power so our credit risk is concentrated. If either customer were to experience financial difficulties, we could be subject to a material and adverse effect on our financial condition and results of operations.

Our only two significant customers with which we currently have a direct contractual relationship are Georgia Power and BNP. We benefit from BNP's credit 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. If either BNP or Georgia Power failed to pay us or were 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.

Demand for electricity from our plants may decline due to difficult economic conditions in the southeastern United States.

A sustained decline in economic conditions in the southeastern United States where our Plants are located may lead to sustained lower demand for electricity from our merchant facilities, which may have a material adverse effect on our financial condition and results of operations.

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

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

Our operations have not been profitable and if we are unable to generate net income, the price of our common stock will be adversely affected.

For the years ended June 30, 2010 and 2009, we had losses of $44.9 million and $45.5 million, respectively, before income taxes. We expect to continue to operate in a difficult merchant power market in the SERC region in the near term.

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 very limited and does 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.

Our credit rating or general credit conditions may prevent us from being able to access our lines of credit or refinance our debt facilities.

We currently have in place an $80.0 million working capital facility which expires on February 8, 2012, a $120.0 million synthetic letter of credit and a $200.0 million term loan, both of which expire on February 8, 2014. Due to our non-investment grade rating, or general credit market conditions, our access to the credit markets to re-finance these facilities may be limited. Additionally, any future credit crisis could hinder our counterparty's ability to perform their existing obligations under our current facilities and limit our access to capital. Our ability to obtain new lines of credit may be limited if financial institutions are unable or unwilling to enter into new facilities. Any inability to access capital may have a material adverse effect on our financial condition, results of operations, and cash flows.

Number 2. *Properties*

Our corporate headquarters are located in Houston, Texas. As of June 30, 2010, 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
Murray	Dalton, GA	Leased(1)(2)
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, or Notes. There is a bargain purchase option whereby we can acquire the asset at the end of the lease for a nominal price.

(2) In addition to the Industrial Revenue Bonds, ultimate title to the real property is held pursuant to a ground lease with a local utility.

Number 3. ***Legal Proceedings***

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

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 November 9, 2007, we filed Form S-1 registration statement with the Securities and Exchange Commission, and on August 18, 2009, we withdrew the registration statement.

The payment of dividends is subject to the restrictions described in Note 4 to the Notes and discussed in Management's Discussion and Analysis of Financial Condition and Results of Operations. We have not paid any dividends on our common stock and do not have any present intention to do so.

Number 5. *Selected Financial Data*

	Year Ended June 30, 2010	Year Ended June 30, 2009	Year Ended June 30, 2008	Period December 4, 2006 through June 30, 2007	Predecessor Information	
					Period July 1, 2006 through February 7, 2007	Year Ended June 30, 2006
	(in thousands)	(in thousands)	(in thousands)	(in thousands)	(in thousands)	(in thousands)
Operating Results Data:						
Revenues:						
Energy sales	$155,389	$206,674	$ 308,605	$ 87,396	$141,080	$264,576
Capacity sales	52,033	54,666	51,416	15,737	34,501	51,688
Total revenues	207,422	261,340	360,021	103,133	175,581	316,264
Operating expenses:						
Cost of fuel	131,898	174,392	268,978	78,127	115,076	222,325
Operating and maintenance	39,636	40,733	52,065	9,722	11,549	18,919
Gas transportation	16,569	16,438	16,382	6,279	9,674	15,893
Selling, general, and administrative	11,689	15,422	29,418	11,777	10,436	14,247
Acquisition contract termination loss	—	—	37,190	—	—	—
Depreciation	23,978	24,272	24,068	9,164	7,614	12,895
Auxiliary power	8,532	8,784	8,437	2,649	4,187	6,905
Insurance	3,466	3,605	3,177	1,531	2,039	3,657
Total operating expenses	235,768	283,646	439,715	119,249	160,575	294,841
Operating (loss) profit	(28,346)	(22,306)	(79,694)	(16,116)	15,006	21,423
Other income (expenses):						
Interest expense	(12,226)	(11,770)	(16,513)	(7,153)	(30,231)	(43,762)
Gain on sale of assets	—	—	—	—	110,109	11,393
Taxes, other than income taxes	(4,134)	(4,355)	(3,457)	(1,161)	(3,106)	(5,821)
Interest income	—	147	2,796	879	3,834	2,361
Other	(230)	(7,206)	(7,065)	912	(3,536)	(900)
Total other (expenses) income	(16,590)	(23,184)	(24,239)	(6,523)	77,070	(36,729)
Net (loss) income before income taxes	(44,936)	(45,490)	(103,933)	(22,639)	92,076	(15,306)
Income tax benefit	—	—	—	3,602	—	—
Net (loss) income after income taxes	$(44,936)	$(45,490)	$(103,933)	$(19,037)	$ 92,076	$(15,306)
Net loss per share—basic and diluted(1)	$ (0.80)	$ (0.81)	$ (1.86)	$ (0.39)	N/A	N/A
Weighted average shares outstanding—basic and diluted(1)	55,969	55,968	55,949	48,603	N/A	N/A
Balance Sheet Data:						
Total property, plant, and equipment, net	$563,525	$648,210	$ 671,114	$693,295	$336,935	$324,799
Total assets	772,254	818,463	870,722	948,767	560,211	546,356
Total current liabilities	23,767	21,078	39,457	20,589	12,492	19,803
Long-term debt	201,000	203,000	195,000	197,000	409,327	479,342
Stockholders'/Member's equity	$529,641	$573,702	$ 615,805	$711,741	$119,695	$ 27,619

(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, 2010. 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, 2010 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 four operational and fully permitted combined-cycle power plants (Murray I, Murray II, Hot Spring and Hinds), located in the southeastern United States with General Electric 7FA gas turbines. Our combined-cycle Plants have an aggregate capacity of 2,390 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 sales proceeds. See discussion below in "*Recent Events*". We acquired our Plants from an affiliate of MatlinPatterson Global Advisors LLC on February 8, 2007.

Three of our four Plants currently operate as merchant power providers. The remaining plant, the Murray I combined-cycle plant, benefits from a fixed-price long-term power purchase agreement, or the GPC PPA, for all of its 630 MW of capacity with Georgia Power, a subsidiary of Southern Company. The GPC PPA, which continues through May 2012, provides for fixed capacity payments that provide stable cash flow. The Company recognized $50.1 million and $50.0 million related to capacity sales on the GPC PPA for the years ended June 30, 2010 and 2009, respectively.

As part of our strategy, we continue to explore and review credible alternatives that may become available to us to enhance shareholder value. Our management team's compensation package includes incentives payable upon successful facility sales or a change in control transaction.

Recent Events

Sandersville Sale—On May 6, 2010, we 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. A subsidiary of ArcLight Energy Partners Fund IV, LP is a shareholder who owns approximately 12% of the Company. We expect to use a portion of our existing tax net operating loss to offset all the taxable gain resulting from the sale. The sale, which was subject to normal representations, warranties, and indemnities, closed on July 9, 2010. We received $129.3 million in 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 we prepaid $58.5 million of our outstanding term debt and $10.0 million of our outstanding working capital facility. For the year ended June 30, 2010, KGen Sandersville LLC's adjusted EBITDA, a non-GAAP financial measure, was a loss of $3.2 million.

Results of Operations

Our results of operations are subject to seasonal variations since demand for electricity, and thus, production capacity, varies with weather conditions. For our merchant plants, we earn the majority of our revenues in the months of May through September. Months other than the peak summer months historically have not been profitable for KGen and are the months during which we typically seek to perform scheduled maintenance-related activities. The below discussion includes the results from our Sandersville plant, whose assets we sold on July 9, 2010. 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, 2010 compared to the Year Ended June 30, 2009.

The following table sets forth our results of operations for the years ended June 30, 2010 and 2009, expressed in thousands of dollars.

	For the Year Ended June 30, 2010	For the Year Ended June 30, 2009	Favorable/(Unfavorable)	
			Change	% Change
Revenues:				
Energy sales	$155,389	$206,674	$(51,285)	(25)%
Capacity sales	52,033	54,666	(2,633)	(5)%
Total revenues	207,422	261,340	(53,918)	(21)%
Operating expenses:				
Cost of fuel	131,898	174,392	42,494	24%
Operating and maintenance	39,636	40,733	1,097	3%
Gas transportation	16,569	16,438	(131)	(1)%
Selling, general, and administrative	11,689	15,422	3,733	24%
Depreciation	23,978	24,272	294	1%
Auxiliary power	8,532	8,784	252	3%
Insurance	3,466	3,605	139	4%
Total operating expenses	235,768	283,646	47,878	17%
Operating loss	(28,346)	(22,306)	(6,040)	(27)%
Other income (expenses):				
Interest expense	(12,226)	(11,770)	(456)	(4)%
Taxes, other than income taxes	(4,134)	(4,355)	221	5%
Interest income	—	147	(147)	(100)%
Other	(230)	(7,206)	6,976	97%
Total other expenses	(16,590)	(23,184)	6,594	28%
Net loss before taxes	(44,936)	(45,490)	554	1%
Income tax benefit	—	—	—	0%
Net loss after taxes	$(44,936)	$(45,490)	$ 554	1%

Operating and Business Metrics We Use to Analyze the Company's Performance for the Year Ended June 30, 2010 and June 30, 2009

In addition to the foregoing results of operations presented in accordance with GAAP, we utilize various non-GAAP operating and business metrics to analyze the Company's performance. We believe these metrics provide useful insight into the Company's performance, assist us in identifying trends in our business, and better allow us to compare our performance to others in our industry. We describe below these various non-GAAP metrics and provide a reconciliation of these metrics for the years ended June 30, 2010 and 2009, to the most directly comparable GAAP measures for those periods. See the reconciliation of net loss to adjusted EBITDA on page 31. This presentation may not include all of the disclosure that SEC regulations require 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, Hot Spring, and Murray II plants and considered our former Sandersville plant to be merchant plants because they are not selling their energy output and capacity pursuant to long-term sales agreements.

	For the Year Ended June 30, 2010	For the Year Ended June 30, 2009
Energy sales	$ 155,389	$ 206,674
Less: Cost of fuel	(131,898)	(174,392)
Less: Contracted energy sales	(36,802)	(43,021)
Add: Contracted cost of fuel	37,387	42,981
Merchant energy margin	24,076	32,242
Capacity sales	52,033	54,666
Less: Contracted capacity sales	(50,101)	(49,975)
Merchant capacity sales	$ 1,932	$ 4,691
Merchant margin	$ 26,008	$ 36,933

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

	For the Year Ended June 30, 2010	For the Year Ended June 30, 2009
Energy sales	$ 155,389	$ 206,674
Less: Merchant sales	(118,587)	(163,653)
Contracted energy sales	36,802	43,021
Less: Contracted cost of fuel	(37,387)	(42,981)
Add: Power sales rights and obligations amortization	8,112	8,112
Adjusted contracted energy margin	7,527	8,152
Contracted capacity sales	50,101	49,975
Add (Less): Noncash deferred capacity revenue	194	(668)
Adjusted contracted capacity sales	$ 50,295	$ 49,307
Adjusted contracted margin	$ 57,822	$ 57,459

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

	For the Year Ended June 30, 2010	For the Year Ended June 30, 2009
Merchant margin	$26,008	$36,933
Adjusted contracted margin	57,822	57,459
Total adjusted margin	$83,830	$94,392

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

	For the Year Ended June 30, 2010	For the Year Ended June 30, 2009
Total operating expenses	$ 235,768	$ 283,646
Less: Cost of fuel	(131,898)	(174,392)
Less: Major maintenance expense	(15,175)	(19,447)
Less: Gas transportation noncash amortization	(1,109)	(1,182)
Less: Selling, general, and administrative expense	(11,666)	(15,422)
Less: Termination and transition costs	(684)	—
Less: Depreciation	(23,978)	(24,272)
Less: D&O insurance expense	(179)	(352)
Add: Taxes, other than income taxes	4,134	4,355
Adjusted plant expenses	$ 55,213	$ 52,934

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, 2010	For the Year Ended June 30, 2009
Selling, general, and administrative expense	$11,666	$15,422
Less: Noncash employee options/awards expense	(875)	(3,271)
Less: Employee severance expense	(1)	(795)
Less: Sale of plant expense	(788)	—
Add: D&O insurance expense	179	352
Adjusted corporate expenses	$10,181	$11,708

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, 2010	For the Year Ended June 30, 2009	Favorable/(Unfavorable)	
			Change	% Change
Merchant energy margin	$24,076	$32,242	$ (8,166)	(25)%
Merchant capacity sales	1,932	4,691	(2,759)	(59)%
Merchant margin	26,008	36,933	(10,925)	(30)%
Adjusted contracted energy margin	7,527	8,152	(625)	(8)%
Adjusted contracted capacity sales	50,295	49,307	988	2%
Adjusted contracted margin	57,822	57,459	363	1%
Total adjusted margin	83,830	94,392	(10,562)	(11)%
Adjusted plant expenses	55,213	52,934	(2,279)	(4)%
Adjusted plant EBITDA	28,617	41,458	(12,841)	(31)%
Adjusted corporate expenses	10,181	11,708	1,527	13%
Adjusted EBITDA	$18,436	$29,750	$(11,314)	(38)%

Selected Operating and Business Metrics

	For the Year Ended June 30, 2010	For the Year Ended June 30, 2009	Favorable/(Unfavorable)	
			Change	% Change
Selected Financial and Operating Data				
Total generation (GWh)	4,133	3,917	216	6%
Merchant generation (GWh)	3,124	3,137	(13)	(0)%
Merchant margin/merchant generation ($/MWh)	$ 8.33	$11.77	$(3.44)	(29)%

Selected Market and Weather Data

	For the Year Ended June 30, 2010	For the Year Ended June 30, 2009	Change	% Change
Selected Market Data(1)				
Average on-peak market power price— Entergy ($/MWh)	$35.57	$46.09	$(10.52)	(23)%
Average on-peak market power price— Southern ($/MWh)	$37.88	$50.63	$(12.75)	(25)%
Average Henry Hub gas price ($/MMbtu)	$ 4.21	$ 5.95	$ (1.74)	(29)%
Selected Weather Data				
Actual CDDs(2)	6,348	6,154	194	3%
Normal CDDs	5,283	5,284	(1)	(0)%
Actual HDDs(3)	8,927	7,364	1,563	21%
Normal HDDs	7,915	7,915	—	0%

Notes:

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

(2) CDD, or cooling degree days, represents the number of degrees 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 during November through March 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, 2010 compared to the Year Ended June 30, 2009.

Total adjusted margin decreased $10.6 million, or 11%, to $83.8 million for the year ended June 30, 2010 compared to the same period in the previous year as a result of a $10.9 million decrease in merchant margin partially offset by a $0.3 million increase in adjusted contracted margin. The $83.8 million in total adjusted margin was comprised of $26.0 million in merchant margin and $57.8 million in adjusted contracted margin.

Merchant margin decreased $10.9 million, or 30%, to $26.0 million for the year ended June 30, 2010. The $10.9 million decrease was made up of an $8.2 million decrease in merchant energy margin and a $2.7 million decrease in merchant capacity sales. The $8.2 million decrease in merchant energy margin related primarily to the decrease in natural gas prices, as evidenced by a 29% decrease in the average Henry Hub gas price from $5.95 per MMbtu to $4.21 per MMbtu for the year ended June 30, 2010 as compared to the previous year, the absence of favorable gas basis differentials at Hot Spring in the 2009 and 2010 period compared to 2008, and the pipeline operational constraints that developed in 2009 that have limited Hot Spring to selling longer schedules which generally have lower financial value. In our markets, merchant energy margins are in part a function of natural gas prices and market heat rates. Thus, lower gas prices at the same level of market heat rates will yield lower merchant energy margins. The $2.7 million decrease in merchant capacity sales was attributable to $4.7 million in merchant capacity sales from a portion of the Murray II plant in the prior year, offset by merchant capacity sales from the Hinds plant in the current year of $2.0 million. The implied merchant spark spread, or merchant margin divided by merchant generation, decreased from $11.77 per MWh to $8.33 per MWh, largely due to the decrease in merchant capacity sales, the effects of generally lower market gas prices and the absence of favorable gas basis differentials at Hot Spring in the 2009 and 2010 period compared to 2008.

Adjusted contracted margin increased $0.3 million, or 1%, to $57.8 million for the year ended June 30, 2010, which was comprised of $7.5 million in adjusted contracted energy margin and $50.3 million in adjusted contracted capacity sales. The $0.3 million increase was made up of a $0.9 million increase in the adjusted contracted capacity sales offset by a $0.6 million decrease in the adjusted contracted energy margin. The $0.9 million increase in adjusted contracted capacity sales was a result of the escalation of the pricing in the GPC PPA. The $0.6 million decrease in adjusted contracted energy margin was largely attributable to lower revenues from the GPC PPA as a result of lower natural gas prices and was also offset by a reduction of costs of replacement power purchased in connection with the GPC PPA for the year ended June 30. 2010 compared to the previous year.

Adjusted plant expenses increased by $2.3 million, or 4%, to $55.2 million for the year ended June 30, 2010. The increase primarily related to $1.0 million associated with the performance of certain non-critical maintenance that was deferred from the previous year, a $0.5 million increase in the LTSA bonus paid, and $0.3 million in costs related to the impact of freezing weather on operations at the Murray facility.

As a result of the foregoing changes in total adjusted margin and adjusted plant expenses, adjusted plant EBITDA decreased by $12.8 million to $28.6 million for the year ended June 30, 2010.

Adjusted corporate expenses decreased by $1.5 million, or 13%, to $10.2 million for the year ended June 30, 2010. The decrease was primarily related to a $0.9 million decrease in payroll expenses, a $0.7 million decrease in commercial marketing fees, and a $0.5 million decrease in legal and professional services expenses.

As a result of the foregoing, adjusted EBITDA decreased by $11.3 million to $18.4 million for the year ended June 30, 2010.

GAAP to Non-GAAP Adjusted EBITDA Reconciliation

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

	For the Year Ended June 30, 2010	For the Year Ended June 30, 2009
Net loss after taxes	$(44,936)	$(45,490)
Add: Interest expense	12,226	11,770
Less: Net interest income	—	(147)
Add: Depreciation	23,978	24,272
Add: Power sales rights and obligations amortization	8,112	8,112
Add: Gas transportation noncash amortization	1,109	1,182
Add (Less): Noncash deferred capacity revenue	194	(668)
Add: Other expenses	230	7,206
EBITDA	913	6,237
Add: Major maintenance expense	15,175	19,447
Add: Termination and transition costs	684	—
Add: Noncash employee options/awards expense	875	3,271
Add: Employee severance expense	1	795
Add: Sale of plant expense	788	—
Adjusted EBITDA	18,436	29,750
Add: Selling, general, and administrative expense	11,666	15,422
Less: Noncash employee options/awards expense	(875)	(3,271)
Less: Employee severance expense	(1)	(795)
Less: Sale of plant expense	(788)	—
Add: D&O insurance expense	179	352
Adjusted plant EBITDA	$ 28,617	$ 41,458

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 loss after taxes using these financial measures for the year ended June 30, 2010 compared to the year ended June 30, 2009.

- Interest expense for the year ended June 30, 2010 was $12.2 million compared to $11.8 million for the same period in 2009. In order to more accurately reflect our financing costs for the year ended June 30, 2010, we elected to move gains and losses on derivatives from the other expense line and reflect them in the interest expense line of our consolidated statement of operations. The $0.5 million increase was made up of a $3.8 million decrease in interest expense due to a reduction of interest rates and outstanding debt compared to the same period in the previous year, offset by $4.3 million in losses on derivatives associated with our interest rate hedging and cash payments on our Swaps.

- Interest income was offset by banking fees for the year ended June 30, 2010. Interest income was $0.1 million for the year ended June 30, 2009. The decrease in interest income was related to lower interest rates when compared to the same period in the previous year.

- Depreciation was $24.0 million and $24.3 million for the years ended June 30, 2010 and 2009, respectively.

- Amortization of contract-based power sales rights and obligations, for both twelve month periods, was $8.1 million and was recorded as a reduction of energy sales.

- Amortization of contract-based natural gas transportation rights and obligations was $1.1 million and $1.2 million for the years ended June 30, 2010 and 2009, and was recorded as an increase of gas transportation expense.

- Noncash deferred capacity revenue, which represents the levelization of capacity sales over the GPC PPA term, of $0.2 million of expense and $0.7 million of revenue for the years ended June 30, 2010 and 2009, respectively, was recorded as capacity sales.

- Other expense for the years ended June 30, 2010 and 2009 was $0.2 million and $7.2 million, respectively. The $0.2 million related to various financing fees and the $7.2 million in the prior year was primarily related to losses on derivatives associated with our interest rate hedging due to cash payments on and a change in the valuation of our Swaps. For the year ended June 30, 2010, the losses on derivatives were reflected in the interest expense line of our consolidated statement of operations.

- Major maintenance expense was $15.2 million and $19.4 million for the years ended June 30, 2010 and 2009, respectively. 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 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 $19.4 million expense in fiscal 2009 primarily related to $18.9 million in connection with the fall 2008 hot gas path inspection performed at Murray II and $0.5 million in other major maintenance expenses at the Hot Spring plant.

- Termination and transition costs were $0.7 million and zero for the years ended June 30, 2010 and 2009, respectively. The $0.7 million expense related to a $0.4 million one-time termination fee paid to DEGS and $0.3 million in transition costs related to the change in operating and maintenance providers.

- Noncash employee options/awards expense for the years ended June 30, 2010 and 2009 was $0.9 million and $3.3 million, respectively, and was recorded as an increase of selling, general, and administrative expense.

- Sale of plant expenses for the years ended June 30, 2010 and 2009 were $0.8 million and zero, respectively, and were recorded as an increase of selling, general, and administrative expense. The

$0.8 million related to expenses associated with the intended sale of the Company's Sandersville power generation facility.

- Selling, general, and administrative expense was $11.7 million and $15.4 million for the years ended June 30, 2010 and 2009, respectively. The decrease was primarily related to $2.4 million decrease in noncash employee options/awards expense, a $0.9 million decrease in payroll expenses, a $0.7 million decrease in commercial marketing fees, a $0.5 million decrease in legal and professional services expenses, offset by an $0.8 million increase in expenses associated with the intended sale of the Company's Sandersville power generation facility.

Liquidity and Capital Resources

Liquidity Position

We expect that cash on hand, cash flow provided by operations, and cash available under our Credit Facility will satisfy our short-term liquidity needs with respect to our current portfolio of working capital assets over the next 12 months. Our liquidity was comprised of the following at June 30, 2010 (in thousands of dollars):

Unrestricted cash and cash equivalents	$ 48,177
Working capital revolver and synthetic letter of credit facility (net of letters of credit issued and cash draws thereunder)	76,126
Total	$124,303

Our principal sources of funds are cash flows from operations and borrowings under our Credit Facility. Our principal use of funds consists of operating expenditures, payments of principal and interest on our Credit Facility, and capital expenditures. On June 30, 2010, we had $76.1 million available under our Credit Facility, of which $56.0 million was under the working capital revolver and $20.1 million was under the synthetic letter of credit facility, for activities related to our plants. We had unrestricted cash on hand of $48.2 million, of which $27.9 million was cash at the parent level and not subject to the lien of the Credit Agreement at June 30, 2010. Similarly, $32.0 million was the balance at the parent level not subject to the Credit Agreement at June 30, 2009. The cash balances on hand at June 30, 2010 do not reflect the $129.3 million in proceeds from the Sandersville sale on July 9, 2010. Management believes that cash on hand, amounts available under our Credit Facility, and cash flows from operations will be adequate to finance capital expenditures and other liquidity commitments over the next 12 months.

Debt and Credit Facility

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

- a $200.0 million term loan facility, or the Term Loan Facility;
- an $80.0 million working capital facility for letters of credit and other liquidity needs, or the Working Capital Facility; and
- a $120.0 million synthetic letter of credit facility to support the collateral requirements under the project documents related to the facilities, or the Collateral Credit Facility.

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

On March 20, 2009, KGen LLC drew $10.0 million under the Working Capital Facility to be used for working capital purposes. Total letters of credit issued under the Working Capital Facility were

$14.0 million as of June 30, 2010. Total letters of credit issued under the Collateral Credit Facility were $99.9 million as of June 30, 2010.

Interest Rate. Borrowings under the Credit Facility bear interest at a spread above LIBOR-based loans. The $200.0 million Term Loan Facility bears interest at LIBOR plus 175 basis points. Please refer to "Number 7. *Quantitative and Qualitative Disclosures About Market Risk*." Amounts borrowed under the $80.0 million Working Capital Facility bear interest at LIBOR plus 200 basis points.

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

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

Security. Borrowings under the Credit Facility are secured by substantially all of the assets of our subsidiaries, which constitute all of our operating assets and generate substantially all of our operating cash flows. Our only significant asset not subject to the lien of the Credit Agreement was a cash balance of $27.9 million at June 30, 2010 that was held at our parent company level.

The Credit Facility and related financing documents contain various affirmative and negative covenants, including (a) financial covenants, (b) limitations on KGen LLC's ability to pay dividends, (c) restrictions on the use of available cash for operations, except as required for debt service payments and, (d) an event of default in the event of a change in control of KGen. At June 30, 2010, we were in compliance with the covenants contained within our Credit Facility.

On May 14, 2010, Standard & Poor's Rating Service affirmed a BB- rating on our Credit Facility with a negative outlook. On July 21, 2010, Moody's Investors Service affirmed a B1 rating on our Credit Facility and revised the outlook to stable.

Contractual Obligations

Our contractual obligations consist primarily of principal and interest payments on debt, 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 as well as from available borrowing under our revolving Working Capital Facility under our Credit Facility. We believe that our sources of liquidity will be sufficient to meet our contractual obligations. The $200.0 million term debt was funded on February 8, 2007. The following table sets forth our contractual obligations as of June 30, 2010 (in thousands of dollars):

	Total	Less than 1 year	1-3 years	3-5 years	More than 5 years
Term debt(1)(2)	$193,000	$ 2,000	$191,000	$ —	$ —
Working capital facility(2)	10,000	—	10,000	—	—
Pipeline payments	152,995	14,797	39,203	38,780	60,215
Hot Spring lateral pipeline	133,540	—	20,031	20,031	93,478
LTSA	31,642	1,036	3,299	3,605	23,702
Other(3)	4,801	774	2,032	1,710	285
Total	$525,978	$18,607	$265,565	$64,126	$177,680

(1) Future interest obligations under our term debt are uncertain due to the variable interest rate. The term debt bears interest at an adjusted rate of LIBOR plus 175 basis points, or 2.1% at June 30, 2010. Based on a 2.1% interest rate at June 30, 2010, $4.0 million and

$10.6 million would be due under the term debt facility in less than one year and one to three years, respectively.

(2) Amounts do not reflect any prepayments made from the $129.3 million in proceeds received from the Sandersville sale on July 9, 2010.

(3) Minimum lease rental payments have not been reduced by minimum sublease rentals of $1.4 million due in the future under noncancelable subleases.

Capital Expenditures and Major Maintenance

Total capital expenditures for the years ended June 30, 2010 and 2009 were $2.2 million and $1.4 million, respectively. Of these amounts, $0.3 million and zero related to capital expenditures for the Sandersville plant for the years ended June 30, 2010 and 2009, respectively.

Major maintenance expense was $15.2 million and $19.4 million for the years ended June 30, 2010 and 2009, respectively. 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 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 $19.4 million expense in fiscal 2009 primarily related to $18.9 million in connection with the fall 2008 hot gas path inspection performed at Murray II and $0.5 million in other major maintenance expenses at the Hot Spring plant.

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 major maintenance expenses of $3.7 million for fiscal year 2011.

Cash Flow Analysis

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

	For the Year Ended June 30, 2010	For the Year Ended June 30, 2009
Statements of Cash Flows Data:		
Cash flows provided by (used in):		
Operating activities	$(14,980)	$(11,043)
Investing activities	24,494	(7,787)
Financing activities	(2,000)	8,000
Increase (decrease) in cash and cash equivalents	7,514	(10,830)
Cash and cash equivalents at beginning of period	40,663	51,493
Cash and cash equivalents at end of period	$ 48,177	$ 40,663

Cash Flows from Operating Activities. Our cash flows used in operations were $15.0 million for the year ended June 30, 2010, primarily related to a net loss of $44.9 million, payments from settlement of derivative instruments of $6.0 million, a $3.5 million decrease in accounts receivable, a $1.4 million decrease in spare parts inventory, and a $0.6 million decrease in prepaid expenses and other current assets, which was offset primarily by depreciation expense of $24.0 million, amortization expense of $9.2 million, valuation of derivative instruments of $4.3 million, stock-based compensation of $0.9 million, and a increase in accounts payable of $2.1 million. We also incurred $7.1 million of cash interest during the period under our outstanding Credit Facility.

Cash Flows from Investing Activities. Our cash flows provided by investing activities for the year ended June 30, 2010 were $24.5 million and related primarily a $25.8 million use of restricted cash and cash equivalents offset by $1.3 million in purchases of property, plant, and equipment.

Cash Flows from Financing Activities. Our cash flows used in financing activities for the year ended June 30, 2010 were $2.0 million and represented $2.0 million in principal payments of long-term debt as required by the Credit Facility.

Off-Balance Sheet Arrangements

The Company did not participate in or have any off-balance sheet arrangements for the years ended June 30, 2010 and 2009, 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.

Recent Accounting Pronouncements

In June 2009, the Financial Accounting Standards Board ("FASB") issued FASB Accounting Standards Codification 105 ("FASB ASC") *Generally Accepted Accounting Principles*, which establishes the FASB ASC as the sole source of authoritative generally accepted accounting principles ("GAAP"). Pursuant to the provisions of FASB ASC 105, the Company updated references to GAAP in its financial statements issued for the year ended June 30, 2010. The adoption of FASB ASC 105 did not impact the Company's financial position or results of operations.

In August 2009, FASB ASC 820-10 *Fair Value Measurements and Disclosures* was issued, effective for the Company for interim periods ending December 2009. In January 2010, an update to FASB ASC 820-10 was issued. FASB ASC 820-10 defines fair value, establishes a framework for measuring fair value in generally accepted accounting principles, and expands disclosures about fair value measurements. The Company adopted this guidance for the year ended June 30, 2010, and it did not have a material impact on its financial position or results of operations.

In February 2010, an update was issued to FASB ASC 855 *Subsequent Events,* effective for the Company for periods ending June 2010. FASB ASC 855 establishes general standards of accounting for and disclosure of events that occur after the balance sheet date but before financial statements are issued or are available to be issued. The Company adopted this guidance for the year ended June 30, 2010 and it did not have a material impact on its financial position or results of operations.

In March and April 2010, an update was issued to FASB ASC 740 *Income Taxes*. FASB ASC 740 establishes financial accounting and reporting standards for the effects of income taxes that result from an enterprise's activities during the current and preceding years. The Company adopted this guidance for the year ended June 30, 2010 and it did not have a material impact on its financial position or results of operations.

Number 7. ***Quantitative and Qualitative Disclosures about Market Risk***

Interest Rate Risks

Our primary market risk is the potential impact of changes in interest rates on our variable rate borrowings. Prior to February 7, 2010, the terms of our Credit Facility required us to maintain interest hedge arrangements on at least fifty percent of our outstanding term debt balance to reduce our exposure to market risk from changes in the interest rate. As a result, we entered into interest rate swaps in order to mitigate the risk associated with the variable rate borrowings.

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

	Maturity Date	Notional Amount	June 30, 2010		June 30, 2009	
			Fair Value	Fixed Rate	Fair Value	Fixed Rate
		(in millions)	(in thousands)		(in thousands)	
Contract #1	Expired	$ —	$ —	—	$ —	—
Contract #2	Expired	$ —	$ —	—	$ —	—
Contract #3	Expired	$ —	$ —	—	$ (922)	4.9%
Contract #4	3-31-2011	$33.0	$ (998)	5.0%	$(1,869)	5.0%
Contract #5	3-31-2012	$33.0	$(2,212)	5.0%	$(2,455)	5.0%
Contract #6	3-31-2013	$33.0	$(3,135)	5.1%	$(2,778)	5.1%

As of June 30, 2010, a significant portion of our outstanding variable rate debt has been converted to a fixed rate through the Swaps. We are exposed to credit related losses in the event of non-performance by the counterparty to the Swaps, however our counterparty is a major financial institution and we consider such risk of loss to be minimal. We will continue to monitor the creditworthiness of our counterparty in light of the current unfavorable financial markets.

Number 8. ***Financial Statements and Supplementary Data***

KGen Power Corporation

Consolidated Financial Statements

For the Years Ended June 30, 2010 and 2009

Contents

INDEPENDENT AUDITORS' REPORT

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

We have audited the accompanying consolidated balance sheet of KGen Power Corporation and subsidiaries (the "Company") as of June 30, 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 audit. The consolidated financial statements of the Company for the year ended June 30, 2009 were audited by other auditors whose report, dated September 25, 2009, expressed an unqualified opinion on those statements.

We conducted our audit 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, 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, 2010

KGen Power Corporation

Consolidated Balance Sheets

(in thousands, except per share amounts)

	June 30, 2010	June 30, 2009
Assets		
Current assets:		
Cash and cash equivalents	**$ 48,177**	$ 40,663
Restricted cash and cash equivalents	**7,167**	32,943
Accounts receivable	**26,329**	22,815
Spare parts inventories	**8,009**	7,232
Prepaid expenses and other current assets	**1,947**	1,336
Assets held for sale	**63,580**	—
Total current assets	**155,209**	104,989
Property, plant, and equipment	**637,344**	705,711
Less: accumulated depreciation	**73,819**	57,501
Net property, plant, and equipment	**563,525**	648,210
Contract-based intangibles (net of $36,154 and $25,498 of accumulated amortization, respectively)	**47,388**	58,044
Deferred charge	**2,575**	2,769
Deferred financing fees (net of $3,032 and $2,138 of accumulated amortization, respectively)	**3,232**	4,126
Other noncurrent assets	**325**	325
Total assets	**$ 772,254**	$ 818,463
Liabilities and stockholders' equity		
Current liabilities:		
Accounts payable and accrued liabilities	**$ 20,983**	$ 19,078
Current portion of long-term debt	**2,000**	2,000
Liabilities associated with assets held for sale	**784**	—
Total current liabilities	**23,767**	21,078
Long-term debt	**201,000**	203,000
Contract-based intangibles (net of $5,039 and $3,604 of accumulated amortization, respectively)	**15,129**	16,564
Other noncurrent liabilities	**2,717**	4,119
Commitments and contingencies (Note 6)		
Stockholders' equity:		
Common stock (par value $.01; 150,000 shares authorized; 55,974 and 55,968 shares issued and outstanding at June 30, 2010 and 2009, respectively)	**560**	560
Additional paid in capital	**742,477**	741,602
Accumulated deficit	**(213,396)**	(168,460)
Total stockholders' equity	**529,641**	573,702
Total liabilities and stockholders' equity	**$ 772,254**	$ 818,463

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, 2010	For the Year Ended June 30, 2009
Revenues:		
Energy sales	**$155,389**	$206,674
Capacity sales	**52,033**	54,666
Total revenues	**207,422**	261,340
Operating expenses:		
Cost of fuel	**131,898**	174,392
Operating and maintenance	**39,636**	40,733
Gas transportation	**16,569**	16,438
Selling, general, and administrative	**11,689**	15,422
Depreciation	**23,978**	24,272
Auxiliary power	**8,532**	8,784
Insurance	**3,466**	3,605
Total operating expenses	**235,768**	283,646
Operating loss	**(28,346)**	(22,306)
Other income (expenses):		
Interest expense	**(12,226)**	(11,770)
Taxes, other than income taxes	**(4,134)**	(4,355)
Interest income	**—**	147
Other	**(230)**	(7,206)
Total other expenses	**(16,590)**	(23,184)
Net loss before taxes	**(44,936)**	(45,490)
Income tax benefit	**—**	—
Net loss after taxes	**$ (44,936)**	$ (45,490)
Net loss per share—basic and diluted	**$ (0.80)**	$ (0.81)
Weighted average shares outstanding—basic and diluted	**55,969**	55,968

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, 2010 and 2009

	Common Stock		Additional	Accumulated	
	Shares	Amount	Paid in Capital	Deficit	Total
Balance at June 30, 2008	55,963	$560	$738,215	$(122,970)	$615,805
Stock-based compensation	5	—	3,387	—	3,387
Net loss		—	—	(45,490)	(45,490)
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**

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, 2010	For the Year Ended June 30, 2009
Cash flows from operating activities		
Net loss	**$(44,936)**	$(45,490)
Adjustments to reconcile net loss to net cash used in operating activities:		
Depreciation	**23,978**	24,272
Amortization of deferred financing fees	**894**	895
Amortization of contract-based intangibles	**9,221**	9,295
Valuation of derivative instruments	**4,276**	7,202
Stock-based compensation	**875**	3,387
Payments from settlement of derivative instruments	**(5,957)**	(5,637)
Changes in operating assets and liabilities:		
Accounts receivable	**(3,514)**	13,948
Spare parts inventories	**(1,418)**	177
Prepaid expenses and other current assets	**(611)**	(64)
Deferred charge	**194**	(668)
Accounts payable and accrued liabilities	**2,081**	(18,353)
Other noncurrent assets	**(56)**	—
Other noncurrent liabilities	**(7)**	(7)
Net cash used in operating activities	**(14,980)**	(11,043)
Cash flows from investing activities		
Purchases of property, plant, and equipment	**(1,282)**	(1,368)
Short-term investments	**—**	2,199
Use of (investment in) restricted cash and cash equivalents	**25,776**	(8,618)
Net cash provided by (used in) investing activities	**24,494**	(7,787)
Cash flows from financing activities		
Repayment of debt	**(2,000)**	(2,000)
Borrowings from working capital revolver	**—**	10,000
Net cash (used in) provided by financing activities	**(2,000)**	8,000
Increase (decrease) in cash and cash equivalents	**7,514**	(10,830)
Cash and cash equivalents at beginning of period	**40,663**	51,493
Cash and cash equivalents at end of period	**$ 48,177**	$ 40,663
Cash paid for		
Interest	**$ 7,079**	$ 10,847
Noncash transactions		
Grant of shares for Board fees	**$ —**	$ 116
Grant of shares to Director	**$ 40**	$ —
Accounts payable related to purchases of property, plant, and equipment	**$ 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, 2010 and 2009

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, 2010, the Company's portfolio of facilities consisted of five operational and fully permitted power plants (the "Plants") located in the southeastern United States with gas turbines having an aggregate capacity of 3,030 megawatts ("MW"). The Plants include four combined-cycle plants (Murray I, Murray II, Hot Spring, and Hinds) and one simple-cycle plant (Sandersville), which the Company sold on July 9, 2010, pursuant to a definitive agreement (see Note 12). The Plants were acquired from an affiliate of MatlinPatterson Global Advisors LLC on February 8, 2007.

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 of June 30, 2010, 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 financial statements in conformity with accounting principles generally accepted in the United States requires management to make estimates and assumptions that affect the amounts reported in the 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.

Effects of Seasonality

The electric power industry is highly seasonal. In the summer months, especially in the southeastern United States, demand for electricity is usually much higher as a result of increased use of air conditioning. The Company's results of operations are subject to seasonal variations since demand for electricity, and thus production capacity, varies with weather conditions. Four of the plants operate on a merchant basis without long-term purchase agreements, and therefore are exposed to significant volatility in prices and generation demand. The Company earns the majority of its annual revenues in the five summer months, May through September. The shoulder periods, months other than the peak summer months, historically

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

have not been profitable for the Company and are 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.

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, 2010 or 2009.

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.

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, 2010 and 2009, 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 are capitalized costs associated with debt issuance. Costs incurred to secure debt were capitalized and are being amortized over the life of the borrowing.

Fair Value of Financial Instruments

The Company's financial instruments consist primarily of cash and cash equivalents, restricted cash and cash equivalents, accounts receivable, accounts payable, debt instruments, and interest rate derivatives. The carrying values of 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

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

to the short-term nature of these instruments. The carrying value of interest rate derivative instruments represents the fair value, which is based on estimates using standard pricing models that take 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.

Concentration of Credit Risk

The Company's only two customers as of June 30, 2010 are Georgia Power Company ("GPC") and BNP Paribas Energy Trading GP ("BNP"). The Company does not believe these customers represent 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. If a substantial portion of the Company's long-term power sales contract with GPC was modified or terminated, the Company could be adversely affected to the extent that it would be unable to find other customers at the same level of contract profitability. The Company does not believe these customers represent a significant credit risk due to their payment history and, therefore, does not require collateral for accounts receivable. However, the contracts do provide for the customers to post collateral upon certain defined credit-related events. Approximately 75% of the accounts receivable balance at June 30, 2010 represented amounts owed from GPC and approximately 25% represented amounts owed from BNP. Revenues recognized from GPC represented approximately 42% of the total revenues for the year ended June 30, 2010 and approximately 58% represented revenues recognized from BNP.

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.

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.

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

Loss Per Share

Basic loss per share is calculated by dividing net loss by the weighted average number of shares of common stock outstanding during the period. Fully diluted loss per share is computed on the same basis as basic loss per share as the inclusion of any other potential shares outstanding would be anti-dilutive. There were no unexercised in-the-money stock options to purchase shares of common stock for the years ended June 30, 2010 and 2009. Unexercised out-of-the-money stock options to purchase a weighted average of 1,469,590 shares and 2,517,831 shares of common stock for the years ended June 30, 2010 and 2009, respectively, were not considered in the loss per share calculation as such inclusion would have been anti-dilutive. Had the Company recognized net income for the years ended June 30, 2010 and 2009, incremental shares attributable to restricted stock awards would have increased diluted shares outstanding by 7,420 shares and 2,799 shares for the years ended June 30, 2010 and 2009, respectively. Amounts shown below are in thousands, except per share amounts.

	For the Year Ended June 30, 2010	For the Year Ended June 30, 2009
Numerator:		
Net loss	$(44,936)	$(45,490)
Denominator:		
Weighted average shares outstanding—basic and diluted	55,969	55,968
Net loss per share—basic and diluted	$ (0.80)	$ (0.81)

Other Comprehensive Income

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

New Accounting Pronouncements

In June 2009, the Financial Accounting Standards Board ("FASB") issued FASB Accounting Standards Codification 105 ("FASB ASC") *Generally Accepted Accounting Principles*, which establishes the FASB ASC as the sole source of authoritative generally accepted accounting principles ("GAAP"). Pursuant to the provisions of FASB ASC 105, the Company updated references to GAAP in its financial statements issued for the year ended June 30, 2010. The adoption of FASB ASC 105 did not impact the Company's financial position or results of operations.

In August 2009, FASB ASC 820-10 *Fair Value Measurements and Disclosures* was issued, effective for the Company for interim periods ending December 2009. In January 2010, an update to FASB ASC 820-10 was issued. FASB ASC 820-10 defines fair value, establishes a framework for measuring fair value in generally accepted accounting principles, and expands disclosures about fair value measurements. The Company adopted this guidance for the year ended June 30, 2010, and it did not have a material impact on its financial position or results of operations.

In February 2010, an update was issued to FASB ASC 855 *Subsequent Events,* effective for the Company for periods ending June 2010. FASB ASC 855 establishes general standards of accounting for and disclosure of events that occur after the balance sheet date but before financial statements are issued

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

or are available to be issued. The Company adopted this guidance for the year ended June 30, 2010 and it did not have a material impact on its financial position or results of operations.

In March and April of 2010, an update was issued to FASB ASC 740 *Income Taxes*. FASB ASC 740 establishes financial accounting and reporting standards for the effects of income taxes that result from an enterprise's activities during the current and preceding years. The Company adopted this guidance for the year ended June 30, 2010 and it did not have a material impact on its financial position or results of operations.

2. Property, Plant, and Equipment

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

	Estimated Useful Life	June 30, 2010	June 30, 2009
Land	—	$ 3,312	$ 4,201
Buildings	40 years	26,382	28,612
Gas and steam turbines	30 years	181,733	235,985
Steam generators and auxiliaries	30 years	48,959	48,402
Transmission and fuel gas pipelines	30 years	51,038	57,191
Systems and equipment	5-30 years	120,210	122,616
Other plant	3-30 years	205,710	208,704
Total property, plant, and equipment		637,344	705,711
Less: accumulated depreciation		73,819	57,501
Net property, plant, and equipment		$563,525	$648,210

During the year ended June 30, 2010, the Company decided to sell the assets of its simple-cycle generation facility (see Note 12).

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				
Hinds firm transportation contract	March 31, 2010	$ 669	$ (669)	$ —
Murray firm transportation contract	November 30, 2016	638	(222)	416
Hot Spring firm transportation contracts	Various	18,861	(4,148)	14,713
Total liabilities		$20,168	$ (5,039)	$15,129

	Term	Original Cost	Accumulated Amortization	June 30, 2009
Assets				
Murray I Georgia Power contract	May 31, 2012	$43,265	$(19,411)	$23,854
Murray firm transportation contracts	Various	40,277	(6,087)	34,190
Total assets		$83,542	$(25,498)	$58,044
Liabilities				
Hinds firm transportation contract	March 31, 2010	$ 669	$ (522)	$ 147
Murray firm transportation contract	November 30, 2016	638	(157)	481
Hot Spring firm transportation contracts	Various	18,861	(2,925)	15,936
Total liabilities		$20,168	$ (3,604)	$16,564

For the years ended June 30, 2010 and 2009, amortization of contract-based power sales rights and obligations was $8.1 million and was recorded as a reduction of energy sales on the consolidated statements of operations. For the years ended June 30, 2010 and 2009, amortization of contract-based natural gas transportation rights and obligations was $1.1 million and $1.2 million, respectively, and was recorded as an increase of gas transportation expenses on the consolidated statements of operations.

4. Long-Term Debt

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

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

On February 8, 2007, KGen LLC, a wholly-owned subsidiary of the Company, entered into a credit agreement with Morgan Stanley (the "Credit Agreement") and related security deposit agreement (the "Security Deposit Agreement") with Union Bank, N.A., as collateral agent, and The Bank of New York, as depository agent, to provide term debt in the amount of $200.0 million. The term debt bears interest at an adjusted rate based on the London Interbank Offered Rate ("LIBOR") plus 175 basis points, has a term of

4. Long-Term Debt (Continued)

seven years, and requires a $2.0 million principal payment per year made in quarterly installments. KGen LLC's obligations and indebtedness under the Credit Agreement are secured by a security interest in all of the assets and all of the membership interests of KGen LLC and its subsidiaries. The interest rate on the term debt was 2.1% at both June 30, 2010 and 2009.

KGen LLC also entered into an $80.0 million working capital facility for other liquidity needs and a $120.0 million synthetic letter of credit facility to support the collateral requirements at the project level. The working capital facility charges a 200 basis point fee for outstanding letters of credit, bears interest at LIBOR plus 200 basis points for outstanding draws, and has a 50 basis point commitment fee for any unused portion. It has a five-year term expiring on February 8, 2012. On March 20, 2009, KGen LLC drew $10.0 million under the working capital facility. For the year ended June 30, 2010, the proceeds of the drawdown were used for working capital purposes. There were $14.0 million and $8.0 million of outstanding letters of credit issued under the working capital facility as of June 30, 2010 and 2009, respectively. KGen LLC pays a fee of 191 basis points on the $120.0 million synthetic letter of credit facility. The synthetic letter of credit facility has a seven-year term expiring on February 8, 2014. At both June 30, 2010 and 2009, a letter of credit, supporting the power sales contract with GPC, with a current outstanding amount of $80.0 million, and $19.9 million of other letters of credit were outstanding under the synthetic letter of credit facility.

The remaining future minimum principal payments under the term debt and the working capital facility subsequent to June 30, 2010 are as follows (in thousands of dollars):

2011	2,000
2012	12,000
2013	2,000
2014	187,000
Total	$203,000

The Credit Agreement and related financing documents contain various affirmative and negative covenants, including (a) financial covenants, (b) limitations on KGen LLC's ability to pay dividends, (c) restrictions on the use of available cash for operations, except as required for debt service payments and (d) an event of default in the event of a change in control of KGen. At June 30, 2010, KGen LLC was in compliance with these covenants.

Under the terms of the Credit Agreement, KGen LLC is restricted from making dividend payments, loans or advances to the Company. These restrictions resulted in restricted net assets of the Company's subsidiaries exceeding 25% of the consolidated net assets of the Company and its subsidiaries. The amount of restricted net assets was $490.0 million at June 30, 2010, of which $92.7 million was restricted net current assets.

5. Restricted Cash and Cash Equivalents

The Credit Agreement requires KGen LLC to maintain six months of principal and interest payments reserve in cash. At June 30, 2010 and 2009, the restricted balance, in accordance with this requirement, was $4.7 million and $5.8 million, respectively.

Additionally, the Security Deposit Agreement requires 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 and 2009, the restricted balance, in accordance with this requirement, was $2.5 million and $27.1 million, respectively.

6. Commitments and Contingencies

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

Commitments—KGen Murray I and II LLC has a power purchase agreement with GPC ("GPC PPA") expiring May 31, 2012. Under the terms of the GPC PPA, the Company sells a unit contingent 550 to 680 MW of capacity and associated energy to GPC. The capacity price under the GPC PPA escalates annually. The monthly minimum commitment of 550 MW is 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, 2010 and 2009 was based on a 630 MW designation, which was in excess of the monthly minimum commitment.

The future minimum capacity sales payments (subject to the adjustments discussed below and based upon a capacity of 550 MW) to be recognized under the GPC PPA for the remaining years subsequent to June 30, 2010, are as follows (in thousands of dollars):

2011	44,785
2012	37,586
Total	$82,371

The Company recognized $50.1 million and $50.0 million, respectively, related to capacity sales on the GPC PPA for the years ended June 30, 2010 and 2009. The Company recognized income of $0.2 million and expense of $0.7 million in deferred charges for the years ended June 30, 2010 and 2009, 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 is calculated to approximate a pass-through of fuel and variable operations and maintenance costs. The Company recognized $38.1 million and $50.4 million, respectively, related to energy sales on the GPC PPA for the years ended June 30, 2010 and 2009.

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

The amount receivable from the GPC PPA was $19.6 million and $16.6 million at June 30, 2010 and 2009, respectively.

A letter of credit, issued pursuant to the synthetic letter of credit facility under the Credit Agreement, supports 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.

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, 2010 and 2009, the Company paid BNP $0.6 million and $0.9 million, respectively, for energy management.

6. Commitments and Contingencies (Continued)

The Company has a fuel supply agreement with Sequent Energy Management ("Sequent"), a subsidiary of AGL Resources, which supports the GPC PPA. This full requirements contract is for firm delivery of 85,106 decatherms per day ("Dth/day") and expires May 31, 2012, with evergreen annual renewals absent notice from either party. Sequent retains 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 is based on a combination of related gas price indices and other components similar to the pricing in the GPC PPA. Sequent delivers natural gas to several pipeline receipt points from which the Company has long-term gas transportation contracts with East Tennessee Natural Gas Company for 168,000 Dth/day of firm capacity.

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. 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 Company entered into long-term service agreements with General Electric International ("GE") to provide maintenance services at the Hinds, Hot Spring, and Murray facilities. All maintenance costs paid to GE are expensed as incurred. The agreement terms vary based on the start date but end after the later of the second major inspection or attainment of specified aggregate factored hours or factored starts. 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, KGen Hot Spring LLC, and KGen Sandersville LLC, the 100% owned subsidiaries of the Company that, respectively, own the Hinds, Hot Spring, and Sandersville plants. The termination was effective for the Sandersville plant on February 1, 2010 and was effective for the Hinds and Hot Spring plants on February 15, 2010. The Company was required to pay DEGS approximately $0.4 million, in the aggregate, in connection with the termination of all of the agreements. KGen Hinds LLC, KGen Hot Spring LLC, and KGen Sandersville LLC executed new operating agreements with NAES Corporation ("NAES"), a third party operations and maintenance provider that replaced DEGS as the service provider for such facilities. The operating and maintenance agreement between DEGS and KGen Murray I and II LLC remains in place. The Company paid DEGS $14.4 million and $23.2 million, respectively, for the years ended June 30, 2010 and 2009, for all operations and maintenance services, management fees, and termination fees. The Company paid NAES $2.1 million for the year ended June 30, 2010, for management fees and payroll.

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, subject to certain approvals including the Federal Energy Regulatory Commission. This lateral pipeline is being constructed in order for Hot Spring to access the

6. Commitments and Contingencies (Continued)

increased scheduling flexibility on TETCO's system. The pipeline is expected to be in service by summer 2011 with financial incentives of up to $0.8 million payable to TETCO if the pipeline is completed before July 1, 2011. The Company is required to post collateral to support construction of the pipeline and as of April 7, 2010 posted a $6.0 million letter of credit. The Company's collateral requirements will increase during the construction process and will be approximately $39.0 million upon the in-service date of the pipeline lateral. Additionally, once the pipeline is operational, there will be annual fixed transportation fees of approximately $6.7 million associated with the new firm transportation agreements for the 20-year term. The collateral requirements will decrease proportionally over the 20-year term.

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 $0.5 million and $0.6 million, respectively, for the years ended June 30, 2010 and 2009.

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, 2010, and thereafter are as follows (in thousands of dollars):

2011	$ 570
2012	570
2013	570
2014	570
2015	570
Thereafter	1,425
Total(1)	$4,275

(1) Minimum lease rental payments have not been reduced by minimum sublease rentals of $1.4 million due in the future under noncancelable subleases.

As of June 30, 2010, the Company employed 17 people. As of June 30, 2009, the Company employed 20 people, however subsequent to June 30, 2009, a workforce reduction took place. In connection with these reductions for the year ended June 30, 2009, the Company paid out approximately $0.3 million in post-employment benefits for the terminated employees.

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. As of June 30, 2010, the Company has not accrued any amounts related to these agreements.

On June 30, 2009, the Board of Directors of the Company approved the adoption of a shareholder rights plan. The Board took this action to protect the Company's shareholders from any attempt that might be made to accumulate a controlling share position in the Company, including a share position that would

6. Commitments and Contingencies (Continued)

allow one shareholder or group of shareholders to hinder a sale transaction approved by the Board, without compensating all shareholders fairly for that control.

In connection with the rights plan, the Board declared a dividend of one right for each share of common stock of the Company outstanding as of the close of business on July 6, 2009. Each right, when it becomes exercisable, will entitle the registered holder to purchase from the Company one unit of one-thousandth of a share of Series A Preferred Stock, par value $0.01 per share, at a purchase price of $25 per unit, subject to adjustment. The rights of a holder of a unit are substantially equivalent to the rights of a holder of a share of common stock.

Under the rights plan, the rights will be exercisable on the earlier to occur of (i) the 10th calendar day after a public announcement that a person or group has become the beneficial owner of 15% or more of the Company's outstanding common stock (which includes common stock referenced in derivative transactions and securities), or (ii) the 10th calendar day (or such late date as may be determined by the Board) after the commencement of a tender or exchange offer the consummation of which would result in a person or group becoming such a 15% or greater beneficial owner. In the event that any person or group acquires such a beneficial ownership, each right will entitle its Holder to purchase, at the then-current exercise price of the rights, a number of Units having a market value (determined based on the market price of the Company's common stock) of twice the exercise price. When a person or group becomes a 15% or greater beneficial owner, the rights owned by such person or group will become void and will not be exercisable, thereby diluting such person's or group's holdings. If a person or group becomes a 15% or greater beneficial owner, instead of allowing the rights to become exercisable, the Board may, at its election, exchange each outstanding rights (other than the rights held by such person or group) for three (3) units, or at the election of the Board, three (3) shares of common stock. The Board may at its option redeem the outstanding rights at a redemption price of $0.0001 per right, or terminate the rights plan at any time prior to earlier of the expiration of the rights plan or the 10th calendar day after a public announcement that a person or group has become the beneficial owner of 15% or more of the Company's outstanding common stock. The Company intends to seek ratification of the rights plan by the Company's stockholders at the Company's 2009 annual meeting. The rights plan will expire on July 6, 2012 or earlier if (1) the Board redeems the rights outstanding under the rights plan or terminates the rights plan, (2) the Company's stockholders vote not to approve the rights plan or (3) if the Company's stockholders have not approved the rights plan by July 6, 2010. The rights plan includes a "qualified offer" provision under which, if the Board refuses to redeem the rights under the rights plan within 90 days after a "qualified offer" is commenced, holders of a majority of the Company's outstanding shares may vote to terminate the rights plan.

The adoption of the rights plan has no effect on the financial strength of the Company or its business plans. Until the rights become exercisable, they will have no dilutive effect on the value of the common stock, will not affect reported earnings per share, should not be taxable to the Company or shareholders, and will not change the way in which shareholders can trade the Company's shares.

NERC Violations—On September 23, 2009, KGen Hot Spring LLC ("Hot Spring"), a 100% owned subsidiary of the Company, self-reported to the SERC Reliability Corporation ("SERC"), that it failed to include certain protection system components in its maintenance and testing program which may constitute a violation of one of the North American Electric Reliability Corporation Reliability Standards ("NERC Standards"). On December 7, 2009, SERC notified Hot Spring that it had completed its

6. Commitments and Contingencies (Continued)

assessment to determine Hot Spring's compliance with the NERC Standards, for which Hot Spring self-reported, and concluded that insufficient basis existed to allege a violation or noncompliance of said NERC Standards and requirements.

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

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

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 is the sole holder of the Bonds.

The agreements executed in connection with the transfer of the Bonds permit the limited liability companies to make payments to the Company in the form of intercompany book entries without the actual transfer of cash. At both June 30, 2010 and 2009, $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 properties 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.

8. Derivatives

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

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

The short-term portion of the Swaps as of June 30, 2010 and 2009 was $3.6 million and $3.9 million, respectively, and was recorded in accounts payable and accrued liabilities. The long-term portion of the Swaps as of June 30, 2010 and June 30, 2009 was $2.7 million and $4.1 million, respectively, and was recorded in other noncurrent liabilities.

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

	Location of Gain (Loss) on Derivatives	Gain (Loss) on Derivatives
For the year ended June 30, 2010	Interest expense	$(4,276)
For the year ended June 30, 2009	Other income (expenses)	$(7,202)

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

The three levels of the fair value hierarchy are:

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

Level 2—Pricing inputs include 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.

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.

9. Share-Based Payments (Continued)

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 3, 2007, stock awards were granted to non-employee directors of the company. The non-employee director grants consisted of liability awards of common stock totaling $100 thousand per year for each director with the number of shares granted determined by the market price of the Company's stock quarterly and were measured and recognized at fair value through earnings as settled at fair value. The last shares issued under the May 3, 2007 grants took place in July 2008.

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 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 restricted stock units 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 restricted stock units will not have voting rights. Stock compensation expense related to the restricted stock units was $0.1 million and $10,000 for the years ended June 30, 2010 and 2009. The restricted stock units will be recognized over a weighted average remaining recognition period of 1.89 years. These restricted stock units 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, 2010 and 2009 are noted in the following table:

	June 30, 2010	June 30, 2009
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, 2010:

	Shares Under Option	Weighted-Average Exercise Price Per Share	Weighted-Average Remaining Contractual Term (Years)	Aggregate Intrinsic Value
Outstanding June 30, 2009	2,495,224	$15.42		
Granted				
Exercised				
Forfeited or expired	(1,698,927)	$15.16		
Outstanding June 30, 2010	796,297	$15.98	6.77	—
Vested or expected to vest at June 30, 2010	796,297	$15.98	6.77	—
Exercisable at June 30, 2010	796,297	$15.98	6.77	—

The Company recorded compensation expense of $0.8 million and $3.3 million for the years ended June 30, 2010 and 2009, respectively, related to stock options outstanding. As of June 30, 2010, all options were vested and there was no unrecognized compensation expense remaining on the options. As of June 30, 2009, there was $0.9 million of total unrecognized compensation expense related to unvested options. For the years ended June 30, 2010 and 2009, no options were granted or exercised.

10. Income Taxes

For the years ended June 30, 2010 and 2009, there were no current or deferred income tax provision (benefits) included in the net loss.

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

	For the Year Ended June 30, 2010	For the Year Ended June 30, 2009
Statutory rate	35%	35%
Tax at statutory rate	$(15,728)	$(15,921)
Increase (decrease) due to:		
Nondeductible meals and entertainment	7	4
State tax benefit	(1,717)	(2,062)
Return to provision	(93)	(4)
Adjustment to valuation allowance	17,531	17,983
Total provision	$ —	$ —

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

	At June 30, 2010	At June 30, 2009
Deferred tax assets:		
Interest rate derivatives	$ 2,472	$ 3,124
Contract-based intangible assets	15,109	11,329
Nonqualified stock options expense	5,375	5,036
Accrued expenses	21	258
Net operating loss	81,113	60,493
Contribution carryforward	16	—
Net deferred tax assets	104,106	80,240
Deferred tax liabilities:		
Property, plant, and equipment	19,346	13,886
Prepaid expenses	613	294
Contract-based intangible liabilities	4,043	3,488
Net deferred tax liability	24,002	17,668
Valuation allowance	80,104	62,572
Deferred tax asset (liabilities), net	$ —	$ —

At June 30, 2010, the Company had a federal net operating loss carryforward of $209.3 million which will expire between 2027 and 2030. The amount of taxable income that the Company can offset with this carryforward is subject to limitations under Section 382 of the Internal Revenue Code, which is applicable to corporations in certain instances following an ownership change (as such term is defined for income tax purposes).

10. Income Taxes (Continued)

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

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

11. Related-Party Transactions

On May 6, 2010, 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, L.P. A subsidiary of ArcLight Energy Partners Fund IV, L.P. is a shareholder who owns approximately 12% of the Company. The arms-length sale closed on July 9, 2010. The Company received $129.3 million in cash sales proceeds which represents a $130.0 million purchase price less a working capital adjustment.

12. Assets Held for 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. The sale closed on July 9, 2010. The Company received $129.3 million in 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. The Company expects to use a portion of its existing tax net operating loss to offset all of the taxable gain resulting from the sale.

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 of these assets upon their classification of assets held for sale on May 6, 2010. They consist of the following (in thousands of dollars):

	June 30 2010
Spare parts inventories	$ 641
Property, plant, and equipment	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

13. Subsequent Events

On August 13, 2010, the Board of Directors granted a total of 237,268 restricted stock units ("RSUs") to senior employees and the Chairman of the Board of Directors pursuant to the KGen Power Corporation 2006 Equity Incentive 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. Of the remaining unvested RSUs, 106,769 will vest upon the consummation of a sale of the Murray I and II power generation facilities; 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. All unvested RSUs will vest upon the consummation of a change in control of the Company. Stock compensation expense related to these RSUs will begin during the three months ended September 30, 2010.

Subsequent events were analyzed and considered through September 27, 2010, the issuance date of this report.

Part III

Number 9. ***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, 2010:

Name	Age	Position
Thomas B. White	54	President, Chief Executive Officer, and Director
James H. Sweeney	51	Senior Vice President, Energy Management
William R. Marlow	43	General Counsel and Secretary
Charles L. Holland	68	Senior Vice President, Operations
W. Kevin Redmond	45	Chief Accounting Officer and Controller
Tina C. Lee	39	Vice President, Energy Management
Stuart J. Prall	36	Vice President, Operations
Steven B. McDowell	35	Vice President, Mergers & Acquisitions and Finance
Daniel T. Hudson	44	Chairman of the Board
James P. Jenkins	62	Director
Gerald J. Stalun	51	Director

Officers

Thomas B. White

Mr. White became a director in April 2008 and was named President and Chief Executive Officer in March 2009. Since 2006, Mr. White has been 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 has been responsible for the identification, evaluation, and closing on private equity type investments in physical energy assets and businesses, as well as supporting continuing asset management activities for investments made by Stark through the energy asset team and investment 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 is 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.

James H. Sweeney

Mr. Sweeney has been our Senior Vice President, Energy Management 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 Senior 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 has over 15 years of experience working with energy related companies. 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 Suez Energy Generation) 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 Partners LP and Montgomery Energy Partners LP. He is responsible for M&A, capital formation / management from private equity, third-party debt, and equity- raising. Until April, 2010, Mr. Hudson was a Director and CFO of Navasota Holdings Texas Partners LP, a 1,650 MW ERCOT portfolio. During 20 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 The TCW Group, Inc's Energy & Infrastructure Group (TCW EIG). TCW EIG currently has approximately $7 billion of energy and infrastructure investments under management. Mr. Stalun has more than 20 years 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 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 has an MBA from the University of Chicago, is a Certified Public Accountant and attended the University of Illinois as an undergraduate. Previous board memberships include Bosque Power and Falcon Gas Storage.

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 10. ***Certain Relationships and Related Transactions, and Director Independence***

Transactions with Related Persons

On May 6, 2010, 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, L.P. A subsidiary of ArcLight Energy Partners Fund IV, L.P. is a shareholder who owns approximately 12% of the Company. The arms-length sale closed on July 9, 2010. The Company received $129.3 million in cash sales proceeds which represents a $130.0 million purchase price less a working capital adjustment.

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."