

KGEN POWER CORPORATION

ANNUAL REPORT

For the Fiscal Year Ended June 30, 2009

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TABLE OF CONTENTS

PART I		
Number 1.	Business	4
Number 1A.	Risk Factors	13
Number 2.	Properties	21
Number 3.	Legal Proceedings	21
PART II		
Number 4.	Market for Registrant’s Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities	21
Number 5.	Selected Financial Data	22
Number 6.	Management’s Discussion and Analysis of Financial Condition and Results of Operation	23
Number 7.	Quantitative and Qualitative Disclosures about Market Risk	36
Number 8.	Financial Statements and Supplementary Data	37
PART III		
Number 9.	Directors, Officers and Corporate Governance	61
Number 10.	Certain Relationships and Related Transactions, and Director Independence . .	64

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 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 perating 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 five operational and fully permitted power plants, or the Plants, located in the southeastern United States with General Electric 7FA and 7EA gas turbines. The Plants have an aggregate capacity of 3,030 megawatts, or MW. The Plants include four combined-cycle plants (Murray I, Murray II, Hot Spring and Hinds) and one simple-cycle plant (Sandersville). We acquired the Plants from an affiliate of MatlinPatterson Global Advisors LLC, 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, but overall it has been reduced between 5% and 8% due to the recent recession, with the industrial sector being hit the hardest. We now 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.

Four of the Plants currently operate as merchant power providers. The remaining plant, the Murray I combined-cycle plant, benefits from a fixed-price long-term power purchase agreement, or the GPC PPA, for all of its 630 MW of capacity with Georgia Power, a subsidiary of Southern Company. The GPC PPA, which continues through May 2012, provides for fixed capacity payments and is our most significant source of stable cash flow. On June 6, 2008, the Sandersville simple-cycle plant entered into a power purchase agreement, or the Sandersville PPA, for a unit contingent 250 to 280 MW of capacity and associated energy with Southern Power Company. The Sandersville PPA commences on June 1, 2011 and continues through December 31, 2015.

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 Power Plants

<u>Plant</u>	<u>Location</u>	<u>Turbines</u>	<u>Heat Rate(1)</u>	<u>Total Capacity (MW) (2)</u>	<u>Commercial Operation Date</u>
Combined-Cycle Plants					
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
Simple-Cycle Plant					
Sandersville	Washington County, Georgia	7EA	12,150	640	June 2002
Total				<u>3,030</u>	

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

(2) Nominal operating capacity.

The Plants are strategically located within 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, the 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.

The Plants are operated pursuant to operation and maintenance agreements with Duke Energy Generation Services, or DEGS. DEGS provides operations, certain accounting, human resources, engineering, environmental, health and safety compliance, and other services for the Plants. Many of the DEGS personnel at the Plants have worked there since the Plants commenced operations. DEGS utilizes its own personnel, supplemented by outside contractors on an as-needed basis, to perform such services. DEGS also provides, when requested, technical and commercial services, health and safety services, and human resources support for plant employees.

The energy management services for the power and capacity of the Plants are provided by Fortis Energy Marketing & Trading GP, or Fortis. The services provided by Fortis include seeking purchasers for our merchant power sales and handling our natural gas purchases to meet operating needs for electricity placed through Fortis 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 Fortis, we are able to use Fortis' 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 87.7% for the year ended June 30, 2009, or 95.1% excluding major maintenance. The 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. The Company's results of operations are subject to seasonal variations since demand for electricity, and production capacity, varies with weather conditions. Four of the Plants currently operate on a merchant basis without long-term purchase agreements, and therefore are exposed to significant volatility in prices and generation demand. The Company earns the majority of its annual revenues in the five summer months, May through September. The shoulder periods, months other than the peak summer months, historically have not been profitable for the Company and are typically the months during which the Company seeks to perform scheduled maintenance-related activities.

Principal Customers

Currently, Georgia Power is our most significant customer, with payments by it under the GPC PPA accounting for approximately 36.0% and 31.0% of our revenues for the years ended June 30, 2009 and 2008, respectively. Most of our remaining sales are merchant sales made through Fortis 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, Fortis'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 the 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.

Our Sandersville facility is interconnected to the GITS at the 500 kV Warthen substation pursuant to a long-term interconnection agreement with Georgia Power.

The Entergy transmission system has been experiencing increased congestion which has impacted our ability to sell the output of our Hinds and Hot Spring facilities. Recently Entergy has 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. Several projects are forecasted to be finished prior to summer 2010.

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 Corporation, or TETCO. We have gas transportation contracts with TETCO, subject to evergreen renewals every two years, unless a notice of cancellation is provided by either party, that provide 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 and provide interruptible capacity of 100,000 Dth/day year round.

At our Hot Spring facility, natural gas is delivered through a lateral pipeline interconnected to CenterPoint, a subsidiary of CenterPoint Energy, Inc. 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 and provide interruptible capacity of 50,000 Dth/day for the year round.

CenterPoint experienced several system issues earlier this year followed by 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 required schedules that were at least 21 hours. In addition to sourcing longer scheduled sales when possible, we have been working with CenterPoint on various short-term alternatives to regain the flexibility and long-term options.

We do not have any firm pipeline transport contracts in place for our Sandersville facility. We can have natural gas delivered to Sandersville through an interconnection with Southern Natural Gas Company, a subsidiary of El Paso Corporation, with which we have secured interruptible transportation services.

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, 2009, we employed 20 people all of whom are located at our corporate office in Houston, Texas. Subsequent to June 30, 2009, a workforce reduction took place, and we currently employ 15 people.

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 the 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, 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

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 the 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 EPAAct.

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, every three years we are required 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, such loss may 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 permits 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, state regulatory authorities have a parallel authority under the PUHCA of 2005 concerning 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.

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 operations from federal, state and local agencies. Based on current trends, we expect that environmental and land use laws and regulations will continue to change and 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. 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 sulfur dioxide, or SO₂, 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. We have applied for and obtained Title V permits for all of our Plants.

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 United States Environmental Protection Agency, or 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.

Proposed and Recently Adopted Air Quality Regulations. During 2005, the EPA adopted the Clean Air Interstate Rule, or CAIR, which expands the nitrogen oxide, or NO_x, and SO₂ “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 SO₂ in 2010 and 2015. All of the Plants are located in areas presently in attainment of NAAQS.

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, we began complying with the current version of CAIR on January 1, 2009, and must continue to comply until the EPA rewrites the rule. EPA officials have indicated that a new CAIR proposal may be issued by January 2010 and a final rule may be in effect in early 2011.

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 PM_{2.5}, 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. It is unclear at this time what actions the EPA might take with respect to the petition, given the EPA’s planned rewrite of the CAIR rule.

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 SO₂ 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.

Proposed Climate Change Legislation and Regulations. There is a growing consensus in the U.S. and globally that emissions of greenhouse gases, or GHGs, are linked to global climate change and this consensus may lead to more stringent regulation of GHG emissions in the future. Increased public concern and mounting political pressure may result in regional and/or federal requirements to reduce or mitigate the effects of GHG emissions, including from power plants. For example, the EPA issued an Advance Notice of Proposed Rule making on July 11, 2008 requesting public comment on how to respond to the U.S. Supreme Court’s decision in *Massachusetts v. EPA* in which the Supreme Court ruled that the Clean Air Act authorizes regulation of GHG emissions from automobiles and light duty trucks. In a related action, on April 24, 2009, the EPA issued a proposed finding that carbon dioxide, or CO₂ and other GHGs endanger public health and welfare, which could require the EPA to issue emissions limits for GHG emissions from motor vehicles. Such regulation of GHG emissions from mobile sources could set the stage for similar regulation of GHG emissions from stationary sources, such as power plants, in the future.

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) in a vote of 219 to 212. The bill proposes a comprehensive “cap and trade” system for targeted reductions of GHG emissions (17% from 2005 levels by 2020 and 83% by 2050). Democrats in the Senate are expected to draft their own climate change bill, the details of which are currently unknown. With strong Republican opposition and the recent congressional focus on the economy and health care, prospects for passage of a climate change bill in the Senate this year are uncertain.

Regulation of CO₂ 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 CO₂ produced. It is uncertain whether existing emitters will be awarded allowance or be required to purchase allowances under federal regulatory framework. Our power generation operations primarily use natural gas and therefore emit less CO₂ than coal-fired generation facilities. Natural-gas fired combined cycle facilities emit 50% to 60% less CO₂ 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. The exact amount of renewable purchases is up for debate but purchase requirements in the 5% to 20% range have been discussed. Additionally, several states have already enacted statewide or

regional RPS programs and several other states are considering enacting RPS programs. Should a national RPS be enacted, or should the states or regions where our Plants operate enact RPS programs, the demand for power from our facilities may be reduced as purchasers may be required to obtain that power from renewable resources. As with GHG regulation, prospects for passage of a national RPS bill or state RPS programs this year are uncertain.

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 operation and maintenance expenses. In addition, an unplanned outage may reduce our revenues as a result of selling fewer mega-watt 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 Sandersville and Murray II plants 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 the 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 the 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 assure you 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 assure you 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 EAct 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 EAct 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

Most of the 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.

Four of the 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. The prospect of 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 2013. 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 and peaker 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 the Plants. Delivery of fuel to the 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 the 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 Fortis. We benefit from Fortis' 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 Fortis 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 the Plants and for certain marketing of our electricity, and if such service providers cease to perform such services or fail to perform such services adequately, it could adversely affect our results of operations and cash flows.

We currently have few employees of our own and are dependent on contractual arrangements with third parties for the operation and maintenance of the Plants. All of the Plants are operated by DEGS under operating and maintenance agreements. In addition, GEI provides maintenance services to our combined-cycle plants under LTSAs. Fortis acts as commercial marketer for the power produced by four of the Plants other than the Murray I plant. Procurement of fuel for the Plants, except for sales under the GPC PPA for Murray I and natural gas supply from Sequent for Murray I, is provided by Fortis. Currently, Fortis 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, GEI, Sequent or Fortis that interrupts one of their services or one of them experiences financial difficulties that adversely affect their ability to provide services, our results of operations, financial condition and cash flows may be adversely affected. In this regard, DEGS and Fortis 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.

It is our intent that Fortis 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 Fortis' 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 Fortis' 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 year ended June 30, 2009 and 2008, we had losses of \$45.5 million and \$103.9 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, 2009, we leased approximately 20,200 square feet of office space. In addition, we own and lease various real property and facilities relating to our power generation business. We believe we have satisfactory title to the 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:

<u>Site Name</u>	<u>Location</u>	<u>Owned/Leased</u>
Corporate Office	Houston, TX	Leased
Murray	Dalton, GA	Leased(1)(2)
Hinds	Jackson, MS	Owned
Hot Spring	Malvern, AR	Leased(1)
Sandersville	Warthen, GA	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. In October 2008, KGen Hinds LLC entered into a settlement agreement related to the litigation associated with amounts owed in lieu of property taxes for the 2006 and 2007 tax years. Pursuant to this settlement, the Company and the relevant taxing authorities have agreed upon property values for the 2008 through 2010 tax years.

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

	Predecessor Information					
	Year Ended June 30, 2009 <small>(in thousands)</small>	Year Ended June 30, 2008 <small>(in thousands)</small>	Period December 4, 2006 through June 30, 2007 <small>(in thousands)</small>	Period July 1, 2006 through February 7, 2007 <small>(in thousands)</small>	Year Ended June 30, 2006 <small>(in thousands)</small>	Period August 5, 2004 through June 30, 2005 <small>(in thousands)</small>
Operating Results Data:						
Revenues:						
Energy sales	\$206,674	\$ 308,605	\$ 87,396	\$141,080	\$264,576	\$ 75,026
Capacity sales	54,666	51,416	15,737	34,501	51,688	16,511
Total revenues	261,340	360,021	103,133	175,581	316,264	91,537
Operating expenses:						
Cost of fuel	174,392	268,978	78,127	115,076	222,325	67,208
Operating and maintenance	40,733	52,065	9,722	11,549	18,919	30,081
Gas transportation	16,438	16,382	6,279	9,674	15,893	13,919
Selling, general and administrative	15,422	29,418	11,777	10,436	14,247	13,613
Acquisition contract termination loss	—	37,190	—	—	—	—
Depreciation	24,272	24,068	9,164	7,614	12,895	12,956
Auxiliary power	8,784	8,437	2,649	4,187	6,905	5,355
Insurance	3,605	3,177	1,531	2,039	3,657	3,375
Total operating expenses	283,646	439,715	119,249	160,575	294,841	146,507
Operating (loss) profit	(22,306)	(79,694)	(16,116)	15,006	21,423	(54,970)
Other income (expenses)						
Interest expense	(11,770)	(16,513)	(7,153)	(30,231)	(43,762)	(36,691)
Debt extinguishment loss	—	—	—	—	—	(33,099)
Gain on sale of assets	—	—	—	110,109	11,393	—
Taxes, other than income taxes	(4,355)	(3,457)	(1,161)	(3,106)	(5,821)	(5,391)
Interest income	147	2,796	879	3,834	2,361	713
Other	(7,206)	(7,065)	912	(3,536)	(900)	(2,637)
Total other income (expenses)	(23,184)	(24,239)	(6,523)	77,070	(36,729)	(77,105)
Net (loss) income before income taxes	(45,490)	(103,933)	(22,639)	92,076	(15,306)	(132,075)
Income tax benefit	—	—	3,602	—	—	—
Net (loss) income after income taxes	\$(45,490)	\$(103,933)	\$(19,037)	\$ 92,076	\$(15,306)	\$(132,075)
Net loss per share—basic and diluted(1)	\$ (0.81)	\$ (1.86)	\$ (0.39)	N/A	N/A	N/A
Weighted average shares outstanding—basic and diluted(1)	55,968	55,949	48,603	N/A	N/A	N/A
Balance Sheet Data:						
Total property, plant, and equipment, net	\$648,210	\$ 671,114	\$693,295	\$336,935	\$324,799	\$ 422,781
Total assets	818,463	870,722	948,767	560,211	546,356	566,956
Total current liabilities	21,078	39,457	20,589	12,492	19,803	29,234
Long-term debt	203,000	195,000	197,000	409,327	479,342	473,501
Stockholders'/Member's equity	\$573,702	\$ 615,805	\$711,741	\$119,695	\$ 27,619	\$ 42,925

(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, 2009. Unless the context otherwise requires or indicates, references to "KGen," "Company," "we," "our," and "us" refer to KGen Power Corporation and its subsidiaries. Statements in our discussion may be forward-looking. These forward-looking statements involve risk and uncertainties. We caution that a number of factors could cause future results to differ materially from our expectations. Please see "Number 1A. *Risk Factors*" of Part I of our Annual Report for the fiscal year ended June 30, 2009 regarding certain risk factors related to the Company.

Business Overview

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

Four of the Plants currently operate as merchant power providers. The remaining plant, the Murray I combined-cycle plant, benefits from a fixed-price long-term power purchase agreement, or the GPC PPA, for all of its 630 MW of capacity with Georgia Power, a subsidiary of Southern Company. The GPC PPA, which continues through May 2012, provides for fixed capacity payments that provide stable cash flow. The Company recognized \$50.0 million and \$49.8 million related to capacity sales on the GPC PPA for the year ended June 30, 2009 and 2008, respectively. On June 6, 2008, the Sandersville simple-cycle plant entered into a power purchase agreement, or the Sandersville PPA, for a unit contingent 250 to 280 MW of capacity and associated energy with Southern Power Company. The Sandersville PPA commences on June 1, 2011 and continues through December 31, 2015.

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

Recent Events

Employee Matters

The employment of Richard McLean, the former Chief Executive Officer and Chief Financial Officer appointed on May 27, 2008 as Chief Executive Officer, was terminated on March 12, 2009. Mr. McLean was a party to an employment agreement that provided for certain termination payments. The Company entered into a separation agreement on May 4, 2009 that provides for certain termination payments and benefits in accordance with the Company's obligations under the employment agreement. Mr. McLean has received and will receive cash payments and health benefits totaling approximately \$0.5 million, which was accrued as of March 31, 2009. The agreement specified that his termination payments and benefits will be paid out over a 12 month period starting in May of 2009. Therefore, \$0.1 million has been paid out to Mr. McLean as of June 30, 2009. In accordance with his employment agreement, all unvested options held by him vested upon his termination. By their terms, these options will remain exercisable until May 2010. Also, in accordance with his employment agreement, Mr. McLean is entitled to additional compensation in the event of a change in control within six months of the separation date indicated above.

Thomas B. White was named President and Chief Executive Officer, effective March 13, 2009. In connection with his appointment, the Company entered into an employment agreement with Mr. White providing for a two and a half year employment term (subject to renewal) with an annual base salary of \$0.4 million, transaction bonuses upon the successful completion of sales of the Company's generation facilities and/or a sale of the Company, and 20,000 restricted stock units. Mr. White has served on our Board of Directors since April 18, 2008 and will continue his role on the Board.

As of June 30, 2009, we employed 20 people, however in May 2009, a workforce reduction plan was initiated and subsequent to June 30, 2009, we employ 15 people. In connection with these reductions for the year ended June 30, 2009, we accrued approximately \$0.3 million in post-employment benefits for the terminated employees.

Changes to the Board

Jeffrey S. Stein resigned from the Board of Directors effective November 26, 2008. Mr. Stein cited personal time constraints as the reason for his decision.

Shareholder Rights Plan

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 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 an exercise 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 later 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 the 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.

Results of Operations

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

Consolidated Results of Operations of KGen for the Year Ended June 30, 2009 compared to the Year Ended June 30, 2008.

The following table sets forth our results of operations for the year ended June 30, 2009 and 2008, expressed in thousands of dollars.

	For the Year Ended June 30, 2009	For the Year Ended June 30, 2008	Favorable/(Unfavorable)	
			Change	% Change
Revenues:				
Energy sales	\$206,674	\$ 308,605	\$(101,931)	(33%)
Capacity sales	54,666	51,416	3,250	6%
Total revenues	261,340	360,021	(98,681)	(27%)
Operating expenses:				
Cost of fuel	174,392	268,978	94,586	35%
Operating and maintenance	40,733	52,065	11,332	22%
Gas transportation	16,438	16,382	(56)	(0%)
Selling, general, and administrative	15,422	29,418	13,996	48%
Acquisition contract termination loss	—	37,190	37,190	100%
Depreciation	24,272	24,068	(204)	(1%)
Auxiliary power	8,784	8,437	(347)	(4%)
Insurance	3,605	3,177	(428)	(13%)
Total operating expenses	283,646	439,715	156,069	35%
Operating loss	(22,306)	(79,694)	57,388	72%
Other income (expenses):				
Interest expense	(11,770)	(16,513)	4,743	29%
Taxes, other than income taxes	(4,355)	(3,457)	(898)	(26%)
Interest income	147	2,796	(2,649)	(95%)
Other	(7,206)	(7,065)	(141)	(2%)
Total other expenses	(23,184)	(24,239)	1,055	4%
Net loss before taxes	(45,490)	(103,933)	58,443	56%
Income tax benefit	—	—	—	0%
Net loss after taxes	<u>\$ (45,490)</u>	<u>\$(103,933)</u>	<u>\$ 58,443</u>	<u>56%</u>

Operating and Business Metrics We Use to Analyze the Company's Performance for the Year Ended June 30, 2009 and June 30, 2008

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 year ended June 30, 2009 and 2008, to the most directly comparable GAAP measures for those periods. See the reconciliation of net loss to adjusted EBITDA on page 30. 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 currently consider Hinds, Hot Spring, Murray II and Sandersville to be merchant plants because they are currently not selling their energy output and capacity pursuant to long-term sales agreements.

	<u>For the Year Ended June 30, 2009</u>	<u>For the Year Ended June 30, 2008</u>
Energy sales	\$ 206,674	\$ 308,605
<i>Less:</i> Cost of fuel	(174,392)	(268,978)
<i>Less:</i> Contracted energy sales	(43,021)	(62,617)
<i>Add:</i> Contracted cost of fuel	<u>42,981</u>	<u>63,594</u>
Merchant energy margin	32,242	40,604
Capacity sales	54,666	51,416
<i>Less:</i> Contracted capacity sales	<u>(49,975)</u>	<u>(49,853)</u>
Merchant capacity sales	<u>\$ 4,691</u>	<u>\$ 1,563</u>
Merchant margin	<u><u>\$ 36,933</u></u>	<u><u>\$ 42,167</u></u>

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.

	<u>For the Year Ended June 30, 2009</u>	<u>For the Year Ended June 30, 2008</u>
Energy sales	\$ 206,674	\$ 308,605
<i>Less:</i> Merchant sales	<u>(163,653)</u>	<u>(245,988)</u>
Contracted energy sales	43,021	62,617
<i>Less:</i> Contracted cost of fuel	(42,981)	(63,594)
<i>Add:</i> Power sales rights and obligations amortization	<u>8,112</u>	<u>8,112</u>
Adjusted contracted energy margin	8,152	7,135
Contracted capacity sales	49,975	49,853
<i>Less:</i> Noncash deferred capacity revenue	<u>(668)</u>	<u>(1,512)</u>
Adjusted contracted capacity sales	<u>\$ 49,307</u>	<u>\$ 48,341</u>
Adjusted contracted margin	<u>\$ 57,459</u>	<u>\$ 55,476</u>

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

	<u>For the Year Ended June 30, 2009</u>	<u>For the Year Ended June 30, 2008</u>
Merchant margin	\$36,933	\$42,167
Adjusted contracted margin	<u>57,459</u>	<u>55,476</u>
Total adjusted margin	<u>\$94,392</u>	<u>\$97,643</u>

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 an acquisition contract termination loss, (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.

	<u>For the Year Ended June 30, 2009</u>	<u>For the Year Ended June 30, 2008</u>
Total operating expenses	\$ 283,646	\$ 439,715
<i>Less:</i> Cost of fuel	(174,392)	(268,978)
<i>Less:</i> Major maintenance expense	(19,447)	(31,336)
<i>Less:</i> Gas transportation noncash amortization	(1,182)	(1,032)
<i>Less:</i> Selling, general and administrative expense	<u>(15,422)</u>	<u>(29,418)</u>
<i>Less:</i> Acquisition contract termination loss . . .	—	(37,190)
<i>Less:</i> Depreciation	(24,272)	(24,068)
<i>Less:</i> D&O insurance expense	(352)	(271)
<i>Add:</i> Taxes, other than income taxes	<u>4,355</u>	<u>3,457</u>
Adjusted plant expenses	<u>\$ 52,934</u>	<u>\$ 50,879</u>

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 and (b) the addition of director and officer insurance expense.

	For the Year Ended June 30, 2009	For the Year Ended June 30, 2008
Selling, general and administrative expense	\$15,422	\$29,418
<i>Less:</i> Noncash employee options/shares expense	(3,271)	(7,686)
<i>Less:</i> Employee severance expense	(795)	(3,906)
<i>Add:</i> D&O insurance expense	352	271
Adjusted corporate expenses	<u>\$11,708</u>	<u>\$18,097</u>

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, 2009	For the Year Ended June 30, 2008	Favorable/(Unfavorable)	
			Change	% Change
Merchant energy margin	\$32,242	\$40,604	\$(8,362)	(21%)
Merchant capacity sales	4,691	1,563	3,128	100%
Merchant margin	36,933	42,167	(5,234)	(12%)
Adjusted contracted energy margin	8,152	7,135	1,017	14%
Adjusted contracted capacity sales	49,307	48,341	966	2%
Adjusted contracted margin	57,459	55,476	1,983	4%
Total adjusted margin	94,392	97,643	(3,251)	(3%)
Adjusted plant expenses	52,934	50,879	(2,055)	(4%)
Adjusted plant EBITDA	41,458	46,764	(5,306)	(11%)
Adjusted corporate expenses	11,708	18,097	6,389	35%
Adjusted EBITDA	<u>\$29,750</u>	<u>\$28,667</u>	<u>\$ 1,083</u>	4%

Selected Operating and Business Metrics

	For the Year Ended June 30, 2009	For the Year Ended June 30, 2008	Favorable/(Unfavorable)	
			Change	% Change
Selected Financial and Operating Data				
Total generation (GWh)	3,917	4,425	(508)	(11%)
Merchant generation (GWh)	3,137	3,470	(333)	(10%)
Merchant margin/merchant generation (\$/MWh) . . .	\$11.77	\$12.15	\$(0.38)	(3%)

Selected Market and Weather Data

	<u>For the Year Ended June 30, 2009</u>	<u>For the Year Ended June 30, 2008</u>	<u>Change</u>	<u>% Change</u>
Selected Market Data(1)				
Average on-peak market power price—				
Entergy (\$/MWh)	\$46.09	\$63.27	\$(17.18)	(27%)
Average on-peak market power price—				
Southern (\$/MWh)	\$50.63	\$63.71	\$(13.08)	(21%)
Average Henry Hub gas price (\$/MMbtu) . . .	\$ 5.95	\$ 8.24	\$ (2.29)	(28%)
Selected Weather Data				
Actual CDDs(2)	6,154	6,779	(625)	(9%)
Normal CDDs	5,284	5,278	6	0%
Actual HDDs(3)	7,364	7,116	248	3%
Normal HDDs	7,915	7,986	(71)	(1%)

Notes:

- (1) Data from Platt's Megawatt Daily and Gas Daily publications.
- (2) CDD, or cooling degree days, represents the number of degrees that the mean temperature for a particular day is above 65 degrees Fahrenheit. The CDDs are then accumulated for a given period.
- (3) HDD, or heating degree days, represents the number of degrees that the mean temperature for a particular day is below 65 degrees Fahrenheit. The HDDs are then accumulated for a given period.

Historical Results of Operations of KGen for the Year Ended June 30, 2009 compared to the Year Ended June 30, 2008.

Total adjusted margin decreased \$3.3 million, or 3%, to \$94.4 million for the year ended June 30, 2009 compared to the same period in the previous year as a result of a \$5.2 million decrease in merchant margin partially offset by a \$2.0 million increase in adjusted contracted margin. The \$94.4 million in total adjusted margin was comprised of \$36.9 million in merchant margin and \$57.5 million in adjusted contracted margin.

The \$5.2 million, or 12%, decrease in merchant margin related to cooler weather during the summer months, as evidenced by a 9% decrease in cooling degree days, when compared to the previous year. There was also a corresponding decrease in merchant generation of 10%, to 3,137 GWh for the year ended June 30, 2009. The implied merchant spark spread, or merchant margin divided by merchant generation, decreased by \$0.38 per MWh to \$11.77 per MWh for the year ended June 30, 2009 compared to the previous year.

Adjusted contracted margin increased \$2.0 million, or 4%, to \$57.5 million for the year ended June 30, 2009, which was comprised of \$8.2 million in adjusted contracted energy margin and \$49.3 million in adjusted contracted capacity sales. The \$2.0 million increase was made up of a \$1.0 million increase in the adjusted contracted energy margin and a \$1.0 million increase in the adjusted contracted capacity sales. The \$1.0 million increase in adjusted contracted energy margin was largely attributable to higher natural gas prices in July and August of 2008, as evidenced by the published Gas Daily Henry Hub index increasing 57%, where the majority of the contract margin was earned. The \$1.0 million increase in adjusted contracted capacity sales was a result of the escalation of the pricing in the GPC PPA.

Adjusted plant expenses increased by \$2.1 million, or 4.0%, to \$52.9 million for the year ended June 30, 2009. The increase is primarily related to a \$0.6 million increase in operating and maintenance costs, a \$0.3 million increase in auxiliary power, a \$0.3 million increase in property and liability insurance premiums, and a \$0.9 million increase in property and franchise taxes. As a result of the foregoing, adjusted plant EBITDA decreased by \$5.3 million to \$41.5 million for the year ended June 30, 2009.

Adjusted corporate expenses decreased by \$6.4 million, or 35%, to \$11.7 million for the year ended June 30, 2009. This decrease is primarily related to a \$3.5 million decrease in payroll expense and a \$2.0 million decrease in legal and professional services.

As a result of the foregoing, adjusted EBITDA increased by \$1.1 million to \$29.8 million for the year ended June 30, 2009.

GAAP to Non-GAAP Adjusted EBITDA Reconciliation

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

	For the Year Ended June 30, 2009	For the Year Ended June 30, 2008
Net loss after taxes	\$(45,490)	\$(103,933)
Add: Interest expense	11,770	16,513
Less: Interest income	(147)	(2,796)
Add: Depreciation	24,272	24,068
Add: Power sales rights and obligations amortization	8,112	8,112
Add: Gas transportation noncash amortization	1,182	1,032
Less: Noncash deferred capacity revenue	(668)	(1,512)
Add: Acquisition contract termination loss	—	37,190
Add: Other expenses	7,206	7,065
EBITDA	<u>6,237</u>	<u>(14,261)</u>
Add: Major maintenance expense	19,447	31,336
Add: Noncash employee options/shares expense	3,271	7,686
Add: Employee severance expense	795	3,906
Adjusted EBITDA	<u>29,750</u>	<u>28,667</u>
Add: Selling, general and administrative expense	15,422	29,418
Less: Noncash employee options/shares expense	(3,271)	(7,686)
Less: Employee severance expense	(795)	(3,906)
Add: D&O insurance expense	352	271
Adjusted plant EBITDA	<u>\$ 41,458</u>	<u>\$ 46,764</u>

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, 2009 compared to the year ended June 30, 2008.

- Interest expense for the year ended June 30, 2009 was \$11.8 million compared to \$16.5 million for the same period in 2008. The decrease in interest expense related to a reduction in interest rates and outstanding debt compared to the same period in the previous year.
- Interest income for the year ended June 30, 2009 and 2008 was \$0.1 million and \$2.8 million, respectively. The decrease in interest income was related to lower interest rates, lower average cash balances, and higher banking fees compared to the same period in the previous year.
- Depreciation was \$24.3 million and \$24.1 million for the year ended June 30, 2009 and 2008, 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, for the year ended June 30, 2009 and 2008, was \$1.2 million and \$1.0 million, respectively, and was recorded as an increase of gas transportation expense.
- Noncash deferred capacity revenue of \$0.7 million and \$1.5 million was recorded as capacity sales for the year ended June 30, 2009 and 2008, respectively.
- There was an acquisition contract termination loss of \$37.2 million during the year ended June 30, 2008, associated with the termination of the proposed acquisition of Complete Energy Holdings, LLC.
- Other expense for the year ended June 30, 2009 and 2008 was expense of \$7.2 million and \$7.1 million, respectively, and primarily related to losses on derivatives associated with our interest rate hedging due to a change in the fair value of \$2.6 million and \$7.9 million, respectively, and cash payments of \$5.6 million, of which \$1.0 million related to amounts accrued during the year ended June 30, 2008, and cash proceeds of \$0.3 million, respectively, on our swaps.
- Major maintenance expense was \$19.4 million and \$31.3 million for the year ended June 30, 2009 and 2008, respectively. The \$19.4 million in expenses primarily related to the scheduled major maintenance at Murray II. The \$31.3 million in expenses primarily related to scheduled major maintenance outages at both Hot Spring and Murray I.
- Noncash stock compensation expense, for the year ended June 30, 2009 and 2008, was \$3.3 million and \$7.7 million, respectively, and was recorded as an increase of selling, general, and administrative expense. The decrease in noncash options expense was primarily due to a reduction in senior executive termination expenses for the year ended June 30, 2009 compared to June 30, 2008.
- Selling, general, and administrative expense included \$0.8 million and \$3.9 million in severance expense for the year ended June 30, 2009 and 2008, respectively.

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, 2009 (in thousands of dollars):

Unrestricted cash and cash equivalents	\$ 40,663
Working capital revolver and synthetic letter of credit facility (net of letters of credit issued and cash draws thereunder)	<u>62,126</u>
Total	<u>\$102,789</u>

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, 2009, we had \$62.1 million available under our Credit Facility, of which \$62.0 million was under the working capital revolver and \$0.1 million was under the synthetic letter of credit facility, for activities related to our plants. We had cash on hand of \$40.7 million, of which \$32.0 million was cash at the parent level and not subject to the lien of the Credit Agreement at June 30, 2009. Similarly, \$40.5 million was the balance at the parent level not subject to the

Credit Agreement at June 30, 2008. 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 \$8.0 million as of June 30, 2009. Total letters of credit issued under the Collateral Credit Facility were \$19.9 million as of June 30, 2009.

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

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

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

Security. Borrowings under the Credit Facility are secured by substantially all of the assets of our subsidiaries, which constitute all of our operating assets and generate substantially all of our operating cash flows. Our only significant asset not subject to the lien of the Credit Agreement was a cash balance of \$32.0 million at June 30, 2009 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, 2009, we were in compliance with the covenants contained within our Credit Facility.

At the inception of our current financing facility on February 8, 2007, Moody’s Investor Service, or Moody’s, issued a debt rating of Ba3 for our facilities. Standard and Poor’s, or S&P, issued an initial debt rating on our current facility in February of 2007 of BB–, which is equivalent with Moody’s rating. On December 2, 2008, Moody’s downgraded KGen’s debt rating to B1 citing continuing weakness in the merchant energy markets and placed the company under review. On April 23, 2009, Moody’s completed their review and affirmed its current B1 rating and revised its outlook to negative. On June 3, 2008 KGen received an opinion from S&P that upgraded KGen to BB, citing the strength of the Georgia Power PPA

and the low level of debt per kW combined with high liquidity. On December 8, 2008 and again on June 30, 2009, S&P reaffirmed its current rating of BB and a 1 recovery rating.

We continue to believe that the Moody's and S&P ratings will not have a material adverse financial impact on us.

Contractual Obligations

Our contractual obligations consist primarily of principal and interest payments on term debt, obligations under firm gas transportation agreements, 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, 2009 (in thousands of dollars):

	<u>Total</u>	<u>Less than 1 year</u>	<u>1-3 years</u>	<u>3-5 years</u>	<u>More than 5 years</u>
Term debt(1)	195,000	2,000	4,000	189,000	—
Working Capital Facility	10,000	—	10,000	—	—
Pipeline payments	167,729	14,482	41,261	38,976	73,011
LTSA	8,933	1,030	3,234	3,462	1,208
Other	5,818	859	1,567	1,347	2,045
Total	<u>387,480</u>	<u>18,370</u>	<u>60,062</u>	<u>232,785</u>	<u>76,263</u>

(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, 2009. Based on a 2.1% interest rate at June 30, 2009, \$4.1 million, \$8.1 million, and \$6.0 million would be due under the term debt facility in less than one year, one to three years, and three to five years, respectively.

Capital Expenditures and Major Maintenance

Total capital expenditures for the year ended June 30, 2009 and 2008 were \$1.4 million and \$1.9 million, respectively.

Major maintenance expense was \$19.4 million and \$31.3 million for the year ended June 30, 2009 and 2008, respectively. The \$19.4 million in expenses primarily related to the scheduled major maintenance at Murray II. The \$31.3 million in expenses primarily related to scheduled major maintenance outages at both Hot Spring and Murray I.

We incur costs for major maintenance on the Plants which are expensed in the period incurred. Major maintenance expenses include overhauls and replacements of major components of our power plants. Historically, the Company only included expenses of major maintenance associated with periodic hot gas path inspections in major maintenance that it reported. In order to provide a better picture of total major maintenance costs, we have modified the classification of major maintenance expenses to include other expenses consistent with the foregoing definition. The revised classification has no net impact on our financial results as it moves expenses from the routine operating category to the major maintenance category. For example, during the year ended June 30, 2009 under our modified methodology, our major maintenance expenses totaled \$19.4 million, under our previous methodology \$16.6 million would have been presented in the major maintenance category and \$2.8 million as an operating expense.

Cash Flow Analysis

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

	<u>For the Year Ended June 30, 2009</u>	<u>For the Year Ended June 30, 2008</u>
Statement of Cash Flow Data:		
Cash flows provided by (used in):		
Operating activities	\$(11,043)	\$(52,856)
Investing activities	(7,787)	16,034
Financing activities	<u>8,000</u>	<u>(2,000)</u>
Decrease in cash and cash equivalents	(10,830)	(38,822)
Cash and cash equivalents at beginning of period	<u>51,493</u>	<u>90,315</u>
Cash and cash equivalents at end of period	<u>\$ 40,663</u>	<u>\$ 51,493</u>

Cash Flows from Operating Activities. Our cash flows used in operations were \$11.0 million for the year ended June 30, 2009, primarily related to depreciation expense of \$24.3 million, amortization expense of \$9.3 million, valuation of derivative instruments of \$7.2 million, stock-based compensation of \$3.4 million and collections of accounts receivable of \$13.9 million which was offset primarily by a net loss of \$45.5 million, cash settlements on our interest rate Swaps of \$5.6 million and a decrease in accounts payable of \$18.4 million. We also incurred \$10.8 million of cash interest during the period under our outstanding Credit Facility.

Cash Flows from Investing Activities. Our cash flows used in investing activities for the year ended June 30, 2009 were \$7.8 million and primarily related to the investment in restricted cash requirements for major maintenance.

Cash Flows from Financing Activities. Our cash flows from financing activities for the year ended June 30, 2009 were \$8.0 million and represented borrowings from our working capital facility of \$10.0 million, offset by \$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 year ended June 30, 2009 and 2008, 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 September 2006, the Financial Accounting Standards Board (“FASB”) issued SFAS No. 157, *Fair Value Measurements* (“SFAS No. 157”). SFAS No. 157 defines fair value, establishes a framework for measuring fair value in generally accepted accounting principles and expands disclosures about fair value measurements. SFAS No. 157 does not require any new fair value measurements. Rather, its application will be made pursuant to other accounting pronouncements that require or permit fair value measurements. SFAS No. 157 is effective for financial statements issued for fiscal years beginning after November 15, 2007, and interim periods within those years. The provisions of SFAS No. 157 are to be applied prospectively upon adoption, except for limited specified exceptions.

SFAS No. 157 was effective for the Company on July 1, 2008. The Company evaluated the requirements of SFAS No. 157 and believes the interest rate swap derivatives (See Note 8) are valued using Level 2 fair value measurements. Under SFAS No. 157, 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.

In February 2007, the FASB issued SFAS No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities* (“SFAS No. 159”) which permits entities to choose to measure many financial instruments and certain other items at fair value that are not currently required to be measured at fair value. SFAS No. 159 was effective for the Company on July 1, 2008. The requirements of SFAS No. 159 did not have an impact on the Company’s consolidated financial statements.

In March 2008, the FASB issued SFAS No. 161, *Disclosures about Derivative Instruments and Hedging Activities* (“SFAS No. 161”). SFAS No. 161 establishes improved financial reporting for derivative instruments and hedging activities by requiring enhanced disclosures to enable investors to better understand their effects on an entity’s financial position, financial performance, and cash flows. SFAS No. 161 was effective for the Company on January 1, 2009. The Company evaluated the requirements of SFAS No. 161 and added additional disclosures. See Note 8. “Derivatives” of the Notes.

In May 2009, The FASB issued SFAS No. 165, *Subsequent Events* (“SFAS No. 165”). SFAS No. 165 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 Statement sets forth the period after the balance sheet date during which management of a reporting entity should evaluate events or transactions that may occur for potential recognition or disclosure in the financial statements; the circumstances under which an entity should recognize events or transactions occurring after the balance sheet date in its financial statements; and the disclosures that an entity should make about events or transactions that occurred after the balance sheet date. SFAS No. 165 was effective for the Company on June 15, 2009. Subsequent events were analyzed and considered through September 25, 2009.

In June 2009, the FASB issued SFAS No. 168, *The FASB Accounting Standards Codification and the Hierarchy of Generally Accepted Accounting Principles—a replacement of FASB Statement No. 162* (“SFAS No. 168”), which states that The *FASB Accounting Standards Codification* (Codification) will become the source of authoritative U.S. generally accepted accounting principles (“GAAP”) recognized by the FASB to be applied to nongovernment entities. Rules and interpretative releases of the Securities and Exchange Commission (“SEC”) under authority of federal securities laws are also sources of authoritative GAAP for SEC registrants. On the effective date of this Statement, September 15, 2009, the Codification will supersede all then-existing non-SEC accounting and reporting standards. All other non-grandfathered non-SEC accounting literature not included in the Codification will become non-authoritative. SFAS No. 168 will be effective for the Company for the first quarter of fiscal year 2010. The requirements of SFAS No. 168 will not have an impact on the Company’s consolidated financial statements other than modifying the footnotes to reference the Codification.

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. The terms of our Credit Facility require 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 have entered into interest rate swaps in order to mitigate the risk associated with the variable rate borrowings.

KGen LLC has four current interest rate swap agreements, or Swaps. These Swaps are intended to hedge the risk associated with variable interest rates. For each of the Swaps, the Company has historically paid its counterparty the equivalent of a fixed interest payment on a predetermined notional value, and we received the equivalent of a floating interest payment based on a three-month LIBOR rate calculated on the same notional value. These payments were made on a quarterly basis. During the year ended June 30, 2009, the Company and its counterparty amended the swap agreements to reduce the Company's fixed rate payments component and change the basis of the counterparty's floating rate payments. We now receive the equivalent of a floating interest payment based on a one-month LIBOR rate calculated on the same notional value. These payments are made on a monthly basis. While the notional value of each of the Swaps does not vary over time, the Swaps are designed to mature sequentially. The total notional amount of the Swaps as of June 30, 2009 was \$132.0 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 (in millions)	June 30, 2009		June 30, 2008	
			Fair Value (in thousands)	Fixed Rate	Fair Value (in thousands)	Fixed Rate
Contract #1	Expired	\$ —	\$ —	—	\$ —	—
Contract #2	Expired	\$ —	\$ —	—	\$ (493)	5.2%
Contract #3	3-31-2010	\$33.0	\$ (922)	4.9%	\$ (942)	5.1%
Contract #4	3-31-2011	\$33.0	\$(1,869)	5.0%	\$(1,184)	5.1%
Contract #5	3-31-2012	\$33.0	\$(2,455)	5.0%	\$(1,340)	5.1%
Contract #6	3-31-2013	\$33.0	\$(2,778)	5.1%	\$(1,480)	5.2%

As of June 30, 2009, the majority 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, 2009 and 2008
Contents**

Report of Independent Auditors	38
Consolidated Financial Statements	
Consolidated Balance Sheets	39
Consolidated Statements of Operations	40
Consolidated Statements of Stockholders' Equity	41
Consolidated Statements of Cash Flows	42
Notes to Consolidated Financial Statement	43

Report of Independent Auditors

The Board of Directors and Stockholders of KGen Power Corporation

We have audited the accompanying consolidated balance sheets of KGen Power Corporation as of June 30, 2009 and 2008, and the related consolidated statements of operations, stockholders' equity, and cash flows for the years then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. We were not engaged to perform an audit of the Company's internal control over financial reporting. Our audits included 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, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of KGen Power Corporation at June 30, 2009 and 2008, and the consolidated results of its operations and its cash flows for the years then ended in conformity with U.S. generally accepted accounting principles.

/s/ Ernst & Young LLP

Houston, Texas
September 25, 2009

KGen Power Corporation
Consolidated Balance Sheets
(in thousands, except per share amounts)

	<u>June 30, 2009</u>	<u>June 30, 2008</u>
Assets		
Current assets:		
Cash and cash equivalents	\$ 40,663	\$ 51,493
Restricted cash and cash equivalents	32,943	24,325
Short-term investments	—	2,199
Accounts receivable	22,815	36,763
Spare parts inventories	7,232	7,409
Prepaid expenses and other current assets	1,336	1,272
	<hr/>	<hr/>
Total current assets	104,989	123,461
Property, plant, and equipment	705,711	704,343
Less: accumulated depreciation	57,501	33,229
	<hr/>	<hr/>
Net property, plant, and equipment	648,210	671,114
Contract-based intangibles (net of \$25,498 and \$14,842 of accumulated amortization, respectively)	58,044	68,700
Deferred charge	2,769	2,101
Deferred financing fees (net of \$2,138 and \$1,243 of accumulated amortization, respectively)	4,126	5,021
Other noncurrent assets	325	325
	<hr/>	<hr/>
Total assets	<u>\$ 818,463</u>	<u>\$ 870,722</u>
Liabilities and stockholders' equity		
Current liabilities:		
Accounts payable and accrued liabilities	\$ 19,078	\$ 37,457
Current portion of long-term debt	2,000	2,000
	<hr/>	<hr/>
Total current liabilities	21,078	39,457
Long-term debt	203,000	195,000
Contract-based intangibles (net of \$3,604 and \$2,243 of accumulated amortization, respectively)	16,564	17,925
Other noncurrent liabilities	4,119	2,535
Commitments and contingencies (Note 6)	—	—
Stockholders' equity:		
Common stock (par value \$.01; 150,000 shares authorized; 55,968 and 55,963 shares issued and outstanding at June 30, 2009 and 2008, respectively)	560	560
Additional paid in capital	741,602	738,215
Accumulated deficit	(168,460)	(122,970)
	<hr/>	<hr/>
Total stockholders' equity	573,702	615,805
	<hr/>	<hr/>
Total liabilities and stockholders' equity	<u>\$ 818,463</u>	<u>\$ 870,722</u>

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)

	<u>For the Year Ended June 30, 2009</u>	<u>For the Year Ended June 30, 2008</u>
Revenues:		
Energy sales	\$206,674	\$ 308,605
Capacity sales	54,666	51,416
Total revenues	<u>261,340</u>	<u>360,021</u>
Operating expenses:		
Cost of fuel	174,392	268,978
Operating and maintenance	40,733	52,065
Gas transportation	16,438	16,382
Selling, general, and administrative	15,422	29,418
Acquisition contract termination loss	—	37,190
Depreciation	24,272	24,068
Auxiliary power	8,784	8,437
Insurance	3,605	3,177
Total operating expenses	<u>283,646</u>	<u>439,715</u>
Operating loss	(22,306)	(79,694)
Other income (expenses):		
Interest expense	(11,770)	(16,513)
Taxes, other than income taxes	(4,355)	(3,457)
Interest income	147	2,796
Other	(7,206)	(7,065)
Total other expenses	<u>(23,184)</u>	<u>(24,239)</u>
Net loss before taxes	(45,490)	(103,933)
Income tax benefit	—	—
Net loss after taxes	<u>\$(45,490)</u>	<u>\$(103,933)</u>
Net loss per share—basic and diluted	\$ (0.81)	\$ (1.86)
Weighted average shares outstanding—basic and diluted	55,968	55,949

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

KGen Power Corporation
Consolidated Statements of Stockholders' Equity
(in thousands)
For the Year Ended June 30, 2009 and 2008

	<u>Common Stock</u>		<u>Additional Paid in Capital</u>	<u>Accumulated Deficit</u>	<u>Total</u>
	<u>Shares</u>	<u>Amount</u>			
Balance at June 30, 2007	55,945	\$560	\$730,218	\$ (19,037)	\$ 711,741
Stock-based compensation	18	—	7,997	—	7,997
Net loss	—	—	—	(103,933)	(103,933)
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

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

KGen Power Corporation
Consolidated Statements of Cash Flows
(in thousands)

	<u>For the Year Ended June 30, 2009</u>	<u>For the Year Ended June 30, 2008</u>
Cash flows from operating activities		
Net loss	\$(45,490)	\$(103,933)
Adjustments to reconcile net loss to net cash used in operating activities:		
Depreciation	24,272	24,068
Amortization of deferred financing fees	895	895
Amortization of contract-based intangibles	9,295	9,144
Valuation of derivative instruments	7,202	7,608
Stock-based compensation	3,387	7,997
(Payments) proceeds from settlement of derivative instruments	(5,637)	309
Changes in operating assets and liabilities:		
Accounts receivable	13,948	(11,812)
Spare parts inventories	177	(335)
Prepaid expenses and other current assets	(64)	(919)
Deferred charge	(668)	(1,512)
Other noncurrent assets	—	691
Accounts payable and accrued liabilities	(18,353)	14,908
Other noncurrent liabilities	(7)	35
Net cash used in operating activities	<u>(11,043)</u>	<u>(52,856)</u>
Cash flows from investing activities		
Purchases of property, plant, and equipment	(1,368)	(1,887)
Short-term investments	2,199	2,041
(Investment in) use of restricted cash and cash equivalents	(8,618)	15,880
Net cash (used in) provided by investing activities	<u>(7,787)</u>	<u>16,034</u>
Cash flows from financing activities		
Repayment of debt	(2,000)	(2,000)
Borrowings from working capital revolver	10,000	—
Net cash provided by (used in) financing activities	<u>8,000</u>	<u>(2,000)</u>
Decrease in cash and cash equivalents	(10,830)	(38,822)
Cash and cash equivalents at beginning of period	51,493	90,315
Cash and cash equivalents at end of period	<u>\$ 40,663</u>	<u>\$ 51,493</u>
Cash paid for		
Interest	\$ 10,847	\$ 15,713
Noncash transactions		
Grant of shares for Board fees	\$ 116	\$ 310

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

KGen Power Corporation
Notes to Consolidated Financial Statements
For the Year ended June 30, 2009 and 2008

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. The portfolio of facilities consists of five operational and fully permitted power plants (the “Plants”) located in the southeastern United States with gas turbines having an aggregate capacity of 3,030 megawatts (“MW”). The Plants include four combined-cycle plants (Murray I, Murray II, Hot Spring, and Hinds) and one simple-cycle plant (Sandersville). The Plants were acquired from an affiliate of MatlinPatterson Global Advisors LLC on February 8, 2007.

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, as well as any variable interest entities for which the Company is the primary beneficiary (since the acquisition of KGLLC). All significant intercompany balances and transactions have been eliminated in consolidation.

Reclassifications

Certain reclassifications have been made to the prior year financial statements to conform to the current year presentation.

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

KGen Power Corporation
Notes to Consolidated Financial Statements (Continued)
For the Year ended June 30, 2009 and 2008

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

without long-term purchase agreements, and therefore are exposed to significant volatility in prices and generation demand. The Company earns the majority of its annual revenues in the five summer months, May through September. The shoulder periods, months other than the peak summer months, historically have not been profitable for the Company and are the months during which the Company seeks to perform scheduled maintenance related activities.

Cash and Cash Equivalents and Restricted Cash and Cash Equivalents

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

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

Short-Term Investments

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

Spare Parts Inventories

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

Contract-Based Intangibles

Contract-based intangibles consist of the estimated fair value of contractual rights and obligations related to power purchase agreements and firm transportation contracts. The intangibles are being amortized using the straight-line method over the life of the specific contracts, and such amortization is reflected as an adjustment to the associated revenue or expense item. The contract-based intangibles are reviewed quarterly for impairment. No impairment was indicated at June 30, 2009 or 2008.

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 year ended June 30, 2009 and 2008, no events or changes in circumstances indicated the carrying value of long-lived assets held for use might not be fully recoverable.

KGen Power Corporation
Notes to Consolidated Financial Statements (Continued)
For the Year ended June 30, 2009 and 2008

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

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, short-term investments, accounts receivable, accounts payable, debt instruments, and interest rate derivatives. The carrying value 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 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. The carrying value of the debt instruments approximates the fair value as the instruments bear a floating market-based interest rate.

Concentration of Credit Risk

The Company's only two customers as of June 30, 2009 are Georgia Power Company ("GPC") and Fortis Energy Marketing & Trading GP ("Fortis"). 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.

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

KGen Power Corporation
Notes to Consolidated Financial Statements (Continued)
For the Year ended June 30, 2009 and 2008

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

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.

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.

	<u>For the Year Ended June 30, 2009</u>	<u>For the Year Ended June 30, 2008</u>
Numerator:		
Net loss	<u>\$(45,490)</u>	<u>\$(103,933)</u>
Denominator:		
Weighted average shares outstanding—basic and diluted	<u>55,968</u>	<u>55,949</u>
Net loss per share—basic and diluted	<u>\$ (0.81)</u>	<u>\$ (1.86)</u>

Other Comprehensive Income

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

Business Segment Information

The Company's business, operation of electric power generation plants and sale of electricity and electrical generation capacity, constitutes a single reportable segment.

New Accounting Pronouncements

In September 2006, the Financial Accounting Standards Board ("FASB") issued SFAS No. 157, *Fair Value Measurements* ("SFAS No. 157"). SFAS No. 157 defines fair value, establishes a framework for measuring fair value in generally accepted accounting principles and expands disclosures about fair value measurements. SFAS No. 157 does not require any new fair value measurements. Rather, its application will be made pursuant to other accounting pronouncements that require or permit fair value measurements. SFAS No. 157 is effective for financial statements issued for fiscal years beginning after November 15, 2007, and interim periods within those years. The provisions of SFAS No. 157 are to be applied prospectively upon adoption, except for limited specified exceptions.

SFAS No. 157 was effective for the Company on July 1, 2008. The Company evaluated the requirements of SFAS No. 157 and believes the interest rate swap derivatives (See Note 8) are valued using Level 2 fair value measurements. Under SFAS No. 157, instruments valued using Level 2 measurements are valued based on either quoted prices for similar instruments in active markets, quoted prices for

KGen Power Corporation
Notes to Consolidated Financial Statements (Continued)
For the Year ended June 30, 2009 and 2008

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

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.

In March 2008, the FASB issued SFAS No. 161, *Disclosures about Derivative Instruments and Hedging Activities* (“SFAS No. 161”). SFAS No. 161 establishes improved financial reporting for derivative instruments and hedging activities by requiring enhanced disclosures to enable investors to better understand their effects on an entity’s financial position, financial performance, and cash flows. SFAS No. 161 was effective for the Company on January 1, 2009. The Company evaluated the requirements of SFAS No. 161 and added additional disclosures (See Note 8).

In May 2009, The FASB issued SFAS No. 165, *Subsequent Events* (“SFAS No. 165”). SFAS No. 165 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 Statement sets forth the period after the balance sheet date during which management of a reporting entity should evaluate events or transactions that may occur for potential recognition or disclosure in the financial statements; the circumstances under which an entity should recognize events or transactions occurring after the balance sheet date in its financial statements; and the disclosures that an entity should make about events or transactions that occurred after the balance sheet date. SFAS No. 165 was effective for the Company on June 15, 2009. Subsequent events were analyzed and considered through September 25, 2009.

In June 2009, the FASB issued SFAS No. 168, *The FASB Accounting Standards Codification and the Hierarchy of Generally Accepted Accounting Principles—a replacement of FASB Statement No. 162* (“SFAS No. 168”), which states that The *FASB Accounting Standards Codification* (Codification) will become the source of authoritative U.S. generally accepted accounting principles (“GAAP”) recognized by the FASB to be applied to nongovernment entities. Rules and interpretative releases of the Securities and Exchange Commission (“SEC”) under authority of federal securities laws are also sources of authoritative GAAP for SEC registrants. On the effective date of this Statement, September 15, 2009, the Codification will supersede all then-existing non-SEC accounting and reporting standards. All other non-grandfathered non-SEC accounting literature not included in the Codification will become non-authoritative. SFAS No. 168 will be effective for the Company for the first quarter of fiscal year 2010. The requirements of SFAS No. 168 will not have an impact on the Company’s consolidated financial statements other than modifying the footnotes to reference the Codification.

KGen Power Corporation
Notes to Consolidated Financial Statements (Continued)
For the Year ended June 30, 2009 and 2008

2. Property, Plant, and Equipment

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

	Estimated Useful Life	June 30, 2009	June 30, 2008
Land	—	\$ 4,201	\$ 4,201
Buildings	40 years	28,612	28,612
Gas and steam turbines	30 years	235,985	235,985
Steam generators and auxiliaries	30 years	48,402	48,402
Transmission and fuel gas pipelines	30 years	57,191	57,191
Systems and equipment	5-30 years	122,616	122,611
Other plant	3-30 years	208,704	207,341
Total property, plant, and equipment		<u>705,711</u>	<u>704,343</u>
Less: accumulated depreciation		<u>57,501</u>	<u>33,229</u>
Net property, plant, and equipment		<u><u>\$648,210</u></u>	<u><u>\$671,114</u></u>

3. Contract-Based Intangibles

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

	Term	June 30, 2009	June 30, 2008
Assets			
Murray I Georgia Power contract	May 31, 2012	\$23,854	\$31,965
Murray firm transportation contracts	Various	<u>34,190</u>	<u>36,735</u>
Total assets		<u><u>\$58,044</u></u>	<u><u>\$68,700</u></u>
Liabilities			
Hinds firm transportation contract	March 31, 2012	\$ 147	\$ 220
Murray firm transportation contract	November 30, 2016	481	546
Hot Spring firm transportation contracts	Various	<u>15,936</u>	<u>17,159</u>
Total liabilities		<u><u>\$16,564</u></u>	<u><u>\$17,925</u></u>

For both of the years ended June 30, 2009 and 2008, 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, 2009 and 2008, amortization of contract-based natural gas transportation rights and obligations was \$1.2 million and \$1.0 million, respectively, and was recorded as an increase of gas transportation expenses on the consolidated statements of operations.

KGen Power Corporation
Notes to Consolidated Financial Statements (Continued)
For the Year ended June 30, 2009 and 2008

4. Long-Term Debt

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

	<u>Interest Rate</u>	<u>Maturity</u>	<u>June 30, 2009</u>	<u>June 30, 2008</u>
Term debt	Variable	February 8, 2014	\$195,000	\$197,000
Working capital facility	Variable	February 8, 2012	10,000	—
Total debt outstanding			<u>205,000</u>	<u>197,000</u>
Less: current portion			<u>2,000</u>	<u>2,000</u>
Total long-term debt			<u>\$203,000</u>	<u>\$195,000</u>

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 of California, as collateral agent and The Bank of New York, as depository agent, to provide term debt in the amount of \$200.0 million. The term debt bears interest at an adjusted rate based on the London Interbank Offered Rate (“LIBOR”) plus 175 basis points, has a term of seven years and requires a \$2.0 million principal payment per year made in quarterly installments. KGen LLC’s obligations and indebtedness under the Credit Agreement are secured by a security interest in all of the assets and all of the membership interests of KGen LLC and its subsidiaries. The interest rate incurred on the term debt was 2.1% and 4.5% at June 30, 2009 and 2008, respectively.

KGen LLC also entered into an \$80.0 million working capital facility for other liquidity needs and a \$120.0 million synthetic letter of credit facility to support the collateral requirements at the project level. The working capital facility charges a 200 basis point fee for outstanding letters of credit, bears interest at LIBOR plus 200 basis points for outstanding draws, and has a 50 basis point commitment fee for any unused portion. It has a five-year term expiring on February 8, 2012. On March 20, 2009, KGen LLC drew \$10.0 million under the working capital facility. The proceeds of the drawdown will be used for working capital purposes. Letters of credit have been issued under the working capital facility as of June 30, 2009 and 2008 for \$8.0 million and \$12.5 million, 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. As of June 30, 2009, a letter of credit, supporting the power sales contract with GPC, with a current outstanding amount of \$100.0 million and \$19.9 million of other letters of credit have been issued under such facility.

The remaining future minimum principal payments under the term debt and the working capital facility subsequent to June 30, 2009 are as follows (in thousands of dollars):

2010	2,000
2011	2,000
2012	12,000
2013	2,000
Thereafter	<u>187,000</u>
Total	<u>\$205,000</u>

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,

KGen Power Corporation
Notes to Consolidated Financial Statements (Continued)
For the Year ended June 30, 2009 and 2008

4. Long-Term Debt (Continued)

(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, 2009, 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 \$531.3 million at June 30, 2009, of which \$42.1 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, 2009 and June 30, 2008, the restricted balance, in accordance with this requirement, was \$5.8 million and \$7.0 million, respectively.

Additionally, the Security Deposit Agreement requires KGen LLC to reserve quarterly the amount of major maintenance expenditures expected to be incurred during the following 12 months. At June 30, 2009 and June 30, 2008, the restricted balance, in accordance with this requirement, was \$27.1 million and \$17.3 million, respectively.

6. Commitments and Contingencies

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 year ended June 30, 2009 and 2008 based on a 630 MW designation, 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, 2009, are as follows (in thousands of dollars):

2010	43,908
2011	44,785
2012	<u>37,586</u>
Total	<u>\$126,279</u>

The Company recognized \$50.0 million and \$49.8 million, respectively, related to capacity sales on the GPC PPA for the year ended June 30, 2009 and 2008. The Company recognized \$0.7 million and \$1.5 million in deferred charges for the year ended June 30, 2009 and 2008, 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.

KGen Power Corporation
Notes to Consolidated Financial Statements (Continued)
For the Year ended June 30, 2009 and 2008

6. Commitments and Contingencies (Continued)

The price of the associated energy is calculated to approximate a pass-through of fuel and variable operations and maintenance costs. The Company recognized \$50.4 million and \$67.2 million, respectively, related to energy sales on the GPC PPA for the year ended June 30, 2009 and 2008.

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 \$16.6 million and \$26.6 million at June 30, 2009 and 2008, respectively.

Prior to the Company's acquisition of KGLLC, Duke Capital LLC (the "Duke Affiliate") was required under the GPC PPA to post a performance guarantee 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. KGLLC reimbursed the Duke affiliate for the actual costs of maintaining the performance guarantee. In connection with the Company's acquisition of KGLLC, the GPC PPA was amended to allow KGen LLC to replace the Duke affiliate performance guarantee with a letter of credit issued pursuant to the synthetic letter of credit facility under the Credit Agreement.

Fortis is the commercial marketer for all of the Company's facilities and Duke Energy Generating Services ("DEGS") is the operations and maintenance provider for all the Company's facilities. The Company compensates Fortis based on a percentage of gross margin not to be less than a minimum management fee. For the year ended June 30, 2009 and 2008, the Company paid Fortis \$0.9 million and \$0.5 million for energy management services and paid DEGS \$23.2 million and \$19.9 million for operations and maintenance services and fees, respectively. The net receivable from Fortis was \$5.9 million and \$10.1 million at June 30, 2009 and 2008, respectively.

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 Corporation to deliver gas to the Hinds facility. The firm transport contract is subject to evergreen renewals every two years, unless a notice of cancellation is provided by either party and provides firm capacity of 80,000 Dth/day in the summer peak period and lesser amounts in the other parts of the year.

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

KGen Power Corporation
Notes to Consolidated Financial Statements (Continued)
For the Year ended June 30, 2009 and 2008

6. Commitments and Contingencies (Continued)

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.

The Company entered into standby letters of credit that support obligations to The Southern Company, Texas Eastern Transmission Company, GPC, Mississippi Power Company, and Tennessee Valley Authority. At June 30, 2008, letters of credit were supported by \$2.2 million of short-term investments as collateral. At June 30, 2009, there was no obligation for short-term investments as collateral. All letters of credit that support obligations are now issued under the working capital and synthetic letter of credit facilities.

The Company entered into a standby letter of credit that supports the lease of its executive offices. This letter of credit was supported with \$100,000 of cash and cash equivalents as collateral. On April 9, 2008, this letter of credit expired and approximately \$113,000 of principal and interest was redeemed to the Company.

The Company had a three-year operating lease for its executive office space expiring September 30, 2007. On August 8, 2007, the company executed a new lease, which includes its current space of 10,800 square feet plus an additional 9,400 square feet. In addition, the lease term was extended through September 20, 2017. Rent expense under this lease was \$0.6 million and \$0.4 million, respectively, for the year ended June 30, 2009 and 2008.

The future minimums lease payments for the five years subsequent to June 30, 2009, and thereafter are as follows (in thousands of dollars):

2010	584
2011	584
2012	584
2013	584
2014	584
Thereafter	<u>2,045</u>
Total	<u>\$4,965</u>

On June 18, 2007, the Company signed a purchase and sales agreement with affiliates of Complete Energy Holdings, LLC (“CEH”) to acquire 1,859 MW of capacity for \$1.3 billion, plus working capital adjustments. During the year ended June 30, 2008, the Company entered into a termination and mutual release agreement with CEH and certain of its affiliates pursuant to which the Company made a \$35.0 million payment to CEH in full settlement of its liabilities to CEH in connection with the purchase and sale agreement. In addition, the Company incurred \$2.2 million in professional fees to certain third-party consultants and advisors that assisted with the evaluation and negotiation of the CEH acquisition. The expenses related to the CEH acquisition were recorded in acquisition contract termination loss on the consolidated statements of operations.

In April 2008, KGen Murray I and II LLC entered into a power and gas purchase agreement to supply 225 MW of capacity and associated energy and 40,000 Dth/day of fuel to Fortis. The agreement

KGen Power Corporation
Notes to Consolidated Financial Statements (Continued)
For the Year ended June 30, 2009 and 2008

6. Commitments and Contingencies (Continued)

commenced on June 1, 2008 and continued through September 30, 2008. For the year ended June 30, 2009 and 2008, total capacity sales recognized under this contract were \$4.7 million and \$1.6 million, respectively.

On April 30, 2008, KGen Hinds LLC entered into a five-year water solutions agreement with GE Mobile Water, Inc. The agreement provides for the treatment and processing of water used at the Hinds facility. Agreement pricing is derived from a combination of a fixed base fee and a variable fee per thousand gallons of water processed. The fee will escalate annually based upon an agreed upon index.

On June 6, 2008, KGen Sandersville LLC entered into a power purchase agreement with Southern Power Company ("Sandersville PPA") expiring on December 31, 2015. Under the terms of the Sandersville PPA, KGen Sandersville LLC will sell a unit contingent 250 to 280 MW of capacity and associated energy to Southern Power Company. The capacity price under the contract escalates annually. The PPA commences on June 1, 2011, and therefore, no capacity revenues were recognized for the year ended June 30, 2009 and 2008.

The employment of Gerald Lindner, the former Chairman and Chief Executive Officer and Donald Boyd, the former Chief Operating Officer and Executive Vice President, was terminated on May 6, 2008 and May 23, 2008, respectively. Each was a party to an employment and severance agreement that provided for certain termination payments. The Company negotiated separation agreements with each of Mr. Lindner and Mr. Boyd providing for payments and benefits in full settlement of the Company's obligations under their respective employment agreements. Mr. Lindner received a cash payment of approximately \$2.7 million in November 2008 pursuant to his separation agreement. Mr. Boyd received a payment of approximately \$0.5 million in November 2008 and an additional payment of approximately \$0.5 million in January 2009 pursuant to his separation agreement. Mr. Boyd will also receive health benefits for 18 months. In accordance with their employment agreements, all unvested options held by them vested upon their respective termination. Under the settlement agreement terms, these options will remain exercisable until November 2009.

The employment of Richard McLean, the former Chief Executive Officer and Chief Financial Officer appointed on May 27, 2008 as Chief Executive Officer, was terminated on March 12, 2009. Mr. McLean was a party to an employment agreement that provided for certain termination payments. The Company entered into a separation agreement on May 4, 2009 that provides for certain termination payments and benefits in accordance with the Company's obligations under the employment agreement. Mr. McLean will receive cash payments and health benefits totaling approximately \$0.5 million, which was accrued as of March 31, 2009. The agreement specified that his termination payments and benefits will be paid out over a 12 month period starting in May of 2009. Therefore, \$0.1 million has been paid out to Mr. McLean as of June 30, 2009. In accordance with his employment agreement, all unvested options held by him vested upon his termination. By their terms, these options will remain exercisable until May 2010. Also in accordance with his employment agreement, Mr. McLean is entitled to additional compensation in the event of a change in control within six months of the separation date indicated above.

As of June 30, 2009, the Company employed 20 people, however subsequent to June 30, 2009, a workforce reduction took place and the Company currently employs 15 people. In connection with these reductions for the year ended June 30, 2009, the Company accrued approximately \$0.3 million in post-employment benefits for the terminated employees.

KGen Power Corporation
Notes to Consolidated Financial Statements (Continued)
For the Year ended June 30, 2009 and 2008

6. Commitments and Contingencies (Continued)

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, 2009, the Company has not accrued any amounts related to these agreements.

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. In October 2008, KGen Hinds LLC entered into a settlement agreement related to the litigation associated with amounts owed in lieu of property taxes for the 2006 and 2007 tax years. Pursuant to this settlement, the Company and the relevant taxing authorities have agreed upon property values for the 2008 through 2010 tax years.

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 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

KGen Power Corporation
Notes to Consolidated Financial Statements (Continued)
For the Year ended June 30, 2009 and 2008

6. Commitments and Contingencies (Continued)

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.

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, 2009 and 2008, \$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 measure 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

KGen Power Corporation
Notes to Consolidated Financial Statements (Continued)
For the Year ended June 30, 2009 and 2008

8. Derivatives (Continued)

interest rate payable by KGen LLC was 5.0% at June 30, 2009. 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, 2009 and 2008 was \$3.9 million and \$2.9 million, respectively, and was recorded in accounts payable and accrued liabilities. The long-term portion of the Swaps as of June 30, 2009 and June 30, 2008 was \$4.1 million and \$2.5 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):

	<u>Location of Gain (Loss) on Derivatives</u>	<u>Gain (Loss) on Derivatives</u>
For the year ended June 30, 2009	Other income (expenses)	\$(7,202)
For the year ended June 30, 2008	Other income (expenses)	\$(7,608)

The Company evaluated the requirements of SFAS No. 157, *Fair Value Measurements* ("SFAS No. 157") and believes the Swaps are valued using Level 2 fair value measurements. Under SFAS No. 157, 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 under SFAS No. 157 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.

The Company also considered the effect of its nonperformance risk in determining the fair value of its liabilities, as required under SFAS No. 157. The consideration of nonperformance risk resulted in an adjustment of \$0.8 million for the year ended June 30, 2009. The adjustment reduced the fair value of the Company's Swap liabilities on the consolidated balance sheets and increased the gain on derivatives on the consolidated statements of operations.

KGen Power Corporation
Notes to Consolidated Financial Statements (Continued)
For the Year ended June 30, 2009 and 2008

9. Share-Based Payments

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

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

On May 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 are measured and recognized at fair value through earnings as settled at fair value.

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. The restricted stock awards consisted of 20,000 restricted stock units which vest according to the following schedule:

<u>Date of Vest</u>	<u># of Vested Units</u>
May 22, 2010	6,667
May 22, 2011	6,667
May 22, 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 \$10,000 for the year ended June 30, 2009. The restricted stock units will be recognized over a weighted average 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.

KGen Power Corporation
Notes to Consolidated Financial Statements (Continued)
For the Year ended June 30, 2009 and 2008

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 year ended June 30, 2009 and 2008 are noted in the following table:

	<u>June 30, 2009</u>	<u>June 30, 2008</u>
Risk-free interest rate	4.66%	4.66%
Expected volatility	32.26%	32.27%
Expected term in years	5.97	5.99
Expected dividends	—	—
Fair value (per option)	\$5.33	\$5.34

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, 2009:

	<u>Shares Under Option</u>	<u>Weighted- Average Exercise Price Per Share</u>	<u>Weighted- Average Remaining Contractual Term (Years)</u>	<u>Aggregate Intrinsic Value</u>
Outstanding June 30, 2008	2,521,928	\$15.43	4.18	\$10,276,205
Granted				
Exercised				
Forfeited or expired . .	<u>(26,704)</u>	<u>\$15.80</u>	—	—
Outstanding June 30, 2009	2,495,224	\$15.42	2.76	\$ —
Vested or expected to vest at June 30, 2009	2,495,224	15.42	2.76	—
Exercisable at June 30, 2009	2,263,141	15.42	2.26	—

Total compensation cost for share-based payment arrangements recognized in income was \$3.3 million and \$8.0 million, respectively, for the year ended June 30, 2009 and 2008. As of June 30, 2009 and 2008, there was \$1.0 million and \$3.5 million, respectively, of total unrecognized compensation cost related to non-vested options. As of June 30, 2009, the cost is expected to be recognized over a weighted average period of 0.61 years.

KGen Power Corporation
Notes to Consolidated Financial Statements (Continued)
For the Year ended June 30, 2009 and 2008

10. Income Taxes

For the year ended June 30, 2009 and 2008, 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):

	<u>For the Year Ended June 30, 2009</u>	<u>For the Year Ended June 30, 2008</u>
Statutory rate	35%	35%
Tax at statutory rate	\$(15,921)	\$(36,377)
Increase (decrease) due to:		
Nondeductible meals and entertainment	4	15
State tax benefit	(2,062)	(3,011)
Return to provision	(4)	(215)
Adjustment to valuation allowance	17,983	39,588
Total provision	<u>\$ —</u>	<u>\$ —</u>

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

	<u>At June 30, 2009</u>	<u>At June 30, 2008</u>
Deferred tax assets:		
Interest rate derivatives	\$ 3,124	\$ 2,271
Contract-based intangible assets	11,329	6,180
Nonqualified stock options expense	5,036	3,400
Accrued expenses	258	1,367
Net operating loss	<u>60,493</u>	<u>41,467</u>
Net deferred tax assets	<u>80,240</u>	<u>54,685</u>
Deferred tax liabilities:		
Property, plant, and equipment	13,886	6,707
Prepaid expenses	294	291
Contract-based intangible liabilities	<u>3,488</u>	<u>3,102</u>
Net deferred tax liability	17,668	10,100
Valuation allowance	<u>62,572</u>	<u>44,585</u>
Deferred tax asset (liabilities), net	<u>\$ —</u>	<u>\$ —</u>

At June 30, 2009, the Company had a federal net operating loss carryforward of \$156.5 million which will expire between 2027 and 2029. A wholly-owned subsidiary of the Company had an estimated net operating loss carryforward of approximately \$115,000, which will expire in 2025 and 2026. The utilization of this carryforward is subject to a Section 382 limitation.

KGen Power Corporation
Notes to Consolidated Financial Statements (Continued)
For the Year ended June 30, 2009 and 2008

10. Income Taxes (Continued)

Management has determined that valuation allowances are necessary as of June 30, 2009 and 2008, 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, 2009.

The Company filed income tax returns in the United States federal jurisdiction and in various 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

The Company provided asset management services to KMPAM Holdco LLC, formerly known as KGen Holdco LLC, with respect to certain assets that were held as part of our business prior to our acquisition of KGen Partners LLC from KMPAM Holdco LLC in February 2007. KMPAM Holdco LLC is controlled by MatlinPatterson Global Advisers LLC. Ramon Betolaza, a former director of the Company, is a Partner of MatlinPatterson Global Advisers and shares in the profits of such entity. Under the services agreement with KMPAM Holdco LLC, the Company received payments of \$50,000 per month plus reimbursement for out-of-pocket expenses in connection with the asset management services. The services agreement was terminated effective May 31, 2008.

12. Registration of Shares with the Securities and Exchange Commission

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

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, 2009:

<u>Name</u>	<u>Age</u>	<u>Position</u>
Thomas B. White	53	President, Chief Executive Officer and Director
James H. Sweeney	50	Senior Vice President, Energy Management
William R. Marlow	42	General Counsel and Secretary
Charles L. Holland	67	Senior Vice President, Operations
W. Kevin Redmond	44	Chief Accounting Officer and Controller
Tina C. Lee*	38	Vice President, Energy Management
Stuart J. Prall*	35	Vice President, Operations
Steven B. McDowell*	34	Vice President, Mergers & Acquisitions and Finance
Daniel T. Hudson	43	Chairman of the Board
James P. Jenkins	61	Director
Gerald J. Stalun	50	Director

*Effective July 1, 2009

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 become 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 a 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 a principal owner of Navasota Energy Partners LP and Montgomery Energy Partners LP, as well as Managing Member and CFO of Navasota Holdings Texas Partners LP, a 1,650 MW ERCOT portfolio. He is responsible for M&A, capital formation / management from private equity, third party debt and equity-raising. 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 Adelpia, 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

Set forth below is a description of certain transactions entered into between our company and our executive officers, directors and 5% stockholders.

The Company provided asset management services to KMPAM Holdco LLC, formerly known as KGen Holdco LLC, with respect to certain assets that were held as part of our business prior to our acquisition of KGen Partners LLC from KMPAM Holdco LLC in February 2007. KMPAM Holdco LLC is controlled by MatlinPatterson Global Advisers LLC. Ramon Betolaza, a former director of the Company, is a Partner of MatlinPatterson Global Advisers and shares in the profits of such entity. Under the services agreement with KMPAM Holdco LLC, the Company received payments of \$50,000 per month plus reimbursement for out-of-pocket expenses in connection with the asset management services. The services agreement was terminated effective May 31, 2008.

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 to be "independent."

In making this determination, the Company was aware that in 2006, Navasota Energy, of which Mr. Hudson is a Managing Member and Chief Financial Officer, purchased turbines for an aggregate of \$59.0 million from a subsidiary of KGLLC. These purchases occurred prior to the existence of the Company and its acquisition of KGLLC, and the relevant subsidiary was no longer a subsidiary at the time of the Company's acquisition of KGLLC. Accordingly, the Company did not believe that this transaction would interfere with Mr. Hudson's exercise of independent judgment in carrying out his responsibilities as a director of the Company.