Southern Nuclear Operating Company
Vogtle Electric Generating Plant, Units 3 & 4
COL Application

COLA Table of Contents

Vogtle Early Site Permit Application

Vogtle Electric Generating Plant - Units 3 & 4

COL Application

Part 1

General and Financial Information

Revision 0

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LIST OF ACRONYMS

AFUDC	Allowance Funds Used During Construction
BLS	Bureau of Labor Statistics
COL	Combined License
DCD	Design Control Document
EMC	Electric Membership Corporation
EPC	Engineering, Procurement and Construction
EPZ	Emergency Planning Zone
ESP	Early Site Permit
ESPA	Early Site Permit Application
FNP	Joseph M. Farley Nuclear Plant
GDC	General Design Criteria
GPC	Georgia Power Company
HNP	Edwin I. Hatch Nuclear Plant
IBR	Incorporation By Reference
LLC	Limited Liability Corporation
LWA	Limited Work Authorization
MEAG	Municipal Electric Authority of Georgia
MW_e	Megawatt electric
MW_t	Megawatt thermal
ODCM	Offsite Dose Calculation Manual
OPC	Oglethorpe Power Corporation
PSC	Public Service Commission
PWR	Pressurized Water Reactor
ROC	Retail Operating Company
RUS	Rural Utilities Service
SEC	Securities and Exchange Commission
SNC	Southern Nuclear Operating Company
VEGP	Vogtle Electric Generating Plant

1.0 GENERAL INFORMATION

This part of the Combined License (COL) Application for the Vogtle Electric Generating Plant, Units 3 and 4 (VEGP), addresses the requirements of 10 CFR 50.33, "Content of applications; general information," and provides details of the applicant's corporate identity and location; applicant's ownership organization; the types of licenses being applied for; the applicant's financial qualifications; decommissioning funding assurance; foreign ownership, control, or domination information; and agreement limiting access to classified information.

1.1 APPLICANT'S AND OWNERS' CORPORATE INFORMATION

1.1.1 APPLICANT AND OWNERS

Southern Nuclear Operating Company, Inc. (SNC) has been authorized by VEGP Owner Georgia Power Company (who acts as agent for the other VEGP Owners) to apply for COLs for VEGP Units 3 and 4. SNC submits this application individually, and for the Owner licensees to be named on the VEGP Units 3 and 4 COLs. The names of the Owner licensees are as follows:

- Georgia Power Company;
- Oglethorpe Power Corporation (An Electric Membership Corporation);
- Municipal Electric Authority of Georgia; and
- The City of Dalton, Georgia, an incorporated municipality in the State of Georgia acting by and through its Board of Water, Light and Sinking Fund Commissioners (Dalton Utilities).

SNC is the Applicant for Combined Licenses for VEGP Units 3 and 4, and will construct and operate these new units on behalf of the VEGP Owners. However, SNC will not have any ownership interest in VEGP Units 3 and 4. Georgia Power Company (GPC), as an Owner of VEGP Units 3 and 4, has entered into an agreement with the other Co-owners to decide on the ownership of VEGP Units 3 and 4 by mid-2008. Currently, GPC expects the other Co-owners to participate as well. Thus, the Owners of the existing VEGP units (i.e., Units 1 and 2), listed above, are projected to be the Owners of VEGP Units 3 and 4**,** and to be licensees of these new units in addition to SNC.

The addresses of SNC and Owner licensees are as follows:

- Southern Nuclear Operating Company, Inc.
  P.O. Box 1295
  Birmingham, AL 35201-1295

- Georgia Power Company
  241 Ralph McGill Boulevard, NE
  Atlanta, GA 30308

- Oglethorpe Power Corporation (An Electric Membership Corporation)
  2100 East Exchange Place
  Tucker, GA 30084-5336

- Municipal Electric Authority of Georgia
  1470 Riveredge Parkway, NW
  Atlanta, GA 30328

- Dalton Utilities
  1200 V. D. Parrott, Jr. Parkway
  Dalton, GA 30720

SNC requests that the NRC issue the VEGP Units 3 and 4 combined licenses with SNC as the operator and constructor, licensed to "construct, possess, manage, use, operate, and maintain" the facilities. SNC further requests that the NRC issue the VEGP Units 3 and 4 combined licenses with Georgia Power Company (GPC), Oglethorpe Power Corporation (OPC), Municipal Electric Authority of Georgia (MEAG), and the City of Dalton (Dalton) as the Owners of VEGP Units 3 and 4, licensed to "possess but not operate" the facilities.

SNC has entered into agreements with GPC (and GPC with the other owners) to provide SNC the authority to apply for and hold a COL, and to operate the facilities on the owners' behalf. SNC will enter into similar agreements to construct the facilities. As such, SNC is granted the authority, on behalf of the Owners, to manage all aspects of plant construction and operation including but not limited to management of the construction of the units, control of the exclusion area, security, and emergency planning. Additionally, SNC has implemented a 10 CFR 50 Appendix B quality assurance program applicable to both construction and operation as part of its obligations. Finally, SNC has entered into agreements with GPC specifying: (1) the arrangements for provision of a continued source of off-site power; (2) the arrangements for controlling operation, maintenance, repair, and other activities with respect to the transmission lines and switchyard in the Exclusion Area; and (3) a requirement that GPC obtain approval from SNC prior to implementing any changes to equipment located in the Exclusion Area. These elements are discussed in Section 8.2 of Part 2 of this application.

1.1.2 DESCRIPTION OF BUSINESS OR OCCUPATION

- SOUTHERN NUCLEAR OPERATING COMPANY, INC. (NON-OWNER APPLICANT)

SNC is a wholly owned subsidiary of Southern Company and is engaged in the operation of nuclear power plants on behalf of the Southern Electric System. SNC is a corporation organized and existing under the laws of the State of Delaware. SNC was formed for the purpose of operating nuclear facilities owned by other subsidiaries of Southern Company. Traditional electrical operating companies that are subsidiaries of Southern Company are Georgia Power Company, Alabama Power Company, Gulf Power Company, and Mississippi Power Company. SNC currently operates the Edwin I. Hatch Nuclear Plant (HNP), Units 1 and 2; and the Vogtle Electric Generating Plant (VEGP), Units 1 and 2, for Georgia Power Company, Oglethorpe Power Corporation, Municipal Electric Authority of Georgia, and the City of Dalton (i.e., Dalton Utilities) (the owners). SNC also operates the Joseph M. Farley Nuclear Plant (FNP), Units 1 and 2, for Alabama Power Company. The combined electric generation of the three plants is in excess of 6000 megawatts (MW_e's).

The traditional service area of Southern Company includes Alabama, Georgia, and portions of Mississippi and Florida. Southern Company's composite power plants have a total installed generating capacity of over 42,000 MW_e's as of January 1, 2008.

- GEORGIA POWER COMPANY (OWNER)

Georgia Power Company (GPC) is engaged in the generation and transmission of electricity and the distribution and sale of such electricity within the State of Georgia and at wholesale within the southeastern United States. GPC serves more than two million retail customers in a service area of approximately 57,000 square miles of the State of Georgia's land area. With a rated capability of approximately 20,000 MW_e's, GPC currently provides retail electric service in all but four (4) of Georgia's 159 counties.

- OGLETHORPE POWER CORPORATION (OWNER)

Oglethorpe Power Corporation (An Electric Membership Corporation) (OPC) supplies electricity at wholesale to 38 Electric Membership Corporations (EMCs) in the State of Georgia, which in turn distribute this electricity at retail to their residential, commercial and industrial customers. The EMCs serve approximately 1.7 million electric consumers (meters) representing approximately 4.1 million people of the nine million total residents in the State of Georgia. The EMCs serve consumers in 150 of the 159 counties in Georgia.

- MUNICIPAL ELECTRIC AUTHORITY OF GEORGIA (OWNER)

Municipal Electric Authority of Georgia (MEAG) is an electric generation and transmission public corporation, which provides wholesale power to 49 communities in the State of Georgia and other wholesale customers. These communities, in turn, supply electricity to approximately 308,000 retail accounts, representing a total population of approximately 614,000, in their respective service areas across the state.

- CITY OF DALTON (OWNER)

The City of Dalton (Dalton) is a municipality within the State of Georgia. Acting by and through its Board of Water, Light and Sinking Fund Commissioners, doing business as Dalton Utilities, Dalton owns electric generation capacity, transmission capacity and a distribution system. Dalton is a duly incorporated municipality under the laws of the State of Georgia.

1.1.3 ORGANIZATION AND MANAGEMENT

- SOUTHERN NUCLEAR OPERATING COMPANY, INC. (NON-OWNER APPLICANT)

SNC is a Delaware corporation that is headquartered in Birmingham, Alabama. SNC is a wholly-owned subsidiary of Southern Company, a Delaware corporation with its principal office in Atlanta, Georgia. Neither SNC, nor its parent, Southern Company, is owned, controlled, or dominated by an alien, a foreign corporation, or a foreign government.

The names and business addresses of SNC's directors and principal officers, all of whom are citizens of the U.S., are as follows (Reference 1.7-1):

SNC Directors		
Name	**Title**	**Business Address**
D. M. Ratcliffe	Chairman, Southern Company - President and Chief Operating Officer	30 Ivan Allen Jr. Blvd NW Atlanta, GA 30308
M. D. Garrett	Georgia Power Company - President and Chief Executive Officer	241 Ralph McGill Blvd, NE Atlanta, GA 30308
C. D. McCrary	Alabama Power Company - President and Chief Executive Officer	600 N 18th St Birmingham, AL 35202
J. B. Beasley, Jr.	Southern Nuclear Operating Company, Inc - President and Chief Executive Officer	P.O. Box 1295 Birmingham, AL 35201

SNC Principal Officers		
Name	**Title**	**Business Address**
J. B. Beasley, Jr	SNC Director, Southern Nuclear Operating Company, Inc – President and Chief Executive Officer	P.O. Box 1295 Birmingham, AL 35201
J. T. Gasser	Southern Nuclear Operating Company, Inc – Executive Vice President	P.O. Box 1295 Birmingham, AL 35201
J. A. Miller	Southern Nuclear Operating Company, Inc – Senior Vice President, Nuclear Development	P.O. Box 1295 Birmingham, AL 35201
L. M. Stinson	Southern Nuclear Operating Company, Inc – Vice President, Fleet Operations Support	P.O. Box 1295 Birmingham, AL 35201
M. M. Caston	Southern Nuclear Operating Company, Inc – Vice President and Corporate Counsel	P.O. Box 1295 Birmingham, AL 35201
K. S. King	Southern Nuclear Operating Company, Inc - Chief Financial Officer and Vice President, Corporate Services	P.O. Box 1295 Birmingham, AL 35201
D. H. Jones	Southern Nuclear Operating Company, Inc – Vice President, Engineering	P.O. Box 1295 Birmingham, AL 35201
T. E. Tynan	Southern Nuclear Operating Company, Inc – Site Vice President – Vogtle	7821 River Rd Waynesboro, GA 30830
J. R. Johnson	Southern Nuclear Operating Company, Inc – Site Vice President – Farley	P.O. Drawer 470 Ashford, AL 36312
D. R. Madison	Southern Nuclear Operating Company, Inc – Site Vice President – Hatch	11028 Hatch Pkwy, North Baxley, GA 31513

- GEORGIA POWER COMPANY (OWNER)

GPC is a Georgia corporation with its principal office in Atlanta, Georgia. GPC is a wholly owned subsidiary of Southern Company, a Delaware corporation with its principal office also in Atlanta, Georgia.

Neither GPC nor its corporate parent, Southern Company, is owned, controlled, or dominated by an alien, foreign corporation, or foreign government.

The names and business addresses of GPC's directors and principal officers, all of whom are citizens of the U.S., are as follows:

GPC Directors		
Name	**Title**	**Business Address**
R. L. Brown, Jr	GPC Director	250 E Ponce De Leon Ave, 8th Fl Decatur, GA 30030
R. D. Brown	GPC Director	100 Auburn Ave, NE Atlanta, GA 30303
A. R. Cablik	GPC Director	1513 Johnson Ferry Rd Suite T-20 Marietta, GA 30062
M. D. Garrett	GPC Director	241 Ralph McGill Blvd, NE Atlanta, GA 30308
D. M. Ratcliffe	GPC Director	30 Ivan Allen Jr. Blvd NW Atlanta, GA 30308
J. C. Tallent	GPC Director	63 Hwy 515 Blairsville, GA 30512
D. G. Thompson	GPC Director	4020 Powers Ferry Rd Atlanta, GA 30342
R. W. Ussery	GPC Director	P.O. Box 1360 Fortson, GA 31808
W. Jerry Vereen	GPC Director	301 Riverside Dr Moultrie, GA 31768-8603
E. J. Wood, III	GPC Director	P.O. Box 4418, MC0103 Atlanta, GA 30302-4418

GPC Principal Officers		
Name	**Title**	**Business Address**
M. D. Garrett	President and Chief Executive Officer	241 Ralph McGill Blvd, NE Atlanta, GA 30308
C. S. Thrasher	Executive Vice President, Treasurer and Chief Financial Officer	241 Ralph McGill Blvd, NE Atlanta, GA 30308
A. P. Daiss	Vice President, Comptroller and Chief Accounting Officer	241 Ralph McGill Blvd, NE Atlanta, GA 30308
C. C. Womack	Executive Vice President, External Affairs	241 Ralph McGill Blvd, NE Atlanta, GA 30308
M. A. Brown	Executive Vice President, Customer Service Organization	241 Ralph McGill Blvd, NE Atlanta, GA 30308
J. H. Miller III	Senior Vice President and General Counsel	241 Ralph McGill Blvd, NE Atlanta, GA 30308
J. M. Anderson	Senior Vice President, Charitable Giving	241 Ralph McGill Blvd, NE Atlanta, GA 30308
D. E. Jones	Senior Vice President, Fossil & Hydro Generation	241 Ralph McGill Blvd, NE Atlanta, GA 30308
O. C. Harper IV	Vice President, Resource Planning and Nuclear Development	241 Ralph McGill Blvd, NE Atlanta, GA 30308

- OGLETHORPE POWER CORPORATION (OWNER)

Oglethorpe Power Corporation (An Electric Membership Corporation) (OPC) was organized under the Georgia Electric Membership Corporation Act (Official Code of Georgia Annotated, Title 46, Chapter 3, Article 4) and operates on a not-for-profit basis.

OPC is neither owned, controlled nor dominated by an alien, foreign corporation or foreign government.

The names and business addresses of OPC's principal officers and the members of its governing body, all of whom are citizens of the U.S., are as follows:

OPC Directors		
Name	**Title**	**Business Address**
Benny W. Denham	Chairman	2100 East Exchange Pl Tucker, GA 30084-5336
Sam Rabun	Vice Chairman	2100 East Exchange Pl Tucker, GA 30084-5336
Marshall S. Millwood	Director	2100 East Exchange Pl Tucker, GA 30084-5336
Larry N. Chadwick	Director	2100 East Exchange Pl Tucker, GA 30084-5336
M. Anthony Ham	Director	2100 East Exchange Pl Tucker, GA 30084-5336
H. B. "Bud" Wiley Jr.	Director	2100 East Exchange Pl Tucker, GA 30084-5336
Gary A. Miller	Director	2100 East Exchange Pl Tucker, GA 30084-5336
Jeffrey W. Murphy	Director	2100 East Exchange Pl Tucker, GA 30084-5336
C. Hill Bentley	Director	2100 East Exchange Pl Tucker, GA 30084-5336

OPC Directors (cont'd.)		
Name	**Title**	**Business Address**
Gary W. Wyatt	Director	2100 East Exchange Pl Tucker, GA 30084-5336
Wm. Ronald Duffey	Director	2100 East Exchange Pl Tucker, GA 30084-5336

OPC Principal Officers		
Name	**Title**	**Business Address**
Thomas A. Smith	President and CEO	2100 East Exchange Pl Tucker, GA 30084-5336
Michael W. Price	Chief Operating Officer	2100 East Exchange Pl Tucker, GA 30084-5336
Elizabeth B. Higgins	Chief Financial Officer	2100 East Exchange Pl Tucker, GA 30084-5336
W. Clayton Robbins	Senior Vice President - Government Relations and Chief Administrative Officer	2100 East Exchange Pl Tucker, GA 30084-5336
William F. Ussery	Senior Vice President, Member and External Relations	2100 East Exchange Pl Tucker, GA 30084-5336
Jami G. Reusch	Vice President, Human Resources	2100 East Exchange Pl Tucker, GA 30084-5336

- MUNICIPAL ELECTRIC AUTHORITY OF GEORGIA (OWNER)

MEAG is a public corporation and an instrumentality of the State of Georgia, a body corporate and politic, created by the General Assembly of the State of Georgia in its 1975 Session (Official Code of Georgia Annotated, Title 46, Chapter 3, Article 3).

MEAG is neither owned, controlled nor dominated by an alien, foreign corporation or foreign government.

The names and business addresses of MEAG's principal officers and the members of its governing body, all of whom are citizens of the U.S., are as follows:

MEAG Directors		
Name	**Title**	**Business Address**
L. Keith Brady	Chairman	25 LaGrange St Newnan, GA 30263
Roland C. Stubbs, Jr.	Vice-Chairman	115 Mims Rd Sylvania, GA 30467
Kerry S. Waldron	Secretary-Treasurer	106 S. Hutchinson Ave Adel, GA 31620
Patrick C. Bowie, Jr.,	Board Member	200 Ridley Ave LaGrange, GA 30241
Kelly E. Cornwell	Board Member	P.O. Box 248 Calhoun, GA 30703-0248
John H. Flythe	Board Member	P.O. Box 218 Fitzgerald, GA 31750
Robert. W. Lewis	Board Member	675 N. Marietta Pkwy Marietta, GA 30060-1528
Steve A. Rentfrow	Board Member	P.O. Box 1218 Cordele, GA 31010-1218
Robert C. Sosebee	Board Member	1953 Homer Rd Commerce, GA 30529

MEAG Principal Officers		
Name	**Title**	**Business Address**
Robert P. Johnston	President and Chief Executive Officer	1470 Riveredge Pkwy, NW Atlanta, GA 30328
Charles B. Manning, Jr.	Senior Vice President, Participant and Corporate Affairs	1470 Riveredge Pkwy, NW Atlanta, GA 30328
Mary G. Jackson	Senior Vice President and Chief Accounting Officer	1470 Riveredge Pkwy, NW Atlanta, GA 30328
James E. Fuller	Senior Vice President and Chief Financial Officer	1470 Riveredge Pkwy, NW Atlanta, GA 30328
Steven M. Jackson	Vice President, Power Supply	1470 Riveredge Pkwy, NW Atlanta, GA 30328
Gary M. Schaeff	Vice President, Transmission	1470 Riveredge Pkwy, NW Atlanta, GA 30328
J. Scott Jones	Vice President, Audit and Risk Management	1470 Riveredge Pkwy, NW Atlanta, GA 30328

- CITY OF DALTON (OWNER)

The City of Dalton (Dalton) is a duly incorporated municipality under the laws of the State of Georgia. Dalton acts by and through its Board of Water, Light and Sinking Fund Commissioners, which does business as Dalton Utilities.

Dalton Utilities is not owned, controlled, or dominated by an alien, foreign corporation, or foreign government.

The names and business addresses of the City of Dalton's governing body (Mayor and Councilmen); the Board of Water, Light and Sinking Fund Commissioners of the City of Dalton; and Dalton Utilities' principal officers (President/Chief Executive Officer, Secretary and Chief Financial Officer), all of whom are citizens of the U.S., are as follows:

Mayor and Council of the City of Dalton		
Name	**Title**	**Business Address**
David Pennington	Mayor	P.O. Box 1205 Dalton, GA 30722
Denise Wood	Councilman	P.O. Box 1205 Dalton, GA 30722
George Sadosuk	Councilman	P.O. Box 1205 Dalton, GA 30722
Dick Lowery	Councilman	P.O. Box 1205 Dalton, GA 30722
Charles Bethel	Councilman	P.O. Box 1205 Dalton, GA 30722

Board of Water, Light and Sinking Fund Commissioners of the City of Dalton		
Name	**Title**	**Business Address**
Norman Burkett	Chairman	c/o Dalton Utilities P.O. Box 869 Dalton, GA 30722
Lamar Hennon	Vice Chairman	c/o Carpets of Dalton/ Home Show Place 3010 Old Dug Gap Rd Dalton, GA 30720
George Mitchell	Commissioner	c/o Dalton Utilities P.O. Box 869 Dalton, GA 30722
Smith Foster	Commissioner	c/o Plantex Machinery Inc. P.O. Box 1761 Dalton, GA 30722-1761
Walter Parsons	Commissioner	c/o Dalton Utilities P.O. Box 869 Dalton, GA 30722

Dalton Utilities Officers		
Name	**Title**	**Business Address**
Don Cope	President and Chief Executive Officer	1200 V. D. Parrott, Jr. Pkwy Dalton, GA 30720
George Mitchell	Secretary	1200 V. D. Parrott, Jr. Pkwy Dalton, GA 30720
Tom Bundros	Chief Financial Officer	1200 V. D. Parrott, Jr. Pkwy Dalton, GA 30720

1.1.4 REQUESTED LICENSES AND AUTHORIZED USES

This application is for two Class 103 combined licenses under 10 CFR Part 52, Subpart C, to construct and operate two additional nuclear power plants at the VEGP site, located adjacent to the existing VEGP Units 1 and 2 in Burke County, Georgia. The two largest population centers (defined as having more than 25,000 residents) in the region are Augusta, Georgia and Aiken, South Carolina. Pursuant to 10 CFR 52.73(a), this application incorporates the Design Control Document (DCD) (Reference 1.7-2) for a simplified passive advanced light water reactor plant provided by Westinghouse Electric Company, LLC (Westinghouse), the entity sponsoring and obtaining the AP1000 design certification documented in 10 CFR Part 52, Appendix D. Throughout this application, the "referenced DCD" is the AP1000 DCD submitted by Westinghouse as Revision 16, including any supplemental material as identified in Reference 1.7-3.

This application also references the Vogtle Early Site Permit Application (ESPA), as permitted by 10 CFR 52.25(c). The current version of that application is Revision 4, submitted to the NRC on March 31, 2008. The Final Safety Analysis Report in Part 2 of this COL application incorporates by reference the Site Safety Analysis Report in the ESPA. The Environmental Report in Part 3 of this COL application does not repeat the environmental information associated with the ESPA but instead provides the information specified in 10 CFR 51.50(c)(1) as it relates to the draft Environmental Impact Statement for the ESPA. Part 5 of this COL application incorporates by reference the Emergency Plan in the ESPA.

The new VEGP nuclear power plants will be used to produce electricity for sale, similar to existing VEGP Units 1 and 2. The period of time for which the license for the unit is requested shall begin upon the NRC's granting of the combined licenses for VEGP and shall expire 40 years from the date upon which the NRC makes a finding that acceptance criteria are met under 10 CFR 52.103(g) or allowing operation during an interim period under 10 CFR 52.103(c).

In addition, this application is for the necessary licenses issued under 10 CFR Part 30, 10 CFR Part 40, and 10 CFR Part 70 to receive, possess, and use byproduct, source and special nuclear material. Byproduct, source, and special nuclear material shall be in the form of sealed neutron sources for reactor startup, sealed sources for reactor instrumentation and radiation monitoring equipment, calibration, and fission detectors in amounts as required. Byproduct, source, and special nuclear material in amounts as required, without restriction to chemical or physical form, shall be for sample analysis or instrument and equipment calibration or associated with radioactive apparatus or components. Special nuclear material shall be in the form of reactor fuel and spent fuel, in accordance with limitations for storage and amounts required for reactor operation, as described in Part 2 of this application.

The current scheduled date for the completion of construction activities on VEGP Unit 3 is October 2015 and on VEGP Unit 4 is October 2016.

Construction and operation of the proposed plant requires compliance with a number of environmental regulations, obtaining a number of associated permits, and performing consultations with Government agencies. An assessment was performed of applicable regulations, permits, and consultations required by Federal, state, regional, local, and potentially affected Native American tribal agencies, and the results are presented in Section 1.5 of the Environmental Report (Part 3 of this application).

Four regulatory agencies have jurisdiction over the rates, financing, or financial reporting incident to the construction and operation of VEGP Units 3 and 4. Those regulatory agencies are the Georgia Public Service Commission, the Federal Energy Regulatory Commission, the U.S. Securities and Exchange Commission (SEC), and Rural Utilities Service (RUS). The mailing addresses of these agencies are as follows (References 1.7-4 through -7):

- Georgia Public Service Commission (Regulates GPC, OPC, MEAG and Dalton Utilities)

  244 Washington Street, SW

  Atlanta, GA 30334
- Federal Energy Regulatory Commission (Regulates GPC)

  888 First Street, NE

  Washington, DC 20426
- U.S. Securities and Exchange Commission (Regulates SNC, GPC and OPC)

  3475 Lenox Road, N.E., Suite 1000
  Atlanta, GA 30326-1232
- Rural Utilities Service (Regulates OPC)

  1400 Independence Ave SW

  Washington, DC 20250-0747

Local news publications that circulate in the area around the proposed facility and that are considered appropriate to give reasonable notice of the application to those parties that might have a potential interest in the proposed facility are as follows:

- The Atlanta Journal-Constitution

  72 Marietta Street NW

  Atlanta, GA 30303

  404-526-5151

- The Augusta Chronicle/Morris News Agency

  725 Broad Street

  Augusta, GA 30901

  706-724-0851

- The True Citizen

  P.O. Box 948

  601 East Sixth Street

  Waynesboro, GA 30830

  706-554-2111

- The Aiken Standard

  326 Rutland Drive NW

  P.O. Box 456

  Aiken, SC 29801

  803-648-2311

SNC applied for an early site permit (ESP) for the VEGP site on August 14, 2006 (Reference 1.7-8) in accordance with 10 CFR 52 Subpart A, "Early Site Permits". The NRC accepted SNC's ESP application on September 19, 2006 (Reference 1.7-9) and the NRC is currently reviewing the application under Docket No. 52-011. SNC also requested a Limited Work Authorization (LWA) through the ESP application in August 2007 (Reference 1.7-10). With the exception of SNC's request for a VEGP ESP and LWA, no other NRC licenses have been applied for, or issued, in connection with proposed VEGP Units 3 and 4.

1.2 RADIOLOGICAL EMERGENCY RESPONSE PLANS

Radiological emergency response plans of State and local government entities in the United States that are wholly or partially within the plume exposure pathway emergency planning zone (EPZ), as well as the plans of State governments wholly or partially within the ingestion pathway

EPZ are referenced in ESP application, Part 5, Emergency Plan, and were previously submitted to the NRC (References 1.7-11 and 1.7-12).

1.3 FINANCIAL QUALIFICATIONS

Pursuant to the requirements of 10 CFR 50.33(f), an applicant for a COL is required to include information sufficient to demonstrate to the NRC the financial qualification of the applicant to carry out the construction and/or operation activities for which the application is sought. Entities that meet the definition of an "electric utility" in 10 CFR 50.2 are exempt from the requirement to demonstrate financial qualification to carry out operation activities and are required only to demonstrate financial qualification to carry out construction activities. Because SNC will recover the cost of operating the units from the Owners, and the Owners will either recover those costs through rates or charges established by the Georgia Public Service Commission or established by the Owner itself, SNC and each of the Owners meet the definition of "electric utility" from 10 CFR 50.2. Accordingly, only the information necessary to demonstrate the financial qualifications of the Owners of VEGP Units 3 and 4 to obtain construction funds and fuel cycle costs is provided in this subsection.

In accordance with 10 CFR 50.33(f) and 10 CFR 50, Appendix C, SNC has estimated the total combined construction costs for the two units of the proposed facility. These costs are estimated in 2008 dollars and are based on a construction period for the project (as defined by 10 CFR 50.10) of 67 months per unit. Licensing costs and pre-construction activities occur before actual construction and are included in the estimates. The breakdown of the costs and the bases for each is described in Appendix 1A.

- SOUTHERN NUCLEAR OPERATING COMPANY, INC. (NON-OWNER APPLICANT)

Southern Nuclear Operating Company, Inc. (SNC) was established as a company within the Southern Company (Southern) for the purpose of consolidating personnel within the Southern Electric System engaged in nuclear-related activities into a single, integrated organization.

Accordingly, SNC will be the constructor and licensed operator for VEGP Units 3 and 4. Agreements will be entered into for SNC with Georgia Power Company (GPC) to exercise this authority. SNC will be the exclusive entity authorized to construct and operate VEGP Units 3 and 4.

Related to construction, the following pertinent corporate and contractual relationships have been established:

- GPC, as agent for the Owners of the new units, will enter into an Engineering, Procurement and Construction (EPC) Agreement with a consortium comprised of

Westinghouse Electric Company, LLC and Stone & Webster, Inc. ("the Consortium") for the construction of the units. The Owners will make payment to the Consortium through GPC, as agent, for the costs under the EPC contract. SNC will administer the EPC on behalf of the plant Owners.

- GPC has contracted to reimburse SNC for all other funds necessary for the construction of the units. Responsibility for reimbursement of these costs will be absolute. The plant's other Owners (Oglethorpe Power Corporation, Municipal Electric Authority of Georgia, and City of Dalton) have contracted to reimburse GPC for their proportionate shares of these costs. The participation of precise ownership percentages of each Owner will not be finally determined until late 2008.
- GPC is subject to the jurisdiction of two rate regulatory authorities, the Georgia Public Service Commission and the Federal Energy Regulatory Commission. The output of VEGP Units 3 and 4 is expected to be sold to GPC retail customers; accordingly, GPC will include its proportionate share of the aforementioned costs as capital expenditure before the Georgia Public Service Commission and will earn a return on prudently incurred costs from its customers. The other plant Owners will recover their costs through rates and charges to their customers.

Related to operations, the following pertinent corporate and contractual relationships have been established:

- SNC will not have any ownership interest in the new units, the nuclear facilities, nor the fuel. On behalf of the Owners, SNC will be authorized to exercise overall responsibility for plant operations, including exclusive responsibility for safety decisions.
- By contract, GPC and SNC will establish cost responsibility and allocation for the units. The costs experienced directly by SNC in the operation of VEGP Units 3 and 4 will be reimbursed by GPC pursuant to the operating agreement. Other expenses of SNC which are not direct charges to a specific plant will be allocated to GPC and others for whom such expenses are incurred, as appropriate. Responsibility for reimbursement by GPC of these costs will be absolute. GPC will, in turn, be reimbursed by the other plant Owners for their proportionate shares of these costs pursuant to existing agreements. Because the plant Owners are entitled to the entire electric generation from VEGP Units 3 and 4, and do not purchase electric generation from SNC, the costs will not be "rates" subject to regulatory review and approval except as items of costs to the plant Owners.
- GPC will recover its proportionate share of prudently incurred costs of operation of the units in rates charged to customers as authorized by the Georgia Public Service Commission. The other plant Owners will recover their costs through rates and charges to their customers.

- With SNC as the licensed plant operator, GPC has contracted to provide all funds necessary for the safe operation, construction, maintenance, repair, decontamination and decommissioning incurred or accrued by SNC. Thus, the various contractual obligations, and retention of full ownership interest by the plant Owners as well as the Owners' entitlement to all electrical output from the plant, assure that the same level of financial qualification will exist for the new units as for VEGP Units 1 and 2.
- The plant Owners will retain authority to direct, through their agent, GPC, that the plant be shut down in an orderly fashion by SNC (and in accordance with SNC's safety judgment) rather than make specific capital modifications or other major expenditures. This retained authority ultimately will limit SNC's spending authority, but will not encumber SNC's ability to make operational safety decisions and will have no impact on safe operation of the plant.

Thus, consistent with the decisions made when authority was first given by the NRC for SNC to operate the HNP, the FNP, and VEGP Units 1 and 2, SNC, and each of the plant Owners, is an "electric utility" as defined in 10 CFR 50.2. Therefore, under 10 CFR 50.33(f), the financial qualification review required by 10 CFR 50.33(f) is limited to a demonstration that the proposed Owners are financially qualified to carry out necessary construction activities.

- GEORGIA POWER COMPANY (OWNER)

GPC provides the following information required by 10 CFR 50.33(f), 10 CFR 50 Appendix C, and NUREG 1577, Revision 1.

GPC meets the definition of an "electric utility" as that term is defined in 10 CFR 50.2 in that GPC recovers the cost of electricity through rates established by the Georgia Public Service Commission. Therefore, GPC is exempt from financial qualification review for the operating license pursuant to 10 CFR 50.33(f) and in accordance with Section III.1.b of NUREG-1577, Rev. 1. Information regarding financial qualifications to support the construction of VEGP Units 3 and 4 is provided below.

GPC, as a subsidiary of Southern Company, is an investor-owned electric utility serving customers in 57,000 of the state's 59,000 square miles. GPC has just over 2 million retail customers in all but four (4) of Georgia's 159 counties.

Southern Company is the parent firm of GPC, Alabama Power Company, Gulf Power Company, Mississippi Power Company, Southern Power, and SNC as well as certain service and special-purpose subsidiaries. The operating companies, known as the Southern Electric System (System), coordinate system operations and jointly dispatch their generating units to capture the economies available from power pooling. The System is a member of the SERC Reliability Corporation (SERC), a group of electric utilities (and other electric related utilities) coordinating

operations and other measures to maintain a high level of reliability for the electrical system in the southeastern United States. The four retail regulated operating companies ("retail operating companies" or "ROCs") - GPC, Alabama Power Company, Gulf Power Company and Mississippi Power Company – also participate in coordinated generation and transmission planning as appropriate.

GPC's common stock is held solely by Southern Company. Southern Company is investor-owned, and had 102,903 common stockholders at year end 2007.

GPC has a net utility investment of more than $13.8 billion, of which approximately $5.2 billion is invested in generating facilities including 156 generating units (38 fossil steam, 75 hydroelectric, 4 nuclear, 2 combined cycle and 37 combustion turbine units). GPC has a total owned generating capacity of approximately 16,102 MW_e's and a total generating capacity of approximately 20,000 MW_e's; 71% of the energy supplied from owned units is from coal, 18% from nuclear, 3% from hydroelectric, and less than 8% from natural gas and oil.

GPC currently has co-ownership of Hatch Nuclear Plant Units 1 and 2 and Vogtle Electric Generating Plant Units 1 and 2 along with Oglethorpe Power Corporation, Municipal Electric Authority of Georgia, and the City of Dalton.

GPC reports and filings to the Georgia Public Service Commission and the U.S. Securities and Exchange Commission may be found at http://www.psc.state.ga.us/ and at http://investor.southerncompany.com/sec.cfm, respectively. In accordance with 10 CFR 50, Appendix C, Southern Company's 2007 10-K Reports may also be found at http://investor.southerncompany.com/sec.cfm.

Before construction commences, GPC will obtain approval of the facility from the Georgia Public Service Commission certifying the cost to construct. The Georgia Public Service Commission is scheduled to make a decision on this matter in March 2009.

The sources of construction funds for GPC's portion of this facility will be a mixture of internally generated cash and external funding. The external funding will come from a mix of capital (debt, preferred, and equity). GPC plans to finance the construction of VEGP Units 3 and 4 utilizing a mixture of general obligation corporate debt and equity (i.e., GPC does not currently plan to incur project-specific financing for the units) that will maintain its overall capital structure, taking into consideration financial market conditions during construction, and the financial requirements of its other investment in new sources of generation, consistent with GPC's financial goal of maintaining a stable "A" credit rating. Currently, GPC's unsecured long-term bonds are rated A2, A, and A+ by Moody's, Standard and Poor's and Fitch, respectively.

- OGLETHORPE POWER CORPORATION (OWNER)

Oglethorpe Power Corporation (An Electric Membership Corporation) (OPC) provides the following information required by 10 CFR 50.33(f), 10 CFR 50 Appendix C, and NUREG 1577, Revision 1.

OPC meets the definition of an "electric utility" as that term is defined in 10 CFR 50.2 in that OPC recovers the cost of electricity through rates set by OPC itself. Therefore, OPC is exempt from financial qualification review for the operating license pursuant to 10 CFR 50.33(f) and in accordance with Section III.1.b of NUREG-1577, Rev. 1. Information regarding financial qualifications to support the construction of VEGP Units 3 and 4 is provided below.

OPC is a Georgia electric membership corporation incorporated in 1974 and headquartered in metropolitan Atlanta. OPC is owned by 38 retail electric distribution cooperative members (the "Members"). OPC and the Members were each formed pursuant to the Georgia Electric Membership Corporation Act. OPC's principal business is providing wholesale electric power to the Members. As with cooperatives generally, OPC operates on a not-for-profit basis. OPC is the largest electric cooperative in the United States in terms of assets, kilowatt-hour sales and, through the Members, consumers served.

The Members are local consumer-owned distribution cooperatives providing retail electric service on a not-for-profit basis. In general, the customer base of the Members consists of residential, commercial and industrial consumers within specific geographic areas. The Members serve approximately 1.7 million electric consumers (meters) representing approximately 4.1 million people.

OPC has interests in 24 generating units. These units provide OPC with a total of 4744 megawatts (MW_e's) of nameplate capacity, consisting of 1501 MW_e's of coal-fired capacity, 1185 MW_e's of nuclear-fueled capacity, 632 MW_e's of pumped storage hydroelectric capacity, 1411 MW_e's of gas-fired capacity (206 MW_e's of which is capable of running on oil) and 15 MW_e's of oil-fired combustion turbine capacity. OPC purchases approximately 300 MW_e's of power pursuant to a long-term power purchase agreement.

OPC's reports to the U.S. Securities and Exchange Commission may be found at www.sec.gov/cgi-bin/browse-edgar?action=getcompany&CIK=0000788816&owner=include&count=40.

OPC has substantially similar Wholesale Power Contracts with each Member extending through December 31, 2050. Under the Wholesale Power Contracts, each Member is unconditionally obligated, on an express "take-or-pay" basis, for a fixed percentage of the capacity costs (referred to as a "percentage capacity responsibility") of each of OPC's generation and purchased power resources. Each Wholesale Power Contract specifically provides that the

Member must make payments whether or not power is delivered and whether or not a plant has been sold or is otherwise unavailable. OPC is obligated to use its reasonable best efforts to operate, maintain and manage its resources in accordance with prudent utility practices.

Percentage capacity responsibilities have been assigned to all of OPC's generation and purchased power resources. Percentage capacity responsibilities for any future resource will be assigned only to Members choosing to participate in that resource. The Wholesale Power Contracts provide that each Member is jointly and severally responsible for all costs and expenses of all existing generation and purchased power resources, as well as for any approved future resources, whether or not such Member has elected to participate in such future resource. For resources in which less than all Members participate, costs are shared first among the participating Members, and if all participating Members default, each non-participating Member is expressly obligated to pay a proportionate share of such default.

Each Member is required to pay OPC for capacity and energy furnished under its Wholesale Power Contract in accordance with rates established by OPC. OPC is required to revise its rates as necessary so that the revenues derived from its rates, together with its revenues from all other sources, will be sufficient to pay all costs of its system, to provide for reasonable reserves and to meet all financial requirements. OPC will participate in the ownership of proposed VEGP Units 3 and 4 only to the extent that Members choose to participate in these units and are assigned a percentage capacity responsibility by subscribing to 100 percent of the costs associated with OPC's ownership interest. OPC's decision to participate is also subject to RUS approval.

Under the Wholesale Power Contracts, each Member must establish rates and conduct its business in a manner that will enable the Member to pay (1) to OPC when due, all amounts payable by the Member under its Wholesale Power Contract and (2) any and all other amounts payable from, or which might constitute a charge or a lien upon, the revenues and receipts derived from the Member's electric system, including all operation and maintenance expenses and the principal of, premium, if any, and interest on all indebtedness related to the Member's electric system.

The sources of construction funds for OPC's portion of this facility will be primarily external funding. OPC is an eligible borrower under the Rural Electrification Act and is seeking loan funds pursuant to the loan programs of the Rural Utilities Service. To the extent funds are not available from these loan programs, OPC will issue debt in the capital markets as necessary to finance its share of the cost of construction. In addition, OPC will issue tax-exempt financing for any portion of this facility that qualifies (sewage and solid waste disposal facilities). Currently, OPC's secured long-term bonds are rated A3, A, and A by Moody's, Standard and Poor's and Fitch, respectively.

- MUNICIPAL ELECTRIC AUTHORITY OF GEORGIA (OWNER)

The Municipal Electric Authority of Georgia (MEAG) was created by the State of Georgia for the purpose of owning and operating electric generation and transmission facilities to supply bulk electric power to political subdivisions of Georgia which owned and operated electric distribution systems as of March 18, 1975. MEAG (also referred to as “MEAG Power”) currently provides bulk electric power to forty-eight (48) cities and one county in the State of Georgia (the "Participants") pursuant to separate power sales contracts with each Participant. MEAG's power resources include ownership interests in ten (10) electric generating units, all of which have been placed in service, as well as power and energy obtained by MEAG through purchases from and exchanges with other bulk electric suppliers. MEAG also owns transmission facilities which, together with those of other utilities form a statewide integrated transmission system. MEAG's ownership interests in those ten generating units represent 2069 MW_e’s of nominally rated generating capacity.

MEAG meets the definition of an “electric utility” as that term is defined in 10 CFR 50.2 in that MEAG recovers the cost of electricity through rates set by MEAG itself. Therefore, MEAG is exempt from financial qualification review for the operating license pursuant to 10 CFR 50.33(f) and in accordance with Section III.1.b of NUREG-1577, Rev. 1.

MEAG will participate in the ownership of the proposed additional Units at VEGP only to the extent that it first procures binding power sales contracts with those Participants electing to participate in the new project. MEAG will issue revenue bonds, supported by the power sales contracts with the Participants as well as any power purchase agreement between MEAG and a third party, to fund the construction costs relating to its ownership interest. Under each such power sales contract, MEAG will agree to provide the Participant, and the Participant shall agree to take from MEAG, a specified percentage of the output and services thereof and to be responsible for a specified percentage of the related costs. The Participant's payment obligations under such power sales contracts are general obligations to the payment of which its full faith and credit are pledged. MEAG's remedies under such power sales contracts will include specific performance to compel the Participants to assess and collect an annual ad valorem tax sufficient to meet its obligations thereunder.

MEAG has the statutory authority to issue revenue bonds to pay for the costs associated with its ownership interest in the additional Units. Such revenue bonds, and the power sales contracts as collateral for the payment of such bonds, will be validated in Georgia prior to issuance of the bonds. The bond proceeds will be the source of MEAG's payments of its share of the construction costs related to the additional Units.

MEAG's Annual Audit is expected to be available in early to mid April. MEAG's latest available Financial Statements are provided in Appendix 1B.

- CITY OF DALTON (OWNER)

The City of Dalton, Georgia (Dalton) is a municipal corporation organized and existing under the laws of the State of Georgia. Dalton constructs and operates its public utilities through the Board of Water, Light and Sinking Fund Commissioners of the City of Dalton, Georgia ("Dalton Utilities"), which was established in 1913 by an act of the Georgia legislature for the purpose of constructing and operating the public utilities for Dalton. Electric, natural gas, water, sewer, and information technology services are provided to customers of Dalton Utilities within Dalton and certain other surrounding areas. Dalton Utilities sells to its retail customers, the residents of the City of Dalton, at rates set by its board of water and light. Thus, Dalton Utilities meets the definition of an "electric utility" as that term is defined in 10 CFR 50.2 in that the cost of electricity is recovered through rates. Therefore, Dalton Utilities is exempt from financial qualification review for the operating license pursuant to 10 CFR 50.33(f) and in accordance with Section III.1.b of NUREG-1577, Rev. 1. Information regarding financial qualifications to support the construction of VEGP Units 3 and 4 is provided below.

Dalton Utilities serves approximately 45,000 customers with the majority of its operating revenues coming from the carpet industry that is headquartered in northwest Georgia. It owns interests in electric generation facilities, the Georgia Integrated Transmission System, electric distribution, natural gas transmission and distribution, water and sewerage systems, and a retail/wholesale broadband system.

Dalton Utilities has utility plant investment approaching $1 billion, of which $350 million is invested in electric generating, transmission and distribution facilities. Dalton Utilities owns 118 MW_e's of electric generation through its joint ownership of Plants Scherer and Wansley, HNP, and VEGP with GPC, OPC, and MEAG. The balance of Dalton Utilities' generating stack is provided by the Southeastern Power Administration and through a wholesale power contract with Southern Power Company.

Annual operating revenues exceed $171 million with annual investment income of approximately $9.5 million. In accordance with its Bond Indenture, Dalton Utilities submits its annually audited financial statements and material event notices to the nationally recognized municipal securities information repositories acknowledged by the SEC.

The sources of construction funds for Dalton Utilities' portion of VEGP Units 3 and 4 will be from a combination of internally generated funds, investment funds restricted for renewals and extensions, and a possible future debt financing. Currently, Dalton Utilities has total assets of $890 million with only $71 million of outstanding bond debt. Even though the bond debt does not have a pledge of property nor taxation, it is currently rated Aa3 by Moody's and A+ by Standard & Poor's. This bond debt is scheduled to be fully amortized by January 1, 2012. Consequently, Dalton Utilities would have the strength of its balance sheet and financial

flexibility to consider future debt financings. The latest available Financial Statements for the Board of Water, Light and Sinking Fund Commissioners of Dalton are provided in Appendix 1C.

1.4 DECOMMISSIONING FUND ASSURANCE

Regulatory Requirements

Pursuant to the requirements of 10 CFR 50.33(k)(1), an application for a combined license for a production or utilization facility will state information in the form of a report, as described in 10 CFR 50.75, indicating how reasonable assurance will be provided that sufficient funds will be available to decommission the facility. The report provided in Appendix 1D provides this information.

10 CFR 50.75(b) requires each power reactor applicant for a combined license for a production or utilization facility of the type and power level specified in 10 CFR 50.75(c) to submit a decommissioning report, as required by 10 CFR 50.33(k).

(1) The report must contain a certification that financial assurance for decommissioning will be provided no later than 30 days after the Commission publishes notice in the *Federal Register* under 10 CFR 52.103(a). The amount of the financial assurance may be more, but not less, than the amount stated in the table in 10 CFR 50.75(c)(1).

(2) The amount to be provided must be adjusted annually using a rate at least equal to that stated in 10 CFR 50.75(c)(2).

(3) The amount must use one or more of the methods described in 10 CFR 50.75(e) as acceptable to the NRC.

(4) The amount stated in the applicant's certification may be based on a cost estimate for decommissioning the facility. As part of the certification, a copy of the financial instrument obtained to satisfy the requirements of paragraph (e) of this section [10 CFR 50.75] must be submitted to the NRC; however, a combined license applicant need not obtain such financial instrument or submit a copy to the Commission except as provided in 10 CFR 50.75(e)(3).

10 CFR 50.75(c) provides the minimum amounts (January 1986 dollars) required to demonstrate reasonable assurance of funds for decommissioning by reactor type and power level and an adjustment factor to account for escalation of labor, energy, and waste burial costs. (Amounts are based on activities related to the definition of "decommission" in 10 CFR 50.2 and do not include the cost of removal and disposal of spent fuel, non-radioactive structures, or materials beyond that necessary to terminate the license).

For a pressurized water reactor (PWR) with a core thermal power rating of greater than or equal to 3400 MW_t, such as the AP1000 reactor design, 10 CFR 50.75(c)(1)(i) specifies the minimum amount required to demonstrate reasonable assurance of funds for decommissioning as $105 million (1986 dollars). This amount is subject to an adjustment factor at least equal to 0.65 L + 0.13 E + 0.22 B, where L and E are escalation factors for labor and energy, respectively, and are to be taken from regional data of U.S. Department of Labor Bureau of Labor Statistics (BLS), and B is an escalation factor for waste burial and is to be taken from NRC report NUREG-1307, "Report on Waste Burial Charges."

10 CFR 50.75(e)(3) provides the requirements that a COL holder under Subpart C of 10 CFR Part 52 shall, 2 years before and 1 year before the scheduled date for initial loading of fuel under 10 CFR 52.103, submit a report to the NRC containing a certification updating the information described under 10 CFR 50.75(b)(1), including a copy of the financial instrument to be used. No later than 30 days after the Commission publishes notice in the *Federal Register* under 10 CFR 52.103(a), the licensee shall submit a report containing a certification that financial assurance for decommissioning is being provided in an amount specified in the licensee's most recent updated certification, including a copy of the financial instrument obtained to satisfy the requirements of 10 CFR 50.75(e).

1.5 FOREIGN OWNERSHIP, CONTROL, OR DOMINATION

SNC and listed owners are not owned, dominated, or controlled by foreign interests.

1.6 RESTRICTED DATA / CLASSIFIED NATIONAL SECURITY INFORMATION

The COL application for VEGP Units 3 and 4 does not contain any Restricted Data or other Classified National Security Information, nor does it result in any change in access to any Restricted Data or National Security Information. In addition, it is not expected that activities conducted in accordance with the proposed COL will involve such information. However, in the event that such information does become involved, and in accordance with 10 CFR 50.37, "Agreement limiting access to Classified Information," SNC will not permit any individual to have access to, or any facility to possess, Restricted Data or National Security Information until the individual and/or facility has been approved for such access under the provisions of 10 CFR Part 25, "Access Authorization," and/or 10 CFR Part 95, "Facility Security Clearance and Safeguarding of National Security Information and Restricted Data".

1.7 REFERENCES

1.7-1 SNC, "Vogtle Early Site Permit Application," Revision 4, March 2008.

1.7-2 Westinghouse Electric Company, 2007, "AP1000 Design Control Document," APP-GW-GL-700, Revision 16 [ADAMS Accession No. ML071580756].

1.7-3 Westinghouse Electric Company, 2008, "AP1000 Design Control Document Impacts to Support Combined Operating License Application Standardization," APP-GW-GLR-134.

1.7-4 Federal Energy Regulatory Commission, Website www.ferc.gov, accessed August 1, 2007.

1.7-5 Georgia Public Service Commission, Website www.psc.state.ga.us/contactinfo.asp, accessed July 27, 2007.

1.7-6 Rural Utilities Service, Website www.usda.gov/rus, accessed January 4, 2008.

1.7-7 U.S. Securities and Exchange Commission, Website www.sec.gov, accessed January 4, 2008.

1.7-8 SNC, "Vogtle Electric Generating Plant Early Site Permit Application," SNC letter AR-06-1579, dated August 14, 2006 [ADAMS Accession No. ML062290246].

1.7-9 NRC, "ACCEPTANCE OF THE SOUTHERN NUCLEAR OPERATING COMPANY APPLICATION FOR AN EARLY SITE PERMIT (ESP) FOR THE VOGTLE ESP SITE," NRC letter, dated September 19, 2006 [ADAMS Accession No. ML062570424].

1.7-10 SNC, "Vogtle Early Site Permit Application Supplement To Include Limited Work Authorization 2 Activities," SNC letter AR-07-1421, dated August 15, 2007 [ADAMS Accession No. ML072330245].

1.7-11 SNC, "Vogtle Early Site Permit Application Supplemental Emergency Planning Information," SNC letter AR-06-1721, dated August 17, 2006 [ADAMS Accession No. ML062340406].

1.7-12 SNC, "Vogtle Early Site Permit Application Response to Requests for Additional Information Letter No. 5 Involving Emergency Planning," SNC letter AR-07-0656, dated April 16, 2007 [ADAMS Accession No. ML071100334 and ML071100337].

APPENDIX 1A

ESTIMATED TOTAL CONSTRUCTION COST FOR VEGP UNITS 3 AND 4

The estimated total construction cost for VEGP Units 3 and 4 is considered proprietary information and is provided under separate cover (Reference SNC letter AR-08-0436, dated March 28, 2008).

APPENDIX 1B

FINANCIAL STATEMENTS FOR THE BOARD OF MUNICIPAL ELECTRIC AUTHORITY OF GEORGIA

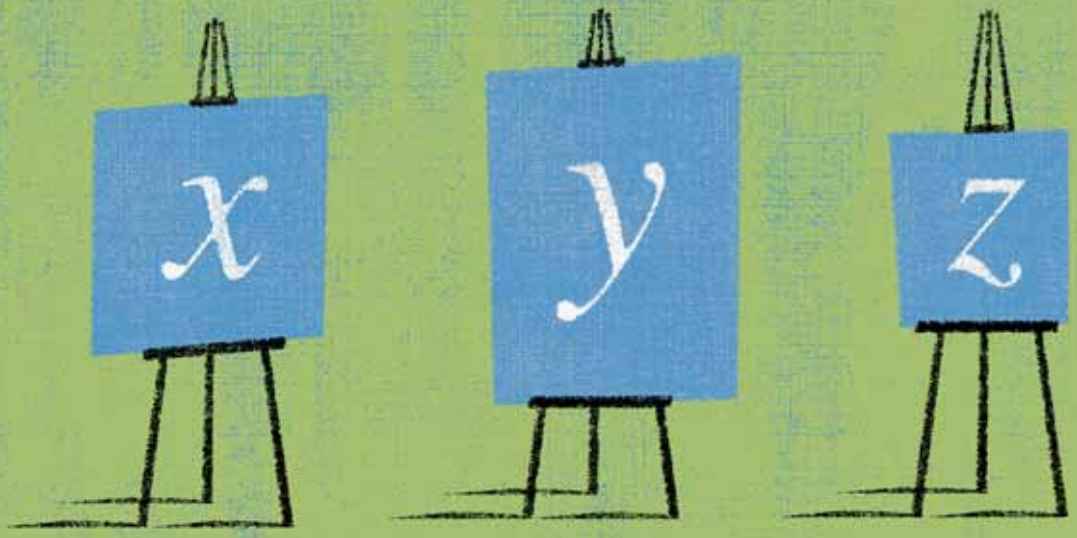
(**NOTE**: This appendix consists of the following four documents that directly follow each other in the order indicated:

- 2006 MEAG Annual Report [70 pages];
- 2007 1st Quarter Report [2 pages];
- 2007 2nd Quarter Report [2 pages] and
- 2007 3rd Quarter Report [2 pages].

These documents are stand-alone documents, developed independent of standard COL application formatting. In addition, MEAG also has an Annual Information Statement that is available upon request.)

MEAG POWER

2006 Annual Report



CHANGE REQUIRES DECISIONS.

It's Fundamental.

BUSINESS DESCRIPTION

The Municipal Electric Authority of Georgia (MEAG Power) exists for one primary reason: to generate and transmit reliable and economical wholesale electric power to our 49 Participants. We have addressed this requirement successfully in our three decades of service since being chartered by the Georgia General Assembly as a public power corporation. We provide power through our co-ownership of four generating plants, sole ownership of a combined cycle facility, ownership of over 1,300 miles of transmission lines with access to 17,500 miles, and the collective assistance of our Participants. In addition, as a business resource, MEAG Power provides our Participants with engineering services, technical consulting, pricing strategies, economic development assistance and political advocacy on energy issues.

MEAG Power is among the country's leading joint action agencies with one of the most diversified fuel portfolios. We were also one of the first public power organizations to extend our power sales contracts, thus providing for the continued operation and financing of our generation and transmission assets in the most efficient manner.

As a public power enterprise, MEAG Power was created to serve our Participants. It is for their benefit, not shareholders', that we exist; it is their decisions at the local level that drive our long-term operations; and it is by combining their voices into one that we help protect their interests as energy policies and legislation are discussed and enacted.

FINANCIAL HIGHLIGHTS
MEAG POWER

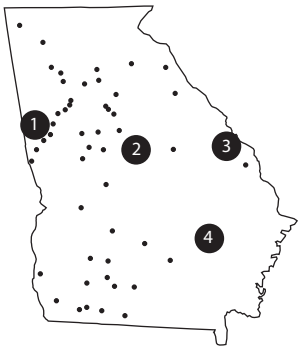
Three-Year Summary of Selected Financial and Operating Data

(Dollars in thousands)	**2006**	2005	2004
Total revenues	**$ 721,484**	$ 703,775	$ 652,236
Total assets	**$ 4,911,720**	$ 4,878,920	$ 4,611,855
Property, plant and equipment – net	**$ 2,135,771**	$ 2,158,531	$ 2,192,452
Debt outstanding (excluding defeased bonds)	**$ 4,099,819**	$ 4,027,879	$ 4,055,316
Annual weighted average interest cost	**4.85%**	4.45%	3.83%
Total delivered energy to MEAG Power Participants (MWh)[1]	**10,484,380**	10,463,171	10,500,367
Cost to MEAG Power Participants (cents per kWh):[2]			
Total cost[1]	**5.45**	4.99	4.68
Bulk power cost	**5.43**	5.06	4.68
SEPA cost[1]	**5.67**	4.10	4.69
Peak demand (MW)	**1,992**	1,979	1,936
Total nominal generating capacity in service (MW)	**2,069**	2,069	2,069

(1) Participants purchase energy directly from the Southeastern Power Administration (SEPA). Such energy is included in these calculations.
(2) Cost related to MEAG Power's electric generating projects.

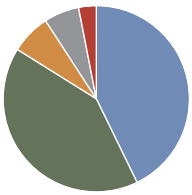
MEAG POWER PARTICIPANTS AND GENERATION PLANTS

Acworth
Adel
Albany
Barnesville
Blakely
Brinson
Buford
Cairo
Calhoun
Camilla
Cartersville
College Park
Commerce
Covington
Crisp County
Doerun
Douglas
East Point
Elberton
Ellaville
Fairburn
Fitzgerald
Forsyth
Fort Valley
Grantville
Griffin
Hogansville
Jackson
LaFayette
LaGrange
Lawrenceville
Mansfield
Marietta
Monroe
Monticello
Moultrie
Newnan
Norcross
Oxford
Palmetto
Quitman
Sandersville
Sylvania
Sylvester
Thomaston
Thomasville
Washington
West Point
Whigham

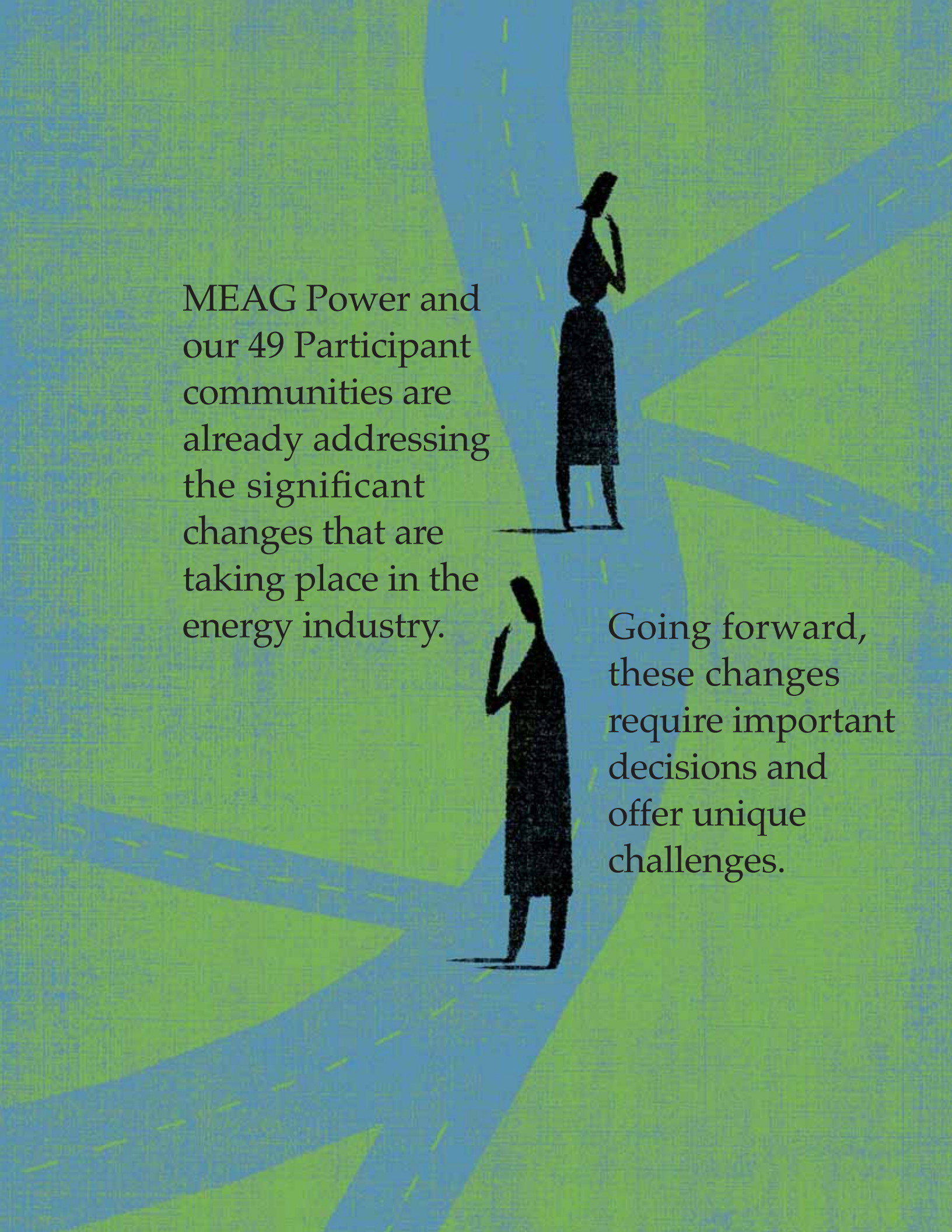


1 Plant Wansley and Wansley Combined Cycle Facility
2 Plant Scherer
3 Plant Vogtle
4 Plant Hatch

DELIVERED ENERGY BY SOURCE – 2006

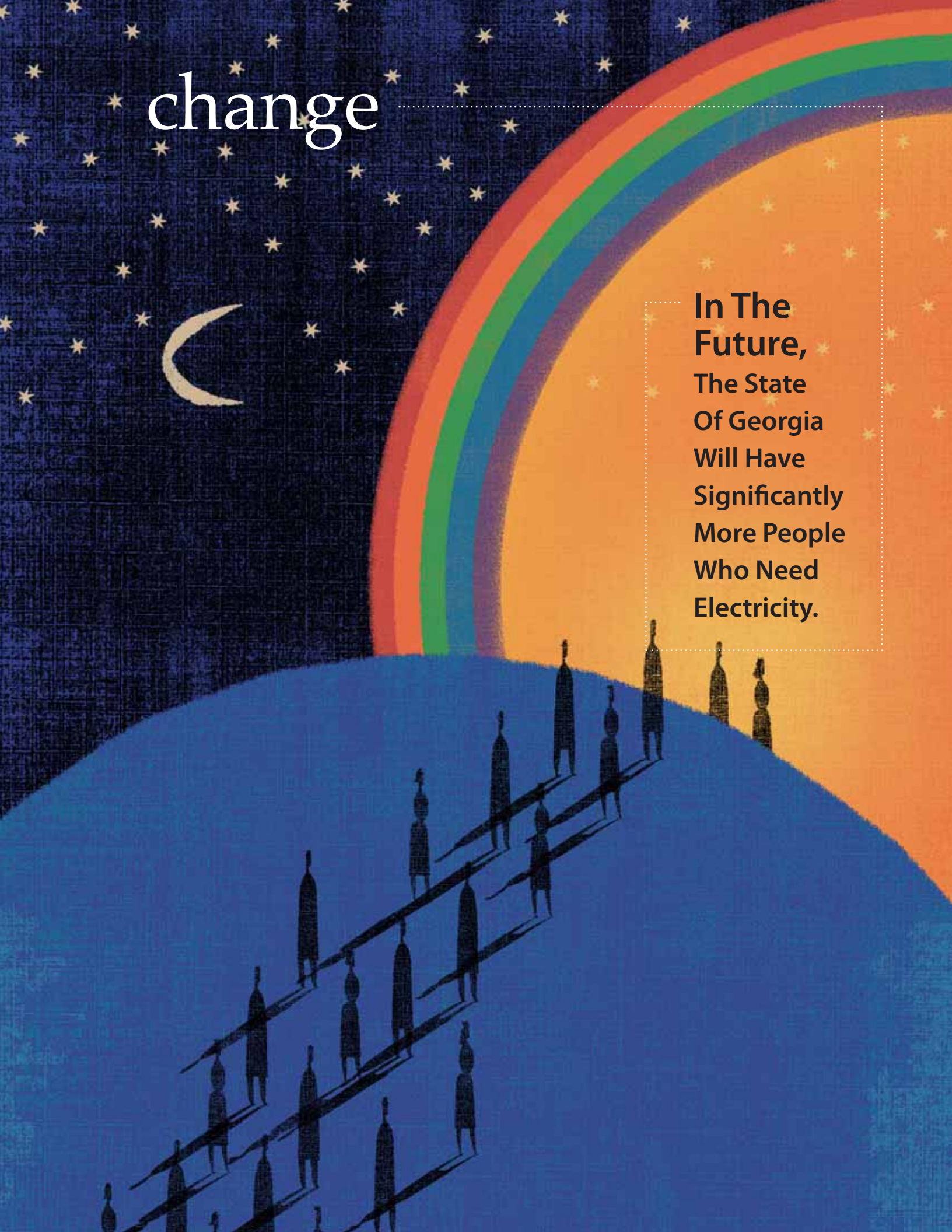


Nuclear – 43%
Coal – 41%
Gas – 7%
SEPA – 6%
Purchases – 3%



MEAG Power and our 49 Participant communities are already addressing the significant changes that are taking place in the energy industry.

Going forward, these changes require important decisions and offer unique challenges.


change
In The Future,
The State Of Georgia Will Have Significantly More People Who Need Electricity.

Where Could It Come From?

Georgia is already the ninth most populous state, and it continues to grow at an enviable rate. Moreover, in the last 13 years the average residential consumer has increased their electrical usage by 16 percent. Specifically, the metropolitan Atlanta area, which includes several MEAG Power Participants, has been the fastest-growing area of the United States since 2000. It is understandable, therefore, that MEAG Power forecasts that our Participants' power supply needs will entail multiple new resource requirements through 2015 and beyond.

Concerns about coal and gas. MEAG Power is considering a variety of resources and fuels as it plans ahead. Today, two of the major fuel types used in baseload generation are coal and gas, but there are mounting risks associated with these fuels. On one hand they are exhibiting price volatility and, on the other, their supply and transport are under capacity constraints. Also, the costs and risks associated with coal are mounting as emission regulations become more stringent and uncertain. Nonetheless, we will thoroughly explore cost/benefit analyses pertaining to these two fuels. Moreover, we will monitor new emission-control technologies that may reduce emissions and thus enhance the desirability of coal.

The possibility of nuclear. Going forward, MEAG Power and our Participants have an opportunity to be part of a possible expansion of nuclear Plant Vogtle. There are factors that make nuclear generation attractive. It is reliable, economical and has less impact on air, water and wildlife than any other option. Additionally, new nuclear facilities will use standardized designs with passive safety systems that have been approved in advance by the Nuclear Regulatory Commission. There are, however, risks involved with accurately estimating final facility construction costs and scheduling.

The evaluation of new power supply sources continues to be a priority at MEAG Power as we seek to best answer the question, "Where could substantial new baseload generation come from?" We are talking with experts in various fields; seeking the input of our Participants; and studying all available information in an effort to make well-informed decisions. Above all, we are intent on maintaining our record of providing reliable, economical wholesale electric power to our Participants.

An Amendment To The Municipal Competitive Trust

Has Been Proposed To The Participants For Approval.

In 1999, deregulation was gaining momentum as the airline, telecommunications and banking industries were all facing sweeping transformations. It seemed that every state would soon deregulate electricity and aggressive competitive pricing would prevail. It was in the face of such change that the Municipal Competitive Trust (Competitive Trust) was formed to ensure that MEAG Power Participants maintained competitive wholesale electric rates to meet those challenges.

Today, the states that did opt for electricity deregulation have some of the highest power prices in the nation. Fortunately, Georgia is not among them, and electricity deregulation is not an immediate concern in the state. As a result, an amendment to the Competitive Trust has been proposed to the Participants.

Savings at hand. The amendment authorizes MEAG Power to apply funds from certain Competitive Trust accounts as a credit to Participants' power sales contract billings for Project One and the General Resolution Projects. Participants gain the benefit of lowering their annual generation charges from MEAG Power during the period 2009 through 2018. The revision also establishes an additional account within the Competitive Trust to permit Participants to help fund their share of any acquisition and/or construction costs of future generation projects. Participants can take advantage of this option to reduce the costs of participation in the potential expansion of Plant Vogtle, thus making their interests more affordable. As of April 30, 2007, a total of 39 Participants have approved the proposed amendment.

MEAG Power Participants understand that the original objective of the Competitive Trust was to help them prudently manage their long-term power supply costs. As energy demands heighten, this objective is still important, and the Competitive Trust, as amended, once again gives Participants the ability to do such long-range planning.

D E C I S I O N

How Can The Participants Take Advantage Of This Amendment?

MEAG Power's Resource Requirements Continue To Increase Year Over Year.

change

D E C I S I O N

How Can The Growing Demand Be Met?

Once, the answer to the above was somewhat simple – build or buy additional, efficient generation capability. Today, the answer is more complex. We must think beyond just the number of megawatts needed.

So as MEAG Power considers how best to meet increased demands, we consider many issues – the dynamics of fuel pricing; new regulations and expectations; possible Congressional mandates for renewable energy as part of our portfolio; compliance with new Federal Energy Regulatory Commission (FERC) requirements; and the potential impact new Plant Vogtle units would have on overall supply.

Integrated Resource Plan. The above factors, as well as careful analysis of our Participants' energy needs, drove MEAG Power's first Integrated Resource Plan (IRP). Approved in April 2006 by MEAG Power's Board of Directors, it takes a long-term view focusing on price stability and competitiveness. The IRP concludes that the best approach for the next 20 years is to acquire 1) peaking resources for near-term needs and 2) baseload resources as they become available. With the Participants' growing energy demand, the ongoing IRP process will support evaluation of the best energy resource mix to service such requirements. Going forward, MEAG Power anticipates adding resources in increments to meet the peaking and intermediate needs of our Participants.

Efficiencies. Another way to address resource requirements is to reduce the need for energy through conservation measures. To that end, MEAG Power routinely evaluates opportunities to improve the efficiencies of its generating plants to reduce cost and environmental impacts. In addition, MEAG Power is working closely with Participants on demand management and operating standards.

With all that is happening and anticipated in the marketplace, it is certain that meeting growing energy demand will be an increasingly complex process. Nonetheless, MEAG Power is committed to doing everything possible to continue to bring our Participants reliable and economical wholesale electricity.

Increased Environmental And Regulatory Compliance

Is A Significant Issue For MEAG Power And Our Participants.

We must continue to inform all those who can influence regulations, make policy and determine parameters for the power industry and make known our views on subjects from renewable resources to possible carbon control programs. Along with our colleagues at the Large Public Power Council and the American Public Power Association, we will stay engaged in the debate.

We are also working to see that all issues are fairly addressed. Such was the case recently, when based on input from MEAG Power and a substantial number of our Participants, FERC reconsidered a compliance requirement and exempted all of our 49 communities from multiple reliability standards that would have been extremely costly for them.

Good stewardship. At the same time, it is important that MEAG Power listens and, along with our Participants, makes every effort to reach compromises and to support sound, technically-based public policy. Hence we are diligently investigating nuclear as an emission-free baseload resource, a complement to our energy-efficient combined cycle facility. We are also investing hundreds of millions of dollars to comply with established emission regulations and have negotiated to continue the Integrated Transmission System (ITS). The ITS further aids compliance with FERC reliability standards, helps us achieve FERC transmission tariff goals, and avoids the need for duplicative transmission facilities, a requirement that would be costly for electricity users. Furthermore, MEAG Power supports the efforts of the state of Georgia, along with the federal government, to reprocess spent nuclear fuel.

Being green. While MEAG Power opposes federal renewable energy mandates, due to differing availabilities in each state, we concur with the priority the Georgia "State Energy Strategy" puts on utilizing renewable biomass resources. Additionally, through our Marketing Services business unit, we offer our Participants the opportunity to participate in a Renewable Energy Credit program.

Finally, MEAG Power is an advocate of what many call the "fourth" fuel – efficiency and conservation. By offering energy audits to our Participants and their customers, we encourage consumers to conserve electricity. It is our belief that efficiency and conservation efforts may well decrease the need for more sweeping environmental and regulatory actions as well as offset the need for new fuel generation.

D E C I S I O N

What Actions Should Be Taken Now?

MESSAGE

From The Chairman Of The Board And The President

Patrick C. Bowie, Jr.
Chairman of the Board

Robert P. Johnston
President and Chief Executive Officer

Change requires decisions. That is a fundamental principle MEAG Power and our 49 Participant communities are well aware of as we move ahead. Change also often involves risks and that, too, is something MEAG Power and our Participants are facing. How certain can we be that the new technology and construction costs of building a nuclear plant will be what we are now estimating? How positive can we be that forthcoming regulations will be feasible, considering the current state of emission control technology?

NEW OPPORTUNITY. REAL RISKS.

In the near future, MEAG Power and our Participants will be making a decision that will affect their communities for the next 60 - 70 years – whether to be a part of the possible expansion of nuclear Plant Vogtle. It is the sort of decision that comes along infrequently, and it is also somewhat coincidental that it occurs as MEAG Power marks the 30th anniversary of delivering power to our Participants.

The resurgence of nuclear energy presents a new opportunity for our Participants to increase baseload generation to meet rising electricity demand. There are, however, risks going forward with this option and, while it is true that we cannot drive them to zero, we are working to minimize these risks to the extent possible.

For example, we will have obtained federal permission to operate the additions to nuclear Plant Vogtle before the new facilities are built. Most importantly, we have ample time to work together with our Participants to analyze their needs, understand the issues and make informed decisions early next year. In the meantime, MEAG Power will continue to investigate all options and support our Participants as they decide their best course of action.

IMMEDIATE NEEDS. MULTIPLE OPTIONS.

Along with the decision regarding Plant Vogtle's possible expansion is the decision concerning our more pressing need for peaking and intermediate power generation. Both decisions are addressed in MEAG Power's Integrated Resource Plan (IRP). The IRP recognizes that we will need to acquire or build at least two more generation units before Plant Vogtle's additional nuclear units would come on line in 2015. To fulfill this need, we are exploring all options to obtain the most economical solution and to maintain our diversified fuel resource portfolio on behalf of our Participants.

INCREASED REGULATIONS. GROWING UNCERTAINTIES.

The Energy Policy Act of 2005 placed MEAG Power's transmission system under more federal jurisdiction. The new legislation gives the Federal Energy Regulatory Commission (FERC) the responsibility for the security and reliability of our country's power grid. FERC has approved 83 reliability standards that will require affected organizations to comply with the applicable standards, and failure to comply carries stiff penalties. FERC's final reliability order is effective June 2007 and, to that end, we have instituted a compliance program to monitor our progress towards meeting all of the requirements.

We recognize that there is support in Congress for more control over certain areas of energy generation and for FERC's initiatives, so we continue to engage constructively in debates about what can be done. Moreover, MEAG Power is working to comply with present regulations and to invest in technologies that can lessen emissions. We will spend over $400 million retrofitting state-of-the-art environmental controls on our coal-fired plants, and we are studying the feasibility of building new nuclear units, which are emission-free. Additionally, we will continue to join forces with others in the public power industry to make known our positions on how environmental challenges might best be addressed.

LOOKING AHEAD. REMEMBERING OUR MISSION.

MEAG Power is currently addressing succession planning. In place now is an active, formal program to identify, promote and develop those people who will manage our enterprise in the future. We have also established a new Participant and Corporate Affairs department to intensify our ability to respond to the growing number of compliance issues and to communicate more effectively with our Participants.

Above all, and no matter what changes emerge, MEAG Power remains committed to our founding mission – to provide reliable and economical wholesale electric power to our Participants. We have accomplished this mission for 30 years by establishing what we believe is the best diversified fuel portfolio and one of the best cost control records of leading joint action agencies in the country. These are hallmarks we will strive to claim for many more years.

May 2007

Board Of Directors

Patrick C. Bowie, Jr.
Chairman
Utility Director
LaGrange

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City Council Member
Commerce

Kelly E. Cornwell
Director of Utilities
Calhoun

Robert W. Lewis
General Manager
Marietta Board of
Lights & Water

Senior Management

left to right

Gary M. Schaeff, Vice President, Transmission

Mary G. Jackson, Senior Vice President, Chief Accounting Officer

Steven M. Jackson, Vice President, Power Supply

Robert P. Johnston, President and Chief Executive Officer

Charles B. Manning, Jr., Senior Vice President,
Participant and Corporate Affairs

James E. Fuller, Senior Vice President, Chief Financial Officer

(not pictured – J. Scott Jones, Vice President, Audit and Risk Management)

MEAG POWER

2006

Financial Review

Management's Discussion and Analysis of Financial Condition and Results of Operations

Introduction

The Municipal Electric Authority of Georgia (MEAG Power) is comprised of the Electric Projects (defined below), the Telecommunications Project (Telecom), as well as the Distribution Services and Marketing Services Business Units (the Business Units). Forty-eight cities and one county of the State of Georgia (Electric Utility Participants) have contracted with MEAG Power for bulk electric power supply needs. MEAG Power also offers specialized services to the Electric Utility Participants through Telecom and the Business Units.

Overview of the Consolidated Financial Statements

This discussion serves as an introduction to the basic consolidated financial statements of MEAG Power to provide the reader with an overview of MEAG Power's financial position and operations.

The Balance Sheet summarizes information on all of MEAG Power's assets and liabilities.

Revenue and expense information is presented in the Statement of Net Revenues. Revenue represents billings for wholesale electricity sales to the Electric Utility Participants and sales of electricity to unrelated parties, as well as billings of Telecom and the Business Units. Expenses primarily include operating costs and debt service-related charges.

The Statement of Cash Flows is presented using the direct method. This method provides broad categories of cash receipts and cash disbursements pertaining to cash provided by or used in operations, investing and financing activities.

The Notes to Financial Statements (Notes) are an integral part of MEAG Power's basic consolidated financial statements and provide additional information on certain components of these statements.

MEAG Power's basic consolidated financial statements include the Electric Projects, Telecom and the Business Units. The Electric Projects consist of:

- Project One (financed under the Power Revenue Bond Resolution);
- Projects Two, Three and Four (the General Resolution Projects financed under the General Power Revenue Bond Resolution);
- The Combined Cycle Project (the CC Project initially financed under the Combustion Turbine Project Bond Resolution, subsequently amended as the Combined Cycle Project Bond Resolution); and
- The Municipal Competitive Trust (Competitive Trust) and the Deferred Lease Financing Trust, herein collectively referred to as the Trust Funds.

Vogtle Expansion Project

In May 2005, MEAG Power and the other co-owners of Plant Vogtle entered into a joint agreement authorizing the potential expansion of up to two additional nuclear units at Plant Vogtle. During December 2005, MEAG Power notified the other co-owners of Plant Vogtle as to its initial election to participate in the potential expansion project at a 22.7% ownership interest. Under the terms of the joint agreement, MEAG Power has the right to reduce its level of participation, including totally withdrawing from the proposed project, at any time through April 15, 2008. In the event that MEAG Power withdraws from the proposed project prior to April 15, 2008, it will be reimbursed any preliminary design and development costs incurred by it, including carrying expenses, from inception through the date of withdrawal. Such expenditures, which are accounted for as preliminary survey costs in materials, supplies and other assets in Project One on the Balance Sheet, totaled $4.5 million as of December 31, 2006.

Additionally, in April 2006, MEAG Power and the other co-owners of Plant Vogtle entered into ownership and operating agreements pertaining to the proposed additional nuclear units. MEAG Power also has the right to withdraw as a party from both of these agreements at any time prior to April 15, 2008.

If MEAG Power elects to continue participation in the potential expansion project beyond the April 15, 2008 withdrawal date, a new MEAG Power project will be established for the purpose of financing the costs associated with the proposed expansion. MEAG Power is currently working with the other co-owners to address permitting and licensing matters. No final decision has been made regarding actual construction.

MEAG Power anticipates that the process of seeking binding contractual commitments from the Electric Utility Participants with respect to participation in the proposed expansion project at Plant Vogtle will begin during October 2007. No indication can be given as to whether the proposed expansion project at Plant Vogtle will proceed to completion, or the level, if any, at which MEAG Power will participate in such expansion project.

Trust Amendment

In June 2006, MEAG Power distributed to the Electric Utility Participants for their consideration a proposed amendment to the terms of the Competitive Trust. The proposed amendment would authorize MEAG Power to apply funds from certain Competitive Trust accounts as a credit to the power sales contract billings of the Electric Utility Participants for the purpose of lowering the annual generation charges from MEAG Power during the period 2009 through 2018. The proposed amendment also authorizes the establishment of an additional account within the Competitive Trust to permit the Electric Utility Participants to fund their share of the acquisition and construction costs of any future MEAG Power generation project joined by such Electric Utility Participants. As of April 30, 2007, a total of 39 Electric Utility Participants have approved the proposed amendment.

Environmental Facilities Reserve Accounts

In August 2006, MEAG Power established separate Environmental Facilities Reserve accounts, one for Project One and the others with respect to the General Resolution Projects. These accounts were established in order to mitigate future planned environmental costs at Plants Scherer and Wansley (the Coal Units) and were funded initially with $77.9 million of the proceeds received from the long-term lease transaction involving MEAG Power's ownership interest in the Coal Units, discussed in Note 2 (C), "Trust Funds - Deferred Lease Financing Trust." Additional funding will be provided from billings to the Electric Utility Participants.

Transmission Facilities

MEAG Power, Georgia Power Company, Georgia Transmission Corporation and the City of Dalton, Georgia each own transmission system facilities which together comprise a statewide, integrated transmission system (ITS). MEAG Power and each other entity may use all transmission system facilities included in the ITS, regardless of ownership, in serving its customers. Bulk power supply is furnished by MEAG Power to the Electric Utility Participants through the ITS. MEAG Power's ITS facilities are included in Project One.

In December 2006, the owners of the ITS exchanged written commitments whereby each owner agreed to waive and not to exercise its right under its respective ITS Agreement (Agreement) to terminate the Agreement on any date prior to December 31, 2027. In accordance with the five-year notice requirement in the Agreement, an owner may provide written notice on or before December 31, 2022, terminating its respective Agreement no earlier than December 31, 2027. These written commitments do not have the effect of modifying, superseding or terminating the Agreement.

Financial Condition Overview

MEAG Power's Consolidated Balance Sheet as of December 31, 2006, 2005 and 2004 is summarized as follows (in thousands):

December 31, 2006	Project One	General Resolution Projects	Combined Cycle Project	Trust Funds	Eliminations	Total Electric Projects	Telecom Project and Business Units	Total
ASSETS:								
Property, plant and equipment – net	$1,393,993	$ 435,402	$291,798	$ –	$ –	$2,121,193	$14,578	$2,135,771
Other non-current assets	434,773	187,140	48,936	748,987	(177,368)	1,242,468	–	1,242,468
Current assets	600,060	174,071	35,825	237,743	(7,412)	1,040,287	4,498	1,044,785
Deferred debits	705,844	211,268	37,532	(474,471)	–	480,173	8,523	488,696
Total Assets	$3,134,670	$1,007,881	$414,091	$512,259	$(184,780)	$4,884,121	$27,599	$4,911,720
LIABILITIES:								
Long-term debt	$2,560,623	$ 866,975	$387,461	$ –	$(177,368)	$3,637,691	$24,920	$3,662,611
Lease finance obligation	–	–	–	274,019	–	274,019	–	274,019
Other non-current liabilities	272,900	44,458	4,559	600	–	322,517	(186)	322,331
Current liabilities	301,147	96,448	22,071	237,640	(7,412)	649,894	2,865	652,759
Total Liabilities	$3,134,670	$1,007,881	$414,091	$512,259	$(184,780)	$4,884,121	$27,599	$4,911,720

December 31, 2005	Project One	General Resolution Projects	Combined Cycle Project	Trust Funds	Total Electric Projects	Telecom Project and Business Units	Total
ASSETS:							
Property, plant and equipment – net	$1,400,852	$441,017	$300,635	$ –	$2,142,504	$16,027	$2,158,531
Other non-current assets	290,570	48,007	51,325	796,627	1,186,529	–	1,186,529
Current assets	474,987	126,368	33,981	255,255	890,591	4,769	895,360
Deferred debits	827,583	290,555	46,248	(533,924)	630,462	8,038	638,500
Total Assets	$2,993,992	$905,947	$432,189	$ 517,958	$4,850,086	$28,834	$4,878,920
LIABILITIES:							
Long-term debt	$2,417,797	$783,394	$404,575	$ –	$3,605,766	$27,135	$3,632,901
Lease finance obligation	–	–	–	262,174	262,174	–	262,174
Other non-current liabilities	300,523	47,702	4,160	396	352,781	(78)	352,703
Current liabilities	275,672	74,851	23,454	255,388	629,365	1,777	631,142
Total Liabilities	$2,993,992	$905,947	$432,189	$ 517,958	$4,850,086	$28,834	$4,878,920

December 31, 2004	Project One	General Resolution Projects	Combined Cycle Project	Trust Funds	Total Electric Projects	Telecom Project and Business Units	Total
ASSETS:							
Property, plant and equipment – net	$1,412,760	$452,189	$310,027	$ –	$2,174,976	$17,476	$2,192,452
Other non-current assets	306,982	46,546	49,388	779,747	1,182,663	–	1,182,663
Current assets	288,622	112,699	32,115	84,357	517,793	7,077	524,870
Deferred debits	861,325	321,454	48,785	(526,696)	704,868	7,002	711,870
Total Assets	$2,869,689	$932,888	$440,315	$ 337,408	$4,580,300	$31,555	$4,611,855
LIABILITIES:							
Long-term debt	$2,401,767	$819,082	$421,164	$ –	$3,642,013	$27,135	$3,669,148
Lease finance obligation	–	–	–	250,840	250,840	–	250,840
Other non-current liabilities	289,099	48,149	3,464	2,311	343,023	580	343,603
Current liabilities	178,823	65,657	15,687	84,257	344,424	3,840	348,264
Total Liabilities	$2,869,689	$932,888	$440,315	$337,408	$4,580,300	$31,555	$4,611,855

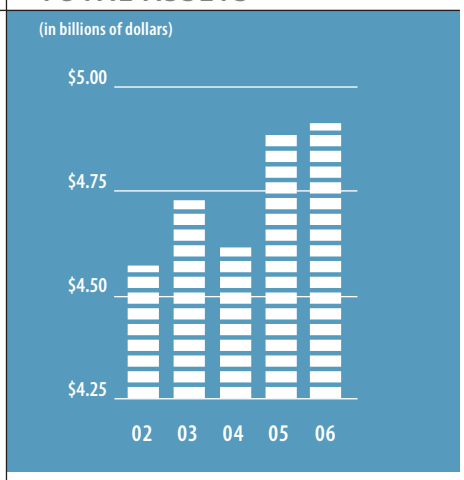
Management's Discussion and Analysis of Financial Condition and Results of Operations

The primary changes in MEAG Power's financial condition as of December 31, 2006 and 2005 were as follows:

2006 Compared to 2005

Assets

- During 2006, property, plant and equipment decreased $22.8 million due to annual depreciation expense exceeding property additions by $43.2 million. An increase of $20.4 million in net nuclear fuel due to reloads, primarily in Project One, partially offset the decline in net property additions.
- An increase of $55.9 million in other non-current assets was due to special funds increasing from commercial paper (CP) note proceeds (see "Financing Activities" below), as well as additional funding and market appreciation in decommissioning and Competitive Trust accounts.
- Current assets increased $149.4 million due primarily to a $129.1 million increase in special funds also resulting mainly from the CP note proceeds, which were partially offset by escrow payments as discussed below. Fuel stocks increased $7.8 million and $10.8 million in Project One and the General Resolution Projects, respectively, to overcome a reduction in 2005 coal deliveries. Materials, supplies and other assets increased $6.4 million due primarily to increases in plant maintenance materials and preliminary survey costs.
- Deferred debits decreased $149.8 million due mainly to debt service billings to the Participants exceeding depreciation expense, as well as certain investment income and reductions in asset retirement obligations.



Total assets increased $32.8 million in 2006 due to increases in special funds, which were partially offset by decreases in deferred debits and net property, plant and equipment.

Liabilities

- Long-term debt increased $29.7 million due primarily to the issuance of CP notes mentioned above, which were partially offset by principal payments and the retirement of debt with escrow proceeds from a previous refunding.
- An increase of $11.8 million in the lease finance obligation was due to normal accretion of the purchase option, as described in Note 2 (C), "Trust Funds – Deferred Lease Financing Trust."
- Other non-current liabilities decreased $30.4 million, primarily due to a decrease in asset retirement obligations of $28.3 million and $3.0 million in Project One and the General Resolution Projects, respectively, resulting from a change in accounting estimate due to a new site-specific decommissioning study.
- Current liabilities increased $21.6 million due primarily to increases in the current portion of long-term debt of $12.0 million and $13.6 million in Project One and the General Resolution Projects, respectively. Funds held for the Participants in the Trust Funds increased $10.8 million due to contributions and earnings. These increases were partially offset by reductions of certain accounts payables totaling $15.8 million, in part related to a decrease in purchased power.

2005 Compared to 2004

Assets

- Property, plant and equipment decreased $33.9 million in 2005 due primarily to annual depreciation expense exceeding property additions in Project One, the General Resolution Projects and the CC Project, which decreased by $11.9 million, $11.2 million and $9.4 million, respectively.
- Other non-current assets increased $3.9 million due to special funds activity. Project One declined $16.4 million due mainly to a decline in special funds of $28.8 million in the construction fund related to transmission capital expenditures, which was partially offset by an increase of $10.7 million in the decommissioning fund resulting from deposits and earnings. An increase of $16.9 million in the Trust Funds was primarily attributable to deposits by Electric Utility Participants and earnings.

2005 Compared to 2004 (Continued)

- Current assets increased $370.5 million due primarily to $261.0 million in the securities lending program discussed in Note 2 (L), "Special Funds and Supplemental Power Account – Securities Lending." Project One increased $186.4 million of which $99.2 million related to securities lending and $85.9 million pertained to bond proceeds held in escrow in special funds. An increase of $170.9 million in the Trust Funds was mainly due to $150.6 million in the securities lending program, as well as a $20.2 million increase in special funds due to deposits of flexible trust funds by the Electric Utility Participants, as well as earnings on these funds. A decline in Telecom participant debt service billings resulted in a $2.2 million decrease in current asset special funds of Telecom and the Business Units.
- Deferred debits declined $73.4 million. Decreases of $33.7 million in Project One and $30.9 million in the General Resolution Projects during 2005 relate primarily to debt service billings during the period exceeding depreciation expense.

Liabilities

- Long-term debt decreased $36.2 million due primarily to retirement of long-term debt totaling $461.2 million. This was partially offset by proceeds from issuance of long-term debt of $407.6 million. Due to these transactions, Project One long-term debt increased $16.0 million and the General Resolution Projects as well as the CC Project decreased $35.7 million and $16.6 million, respectively.
- The lease finance obligation increased $11.3 million due to normal accretion of the purchase option, as described in Note 2 (C), "Trust Funds – Deferred Lease Financing Trust."
- Other non-current liabilities increased $9.1 million, primarily due to an increase of $17.0 million in Project One asset retirement obligations, which were partially offset by a decline of $4.2 million in interest rate swap obligations, also in Project One. Other non-current liabilities of the Trust Funds declined $1.9 million due to certain arbitrage tax payments.
- Current liabilities increased $282.9 million in 2005 primarily reflecting the $261.0 million offsetting liability for the securities lending program discussed above. Funds held for the Participants in the Trust Funds increased $20.3 million. Changes in the current portion of long-term debt contributed to a $7.8 million increase in current liabilities of the CC Project during 2005, as well as a decrease of $2.1 million in Telecom and the Business Units.

Results of Operations

MEAG Power's Consolidated Statement of Net Revenues for the years ended December 31, 2006, 2005 and 2004 is summarized as follows (in thousands):

For the Year Ended December 31, 2006	Project One	General Resolution Projects	Combined Cycle Project	Trust Funds	Total Electric Projects	Telecom Project and Business Units	Total
Revenues:							
Participant	$342,004	$158,603	$64,676	$ –	$565,283	$6,059	$571,342
Other	91,950	36,445	21,574	–	149,969	173	150,142
Total revenues	433,954	195,048	86,250	–	715,252	6,232	721,484
Operating expenses	285,532	130,559	62,980	673	479,744	6,042	485,786
Net operating revenues (loss)	148,422	64,489	23,270	(673)	235,508	190	235,698
Interest expense (income), net	111,755	41,994	16,895	(24,830)	145,814	860	146,674
Decrease (increase) in net costs to be recovered from future billings to Participants	36,667	22,495	6,375	24,157	89,694	(670)	89,024
Total other expenses (income), net	148,422	64,489	23,270	(673)	235,508	190	235,698
Net Revenues	$ –	$ –	$ –	$ –	$ –	$ –	$ –

For the Year Ended December 31, 2005	Project One	General Resolution Projects	Combined Cycle Project	Trust Funds	Total Electric Projects	Telecom Project and Business Units	Total
Revenues:							
Participant	$326,674	$150,075	$51,157	$ –	$527,906	$5,136	$533,042
Other	100,251	34,268	36,036	–	170,555	178	170,733
Total revenues	426,925	184,343	87,193	–	698,461	5,314	703,775
Operating expenses	280,736	119,999	70,075	1,533	472,343	5,984	478,327
Net operating revenues (loss)	146,189	64,344	17,118	(1,533)	226,118	(670)	225,448
Interest expense (income), net	117,713	40,416	17,014	(5,088)	170,055	409	170,464
Decrease (increase) in net costs to be recovered from future billings to Participants	28,476	23,928	104	3,555	56,063	(1,079)	54,984
Total other expenses (income), net	146,189	64,344	17,118	(1,533)	226,118	(670)	225,448
Net Revenues	$ –	$ –	$ –	$ –	$ –	$ –	$ –

For the Year Ended December 31, 2004	Project One	General Resolution Projects	Combined Cycle Project	Trust Funds	Total Electric Projects	Telecom Project and Business Units	Total
Revenues:							
Participant	$320,451	$141,040	$22,747	$ –	$484,238	$7,213	$491,451
Other	104,353	37,386	18,920	–	160,659	126	160,785
Total revenues	424,804	178,426	41,667	–	644,897	7,339	652,236
Operating expenses	289,395	118,277	34,462	2,181	444,315	6,262	450,577
Net operating revenues (loss)	135,409	60,149	7,205	(2,181)	200,582	1,077	201,659
Interest expense (income), net	108,768	39,819	11,842	(3,813)	156,616	1,388	158,004
Decrease (increase) in net costs to be recovered from future billings to Participants	26,641	20,330	(4,637)	1,632	43,966	(311)	43,655
Total other expenses (income), net	135,409	60,149	7,205	(2,181)	200,582	1,077	201,659
Net Revenues	$ –	$ –	$ –	$ –	$ –	$ –	$ –

Management's Discussion and Analysis of Financial Condition and Results of Operations

The primary changes in MEAG Power's results of operations for the years ended December 31, 2006 and 2005 were as follows:

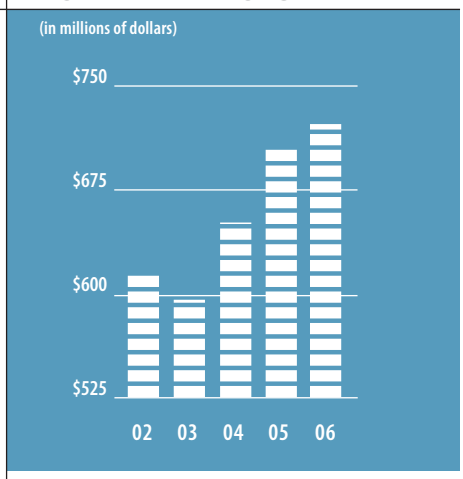
2006 Compared to 2005

Revenues

In 2006, total revenues increased $17.7 million, or 2.5%, to $721.5 million from $703.8 million in 2005 due to an increase of $38.3 million in Participant revenues, which was partially offset by a decrease of $20.6 million in other revenues. Primary factors were as follows:

- Increases in Electric Utility Participant billings for debt service of $21.2 million and operating expenses (see below), excluding depreciation and amortization, for Project One, the General Resolution Projects and the CC Project.
- Other revenues decreased 12.1% due to an $18.0 million decline in off-system energy sales, mainly in Project One and the CC Project, related approximately 85% to price and 15% to volume.
- Energy delivered to Electric Utility Participants declined slightly due to slower than expected economic growth, partially offset by an increase in cooling degree hours.

TOTAL REVENUES



2006 total revenues increased $17.7 million due to Participant billing increases of $38.3 million for debt service and operating expenses, which were offset somewhat by a 12.1% decrease in other revenues, primarily attributable to off-system energy sales.

Operating Expenses

Operating expenses totaled $485.8 million during 2006 compared to $478.3 million in 2005, an increase of $7.5 million, or 1.6%, and were impacted by the following factors:

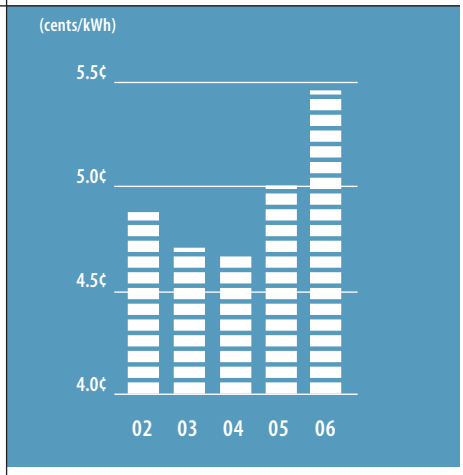
- Coal costs increased $15.6 million due to price, and were partially offset by a decrease in natural gas expense for the CC Project of $10.7 million. Coal consumption was down about 3% and gas consumption increased about 10%; however, the price of natural gas declined by almost 30%.
- A decrease in purchased power expense in Project One of $5.5 million due primarily to lower energy prices and volume.
- Other generating or operating expenses increased $6.0 million due in part to a planned major inspection outage of the Wansley Combined Cycle Facility.

Net Interest Expense

During 2006, net interest expense, which includes stated interest expense and other related components such as amortization of debt discount and expense, interest income, net change in the fair value of financial instruments, and interest capitalized, totaled $146.7 million. This 14.0% decrease from the total of $170.5 million for 2005 is due primarily to changes in the following components of net interest expense:

- Interest expense increased $11.7 million, primarily in Project One, due to higher interest rates and the issuance of additional CP notes mentioned above.
- Interest income increased $9.2 million, primarily in the General Resolution Projects and the Trust Funds, also due to higher interest rates as well as the increase in special funds discussed above.
- The fair value of financial instruments improved by $23.5 million, mainly in Project One and the Trust Funds. An increase in the value of decommissioning investments, partially offset by declines in the value of outstanding swap agreements, accounted for the improvement in Project One. Within the Trust Funds, the change is attributable to an increase in the value of Competitive Trust investments.

COST TO PARTICIPANTS

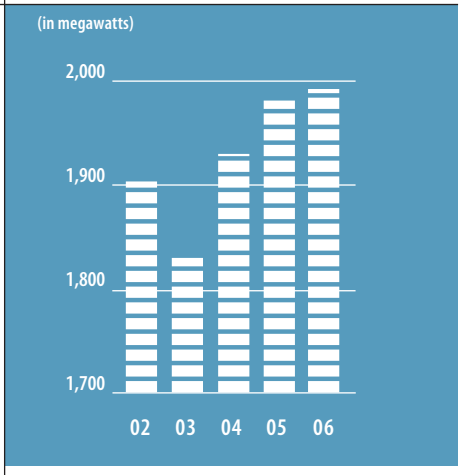


Cents per kWh increased in 2006 due mainly to higher debt service and operating costs.

2006 Compared to 2005 (Continued)

Net Costs to be Recovered

The amount of costs to be recovered from future billings to Participants was reduced by $34.0 million in 2006, primarily in Project One, the CC Project and the Trust Funds, due mainly to fair value improvements, debt service billings to the Participants exceeding depreciation expense and growth in Competitive Trust accounts.



A significant increase in cooling degree hours, mitigated to some degree by slower than expected economic growth, led to a slight growth in the 2006 summer peak.

2005 Compared to 2004

Revenues

Total revenues increased $51.6 million, or 7.9%, to $703.8 million in 2005 from $652.2 million in 2004 due to increases of $41.6 million in Participant revenues and $10.0 million in other revenues. Revenues were impacted by the following factors:

- An increase in CC Project Participant revenue of $28.4 million was due to higher billings for debt service and certain operating expenses for a full year of operations of the CC Project, compared to seven months in 2004.
- A slight decline in 2005 energy delivered to Electric Utility Participants was primarily related to increased output of Participant-owned generation, as well as changes in Participant industrial load mix. These declines were partially offset by increased load due to moderate economic growth and weather factors, including a 7.1% increase in spring and summer cooling degree hours.
- Participant revenue of the Telecom Project and Business Units declined $2.1 million due to reduced Telecom debt service billings in 2005.
- Other revenues of the CC Project increased $17.1 million in 2005 due to a 30.6% increase in off-system energy sales related to price.

Operating Expenses

Operating expenses were $478.3 million in 2005, compared to $450.6 million in 2004, an increase of $27.7 million, or 6.2%, due primarily to fuel costs, which were partially offset by a decrease in depreciation expense. Major factors affecting operating expenses were as follows:

- Fuel increased $47.0 million in 2005, of which $26.1 million pertained to the CC Project and $13.5 million to Project One, due mainly to volume and price increases pertaining to natural gas and coal.
- Plant maintenance was the primary factor in a $4.8 million increase in other generating or operating expenses for Project One during 2005. Such expenses increased $4.3 million in the CC Project due mainly to gas transportation costs.
- Purchased power declined $9.3 million in 2005 for Project One due to the expiration of two capacity and energy contracts.
- Depreciation declined $21.4 million in Project One and $5.6 million in the General Resolution Projects during 2005, due to lower depreciation rates based on engineering studies updated in late 2004. Depreciation increased $5.2 million in the CC Project as a result of a full year of operations.

Net Interest Expense

Net interest expense was $170.5 million in 2005, an increase of $12.5 million, or 7.9%, from $158.0 million in 2004. This increase is comprised mainly of changes in the following components of net interest expense, primarily in Project One, unless noted otherwise:

- Interest expense increased $12.0 million due to interest on 2005 net bond issuances of $101.8 million, as well as interest and fees related to the securities lending program.
- Interest income increased $14.7 million due to higher earnings on investments and the securities lending program.

2005 Compared to 2004 (Continued)

- A decline of $12.4 million in the fair value of financial instruments during 2005 was due primarily to changes in the value of outstanding swap agreements and decommissioning investments.
- Capitalized interest decreased $5.1 million due to completion of the CC Project in 2004.

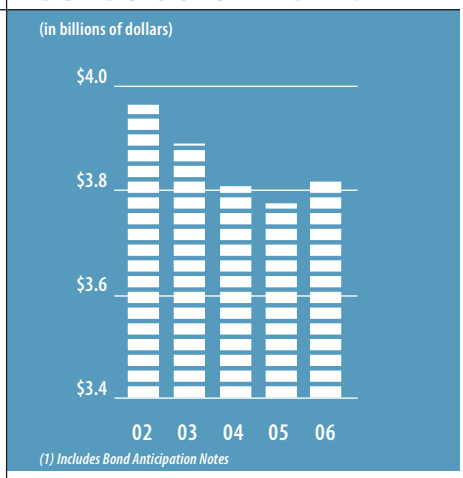
Financing Activities

MEAG Power continues to implement strategies to further improve its competitive position and financial flexibility. These actions include: (1) funding and growth of the Competitive Trust, (2) accelerated amortization of debt service versus useful lives of generation assets financed and (3) refunding fixed and variable rate debt for debt service savings. Following is a brief description of significant financing transactions during 2006:

- In order to finance a portion of MEAG Power's share of the estimated costs of future environmental improvements at the Coal Units, in August 2006, Project One and Projects Two and Three of the General Resolution Projects sold, through a negotiated private placement, $173.2 million of Capital Appreciation Bonds (CABs), which were purchased by the Deferred Lease Financing Trust component of the Trust Funds as an investment. The accretion of the CABs results in interest expense to Projects One, Two and Three with corresponding interest income in the Trust Funds. Such amounts, along with the Trust Funds' investment and the liability of Projects One, Two and Three in the CABs, are eliminated from MEAG Power's consolidated financial statements.
- During 2006, MEAG Power had a net increase in CP notes of $240.5 million. The CP notes were issued for future capital additions and to refinance a portion of outstanding bonds.

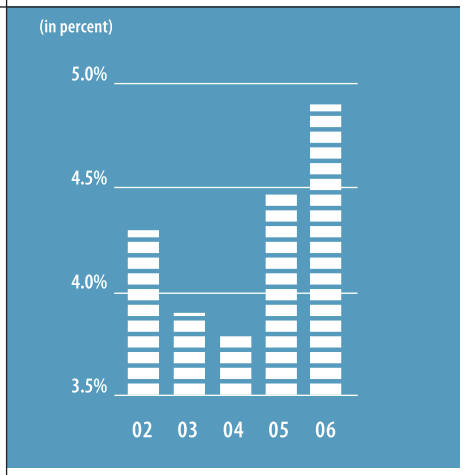
Funds generated from operations are estimated to provide approximately 2% - 28% of construction expenditures over the next three years. The remaining expenditures will be met by issuing long-term bonds and utilizing MEAG Power's existing CP program. To meet short-term cash needs and contingencies, $96.7 million of unused credit was available through arrangements with banks as of December 31, 2006, as described in Note 2 (M), "Long-Term Debt – Subordinated Debt and Other Debt."

BONDS OUTSTANDING[1]



Commercial paper issuances, partially offset by annual principal repayments, led to a $56.9 million increase in bonds outstanding during 2006.

ANNUAL WEIGHTED AVERAGE INTEREST COST



Weighted average interest cost increased as a result of short-term interest rates rising on variable rate debt.

The current unenhanced ratings assigned to the Electric Projects' senior lien and subordinated debt obligations (except for the CC Project senior debt, which is rated A by Standard & Poor's) are as follows:

	Fitch Ratings	Moody's Investors Service	Standard & Poor's
Senior lien debt	A+	A1	A+
Subordinated debt	A+	A2	A
Outlook/trend	Stable	Stable	Stable

Liquidity and Capital Resources

Net cash provided for MEAG Power during 2006 was $517.1 million. This increase in cash was primarily due to operating and investing activities, which yielded $291.0 million and $450.0 million, respectively. These net cash inflows were partially offset by net cash used in capital and related financing activities of $223.9 million. Such outflows were primarily related to retirement of long-term debt and interest payments, which totaled $395.5 million. Issuances of long-term debt in 2006 provided proceeds of $258.7 million.

During 2007 through 2009, maturities of long-term debt and sinking fund redemptions are expected to total $547.3 million. These requirements will be included in the appropriate year's budgeted revenue requirements and collected from the Electric Utility Participants and Telecom participants.

When considering the risks associated with liquidity and capital, MEAG Power is particularly susceptible to changes in the interest rate environment. In rising interest rate markets, MEAG Power may be impacted by increases in costs associated with variable rate subordinated debt and new debt issuances. These increases would be somewhat offset by increases in interest income earned on MEAG Power's investment portfolio. Conversely, when rates decline, MEAG Power may experience decreases in both the cost of some debt and the interest earnings on some investments. To partially mitigate this risk, MEAG Power occasionally implements hedges that help to stabilize these interest rate fluctuations. In addition, MEAG Power maintains a relatively high credit rating which provides access to very competitive funding options when needed.

During 2006, capital additions related to capital improvements at existing generating plants and transmission facilities, as well as purchases of nuclear fuel, totaled $86.8 million. Construction work in progress as of December 31, 2006 totaled $37.7 million.

Construction expenditures are estimated to be $108.0 million, $113.0 million and $68.5 million for the years 2007, 2008 and 2009, respectively. These expenditures are related to capital improvements at existing generating plants and investment in transmission facilities. Also included in the estimates are the costs necessary to comply with certain environmental regulations, as described in Note 2 (Q), "Commitments and Contingencies – Environmental Regulation." Actual construction costs may vary from the estimates because of factors such as changes in economic conditions; revised environmental regulations; changes to existing plants to meet regulatory requirements; updated load forecasts; and the cost of construction labor, equipment and materials.

Consolidated Balance Sheet

December 31, 2006	Project One	General Resolution Projects	Combined Cycle Project	Trust Funds	Eliminations	Total Electric Projects	Telecom Project and Business Units	Total
ASSETS: (in thousands)								
Property, plant and equipment, at cost:								
In service	$ 2,655,175	$ 859,658	$313,406	$ –	$ –	$ 3,828,239	$ 32,073	$ 3,860,312
Less accumulated depreciation	(1,356,401)	(443,621)	(21,741)	–	–	(1,821,763)	(18,047)	(1,839,810)
Property in service – net	1,298,774	416,037	291,665	–	–	2,006,476	14,026	2,020,502
Construction work in progress	27,995	8,973	133	–	–	37,101	552	37,653
Nuclear fuel, net of accumulated amortization	67,224	10,392	–	–	–	77,616	–	77,616
Total property, plant and equipment – net	1,393,993	435,402	291,798	–	–	2,121,193	14,578	2,135,771
Other non-current assets:								
Investment in Alliance	6,943	–	104	–	–	7,047	–	7,047
Special funds, including cash and cash equivalents	427,830	187,140	48,832	748,987	(177,368)	1,235,421	–	1,235,421
Total other non-current assets	434,773	187,140	48,936	748,987	(177,368)	1,242,468	–	1,242,468
Current assets:								
Special funds, including cash and cash equivalents	372,525	118,889	26,126	113,114	–	630,654	3,744	634,398
Supplemental power account, including cash and cash equivalents	1,362	–	–	–	–	1,362	–	1,362
Securities lending collateral	125,263	14,384	–	122,233	–	261,880	–	261,880
Receivables from Participants	33,513	12,546	29	53	–	46,141	629	46,770
Other receivables	12,708	6,001	749	2,343	(7,412)	14,389	116	14,505
Fuel stocks, at average cost	10,515	13,412	–	–	–	23,927	–	23,927
Materials, supplies and other assets	44,174	8,839	8,921	–	–	61,934	9	61,943
Total current assets	600,060	174,071	35,825	237,743	(7,412)	1,040,287	4,498	1,044,785
Deferred debits:								
Net costs to be recovered from future billings to Participants	581,869	151,603	13,998	(474,868)	–	272,602	8,128	280,730
Other deferred debits	123,975	59,665	23,534	397	–	207,571	395	207,966
Total deferred debits	705,844	211,268	37,532	(474,471)	–	480,173	8,523	488,696
Total Assets	$ 3,134,670	$1,007,881	$414,091	$ 512,259	$(184,780)	$ 4,884,121	$ 27,599	$ 4,911,720

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

Consolidated Balance Sheet

December 31, 2006	Project One	General Resolution Projects	Combined Cycle Project	Trust Funds	Eliminations	Total Electric Projects	Telecom Project and Business Units	Total
LIABILITIES: (in thousands)								
Long-term debt:								
Power Revenue bonds	$ 806,877	$ –	$ –	$ –	$ –	$ 806,877	$ –	$ 806,877
General Power Revenue bonds	–	397,711	–	–	–	397,711	–	397,711
Combined Cycle Project Revenue bonds	–	–	379,360	–	–	379,360	–	379,360
Telecommunications Project Revenue bonds	–	–	–	–	–	–	24,920	24,920
Unamortized (discount) premium	1,329	6,586	8,101	–	–	16,016	–	16,016
Total Revenue bonds	808,206	404,297	387,461	–	–	1,599,964	24,920	1,624,884
Subordinated debt	1,739,915	463,300	–	–	(177,368)	2,025,847	–	2,025,847
Unamortized (discount) premium	12,502	(622)	–	–	–	11,880	–	11,880
Total subordinated debt	1,752,417	462,678	–	–	(177,368)	2,037,727	–	2,037,727
Total long-term debt	2,560,623	866,975	387,461	–	(177,368)	3,637,691	24,920	3,662,611
Lease finance obligation	–	–	–	274,019	–	274,019	–	274,019
Other non-current liabilities	272,900	44,458	4,559	600	–	322,517	(186)	322,331
Current liabilities:								
Accounts payable	33,832	17,407	3,695	80	(7,412)	47,602	1,760	49,362
Construction liabilities	579	1,526	14	–	–	2,119	–	2,119
Securities lending collateral	125,263	14,384	–	122,233	–	261,880	–	261,880
Current portion of long-term debt	97,529	45,665	15,680	–	–	158,874	1,015	159,889
Borrowings under lines of credit	200	3,100	–	–	–	3,300	–	3,300
Flexible trust funds held for Participants	–	–	–	115,327	–	115,327	–	115,327
Accrued interest	43,744	14,366	2,682	–	–	60,792	90	60,882
Total current liabilities	301,147	96,448	22,071	237,640	(7,412)	649,894	2,865	652,759
Commitments and contingencies	–	–	–	–	–	–	–	–
Total Liabilities	$3,134,670	$1,007,881	$414,091	$512,259	$(184,780)	$4,884,121	$27,599	$4,911,720

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

Consolidated Statement of Net Revenues

For the Year Ended December 31, 2006 (in thousands)	Project One	General Resolution Projects	Combined Cycle Project	Trust Funds	Eliminations	Total Electric Projects	Telecom Project and Business Units	Total
Revenues:								
Participant	$342,004	$158,603	$64,676	$ –	$ –	$565,283	$6,059	$571,342
Other	91,950	36,445	21,574	–	–	149,969	173	150,142
Total revenues	433,954	195,048	86,250	–	–	715,252	6,232	721,484
Operating expenses:								
Fuel	78,723	70,642	38,500	–	–	187,865	–	187,865
Purchased power	17,576	–	–	–	–	17,576	–	17,576
Other generating or operating expense	113,893	41,526	15,528	673	–	171,620	4,286	175,906
Transmission	9,789	–	–	–	–	9,789	–	9,789
Depreciation and amortization	65,551	18,391	8,952	–	–	92,894	1,756	94,650
Total operating expenses	285,532	130,559	62,980	673	–	479,744	6,042	485,786
Net operating revenue (loss)	148,422	64,489	23,270	(673)	–	235,508	190	235,698
Interest expense (income), net:								
Interest expense	143,013	50,146	18,646	6,701	(4,203)	214,303	1,026	215,329
Amortization of debt discount and expense	3,877	1,471	908	11,845	–	18,101	81	18,182
Interest income	(23,703)	(7,635)	(3,105)	(39,581)	4,203	(69,821)	(142)	(69,963)
Net change in the fair value of financial instruments	(9,948)	(1,612)	446	(3,795)	–	(14,909)	(103)	(15,012)
Interest capitalized	(1,484)	(376)	–	–	–	(1,860)	(2)	(1,862)
Total interest expense (income), net	111,755	41,994	16,895	(24,830)	–	145,814	860	146,674
Decrease (increase) in net costs to be recovered from future billings to Participants	36,667	22,495	6,375	24,157	–	89,694	(670)	89,024
Total other expenses (income), net	148,422	64,489	23,270	(673)	–	235,508	190	235,698
Net Revenues	$ –	$ –	$ –	$ –	$ –	$ –	$ –	$ –

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

Consolidated Statement of Cash Flows

For the Year Ended December 31, 2006	Project One	General Resolution Projects	Combined Cycle Project	Trust Funds	Eliminations	Total Electric Projects	Telecom Project and Business Units	Total
(in thousands)								
Cash flows from operating activities:								
Cash received from Participants	$ 344,388	$ 158,605	$ 63,645	$ 4,077	$ –	$ 570,715	$ 6,033	$ 576,748
Cash received from others	61,925	34,015	22,717	–	–	118,657	218	118,875
Cash paid for operating expenses	(223,118)	(120,194)	(55,912)	(1,102)	–	(400,326)	(4,299)	(404,625)
Net cash provided by operating activities	183,195	72,426	30,450	2,975	–	289,046	1,952	290,998
Cash flows from investing activities:								
Sales and maturities of investment securities	356,089	81,094	57,684	422,137	–	917,004	584	917,588
Purchase of investment securities	(254,445)	(88,582)	(46,871)	(340,706)	177,368	(553,236)	(642)	(553,878)
Interest receipts	16,196	2,875	1,442	43,164	(4,203)	59,474	110	59,584
Distribution from Alliance	26,600	–	–	–	–	26,600	–	26,600
Business Unit reserves	–	–	–	–	–	–	99	99
Net cash provided by (used in) investing activities	144,440	(4,613)	12,255	124,595	173,165	449,842	151	449,993
Cash flows from capital and related financing activities:								
Property additions	(71,886)	(14,470)	(115)	–	–	(86,471)	(306)	(86,777)
Net proceeds from lines of credit	100	3,100	–	–	–	3,200	–	3,200
Proceeds from issuance of long-term debt	305,813	130,280	–	–	(177,368)	258,725	–	258,725
Retirement of long-term debt	(155,499)	(38,562)	(15,080)	–	–	(209,141)	(1,200)	(210,341)
Interest payments	(124,762)	(38,179)	(18,705)	(6,701)	4,203	(184,144)	(1,009)	(185,153)
Environmental facilities reserve funding	32,536	45,678	–	(81,752)	–	(3,538)	–	(3,538)
Net cash provided by (used in) capital and related financing activities	(13,698)	87,847	(33,900)	(88,453)	(173,165)	(221,369)	(2,515)	(223,884)
Increase (decrease) in cash and cash equivalents	313,937	155,660	8,805	39,117	–	517,519	(412)	517,107
Cash and cash equivalents at beginning of year	188,465	72,531	30,281	81,716	–	372,993	4,061	377,054
Cash and cash equivalents at end of year	502,402	228,191	39,086	120,833	–	890,512	3,649	894,161
Other investment securities at end of year	424,578	92,222	35,872	863,501	(177,368)	1,238,805	95	1,238,900
Special funds, Supplemental power account and Securities lending collateral at end of year	$ 926,980	$ 320,413	$ 74,958	$ 984,334	$(177,368)	$2,129,317	$ 3,744	$2,133,061
Reconciliation of net operating revenues (loss) to net cash provided by operating activities:								
Net operating revenues (loss)	$ 148,422	$ 64,489	$ 23,270	$ (673)	$ –	$ 235,508	$ 190	$ 235,698
Adjustments to reconcile net operating revenues (loss) to net cash from operating activities:								
Depreciation and amortization	84,792	21,231	8,952	–	–	114,975	1,757	116,732
Share of net revenues from Alliance	(27,596)	–	–	–	–	(27,596)	–	(27,596)
Change in current assets and liabilities:								
Accounts receivable	2,069	(2,455)	899	(420)	–	93	(48)	45
Fuel stocks	(7,843)	(10,805)	–	–	–	(18,648)	–	(18,648)
Materials, supplies and other assets	(5,484)	(1,126)	(748)	–	–	(7,358)	(4)	(7,362)
Accounts payable and other liabilities	(11,165)	1,092	(1,923)	4,068	–	(7,928)	57	(7,871)
Net cash provided by operating activities	$ 183,195	$ 72,426	$ 30,450	$ 2,975	$ –	$ 289,046	$ 1,952	$ 290,998

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

Consolidated Balance Sheet

December 31, 2005	Project One	General Resolution Projects	Combined Cycle Project	Trust Funds	Total Electric Projects	Telecom Project and Business Units	Total
ASSETS: (in thousands)							
Property, plant and equipment, at cost:							
In service	$ 2,645,497	$ 859,504	$313,324	$ –	$ 3,818,325	$ 31,961	$ 3,850,286
Less accumulated depreciation	(1,311,664)	(428,626)	(12,789)	–	(1,753,079)	(16,290)	(1,769,369)
Property in service – net	1,333,833	430,878	300,535	–	2,065,246	15,671	2,080,917
Construction work in progress	16,421	3,520	100	–	20,041	356	20,397
Nuclear fuel, net of accumulated amortization	50,598	6,619	–	–	57,217	–	57,217
Total property, plant and equipment – net	1,400,852	441,017	300,635	–	2,142,504	16,027	2,158,531
Other non-current assets:							
Investment in Alliance	5,947	–	104	–	6,051	–	6,051
Special funds, including cash and cash equivalents	284,623	48,007	51,221	796,627	1,180,478	–	1,180,478
Total other non-current assets	290,570	48,007	51,325	796,627	1,186,529	–	1,186,529
Current assets:							
Special funds, including cash and cash equivalents	286,263	88,751	23,524	102,676	501,214	4,068	505,282
Supplemental power account, including cash and cash equivalents	402	–	–	–	402	–	402
Securities lending collateral	99,178	11,265	–	150,602	261,045	–	261,045
Receivables from Participants	38,011	12,521	159	18	50,709	536	51,245
Other receivables	9,771	3,511	1,121	1,959	16,362	160	16,522
Fuel stocks, at average cost	2,672	2,607	–	–	5,279	–	5,279
Materials, supplies and other assets	38,690	7,713	9,177	–	55,580	5	55,585
Total current assets	474,987	126,368	33,981	255,255	890,591	4,769	895,360
Deferred debits:							
Net costs to be recovered from future billings to Participants	686,318	225,362	20,373	(534,163)	397,890	7,562	405,452
Other deferred debits	141,265	65,193	25,875	239	232,572	476	233,048
Total deferred debits	827,583	290,555	46,248	(533,924)	630,462	8,038	638,500
Total Assets	$ 2,993,992	$ 905,947	$432,189	$ 517,958	$ 4,850,086	$ 28,834	$ 4,878,920

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

Consolidated Balance Sheet

December 31, 2005	Project One	General Resolution Projects	Combined Cycle Project	Trust Funds	Total Electric Projects	Telecom Project and Business Units	Total
LIABILITIES: (in thousands)							
Long-term debt:							
Power Revenue bonds	$ 871,378	$ –	$ –	$ –	$ 871,378	$ –	$ 871,378
General Power Revenue bonds	–	423,197	–	–	423,197	–	423,197
Combined Cycle Project Revenue bonds	–	–	395,040	–	395,040	–	395,040
Telecommunications Project Revenue bonds	–	–	–	–	–	27,135	27,135
Unamortized (discount) premium	2,293	7,685	9,535	–	19,513	–	19,513
Total Revenue bonds	873,671	430,882	404,575	–	1,709,128	27,135	1,736,263
Subordinated debt	1,530,314	353,175	–	–	1,883,489	–	1,883,489
Unamortized (discount) premium	13,812	(663)	–	–	13,149	–	13,149
Total subordinated debt	1,544,126	352,512	–	–	1,896,638	–	1,896,638
Total long-term debt	2,417,797	783,394	404,575	–	3,605,766	27,135	3,632,901
Lease finance obligation	–	–	–	262,174	262,174	–	262,174
Other non-current liabilities	300,523	47,702	4,160	396	352,781	(78)	352,703
Current liabilities:							
Accounts payable	44,669	16,013	5,619	281	66,582	1,704	68,286
Construction liabilities	2,170	1,630	14	–	3,814	–	3,814
Securities lending collateral	99,178	11,265	–	150,602	261,045	–	261,045
Current portion of long-term debt	85,510	32,114	15,080	–	132,704	–	132,704
Borrowings under lines of credit	100	–	–	–	100	–	100
Flexible trust funds held for Participants	–	–	–	104,505	104,505	–	104,505
Accrued interest	44,045	13,829	2,741	–	60,615	73	60,688
Total current liabilities	275,672	74,851	23,454	255,388	629,365	1,777	631,142
Commitments and contingencies	–	–	–	–	–	–	–
Total Liabilities	$2,993,992	$905,947	$432,189	$517,958	$4,850,086	$28,834	$4,878,920

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

Consolidated Statement of Net Revenues

For the Year Ended December 31, 2005	Project One	General Resolution Projects	Combined Cycle Project	Trust Funds	Total Electric Projects	Telecom Project and Business Units	Total
(in thousands)							
Revenues:							
Participant	$326,674	$150,075	$51,157	$ –	$527,906	$ 5,136	$533,042
Other	100,251	34,268	36,036	–	170,555	178	170,733
Total revenues	426,925	184,343	87,193	–	698,461	5,314	703,775
Operating expenses:							
Fuel	73,917	60,766	49,211	–	183,894	–	183,894
Purchased power	23,042	–	–	–	23,042	–	23,042
Other generating or operating expense	111,465	40,943	11,870	1,533	165,811	4,104	169,915
Transmission	8,034	–	–	–	8,034	–	8,034
Depreciation and amortization	64,278	18,290	8,994	–	91,562	1,880	93,442
Total operating expenses	280,736	119,999	70,075	1,533	472,343	5,984	478,327
Net operating revenues (loss)	146,189	64,344	17,118	(1,533)	226,118	(670)	225,448
Interest expense (income), net:							
Interest expense	134,705	45,558	18,119	4,072	202,454	1,127	203,581
Amortization of debt discount and expense	5,681	1,594	923	11,333	19,531	81	19,612
Interest income	(23,549)	(4,022)	(2,402)	(30,690)	(60,663)	(120)	(60,783)
Net change in the fair value of financial instruments	1,167	(2,537)	372	10,197	9,199	(678)	8,521
Interest capitalized	(291)	(177)	2	–	(466)	(1)	(467)
Total interest expense (income), net	117,713	40,416	17,014	(5,088)	170,055	409	170,464
Decrease (increase) in net costs to be recovered from future billings to Participants	28,476	23,928	104	3,555	56,063	(1,079)	54,984
Total other expenses (income), net	146,189	64,344	17,118	(1,533)	226,118	(670)	225,448
Net Revenues	$ –	$ –	$ –	$ –	$ –	$ –	$ –

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

Consolidated Statement of Cash Flows

For the Year Ended December 31, 2005 (in thousands)	Project One	General Resolution Projects	Combined Cycle Project	Trust Funds	Total Electric Projects	Telecom Project and Business Units	Total
Cash flows from operating activities:							
Cash received from Participants	$ 312,112	$ 146,999	$ 49,611	$ 21,543	$ 530,265	$ 5,118	$ 535,383
Cash received from others	65,205	35,972	38,610	–	139,787	133	139,920
Cash paid for operating expenses	(191,691)	(93,392)	(61,134)	(1,091)	(347,308)	(4,053)	(351,361)
Net cash provided by operating activities	185,626	89,579	27,087	20,452	322,744	1,198	323,942
Cash flows from investing activities:							
Sales and maturities of investment securities	367,406	79,988	51,047	560,222	1,058,663	3,066	1,061,729
Purchase of investment securities	(410,523)	(81,724)	(36,514)	(546,348)	(1,075,109)	(1,762)	(1,076,871)
Interest receipts	19,664	3,393	2,056	35,810	60,923	135	61,058
Distribution from Alliance	35,544	–	–	–	35,544	–	35,544
Business Unit reserves	–	–	–	–	–	34	34
Net cash provided by investing activities	12,091	1,657	16,589	49,684	80,021	1,473	81,494
Cash flows from capital and related financing activities:							
Property additions	(57,866)	(7,891)	(449)	–	(66,206)	(429)	(66,635)
Net payments on lines of credit	(3,350)	–	–	–	(3,350)	–	(3,350)
Proceeds from issuance of long-term debt	352,705	54,849	–	–	407,554	–	407,554
Retirement of long-term debt	(356,440)	(96,001)	(6,775)	–	(459,216)	(2,030)	(461,246)
Interest payments	(110,621)	(36,961)	(18,096)	(4,072)	(169,750)	(1,094)	(170,844)
Net cash used in capital and related financing activities	(175,572)	(86,004)	(25,320)	(4,072)	(290,968)	(3,553)	(294,521)
Increase (decrease) in cash and cash equivalents	22,145	5,232	18,356	66,064	111,797	(882)	110,915
Cash and cash equivalents at beginning of year	166,320	67,299	11,925	15,652	261,196	4,943	266,139
Cash and cash equivalents at end of year	188,465	72,531	30,281	81,716	372,993	4,061	377,054
Other investment securities at end of year	482,001	75,492	44,464	968,189	1,570,146	7	1,570,153
Special funds, Supplemental power account and Securities lending collateral at end of year	$ 670,466	$ 148,023	$ 74,745	$ 1,049,905	$ 1,943,139	$ 4,068	$ 1,947,207
Reconciliation of net operating revenues (loss) to net cash provided by operating activities:							
Net operating revenues (loss)	$ 146,189	$ 64,344	$ 17,118	$ (1,533)	$ 226,118	$ (670)	$ 225,448
Adjustments to reconcile net operating revenues (loss) to net cash from operating activities:							
Depreciation and amortization	82,816	21,007	8,994	–	112,817	1,880	114,697
Share of net revenues from Alliance	(35,917)	–	–	–	(35,917)	–	(35,917)
Change in current assets and liabilities:							
Accounts receivable	(4,671)	531	1,678	(120)	(2,582)	117	(2,465)
Fuel stocks	1,491	2,846	–	–	4,337	–	4,337
Materials, supplies and other assets	(3,230)	(213)	(128)	–	(3,571)	(5)	(3,576)
Accounts payable and other liabilities	(1,052)	1,064	(575)	22,105	21,542	(124)	21,418
Net cash provided by operating activities	$ 185,626	$ 89,579	$ 27,087	$ 20,452	$ 322,744	$ 1,198	$ 323,942

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

1. General Matters

(A) Organization

The Municipal Electric Authority of Georgia (MEAG Power) is a public corporation and an instrumentality of the State of Georgia (the State), created by an Act of the General Assembly of the State (the Act) to supply electricity to local government electric distribution systems. The Act provides that MEAG Power will establish rates and charges so as to produce revenues sufficient to cover its costs, including debt service, but it may not operate any of its projects for profit, unless any such profit inures to the benefit of the public. Forty-eight cities and one county of the State (Electric Utility Participants) have contracted with MEAG Power for bulk electric power supply needs.

MEAG Power is comprised of the Electric Projects as well as the Telecommunications Project and two business units. The Electric Projects consist of Project One, the General Resolution Projects, the Combined Cycle Project and the Trust Funds, all defined in Note 2, "Electric Projects." The Telecommunications Project (Telecom) as well as the Distribution Services and Marketing Services Business Units (the Business Units) are discussed beginning in Note 3, "Telecommunications Project and the Business Units."

(B) Basis of Accounting

The electric utility accounts of MEAG Power are maintained substantially in accordance with the Uniform System of Accounts of the Federal Energy Regulatory Commission (FERC), as provided by the power sales contracts with the Electric Utility Participants. Telecom accounts are maintained substantially in accordance with the Uniform System of Accounts of the Federal Communications Commission. A separate set of accounts is maintained for each of the Electric Projects, as well as Telecom and the Business Units. All such accounts are in conformity with accounting principles generally accepted in the United States (GAAP). MEAG Power has chosen the option permitted by Statement No. 20, "Accounting and Financial Reporting for Proprietary Funds and Other Governmental Entities That Use Proprietary Fund Accounting," of the Governmental Accounting Standards Board (GASB) to implement all Financial Accounting Standards Board (FASB) pronouncements that do not conflict with or contradict GASB pronouncements.

The following have been eliminated from MEAG Power's 2006 consolidated financial statements:

- Certain investment, long-term debt, interest income and interest expense balances, as discussed in Note 2 (M), "Long-Term Debt – Subordinated Debt and Other Debt"; and
- Interproject and Business Units' receivables and payables.

The preparation of the consolidated financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the consolidated financial statements and the related disclosures in these Notes. Actual results could differ from those estimates.

(C) Statement of Cash Flows

In accordance with GASB Statement No. 34, "Basic Financial Statements – and Management's Discussion and Analysis – for State and Local Governments" (GASB Statement 34), the Statement of Cash Flows is presented using the direct method. For reporting cash flows, highly liquid investments purchased with a maturity of three months or less are considered to be cash equivalents except for securities lending investments, as discussed in Note 2 (L), "Special Funds and Supplemental Power Account – Securities Lending."

(D) Property, Plant and Equipment

The cost of property, plant and equipment includes both direct and overhead costs, capitalized interest and the cost of major property replacements. Costs are recorded in construction work in progress (CWIP) and capitalized as the plant asset is placed in service; hence, most of the plant additions are transfers from CWIP. Repairs and replacement of minor items of property are charged to maintenance expense. When property subject to depreciation is retired or otherwise disposed of in the normal course of business, its cost, together with the cost of removal less salvage, is charged to accumulated depreciation, with no gain or loss recorded.

In accordance with FASB Statement No. 34, "Capitalization of Interest Cost," MEAG Power capitalizes interest, which relates primarily to nuclear fuel costs and transmission facilities. The amounts capitalized reflect interest expense, offset by the earnings on the related construction funds.

(E) New Accounting Pronouncements

In February 2007 and September 2006, FASB issued Statement No. 159, "Fair Value Option for Financial Assets and Financial Liabilities – including an Amendment of FASB Statement No. 115" and Statement No. 157, "Fair Value Measurements," respectively. These statements address various measurement and disclosure aspects pertaining to fair value and are effective for MEAG Power on January 1, 2008. MEAG Power is evaluating the statements' impact on its financial reporting.

In July 2006, FASB issued Interpretation 48, "Accounting for Uncertainty in Income Taxes – an interpretation of FASB Statement No. 109" (FIN 48), which prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. FIN 48 became effective for MEAG Power on January 1, 2007 and did not have an impact on MEAG Power's financial statements.

In November 2005, FASB issued Staff Position (FSP) 115-1 and 124-1, "The Meaning of Other-Than-Temporary Impairment and Its Application to Certain Investments," which became effective for MEAG Power on January 1, 2006. This FSP addresses the determination as to when an investment is considered impaired, whether that impairment is other-than-temporary, and the measurement of an impairment loss. It would only impact MEAG Power's financial statements if an investment in the Decommissioning Trust funds became other-than-temporarily impaired, which has not occurred as of December 31, 2006. As discussed in Note 2(G), "Asset Retirement Obligations and Decommissioning," such funds are held by a trustee and the investment management is directed by external investment managers under Nuclear Regulatory Commission (NRC) guidelines.

During 2004, the GASB issued Statement No. 43, "Financial Reporting for Postemployment Benefit Plans Other Than Pension Plans" and Statement No. 45, "Accounting and Financial Reporting by Employers for Postemployment Benefits Other Than Pensions," which were effective for MEAG Power on January 1, 2006 and 2007, respectively. These statements address certain reporting and accounting standards for health and other non-pension benefits offered to retirees and did not have a significant impact on MEAG Power's financial statements.

(F) Vogtle Expansion Project

In May 2005, MEAG Power and the other co-owners of Plant Vogtle entered into a joint agreement authorizing the potential expansion of up to two additional nuclear units at Plant Vogtle. During December 2005, MEAG Power notified the other co-owners of Plant Vogtle as to its initial election to participate in the potential expansion project at a 22.7% ownership interest. Under the terms of the joint agreement, MEAG Power has the right to reduce its level of participation, including totally withdrawing from the proposed project, at any time through April 15, 2008. In the event that MEAG Power withdraws from the proposed project prior to April 15, 2008, it will be reimbursed any preliminary design and development costs incurred by it, including carrying expenses, from inception through the date of withdrawal. Such expenditures, which are accounted for as preliminary survey costs in materials, supplies and other assets in Project One on the Balance Sheet, totaled $4.5 million as of December 31, 2006.

Additionally, in April 2006, MEAG Power and the other co-owners of Plant Vogtle entered into ownership and operating agreements pertaining to the proposed additional nuclear units. MEAG Power also has the right to withdraw as a party from both of these agreements at any time prior to April 15, 2008.

If MEAG Power elects to continue participation in the potential expansion project beyond the April 15, 2008 withdrawal date, a new MEAG Power project will be established for the purpose of financing the costs associated with the proposed expansion. MEAG Power is currently working with the other co-owners to address permitting and licensing matters. No final decision has been made regarding actual construction.

MEAG Power anticipates that the process of seeking binding contractual commitments from the Electric Utility Participants with respect to participation in the proposed expansion project at Plant Vogtle will begin during October 2007. No indication can be given as to whether the proposed expansion project at Plant Vogtle will proceed to completion, or the level, if any, at which MEAG Power will participate in such expansion project.

2. Electric Projects

(A) Project One and the General Resolution Projects

Project One, established and financed under the Power Revenue Bond Resolution, consists of undivided ownership interests in nine generating units, separately owned transmission facilities and working capital. Projects Two, Three and Four (the General Resolution Projects), established and financed under the General Power Revenue Bond Resolution, consist of additional undivided ownership interests in seven generating units.

The resolutions require that payments by Electric Utility Participants for electric power be deposited in special funds and be used only for operating costs, debt service and other stipulated purposes. The resolutions also establish specific funds to hold assets for payment of acquisition costs. Other funds are used to hold assets not subject to the restrictions of the resolutions but designated for specific purposes. Power sales contracts between MEAG Power and each of the Electric Utility Participants require MEAG Power to provide, and the Electric Utility Participants to purchase from MEAG Power, bulk power supply as defined in the contracts. Each Electric Utility Participant is obligated to pay its share of the operating and debt service costs.

During 2004, MEAG Power and each Electric Utility Participant executed an amendment to their power sales contracts (the Amendments) for Project One and the General Resolution Projects which, in part, extended the terms of such contracts until June 2054. The Amendments also revised the method used to allocate the output, services and costs of the General Resolution Projects after the initial term of the related power sales contracts. In addition, the Amendments provided that MEAG Power not extend the term of any existing generation debt outstanding as of November 3, 2004, exclusive of certain working capital debt components, beyond March 1, 2026 for Project One and dates ranging from February 1, 2028 through November 16, 2033 for the General Resolution Projects.

Supplemental bulk power supply is that portion of the Electric Utility Participants' bulk power supply in excess of their entitlement to the output and related services of Project One and the General Resolution Projects. Payments received from the Electric Utility Participants for supplemental bulk power supply are not pledged under either resolution. Supplemental bulk power supply revenue and costs are included in the financial statements of Project One.

(B) Combined Cycle Project

Thirty-two of MEAG Power's 49 communities are Participants in the Combined Cycle Project (CC Project), which began commercial operation on June 1, 2004. The CC Project is wholly owned by MEAG Power and is also known as the Wansley Combined Cycle Facility.

(C) Trust Funds

The financial statements include account balances of the Municipal Competitive Trust and the Deferred Lease Financing Trust, collectively referred to as Trust Funds. The Trust Funds are not fiduciary in nature as they are held for the benefit of Project One, the General Resolution Projects and the CC Project, and accordingly, are accounted for with the Electric Projects. They are not considered trust funds in the context of GASB Statement 34.

The Municipal Competitive Trust

The Municipal Competitive Trust (the Competitive Trust) was established in 1999 to accumulate and grow through common investment a substantial fund to be utilized by the Electric Utility Participants to mitigate higher costs of electricity that may result from the deregulation of the electric industry in Georgia. It was funded with certain rate stabilization and debt service reserve funds totaling approximately $441 million and is comprised of the Reserve Funded Debt, Credit Support Operating and Flexible Operating accounts. Related earnings on investments in these accounts are retained and accounted for as part of the Competitive Trust. Investments of the Competitive Trust have increased to $684.7 million at December 31, 2006 due to investment earnings and additional Electric Utility Participants' contributions.

Except for the Flexible Operating account and for certain limited uses of the Credit Support operating account prior to the commencement of electric retail competition in the State, the funds in the Competitive Trust will be retained and invested. If such competition is approved in Georgia by the General Assembly, funds in the Competitive Trust may be applied only as a reduction to the Electric Utility Participants' costs under the power sales contracts, when necessary to maintain retail competitiveness. If not otherwise expended, monies in the Credit Support Operating account and Reserve Funded Debt account may be withdrawn on or after December 31, 2018 and 2025, respectively. An external trustee holds the funds in the Competitive Trust and maintains balances on an individual Electric Utility Participant basis. At December 31, 2006, all 49 of the Electric Utility Participants were participating in the Competitive Trust.

In June 2006, MEAG Power distributed to the Electric Utility Participants for their consideration a proposed amendment to the terms of the Competitive Trust. The proposed amendment would authorize MEAG Power to apply funds from certain Competitive Trust accounts as a credit to the power sales contract billings of the Electric Utility Participants for the purpose of lowering the annual generation charges from MEAG Power during the period 2009 through 2018. The proposed amendment also authorizes the establishment of an additional account within the Competitive Trust to permit the Electric Utility Participants to fund their share of the acquisition and construction costs of any future MEAG Power generation project joined by such Electric Utility Participants. As of April 30, 2007, a total of 39 Electric Utility Participants have approved the proposed amendment.

Deferred Lease Financing Trust

In June 2000, MEAG Power completed a long-term lease transaction (Lease) with a third party (Lessor) with respect to MEAG Power's total 30.2% undivided interest in Units 1 and 2 of Plant Scherer and its total 15.1% undivided interest in Units 1 and 2 of Plant Wansley and related common facilities at each plant (together, the Undivided Interest). Under the Lease, MEAG Power has leased the Undivided Interest for a term of approximately 50 years. All rent under the Lease was paid by the Lessor at the commencement of the Lease.

The Lessor has subleased the Undivided Interest back to MEAG Power under a sublease for a term of approximately 30 years. Under the sublease, MEAG Power was required to pay the entire balance of the rent due thereunder six months after the commencement of the sublease. During the term of the sublease, MEAG Power will continue to operate and maintain the Undivided Interest and will continue to receive all the output from the Undivided Interest. At the end of the sublease, MEAG Power will have an option to buy out the remaining term of the Lease for a fixed price determined at the commencement of the Lease. This purchase option is being accreted throughout the term of the sublease and was $274.0 million as of December 31, 2006. As a result of the transaction, investments totaling $177.4 million as of December 31, 2006 were available to settle this future obligation. MEAG Power expects that it will have sufficient funds available at the end of the term of the sublease to enable it to exercise its purchase option should it elect to do so. The Lease also addresses the rights and obligations of the parties in the event it is terminated early.

In May 2006, President Bush signed into law an act entitled the "Tax Increase Prevention and Reconciliation Act of 2005" (the 2005 Tax Act). Among other provisions, the 2005 Tax Act imposes an excise tax on certain types of leasing transactions entered into by tax-exempt entities, including states and their political subdivisions. In the absence of any regulations with respect to the application and interpretation of the 2005 Tax Act, MEAG Power does not believe that it will owe any amounts under this excise tax with respect to the Lease. As discussed above in Note 1(E), "New Accounting Pronouncements," the adoption of FIN 48 did not have an impact on MEAG Power's financial statements.

(D) Billings to Electric Utility Participants and Deferred Debits

Wholesale electric sales to Electric Utility Participants are recorded as Participant revenue on an accrual basis. In accordance with the power sales contracts, at the end of each year, MEAG Power determines if the aggregate amount of revenue received from the Electric Utility Participants to provide recovery of costs incurred was in the proper amount. Any excess or deficit amounts resulting in adjustment of billings are refunded or collected from the Electric Utility Participants in the following year. For the years ended December 31, 2006 and 2005, the excess revenue received from Electric Utility Participants was $9.8 million and $12.5 million, respectively, and was included in accounts payable.

Billings to Electric Utility Participants accounted for 79.0% and 75.6% of the Electric Projects' revenues in the years ended December 31, 2006 and 2005, respectively, with sales to other utilities and power marketers, which are also recorded on an accrual basis, comprising other revenues. Three Electric Utility Participants collectively accounted for approximately 27% and 25% of the revenues from Electric Utility Participants in 2006 and 2005, respectively. One of these Electric Utility Participants accounted for 12.0% of Participant revenue in 2006 and 10.8% in 2005. As of December 31, 2006 and 2005, The Energy Authority, as discussed in Note 2 (O), "Investment in Alliance," comprised $9.9 million and $10.2 million, respectively, of current other receivables.

Billings to Electric Utility Participants are designed to recover certain costs, as defined by the bond resolutions and power sales contracts, and principally include current operating costs, scheduled debt principal and interest payments and deposits in certain funds. Timing differences between amounts billed and expenses determined in accordance with GAAP are charged or credited to net costs to be recovered from future billings to Participants in deferred debits on the Balance Sheet. Depreciation and certain debt service billings are examples of such timing differences. All costs are billed to Electric Utility Participants over the period of the power sales contracts. Certain investment income represents earnings on funds not subject to year-end adjustment of billings.

At December 31, 2006 and 2005, net costs to be recovered from future billings to Participants consisted of the following (in thousands):

December 31, 2006	Project One	General Resolution Projects	Combined Cycle Project	Trust Funds	Total
Depreciation, amortization and accretion	$ 2,157,913	$ 560,870	$ 51,914	$ 68,729	$ 2,839,426
Billings to Participants for debt principal	(1,168,898)	(359,425)	(43,022)	–	(1,571,345)
Certain investment income	(464,408)	(65,264)	(7,374)	(57,795)	(594,841)
Participant contributions	–	–	(7,200)	–	(7,200)
Asset retirement obligations	113,246	20,713	–	–	133,959
Credit support operating trust	–	–	–	(205,460)	(205,460)
Reserve funded debt trust	–	–	–	(365,663)	(365,663)
Environmental facilities reserve	(34,046)	(47,706)	–	81,752	–
Other, net	(21,938)	42,415	19,680	3,569	43,726
Net costs to be recovered from future billings to Participants	$ 581,869	$ 151,603	$ 13,998	$(474,868)	$ 272,602

December 31, 2005	Project One	General Resolution Projects	Combined Cycle Project	Trust Funds	Total
Depreciation, amortization and accretion	$ 2,078,988	$ 531,425	$ 42,054	$ 56,883	$ 2,709,350
Billings to Participants for debt principal	(1,069,853)	(313,200)	(28,503)	–	(1,411,556)
Certain investment income	(443,213)	(59,819)	(6,681)	(46,899)	(556,612)
Participant contributions	–	–	(7,200)	–	(7,200)
Asset retirement obligations	132,075	22,367	–	–	154,442
Credit support operating trust	–	–	–	(197,982)	(197,982)
Reserve funded debt trust	–	–	–	(349,277)	(349,277)
Other, net	(11,679)	44,589	20,703	3,112	56,725
Net costs to be recovered from future billings to Participants	$ 686,318	$ 225,362	$ 20,373	$(534,163)	$ 397,890

Other deferred debits consist of unamortized debt costs, resulting from the issuance and refunding of bonds and other deferred charges that are amortized and recovered in future years through billings to Electric Utility Participants.

(E) Materials, Supplies and Other Assets

Materials and supplies include the cost of transmission materials and the average cost of generating plant materials, which is charged to inventory when purchased and then expensed or capitalized to plant, as appropriate. Other assets consist primarily of prepaid assets and preliminary survey costs.

(F) Property, Plant and Equipment

Property, plant and equipment activity for the years ended December 31, 2006 and 2005 is shown (in thousands) in the following table. Land is included in the electric component at a non-depreciable cost basis of $30.8 million and $30.3 million as of December 31, 2006 and 2005, respectively. In 2006, capital additions totaled $86.5 million. These amounts were used for capital improvements at existing generating plants and transmission facilities, as well as purchases of nuclear fuel.

Property, Plant and Equipment	As of December 31, 2004	Increases	Decreases	As of December 31, 2005	Increases	Decreases	As of December 31, 2006
Project One:							
Electric	$ 2,077,220	$ 5,185	$ (4,122)	$ 2,078,283	$ 9,179	$(11,600)	**$2,075,862**
Transmission and distribution	507,850	29,816	(4,159)	533,507	13,976	(2,789)	**544,694**
General	34,904	1,463	(2,660)	33,707	1,386	(474)	**34,619**
Total electric utility plant	2,619,974	36,464	(10,941)	2,645,497	24,541	(14,863)	**2,655,175**
Less accumulated depreciation	(1,275,492)	(47,113)	10,941	(1,311,664)	(49,857)	5,120	**(1,356,401)**
Electric utility depreciable plant, net	1,344,482	(10,649)	–	1,333,833	(25,316)	(9,743)	**1,298,774**
Construction work in progress	22,903	29,392	(35,874)	16,421	35,957	(24,383)	**27,995**
Nuclear fuel	100,077	23,387	(33,209)	90,255	35,822	(15,374)	**110,703**
Less accumulated amortization	(54,702)	(18,164)	33,209	(39,657)	(19,196)	15,374	**(43,479)**
Nuclear fuel, net	45,375	5,223	–	50,598	16,626	–	**67,224**
Total Project One	1,412,760	23,966	(35,874)	1,400,852	27,267	(34,126)	**1,393,993**
General Resolution Projects:							
Electric	829,994	14,144	(1,575)	842,563	2,299	(2,693)	**842,169**
Transmission and distribution	12,406	23	(146)	12,283	421	(26)	**12,678**
General	5,082	449	(873)	4,658	214	(61)	**4,811**
Total electric utility plant	847,482	14,616	(2,594)	859,504	2,934	(2,780)	**859,658**
Less accumulated depreciation	(415,535)	(15,685)	2,594	(428,626)	(16,154)	1,159	**(443,621)**
Electric utility depreciable plant, net	431,947	(1,069)	–	430,878	(13,220)	(1,621)	**416,037**
Construction work in progress	14,349	3,519	(14,348)	3,520	8,064	(2,611)	**8,973**
Nuclear fuel	14,591	3,443	(6,978)	11,056	6,678	(2,063)	**15,671**
Less accumulated amortization	(8,698)	(2,717)	6,978	(4,437)	(2,905)	2,063	**(5,279)**
Nuclear fuel, net	5,893	726	–	6,619	3,773	–	**10,392**
Total General Resolution Projects	452,189	3,176	(14,348)	441,017	(1,383)	(4,232)	**435,402**
Combined Cycle Project:							
Electric utility plant	313,821	–	(497)	313,324	82	–	**313,406**
Less accumulated depreciation	(3,794)	(8,995)	–	(12,789)	(8,952)	–	**(21,741)**
Electric utility depreciable plant, net	310,027	(8,995)	(497)	300,535	(8,870)	–	**291,665**
Construction work in progress	–	498	(398)	100	115	(82)	**133**
Total Combined Cycle Project	310,027	(8,497)	(895)	300,635	(8,755)	(82)	**291,798**
Total property, plant and equipment – net	$ 2,174,976	$18,645	$(51,117)	$ 2,142,504	$17,129	$(38,440)	**$2,121,193**

(G) Asset Retirement Obligations and Decommissioning

MEAG Power adopted FASB Statement No. 143, "Accounting for Asset Retirement Obligations" (FASB Statement 143) on January 1, 2003, which established standards for accounting and reporting of legal obligations relating to the retirement of long-lived assets. As of December 2005, MEAG Power adopted FASB Interpretation 47, "Accounting for Conditional Asset Retirement Obligations – an interpretation of FASB Statement No. 143" (FIN 47), which clarifies the term "conditional asset retirement obligation" pertaining to FASB Statement 143. FIN 47 requires recognition of an asset retirement obligation even if the timing and/or method of settlement are conditional on a future event. As with FASB Statement 143, MEAG Power calculated the present value of applicable disposal costs and increased a corresponding liability associated with those obligations. This liability is accreted during the remaining life of the associated assets and adjusted periodically based upon updated estimates. The costs associated with the corresponding assets have been increased and are being depreciated throughout the remaining lives of the assets.

The adoption of FIN 47, which pertains to MEAG Power's share of asbestos disposal costs at generating facilities listed in Note 2 (J), "Generation and Transmission Facilities – Jointly Owned Generation Facilities," increased the following accounts on MEAG Power's Balance Sheet as of December 31, 2005 (in thousands):

	Project One	General Resolution Projects	Total
Property, plant and equipment – net	$ 290	$ 82	$ 372
Net costs to be recovered from future billings to Participants	1,766	336	2,102
Total increases to assets	$2,056	$418	$2,474
Other non-current liabilities	$2,056	$418	$2,474

The recognition of retirement obligations is driven primarily by decommissioning costs associated with the nuclear plants and also costs associated with coal pile sites and ash ponds related to Plants Scherer and Wansley.

With the adoption of FASB Statement 143, future costs of decommissioning are recognized through the accretion of retirement obligations as part of depreciation expense. For 2006 and 2005, such accretions totaled $15.9 million and $15.0 million, respectively, for Project One and $2.6 million and $2.4 million, respectively, for the General Resolution Projects. Effective December 31, 2006, MEAG Power reduced the liability for asset retirement obligations by $49.7 million based on December 2006 site-specific engineering studies pertaining to the nuclear plants.

Pursuant to NRC guidelines, funds are maintained to hold assets which will be used to pay the future costs to decommission the nuclear plants. The Decommissioning Trust funds, which are held by a trustee, were established to comply with NRC regulations which require licensees of nuclear power plants to provide certain financial assurances that funds will be available when needed for required decommissioning activities.

Under current plans, the nuclear plants will be decommissioned over extended periods at estimated costs (Project One and the General Resolution Projects' portion) as of the year of site-specific studies as follows (dollars in thousands):

	Plant Hatch	Plant Vogtle
Decommissioning period	2034 – 2061	2027 – 2051
Estimated future costs (2006 dollars)	$208,565	$285,324
Amount expensed in 2006	$7,068	$11,153
Accumulated provision in external funds	$129,875	$127,875

A significant factor used in estimating future decommissioning costs was the extension of the Plant Hatch operating license. In January 2002, both Units 1 and 2 received a 20-year operating license extension from the NRC which permits their operation until 2034 and 2038, respectively. As discussed in Note 2 (J), "Generation and Transmission Facilities – Jointly Owned Generation Facilities," Georgia Power Company (GPC) is the operator of the nuclear plants. In June 2007, GPC plans to file an application with the NRC to extend the licenses for Plant Vogtle Units 1 and 2 for an additional 20 years.

Actual decommissioning costs may vary due to changes in the assumed dates of decommissioning, NRC funding requirements, regulatory requirements, costs of labor and equipment, or other assumptions used in determining the estimates. Earnings and inflation assumptions of 5.82% and 4.60%, respectively, were used to determine decommissioning-related billings to Electric Utility Participants for 2007 budget purposes, based on NRC minimum funding levels. The above information is used only for purposes of calculating the funding needs pursuant to NRC guidelines.

(H) Depreciation

Depreciation of plant is computed using the straight-line composite method over the expected life of the plant. Annual depreciation provisions, expressed as a percentage of average depreciable property, are shown below for both 2006 and 2005 as applicable in Project One, the General Resolution Projects and the Combined Cycle Project. The composite electric utility plant depreciation rates are based on engineering studies updated periodically, most recently in 2004. Depreciation expense for 2006 and 2005 totaled $71.1 million and $70.4 million, respectively, and is included in depreciation and amortization in the accompanying Statement of Net Revenues.

Generating Plants	Fuel	Rate
Hatch	Nuclear	1.7%
Vogtle	Nuclear	1.6%
Scherer	Coal	1.8%
Wansley	Coal	2.5%
Wansley Combined Cycle Facility	Natural gas	2.9%

Other Property, Plant and Equipment	Rate
Transmission Plant	2.3%
Distribution Plant	3.2%
General/Other Plant	2.5% – 33.0%

(I) Fuel Costs

Amortization of nuclear fuel is calculated on a units of production basis. Estimated spent nuclear fuel disposal costs, required under the Nuclear Waste Policy Act of 1982, are included in operating expenses and totaled $5.4 million for Project One and $0.9 million for the General Resolution Projects in both 2006 and 2005.

Per contracts GPC has with the U.S. Department of Energy (DOE), permanent disposal of spent nuclear fuel was to begin in 1998. This has not occurred and GPC is pursuing legal remedies against the U.S. Government for breach of contract. Plant Vogtle has sufficient pool storage capacity for spent fuel to maintain full-core discharge capability for both units into 2014. An on-site dry storage facility at Plant Vogtle is scheduled for construction in sufficient time to maintain pool full-core discharge capability. Such a facility became operational at Plant Hatch in 2000 and can be expanded to accommodate spent fuel through the life of the plant.

The Energy Policy Act of 1992 created a Uranium Enrichment Decontamination and Decommissioning Fund which requires annual funding by all domestic utilities that have purchased enriched uranium from the DOE. This fund will be used by the DOE for the cleanup of its nuclear enrichment facilities. Such funding was paid over a 15-year period with the final installment of $1.0 million occurring in 2006.

Emission allowances granted by the U.S. Environmental Protection Agency (EPA) for future years are included in inventory at zero cost. All calendar year EPA-granted allowances were used in both 2006 and 2005. In addition, MEAG Power purchased $3.4 million and $5.3 million of emission allowances during the years ended December 31, 2006 and 2005, respectively, which were used and included in fuel expense.

(J) Generation and Transmission Facilities

Jointly Owned Generation Facilities

At December 31, 2006, MEAG Power's ownership percentages in jointly owned generation facilities were as follows:

	Ownership Percent		
Facility	Project One	General Resolution Projects	Total Ownership
Plant Hatch	17.7%	–	17.7%
Plant Scherer Units 1 and 2	10.0%	20.2%	30.2%
Plant Vogtle	17.7%	5.0%	22.7%
Plant Wansley	10.0%	5.1%	15.1%

MEAG Power, GPC, Oglethorpe Power Corporation (OPC) and the City of Dalton, Georgia (Dalton) jointly own the facilities. GPC has contracted to operate and maintain the jointly owned facilities as agent for the respective co-owners. MEAG Power's proportionate share of plant operating expenses is included in the corresponding operating expense items in the accompanying Statement of Net Revenues.

MEAG Power and GPC are parties to agreements governing the ownership and operation of electric generating and transmission facilities. GPC is agent for the operation of the generating and transmission facilities. In addition, there is an agreement that provides for the sale by MEAG Power to GPC of a portion of the output of each generating unit at Plant Vogtle. Sales to GPC, included in other revenues, were $51.2 million in 2006 and $52.9 million in 2005 for Project One, and $14.4 million in 2006 and $14.9 million in 2005 for the General Resolution Projects.

Transmission Facilities

MEAG Power, GPC, Georgia Transmission Corporation, an affiliate of OPC, and Dalton each own transmission system facilities which together comprise a statewide, integrated transmission system (ITS). MEAG Power and each other entity may use all transmission system facilities included in the ITS, regardless of ownership, in serving its customers. Bulk power supply is furnished by MEAG Power to the Electric Utility Participants through the ITS. MEAG Power's ITS facilities are included in Project One.

In December 2006, the owners of the ITS exchanged written commitments whereby each owner agreed to waive and not to exercise its right under its respective ITS Agreement (Agreement) to terminate the Agreement on any date prior to December 31, 2027. In accordance with the five-year notice requirement in the Agreement, an owner may provide written notice on or before December 31, 2022, terminating its respective Agreement no earlier than December 31, 2027. These written commitments do not have the effect of modifying, superseding or terminating the Agreement.

(K) Derivative Financial Instruments

Derivative financial instruments used in the management of interest rate exposure through swap transactions are governed by MEAG Power's Asset/Liability Management Policy (the Investment Policy) and accounted for in accordance with FASB Statement No. 133, "Accounting for Derivative Instruments and Hedging Activities," as amended and GASB Statement No. 31, "Accounting and Financial Reporting for Certain Investments and for External Investment Pools." These derivatives are not held or issued for trading purposes and MEAG Power management has designated the swaps as hedge instruments. The swap agreements are marked-to-market monthly with the associated gain or loss recognized as a change in fair value of financial instruments and included in net costs to be recovered from future billings to Participants. If the instrument is terminated before the end of the agreement's term, any gain or loss is amortized over a period consistent with the underlying liability.

The counterparties to derivative transactions are major financial institutions with either high investment grade credit ratings or agreements to collateralize their net positions. MEAG Power will be exposed to additional interest rate exposure if a counterparty to a swap transaction defaults or if the swap is terminated. Any termination of the swap agreements may also result in MEAG Power making or receiving a settlement payment. Note 2 (M), "Long-Term Debt – Other Financing Transactions," includes a summary of swap agreements outstanding as of December 31, 2006 and 2005.

MEAG Power also uses fuel-related derivative financial instruments to manage specific risks associated with procurement of natural gas for the CC Project. Such strategies are governed by MEAG Power's Natural Gas Risk Management Policy and primarily include hedging transactions used to manage MEAG Power's natural gas cost. Hedging instruments are marked-to-market monthly and had a fair market value of $(1.0) million as of December 31, 2006 and were not significant as of December 31, 2005.

(L) Special Funds and Supplemental Power Account

Investment Policy

The Investment Policy governs permitted investments, which include direct obligations of the United States Government, certain government agency securities, direct and general obligations of states, certain Federal agency discount notes, and money market mutual funds that are permissible securities, as well as repurchase and reverse repurchase agreements collateralized by permissible securities. In the Decommissioning Trust, in addition to these same categories of investments, the Investment Policy permits common equity investment trusts, asset-backed securities, commercial paper, and corporate notes and bonds, as well as other debt obligations and certificates of deposit. Based on these guidelines, special funds, the supplemental power account and securities lending investments (discussed below) are considered restricted assets as defined by GASB Statement 34.

MEAG Power assumes that callable securities in its investment portfolio will not be called. All of MEAG Power's investments are recorded and carried at fair value. Quoted market prices are used to determine the fair value of all investments. Unrealized gains/losses on investment securities are reported in net change in the fair value of financial instruments on the Statement of Net Revenues.

Credit Risk

Credit risk is the risk that MEAG Power will be unable to recover its investments either by an inability to withdraw the funds through nonperformance of a counterparty or an inability to recover collateral. In accordance with the Investment Policy, MEAG Power manages exposure to credit risk by restricting investments to issuers that meet certain qualifications and therefore limits any potential credit exposure. In addition, all repurchase agreements must be collateralized using securities permissible under the Investment Policy at 102% of the market value of principal and accrued interest. As of December 31, 2006, 100% of MEAG Power's investments in mortgage-backed securities and 100% of its investments in U.S. Government agencies were rated AAA by Standard and Poor's (S&P). These percentages exclude the securities lending program for which the credit risk aspect is discussed in "Securities Lending" below. Investments in money market mutual funds were rated AAAm by S&P and Aaa by Moody's Investors Service (Moody's). Common equity investment trusts are not rated.

Custodial Credit Risk

In the event of failure of the counterparty, custodial credit risk is the risk that MEAG Power would not be able to recover the value of its investments or collateral securities that are in possession of an outside party. MEAG Power limits the potential of such risk by ensuring that all investments are held by MEAG Power or by an agent in its name.

Concentration of Credit Risk

Concentration of credit risk is the chance of a loss due to the magnitude of MEAG Power's investment in a single issuer. Under the Investment Policy, MEAG Power restricts possible concentration of credit risk by placing maximum exposure restrictions by security type. The Investment Policy also requires diversification to control the risk of loss resulting from over-concentration of assets in a specific maturity, issuer, instrument, dealer or bank. External investments with one issuer that comprised 5% or more of the Electric Projects' portfolio (excluding those issued or explicitly guaranteed by the U.S. Government, as well as mutual funds) as of December 31, 2006 were (in thousands):

Issuer	Fair Value	Percentage of Portfolio
Federal Home Loan Mortgage Corporation	$732,779	31.8%
Federal National Mortgage Association	$328,454	14.2%
Federal Home Loan Bank	$273,346	11.9%
Morgan Stanley & Co. Inc.	$124,591	5.4%

Securities Lending

MEAG Power's Board of Directors (the Board) has approved a securities lending program (the program) which allows MEAG Power to lend U.S. Government and agency securities held in the Decommissioning Trust and the Competitive Trust in return for collateral in the form of cash or authorized security types, with a simultaneous agreement to return collateral for the same securities in the future. All investments in the program are considered other investment securities for reporting cash flows.

MEAG Power's Trustee for the Decommissioning Trust is agent for the program and collateral is pledged at 102% of the fair value of the investments loaned and is valued daily. There are no restrictions on the amount of securities that can be lent.

At December 31, 2006, MEAG Power had no credit risk exposure to borrowers because the fair value of the collateral was greater than the fair value of the securities lent. Contracts with the lending agent require them to indemnify MEAG Power if the borrowers fail to return the securities and the collateral is inadequate to replace the securities lent or fail to pay MEAG Power for income distributions while the securities are on loan. There were no violations of legal or contractual provisions, no borrower or lending agent default losses, and no recoveries of prior period losses during the year. There were no income distributions owing on the securities lent.

All securities loans can be terminated on demand by either MEAG Power or the borrower. MEAG Power is not exposed to custodial credit risk as the collateral securities and cash collateral are held in MEAG Power's name. Cash collateral is invested in short-term securities that generally match the obligations of the investments on loan; a portion of the investments are specifically matched to the loans. As of December 31, 2006 and 2005, the fair value of the securities lent was as follows (in thousands):

Securities Lent	**2006**	2005
U.S. Government securities	**$221,667**	$208,997
U.S. Government agency securities	**34,877**	47,895
Total	**$256,544**	$256,892

Interest Rate Risk

All fixed income investments are exposed to interest rate risk. MEAG Power's investments would be subjected to losses due to potential increases in interest rates. The Investment Policy describes the maximum maturity limitations and performance benchmarks for each account in the funds established under the various bond resolutions. These limits are based upon the underlying use of the monies deposited into each account. The maturity restrictions are designed to ensure the assets are not invested longer than the intended use of the funds. The Investment Policy prohibits leveraged floating rate notes, as well as interest only and principal only securities, investments that are highly sensitive to interest rate changes. As of December 31, 2006, maturities of special funds, the supplemental power account and securities lending, as applicable, were as follows (in thousands):

	Maturities (in years):							
Investment Type	Under One	One – Three	Three – Seven	Seven – Ten	Over Ten	No Specific Maturity	Elimination	Total
U.S. Government securities	$ 73,504	$106,763	$104,657	$ –	$ –	$ –	$ –	$ 284,924
U.S. Government agency:								
Discount notes	640,524	–	–	–	–	–	–	640,524
Securities	381,730	137,449	56,442	7,049	5,145	–	–	587,815
Mortgage-backed securities	41,848	83,213	36,222	48,120	26,876	–	–	236,279
Money market mutual funds	33,831	–	–	–	–	–	–	33,831
Common equity investment trusts	–	–	–	–	–	84,200	–	84,200
Municipal bonds	–	–	–	–	177,368	–	(177,368)	–
Repurchase agreements	178,955	–	–	–	–	–	–	178,955
Asset-backed securities	27,428	–	–	–	–	–	–	27,428
Corporate notes	29,500	–	–	–	–	–	–	29,500
Bank notes	12,000	–	–	–	–	–	–	12,000
Certificates of deposit	13,997	–	–	–	–	–	–	13,997
Cash	–	–	–	–	–	(136)	–	(136)
Total Special funds, Supplemental power account and Securities lending collateral	$1,433,317	$ 327,425	$ 197,321	$55,169	$ 209,389	$84,064	$(177,368)	$2,129,317

Environmental Facilities Reserve Accounts

In August 2006, MEAG Power established separate Environmental Facilities Reserve accounts, one for Project One and the others with respect to the General Resolution Projects. These accounts were established in order to mitigate future planned environmental costs at Plants Scherer and Wansley (the Coal Units) and were funded initially with $77.9 million of the proceeds received from the Lease involving MEAG Power's ownership interest in the Coal Units, discussed in Note 2 (C), "Trust Funds – Deferred Lease Financing Trust." Additional funding will be provided from billings to the Electric Utility Participants.

Classification

Investments are classified as current or non-current assets based on whether the securities represent funds available for current disbursement under the terms of the related trust agreement or other contractual provisions. Brief descriptions of funds not discussed elsewhere in these Notes are as follows:

- Construction funds are established to maintain funds for the payment of all costs and expenses related to the cost of acquisition and construction of a project which MEAG Power is permitted to finance through the issuance of debt.
- Revenue and Operating funds are used for the purpose of depositing all revenues and disbursement of the debt service, operating expenses and required fund deposits of the projects.
- Reserve and Contingency funds are used to accumulate and maintain a reserve for payment of the costs of major renewals, replacements, repairs, additions, betterments and improvements for the projects.
- Debt Service accounts are established for the purpose of accumulating funds for the payment of interest and principal on each payment date of the bonds issued for the projects.

At December 31, 2006 and 2005, the fair value of all investments in special funds, the supplemental power account and securities lending as classified in the Balance Sheet were as follows (in thousands):

December 31, 2006	Project One	General Resolution Projects	Combined Cycle Project	Trust Funds	Elimination	Total
Special funds, non-current:						
Decommissioning Trust	$231,202	$ 26,548	$ –	$ –	$ –	$ 257,750
Construction fund	149,323	105,544	2,213	–	–	257,080
Debt Service fund – Reserve and Retirement accounts	–	–	37,403	–	–	37,403
Revenue and Operating fund	–	–	6,988	–	–	6,988
Reserve and Contingency fund	14,505	8,997	2,228	–	–	25,730
Environmental Facilities Reserve account	32,800	46,051	–	–	–	78,851
Competitive Trust:						
Credit Support Operating account	–	–	–	205,297	–	205,297
Reserve Funded Debt account	–	–	–	366,284	–	366,284
Deferred Lease Financing Trust	–	–	–	177,406	(177,368)	38
Total Special funds, non-current	427,830	187,140	48,832	748,987	(177,368)	1,235,421
Special funds, current:						
Revenue and Operating fund	36,159	22,529	20,829	–	–	79,517
Debt Service fund – Debt Service account	95,646	40,453	4,572	–	–	140,671
Subordinated Debt Service fund – Debt Service account	210,084	54,315	725	–	–	265,124
Construction fund	30,636	1,592	–	–	–	32,228
Competitive Trust – Flexible Operating account	–	–	–	113,114	–	113,114
Total Special funds, current	372,525	118,889	26,126	113,114	–	630,654
Supplemental power account	1,362	–	–	–	–	1,362
Securities lending collateral	125,263	14,384	–	122,233	–	261,880
Total Special funds, Supplemental power account and Securities lending collateral	$926,980	$320,413	$74,958	$984,334	$(177,368)	$2,129,317

December 31, 2005	Project One	General Resolution Projects	Combined Cycle Project	Trust Funds	Total
Special funds, non-current:					
Decommissioning Trust	$215,383	$ 24,562	$ –	$ –	$ 239,945
Construction fund	52,806	14,354	7,154	–	74,314
Debt Service fund – Reserve and Retirement accounts	–	–	36,864	–	36,864
Revenue and Operating fund	–	–	5,866	–	5,866
Reserve and Contingency fund	16,434	9,091	1,337	–	26,862
Competitive Trust:					
Credit Support Operating account	–	–	–	197,854	197,854
Reserve Funded Debt account	–	–	–	349,696	349,696
Deferred Lease Financing Trust	–	–	–	249,077	249,077
Total Special funds, non-current	284,623	48,007	51,221	796,627	1,180,478
Special Funds, current:					
Revenue and Operating fund	62,809	37,246	18,272	–	118,327
Debt Service fund – Debt Service account	94,545	40,550	5,252	–	140,347
Subordinated Debt Service fund – Debt Service account	33,196	5,401	–	–	38,597
Construction fund	95,713	5,554	–	–	101,267
Competitive Trust – Flexible Operating account	–	–	–	102,676	102,676
Total Special funds, current	286,263	88,751	23,524	102,676	501,214
Supplemental power account	402	–	–	–	402
Securities lending collateral	99,178	11,265	–	150,602	261,045
Total Special funds, Supplemental power account and Securities lending collateral	$670,466	$148,023	$74,745	$1,049,905	$1,943,139

(M) Long-Term Debt

Power Revenue Bonds and General Power Revenue Bonds

As of December 31, 2006, MEAG Power had validated by court judgments $8.0 billion in Power Revenue bonds for the purpose of financing Project One and $3.4 billion in General Power Revenue bonds for the purpose of financing the General Resolution Projects. Reference to "court judgments" for these bonds, as well as for the bonds described below, indicates that MEAG Power is authorized to issue such bonds up to the validated amount. The resolutions permit the issuance of additional bonds for certain purposes.

Bonds issued under the resolutions are secured by a pledge of electric power revenues attributable to the respective projects after payment of operating costs, as well as by pledges of the assets in the funds established by the bond resolutions. Each Electric Utility Participant's payment obligations under the power sales contracts are general obligations to which each Electric Utility Participant's full faith and credit are pledged. No scheduled debt maturity for any project extends beyond June 2054, the expiration of the power sales contracts for the respective project – see Note 2 (A), "Project One and the General Resolution Projects."

Various bond issues were defeased in previous years by creating separate irrevocable trust funds. New debt was issued and the proceeds used to purchase U. S. Government securities that were placed in the trust funds. The investments and fixed earnings from the investments are sufficient to fully service the defeased debt until the debt is called or matures. For financial reporting purposes, the debt has been considered defeased and therefore removed as a liability from the Balance Sheet of Project One and the General Resolution Projects. As of December 31, 2006, the amount held in escrow to defease debt removed from the Balance Sheet amounted to $216.3 million. As of December 31, 2006, $7.6 billion aggregate principal amount of Power Revenue bonds, General Power Revenue bonds and subordinated debt has been refunded of which $6.2 billion was defeased.

Combined Cycle Project Revenue Bonds

As of December 31, 2006, MEAG Power had validated by court judgments $1.3 billion of CC Project bonds, which includes $200 million for prepayment of fuel costs.

Subordinated Debt and Other Debt

As of December 31, 2006, MEAG Power had validated by court judgments subordinated bonds totaling $3.4 billion for Project One and $1.0 billion for the General Resolution Projects. The resolutions permit the issuance of additional bonds for certain purposes.

Debt issued under the subordinated bond resolutions is subordinate in all respects to the Power Revenue bonds. A principal amount of validated but unissued Power Revenue bonds of not less than the amount of subordinated bonds issued as bond anticipation notes is required to be maintained.

Up to $410.0 million in tax-exempt and taxable commercial paper (CP) notes may be issued. The CP notes issued and outstanding as of December 31, 2006 in the amount of $381.8 million are supported by direct pay letters of credit issued by three commercial banks pursuant to a related reimbursement agreement between MEAG Power and the commercial banks. Any amounts drawn under the letters of credit would be payable by MEAG Power on a semi-annual basis over a three-year period using the banks' interest rates.

Certain subordinated bonds issued as variable rate demand obligations totaled $600.4 million as of December 31, 2006. Bondholders may require repurchase of these subordinated bonds at the time of periodic interest rate adjustments. Agreements have been entered into to provide for the remarketing of the subordinated bonds if such repurchase is required. Agreements have also been entered into with certain banks, which generally provide for the purchase by those banks of subordinated bonds which are not remarketed. Under the terms of these agreements, any bonds purchased by the banks would be payable by MEAG Power on a semi-annual basis over periods generally ranging over five to six years using the banks' interest rates.

In order to finance a portion of MEAG Power's share of the estimated costs of future environmental improvements at the Coal Units, in August 2006, Project One and Projects Two and Three of the General Resolution Projects sold, through a negotiated private placement, $173.2 million of Capital Appreciation Bonds (CABs), which were purchased by the Deferred Lease Financing Trust component of the Trust Funds as an investment. The accretion of the CABs results in interest expense to Projects One, Two and Three with corresponding interest income in the Trust Funds. Such amounts, along with the Trust Funds' investment and the liability of Projects One, Two and Three in the CABs, are eliminated from MEAG Power's consolidated financial statements.

In January 2007, MEAG Power issued $126.3 million of Project One subordinated bonds to refund previously issued tax-exempt CP notes. Of the total, $79.6 million are fixed rate bonds and $46.7 million, maturing 2019 through 2022 (CPI Bonds), bear interest at variable rates (MUNI-CPI Rate) linked to changes in the Consumer Price Index, as reported by the Bureau of Labor Statistics of the U.S. Department of Labor. As noted below in "Other Financing Transactions," in conjunction with the issuance of these bonds, MEAG Power entered into four separate interest rate swap transactions, one with respect to each maturity of the CPI Bonds.

MEAG Power and a consortium of banks have entered into agreements providing for revolving credit lines aggregating $100.0 million. The agreements, which expire in September 2007, generally provide for interest at taxable rates. Changes in lines of credit borrowings during the years ended December 31, 2006 and 2005 were (in thousands):

Borrowings Under Lines of Credit	Balance December 31, 2004	Proceeds	Payments	Balance December 31, 2005	Proceeds	Payments	**Balance December 31, 2006**
Project One	$3,450	$6,277	$9,627	$100	$25,210	$25,110	**$ 200**
General Resolution Projects	–	–	–	–	3,100	–	**3,100**
Total	$3,450	$6,277	$9,627	$100	$28,310	$25,110	**$3,300**

Other Financing Transactions

The information presented below pertains to MEAG Power's swap agreements, outstanding as of December 31, 2006 and 2005, with fair market value amounts corresponding to the market value as of the end of each year as included in other non-current liabilities on the Balance Sheet (dollars in thousands):

	2006	2005
Tax-Exempt		
Notional amount	**$298,640**	$ 237,650
Remaining term	**13 – 41 years**	38 – 42 years
Rate MEAG Power:		
Received	**3.4%**	2.5%
Paid (weighted average rate)	**4.0%**	3.6%
Fair market value	**($6,062)**	($2,658)
Taxable		
Notional amount	**$253,000**	$253,000
Remaining term	**2 – 5 years**	3 – 6 years
Rate MEAG Power:		
Received	**5.1%**	3.3%
Paid (weighted average rate)	**5.4%**	5.4%
Fair market value	**($2,010)**	($4,929)

In January 2004, MEAG Power entered into two floating-to-fixed rate interest rate swap agreements in a notional amount of $100.0 million each. The purpose of the swap transactions was to hedge the interest rate risk on a portion of the variable rate bonds outstanding. The swaps became effective February 1, 2004 and terminated December 31, 2005. Both swaps were tied to the Bond Market Association Municipal Swap Index (BMA Index) and carried fixed rates of 1.67%.

MEAG Power entered into two floating-to-fixed rate interest rate swap agreements in November 2004 in a notional amount of $100.0 million each. The purpose of the swap transactions was to hedge the interest rate risk on a portion of the variable rate bonds outstanding. The swaps became effective January 1, 2005 and terminated December 31, 2005. One swap was tied to the BMA Index and carried a fixed rate of 2.07%. The other swap was tied to the one-month London Interbank Offered Rate (LIBOR) and carried a fixed rate of 2.72%.

In December 2004, MEAG Power entered into two floating-to-fixed rate interest rate swap agreements in a total notional amount of $108.5 million. The purpose of the swap transactions was to hedge the interest rate risk on a portion of the variable rate Series 2005B and C Bonds. The swaps became effective January 19, 2005 and terminate January 1, 2048. The swaps are tied to the BMA Index and carry a fixed rate of 4.32%.

MEAG Power entered into a third floating-to-fixed rate interest rate swap agreement, in January 2005, in a notional amount of $39.2 million to hedge the interest rate risk on the remaining portion of the variable rate Series 2005B and C Bonds. The swap became effective January 19, 2005 and terminates January 1, 2044. The swap is tied to the BMA Index and carries a fixed rate of 4.20%.

In January 2007, MEAG Power entered into four separate interest rate swap transactions in a total notional amount of $46.7 million, to convert the MUNI CPI Rate obligation of the CPI Bonds to a fixed rate obligation. MEAG Power is required, with respect to each maturity of the CPI Bonds, to pay a fixed interest rate and is entitled to receive the MUNI CPI Rate (determined in accordance with terms of the CPI Bonds), each based on a notional amount equal to the principal amount of the CPI Bonds of such maturity.

Under certain circumstances, each of the aforementioned swap transactions is subject to early termination prior to its scheduled termination and prior to the maturity of the related bonds, in which event, MEAG Power may be obligated to make or receive a substantial payment to or from the counterparty.

Bonds and Subordinated Debt Activity

Changes in bonds and subordinated debt during the years ended December 31, 2006 and 2005 were (in thousands):

Bonds and Subordinated Debt	As of December 31, 2004	Increases	Decreases	As of December 31, 2005	Increases	Decreases	**As of December 31, 2006**
Project One:							
Power Revenue Bonds	$1,027,167	$ 7,015	$ (94,611)	$ 939,571	$ 6,142	$ (68,193)	**$ 877,520**
Unamortized (discount) premium, net	3,243	–	(950)	2,293	–	(964)	**1,329**
Subordinated debt	1,450,358	359,103	(261,830)	1,547,631	306,476	(87,306)	**1,766,801**
Unamortized (discount) premium, net	9,055	6,820	(2,063)	13,812	873	(2,183)	**12,502**
Total Project One	2,489,823	372,938	(359,454)	2,503,307	313,491	(158,646)	**2,658,152**
General Resolution Projects:							
General Power Revenue Bonds	472,413	3,539	(24,210)	451,742	3,794	(28,545)	**426,991**
Unamortized (discount) premium, net	8,904	–	(1,219)	7,685	–	(1,099)	**6,586**
Subordinated debt	373,540	54,995	(71,791)	356,744	132,959	(10,018)	**479,685**
Unamortized (discount) premium, net	(758)	146	(51)	(663)	66	(25)	**(622)**
Total General Resolution Projects	854,099	58,680	(97,271)	815,508	136,819	(39,687)	**912,640**
Combined Cycle Project:							
Combined Cycle Project Revenue Bonds	416,895	–	(6,775)	410,120	–	(15,080)	**395,040**
Unamortized (discount) premium, net	11,044	–	(1,509)	9,535	–	(1,434)	**8,101**
Total Combined Cycle Project	427,939	–	(8,284)	419,655	–	(16,514)	**403,141**
Total bonds and subordinated debt	$3,771,861	$431,618	$(465,009)	$3,738,470	$450,310	$(214,847)	**$3,973,933**

Long-Term Debt

All Power Revenue bonds and General Power Revenue bonds except CABs bear interest at fixed rates. Certain subordinated and CC Project bonds have variable interest rates. At December 31, 2006 and 2005, MEAG Power's long-term debt consisted of the following (in thousands):

Project One	2006	2005
Power Revenue Bonds:		
Series L – CABs	$ 5,762	$ 9,410
Series Q – CABs	9,159	9,159
Series U – CABs	1,968	1,968
Series V	54,225	56,430
Series W	62,350	73,005
Series X	53,310	53,740
Series Y	229,565	230,295
Series Z	234,345	245,175
Taxable Series Two	6,655	7,360
Series BB	27,665	27,860
Series CC	29,530	52,425
Series DD	26,440	28,365
Series EE	38,125	38,125
Series FF	36,640	36,840
Total	815,739	870,157
Accretion of CABs	61,781	69,414
Unamortized (discount) premium, net	1,329	2,293
Total Power Revenue bonds outstanding	878,849	941,864
Subordinated Debt:		
Series 1985A – Variable rate	45,420	45,420
Series 1985B – Variable rate	72,900	72,900
Series 1994B – Variable rate	25,000	25,000
Series 1994C – Variable rate	25,000	25,000
Series 1994D – Variable rate	50,000	50,000
Series 1994E – Variable rate	100,000	100,000
Series 1996A – Fixed rate	13,255	80,590
Series 1997A – Fixed rate	122,385	124,085
Series 1997B – Fixed rate	49,305	53,040
Series 1998A – Fixed rate	78,345	80,020
Series 2000A – Taxable variable rate	79,200	79,200
Series 2000B – Taxable variable rate	79,200	79,200
Series 2000C – Variable rate	49,400	49,400
Series 2000D – Variable rate	49,400	49,400
Series 2000E – Variable rate	42,115	42,115
Series 2003A – Fixed rate	19,845	19,845
Series 2003B:		
Variable rate	123,975	123,975
Taxable fixed rate	4,525	4,525
Series 2005A-1 – Taxable fixed rate	76,750	76,750
Series 2005A-2 – CABs	6,627	6,627
Series 2005B – Variable rate	73,825	73,825
Series 2005C – Variable rate	73,825	73,825
Series 2005D – Fixed rate	51,065	51,065
Series 2005E – Fixed rate	28,845	28,845
Series 2005F – Taxable fixed rate	47,800	47,800
Series 2006A – CABs	75,626	–
Series A & B bond anticipation notes:		
Commercial paper	279,486	84,588
Taxable commercial paper	21,075	225
Total	1,764,194	1,547,265
Accretion of CABs	2,607	366
Unamortized (discount) premium, net	12,502	13,812
Total subordinated debt	1,779,303	1,561,443
Total bonds and subordinated debt	2,658,152	2,503,307
Current portion of long-term debt	(97,529)	(85,510)
Total Project One long-term debt	$2,560,623	$2,417,797

General Resolution Projects	2006	2005
General Power Revenue Bonds:		
Series 1989B – CABs	$ 16,818	$ 16,818
Series 1992A	45,575	45,810
Series 1992B	178,670	181,065
Series 1993A	6,055	6,055
Series 1993B	255	295
Series 1993C	33,115	42,840
Series 1993D	–	16,150
Series 2002A	107,025	107,025
Total	387,513	416,058
Accretion of CABs	39,478	35,684
Unamortized (discount) premium, net	6,586	7,685
Total General Power Revenue bonds outstanding	433,577	459,427
Subordinated Debt:		
Series 1985A – Variable rate	23,050	23,050
Series 1985B – Variable rate	47,000	47,000
Series 1985C – Variable rate	47,000	47,000
Series 1997A – Fixed rate	35,795	37,130
Series 1998A – Fixed rate	3,775	4,160
Series 2000A – Taxable variable rate	62,800	62,800
Series 2000B – Variable rate	24,100	24,100
Series 2005A – Taxable fixed rate	54,995	54,995
Series 2006A – CABs	97,539	–
Series A & B bond anticipation notes:		
Commercial paper	41,196	13,442
Taxable commercial paper	40,067	43,067
Total	477,317	356,744
Accretion of CABs	2,368	–
Unamortized (discount) premium, net	(622)	(663)
Total subordinated debt	479,063	356,081
Total bonds and subordinated debt	912,640	815,508
Current portion of long-term debt	(45,665)	(32,114)
Total General Resolution Projects long-term debt	$866,975	$783,394

Combined Cycle Project	2006	2005
Revenue Bonds:		
Series 2002 A – Fixed rate	$237,850	$247,000
Series 2002 B – Variable rate	79,250	82,765
Series 2003 A – Fixed rate	77,940	80,355
Total	395,040	410,120
Unamortized (discount) premium, net	8,101	9,535
Total bonds outstanding	403,141	419,655
Current portion of long-term debt	(15,680)	(15,080)
Total Combined Cycle Project long-term debt	$387,461	$404,575

Debt Service

At December 31, 2006, annual debt service costs to maturity of Power Revenue, General Power Revenue and CC Project bonds, including CABs, which are accreted through December 31, 2006, were as follows (in thousands):

	Project One		General Resolution Projects		Combined Cycle Project		
Year	Principal	Interest	Principal	Interest	Principal	Interest	Total
2007	$ 70,644	$ 24,903	$ 29,280	$ 11,167	$ 15,680	$ 2,682	$ 154,356
2008	69,850	46,418	37,945	21,586	16,440	17,530	209,769
2009	52,138	43,586	24,766	20,584	17,190	16,895	175,159
2010	76,750	41,047	28,450	20,227	17,615	16,220	200,309
2011	80,199	36,077	30,230	18,456	18,015	15,474	198,451
2012 – 2016	383,784	115,308	176,195	61,155	97,375	64,818	898,635
2017 – 2021	63,035	30,143	98,395	10,718	109,990	40,574	352,855
2022 – 2026	81,120	15,246	1,730	138	84,310	13,662	196,206
2027 – 2031	–	–	–	–	18,425	1,750	20,175
Total	$877,520	$352,728	$426,991	$164,031	$395,040	$189,605	$2,405,915

The stated coupon rates on Power Revenue, General Power Revenue and CC Project Bonds outstanding at December 31, 2006 ranged from 2.50% to 10.00% on the tax-exempt series and 3.34% to 4.79% on the taxable series during 2006.

At December 31, 2006, annual debt service costs to maturity of subordinated debt were as follows (in thousands):

	Project One		General Resolution Projects		
Year	Principal	Interest	Principal	Interest	Total
2007	$ 26,885	$ 18,840	$ 16,385	$ 3,193	$ 65,303
2008	41,535	73,028	6,444	15,380	136,387
2009	98,408	70,908	17,925	15,062	202,303
2010	44,319	64,518	21,249	14,167	144,253
2011	54,135	62,389	23,612	13,104	153,240
2012 – 2016	290,577	267,956	108,101	50,480	717,114
2017 – 2021	542,107	192,618	157,725	24,826	917,276
2022 – 2026	281,102	94,092	26,755	2,571	404,520
2027 – 2031	115,319	60,158	101,157	206	276,840
2032 – 2036	31,118	54,592	332	14	86,056
2037 – 2041	55,442	45,432	–	–	100,874
2042 – 2046	68,671	32,097	–	–	100,768
2047 – 2051	75,468	16,533	–	–	92,001
2052 – 2054	41,715	2,607	–	–	44,322
Total	$1,766,801	$1,055,768	$479,685	$139,003	$3,441,257

The interest rates on subordinated debt outstanding at December 31, 2006 ranged from 2.70% to 6.00% on the tax-exempt series and 3.49% to 6.40% on the taxable series during 2006. Interest on variable rate debt is based on various methods including auction-mode, money-market-mode, weekly-mode, LIBOR and the Federal funds rate, and is reset in time increments ranging from one day to 180 days.

Fair Value

The fair value of long-term debt is estimated based on the quoted market prices available for debt obligations with similar characteristics. At December 31, 2006 and 2005, the carrying amounts and estimated fair values of bonds outstanding and subordinated debt were as follows (in thousands):

	2006		2005	
	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
Project One	$2,644,321	$2,764,794	$2,487,202	$2,630,952
General Resolution Projects	906,676	940,493	808,486	849,756
Combined Cycle Project	395,040	412,142	410,120	424,818
Total	$3,946,037	$4,117,429	$3,705,808	$3,905,526

(N) Business Unit Obligations to the Electric Projects

MEAG Power offers specialized services to the Electric Utility Participants and other communities through its Business Units. Membership in the Business Units is by separate contracts between MEAG Power and the participating communities. Each Business Unit has a governing body to set policy upon authority delegated by the Board.

As of December 31, 2006 and 2005, the Electric Projects had receivables related to advances to the Distribution Services Business Unit (Distribution) of $300,000 and $100,000, respectively. These advances are supported by the Distribution participants (certain Electric Utility Participants which elect to participate as well as non-Electric Utility Participants) and are in addition to the power sales contract debt obligations of the Electric Utility Participants described in Note 2 (M), "Long-Term Debt – Subordinated Debt and Other Debt."

(O) Investment in Alliance

Investment in Alliance reflects MEAG Power's investment in The Energy Authority (TEA), a governmental nonprofit power marketing corporation comprised of six Members: MEAG Power, JEA (formerly known as the Jacksonville Electric Authority), South Carolina Public Service Authority, Nebraska Public Power District, Gainesville (Florida) Regional Utilities, and City Utilities of Springfield, Missouri. TEA provides energy products and resource management services to Members and non-members and allocates transaction savings and operating expenses to Members pursuant to Settlement Procedures under the Operating Agreement.

In July 2006, TEA completed an acquisition of Power Resource Managers, LLP, a public power marketing organization that operated in the western United States. As a result, TEA has access to approximately 25,000 megawatts (MW) of its Members' and non-members' generation resources.

In the accompanying consolidated financial statements, for the years ended December 31, 2006 and 2005, an aggregate of $5.8 million and $1.6 million, respectively, of net revenues received from TEA were netted against related fuel, transmission and operating expenses, based on Board-approved methodology for the application of off-system sales revenues. Remaining net revenues of TEA were allocated as sales margins as follows (in thousands):

	2006	2005
Project One	$ 7,246	$10,965
General Resolution Projects	9,296	11,710
Combined Cycle Project	5,244	11,659
Total	$21,786	$34,334

In addition to $2.7 million of contributed capital, MEAG Power has committed an additional $56.9 million through a combination of guarantees. TEA evaluates its credit needs periodically and requests Members to adjust their guarantees accordingly. The guarantee agreements are intended to provide credit support for TEA when entering into transactions on behalf of its Members. Such guarantees would arise if TEA failed to deliver energy, capacity or natural gas as required by contract with a counterparty, or if TEA failed to make payment for purchases of such commodities. If guaranty payments are required, MEAG Power has rights with other Members that such payments would be apportioned based on certain criteria.

The guarantees generally have indefinite terms; however, MEAG Power can terminate its guaranty obligations by providing notice to counterparties and others, as required by the agreements. Such termination would not pertain to any transactions TEA entered into prior to notice being given.

TEA's accounting records are maintained in conformity with the pronouncements of the GASB. In accordance with GASB Statement No. 20, TEA has elected to adopt all applicable FASB statements and interpretations except those that conflict with or contradict GASB pronouncements.

The table below contains the condensed financial information for TEA for the years ended or as of December 31, 2006 and 2005 (in thousands):

	2006	2005
Revenues	$1,587,238	$1,509,836
Gross Margin	$ 159,612	$ 184,479
Increase in Net Assets	$ 134,548	$ 164,980
Member Distributions	$ 129,813	$ 165,412
Current assets	$ 131,467	$ 163,902
Restricted and non-current assets	9,686	6,714
Total Assets	$ 141,153	$ 170,616
Current liabilities	$ 105,154	$ 140,414
Long-term liabilities	2,961	1,899
Net assets	33,038	28,303
Total Liabilities and Net Assets	$ 141,153	$ 170,616

(P) Retirement Plan

MEAG Power is the sponsor and administrator of a single employer non-contributory retirement plan which provides a defined benefit to employees based on years of service and average earnings. The Municipal Electric Authority of Georgia Retirement Plan (the Plan) was established by the Board, and the Plan benefits can only be amended or terminated by Board action. The Plan is funded through a tax-exempt trust fund qualified under sections of the Internal Revenue Code. MEAG Power uses an independent actuarial firm to calculate the Plan's annual required contribution (ARC), which is approved by the Board, fully funded and included as part of the annual system budget. In accordance with disclosure requirements of GASB Statement No. 27, "Accounting for Pensions by State and Local Governmental Employers," additional Plan information is presented below.

For the years ended December 31, 2006, 2005 and 2004, MEAG Power's annual pension cost of $1.3 million, $1.2 million and $1.1 million, respectively, equaled the ARC, which was determined based on actuarial valuations as of January 1 of each year, using the Aggregate Actuarial Cost Method. Under this method: (a) the extent to which the present value of the benefits exceeds the assets is funded on a level percent of pay basis over the average future working lifetime for all participants on an open basis, (b) unfunded actuarial liabilities are not identified or separately amortized, and (c) gains and losses are spread over the future normal costs of the Plan.

Significant actuarial assumptions include: (a) 8.0% investment rate of return, (b) projected annual salary increases of 5.0%, and (c) life expectancy based on the 1994 Group Annuity Mortality Table. The actuarial value of the assets was determined using a method which smoothes the impact of short-term market value volatility over a four-year period.

Certain other financial information concerning the Plan can be obtained by writing to: MEAG Power Retirement Plan, 1470 Riveredge Parkway NW, Atlanta, Georgia 30328-4686.

(Q) Commitments and Contingencies

Nuclear Insurance

Under the Price-Anderson Act, which was renewed as part of the Energy Policy Act of 2005, MEAG Power maintains agreements of indemnity with the NRC that, together with private insurance, cover third-party liability arising from any nuclear incident occurring at the nuclear power plants in which MEAG Power has an ownership interest. The Price-Anderson Act provides for the payment of funds up to a maximum of $10.8 billion for public liability claims that could arise from a single nuclear incident. Each nuclear plant is insured against this liability to a maximum of $300 million by American Nuclear Insurers (ANI). The remaining coverage is provided by a mandatory program of deferred premiums that would be assessed, after a nuclear incident, against all owners of nuclear reactors. The owners of a nuclear power plant could be assessed up to $101 million per incident for each licensed reactor they operate, but not more than an aggregate of $15 million per reactor, per incident would be required to be paid in a calendar year.

GPC, on behalf of all the co-owners of the nuclear plants, is a member of the Nuclear Electric Insurance Limited (NEIL), a mutual insurer established to provide property damage insurance for members' nuclear generating facilities. MEAG Power is also a member of NEIL in its capacity to provide insurance to cover members' costs of replacement power and other costs, which might be incurred during a prolonged accidental outage. Terrorist acts against commercial nuclear power stations are covered under the ANI and NEIL insurance limited to an industry aggregate for all terrorist acts that are not certified pursuant to the Terrorism Risk Insurance Act of 2002, which was renewed in 2005. The NEIL aggregate limitation over a 12-month period is $3.2 billion plus any amounts available through reinsurance or indemnity from an outside source. The non-certified ANI nuclear liability cap is a $300 million shared industry aggregate during the normal ANI policy period.

Under various liability, property and replacement power insurance programs covering MEAG Power's ownership interests in nuclear generating plants, including the Price-Anderson Act, MEAG Power could be assessed deferred premiums to a maximum of $29.2 million for each incident in any one year.

Fuel

Project One and the General Resolution Projects, through GPC, are obligated by various long-term commitments for the procurement of fossil and nuclear fuel to supply a portion of the fuel requirements of its generating plants. Fuel commitments for the years beginning 2007 total approximately $257.4 million for coal through 2011 and $133.3 million for nuclear through 2014. These commitments are calculated based on MEAG Power's ownership percentage of jointly owned generation facilities per operating agreements with GPC, as discussed in Note 2 (J), "Generation and Transmission Facilities – Jointly Owned Generation Facilities." Also discussed within that Note is information regarding sales by MEAG Power to GPC of a portion of the output of each generating unit at Plant Vogtle, which have the effect of reducing MEAG Power's gross commitments for nuclear fuel. Railcar lease commitments through mid-2015 total $4.3 million.

MEAG Power has entered into a long-term gas purchase agreement with Main Street Natural Gas, Inc. (Main Street). Under the terms of the agreement, MEAG Power will purchase, on a "take and pay" basis, for a term of 15 years commencing on February 1, 2007, an average of approximately 2,200 million British thermal units per day of natural gas from Main Street. Such purchases are structured to match the usage in the peak operating season and are expected to equal approximately 25% – 30% of MEAG Power's natural gas requirements for its native load. The price paid by MEAG Power will be based on a discount from a natural gas index. The volatility of the natural gas market precludes MEAG Power from estimating a cost for the 15 year period; however, the commitment is expected to be significant. As described in Note 2 (K) "Derivative Financial Instruments," MEAG Power's natural gas hedges for the CC Project had a fair market value of $(1.0) million as of December 31, 2006 and were not significant as of December 31, 2005. Natural gas pipeline commitments through early 2019 total $47.0 million. Additional commitments for fuel supply will be required in the future.

Environmental Regulation

Plants Hatch, Vogtle, Wansley and Scherer and the CC Project are subject to Federal, State, and local air and water quality requirements. The EPA and the Environmental Protection Division (EPD) of the Georgia Department of Natural Resources have primary responsibility for developing and enforcing the requirements pursuant to statutes such as the Federal Clean Air Act (CAA).

To achieve compliance with newly effective requirements, MEAG Power has invested approximately $86.5 million through 2006 in plant environmental enhancements, including a switch to lower sulfur fuel at certain units and installing technology to reduce nitrogen oxides emissions at other units. To control overall compliance costs, MEAG Power participates in emissions-averaging and allowance trading plans. Compliance going forward will require significant additional capital investment by MEAG Power.

During 2005, the EPA issued three major final rules affecting power plants:

- The Clean Air Interstate Rule (CAIR) requires annual sulfur dioxide emissions reductions in two phases (beginning in 2010 and 2015), and annual nitrogen oxides emissions reductions in two phases (beginning in 2009 and 2015). CAIR affects 28 states, including Georgia and the District of Columbia, whose emissions affect attainment and maintenance of ambient air quality standards for ozone and fine particulate matter in downwind states.
- The Clean Air Mercury Rule (CAMR) requires annual mercury emissions reductions by coal-fired units in all states in two phases (beginning in 2010 and 2018).
- Best Available Retrofit Technology (BART) rules address regional haze requirements under the CAA. These rules require certain large stationary emissions sources, including Plants Scherer and Wansley, to install BART as a component of a longer-term requirement to reduce haze in national parks and wilderness areas to natural conditions.

The State must revise its State Implementation Plan (SIP) to implement Federal CAIR and CAMR requirements and federal regional haze requirements including the BART rule by various dates in 2007. The State must also revise its SIP to implement Federal requirements to attain the National Ambient Air Quality Standards (NAAQS) for fine particulate matter and for ozone by dates to be determined.

State regulations have been proposed to implement CAIR and CAMR requirements, along with requirements towards achieving BART, regional haze, ozone, and fine particulate matter requirements as they relate to MEAG Power's coal capacity. MEAG Power anticipates that to comply with the State's CAIR, CAMR, regional haze, ozone, and fine particulate matter requirements, the total capital investment for necessary equipment additions for the years 2007 through 2014 will be approximately $406.0 million.

In October 2006, the EPA revised the NAAQS for fine particulate matter, significantly tightening the 24-hour standard. The EPA has not yet established implementation plan requirements or an implementation schedule for this revision. Also, the EPA is under a court-approved rulemaking schedule to complete a review and issue an updated ambient ozone standard as necessary by February 2008. A January 2007 EPA final Staff Paper concludes that the current eight-hour standard is not adequate to protect public health and recommends a range of levels as much as 25% less. The exact financial and operational impact of the revised fine particulate matter and ozone standards on MEAG Power cannot be determined at this time.

Various bills have been introduced in the U.S. Senate and House of Representatives to address concerns regarding global climate change. Some of these bills would directly or indirectly regulate carbon dioxide and other greenhouse gas emissions from power plants and other emission sources. Since no such bill has been enacted to date, no exact financial or operational impact on MEAG Power of global climate legislation can be determined at this time.

In April 2007, the U.S. Supreme Court held that the EPA has the statutory authority under the CAA to regulate emissions of greenhouse gases from new motor vehicles. In the 5-4 decision, the Supreme Court stated that greenhouse gases fit well within the CAA's broad definition of "air pollutant." The Supreme Court further stated that the EPA did not offer reasoned explanation for its refusal to decide whether greenhouse gases cause or contribute to climate change, and that this lack of reasoned explanation was therefore "arbitrary, capricious, … or otherwise not in accordance with law." The Court remanded the case back to the District of Columbia Court of Appeals. The exact financial and operational impact of the Supreme Court's decision on MEAG Power cannot be determined at this time.

Legislative and Regulatory Issues

In recent years, a variety of proposals to restructure the electric industry have been introduced at the Federal level and in certain state jurisdictions. Restructuring initiatives have the potential for materially affecting revenues, operations and financial results and condition. The nature of these effects will depend on the content of any legislative or regulatory actions that may be applicable to Project One, the General Resolution Projects, the CC Project, or Electric Utility Participants and cannot be identified with any degree of certainty at the current time.

MEAG Power is not a FERC-jurisdictional utility; however, it is affected by certain FERC rulemakings, including Open Access Transmission Tariffs (OATT) and Standards of Conduct for Transmission Providers. In February 2007, FERC issued Order 890 amending the regulations and the pro forma OATT adopted in Orders 888 and 889. Order 890's requirements include: (i) greater consistency and transparency in available transmission capacity calculations; (ii) open, coordinated and transparent planning; (iii) reforms of energy imbalance penalties; (iv) reform of rollover rights policy; (v) clarification of tariff ambiguities; and (vi) increased transparency and customer access to information.

FERC reaffirmed many of the core elements of Order 888's pro forma OATT in Order 890 including: (i) comparability; (ii) continuance of the protection of native load customer's transmission service rights; and (iii) FERC's current approach to reciprocity for nonjurisdictional transmission owners, which include MEAG Power, was retained and broadened such that, if a Regional Transmission Organization (RTO) or Independent System Operator (ISO) is the transmission provider, reciprocity is owed to all members of the RTO or ISO.

Section 211A of the Federal Power Act, which was added by the 2005 Energy Policy Act, authorized, but did not require, FERC to order non-public utilities (or "unregulated transmitting utilities," which include MEAG Power) to provide transmission services. In Order 890, FERC elected to apply Section 211A's provisions on a case-by-case basis. MEAG Power believes that its current OATT satisfies the "reciprocity" requirements; however, MEAG Power plans some amendments to better conform its OATT to Order 890. MEAG Power also has a native load service obligation that is afforded protections in its existing OATT. Such protections will be retained in any amendments. MEAG Power has participated in a joint transmission planning process for decades and will continue to do so under Order 890.

In March 2007, FERC issued Order 693 entitled "Mandatory Reliability Standards for the Bulk-Power System." In this order, FERC approved 83 of 107 proposed reliability standards developed by the North American Electric Reliability Corporation (NERC), which FERC has certified as the Electric Reliability Organization responsible for developing and enforcing mandatory reliability standards. The mandatory standards are effective June 4, 2007.

In August 2006, the Southeast Electric Reliability Council conducted an audit of MEAG Power's level of compliance with certain NERC standards. Based in part on the audit results, MEAG Power believes it generally is in compliance with the NERC reliability standards approved in Order 693. Compliance with these standards is not expected to have a material effect on MEAG Power's costs.

MEAG Power's ownership in TEA, as discussed in Note 2(O), "Investment in Alliance," satisfies a standard of conduct requirement, which has the effect of requiring MEAG Power to establish a wholesale marketing organization separate and apart from its operating group that controls operations of its generation and transmission facilities.

MEAG Power continues to be actively involved in deliberations concerning restructuring at the Federal and State level. No Federal legislation addressing comprehensive retail electric competition had been passed as of December 31, 2006. No initiative for electric industry restructuring in Georgia commenced in the Georgia General Assembly during the 2007 session, nor is any such effort anticipated in the near term.

In November 2006, Georgia voters approved an amendment to the Constitution of the State that repeals a previous amendment to the Georgia Constitution that expressly authorized the transfer of property acquired by eminent domain to private enterprises for private uses. The approval of this new amendment, which has the effect of requiring approval by an elected governing authority for any redevelopment project where eminent domain is applicable, is not anticipated to have an appreciable impact on MEAG Power's operations.

Mutual Aid Agreement

MEAG Power has entered into a mutual aid agreement with seven Florida utilities for provision of replacement power during an extended outage of a defined baseload generating unit. In the event of an outage of Scherer Units 1 or 2 that extends beyond 60 days, MEAG Power will receive 100 MW at a price based upon a fixed heat rate and a published gas price index. If a counterparty had an extended outage, MEAG Power would provide between 8 MW and 18 MW for a maximum of 305 days. This agreement expires in October 2007.

Litigation

In 2002, the Sierra Club and other plaintiffs filed a civil complaint in U.S. District Court against GPC. The complaint alleged violations of the CAA at Plant Wansley including several counts involving the coal generation units of which MEAG Power is a joint owner. In January 2007, the District Court ruled in favor of GPC, granting GPC's motion for summary judgment on the claims relating to the coal generation units. Therefore, this matter is concluded with no financial statement impact to MEAG Power.

In 2001, MEAG Power was named along with various other electric utilities as a defendant in a lawsuit brought by certain property owners in Georgia. The lawsuit challenged whether the standard easement agreement between an electric utility company and a property owner allows for the installation of fiber-optic telecommunication lines. After various court rulings and related appeals, the plaintiffs filed a Petition for Certiorari to the Georgia Supreme Court, which was denied in May 2006. In October 2006, the trial court granted summary judgment in favor of the defendants. No appeal was filed from the October 2006 Order and the case is concluded.

MEAG Power has contested certain amounts of ad valorem taxes pertaining to Plant Scherer assessed by Monroe County, Georgia for the years 2003 through 2006. As indicated in Note 2 (J), "Generation and Transmission Facilities – Jointly Owned Generation Facilities," MEAG Power has joint ownership interests in Plant Scherer Units 1 and 2. MEAG Power has filed the appropriate appeals and has paid the amount of uncontested taxes assessed for all years. If such appeals are not successful, MEAG Power could be subject to total additional taxes through December 31, 2006 of up to $4.8 million, plus penalties and interest. In April 2007, the Georgia Court of Appeals ruled, in a related case, that Monroe County did not have the authority to change valuations assessed by the State, and Monroe County appealed to the Georgia Supreme Court. No assessment can be made on the likelihood of a particular outcome.

3. Telecommunications Project and the Business Units

As described in Notes 4 – 6, "Telecommunications Project," "Distribution Services Business Unit" and "Marketing Services Business Unit," respectively, MEAG Power offers specialized services to the Electric Utility Participants through Telecom and the Business Units. In the case of the Business Units, such services are also offered to non-Electric Utility Participants. Condensed Balance Sheets and Statements of Net Revenues and Cash Flows of Telecom and the Business Units as of and for the years ended December 31, 2006 and 2005 are presented as supplementary information as follows:

CONDENSED BALANCE SHEET

	December 31, 2006				December 31, 2005			
(in thousands)	Telecom	Distribution	Marketing	Telecom Project and Business Units	Telecom	Distribution	Marketing	Telecom Project and Business Units
ASSETS:								
Property, plant and equipment – net	$14,242	$ 333	$ 3	$14,578	$15,653	$ 364	$ 10	$16,027
Current assets	2,657	803	1,038	4,498	3,208	703	858	4,769
Deferred debits	8,523	–	–	8,523	8,038	–	–	8,038
Total Assets	$25,422	$1,136	$1,041	$27,599	$26,899	$1,067	$868	$28,834
LIABILITIES:								
Long-term debt	$24,920	$ –	$ –	$24,920	$27,135	$ –	$ –	$27,135
Other non-current liabilities	(1,143)	606	351	(186)	(1,040)	725	237	(78)
Current liabilities	1,645	530	690	2,865	804	342	631	1,777
Total Liabilities	$25,422	$1,136	$1,041	$27,599	$26,899	$1,067	$868	$28,834

CONDENSED STATEMENT OF NET REVENUES

For the Years Ended:	December 31, 2006				December 31, 2005			
(in thousands)	Telecom	Distribution	Marketing	Telecom Project and Business Units	Telecom	Distribution	Marketing	Telecom Project and Business Units
Revenues:								
Participant	$2,171	$2,792	$1,096	$6,059	$ 1,551	$2,563	$1,022	$5,136
Other	91	82	–	173	92	86	–	178
Total revenues	2,262	2,874	1,096	6,232	1,643	2,649	1,022	5,314
Operating expenses	1,919	3,010	1,113	6,042	2,263	2,686	1,035	5,984
Net operating revenues (loss)	343	(136)	(17)	190	(620)	(37)	(13)	(670)
Net interest expense (income)	909	(17)	(32)	860	440	(12)	(19)	409
Decrease (increase) in net costs to be recovered from future billings to Participants	(566)	(119)	15	(670)	(1,060)	(25)	6	(1,079)
Total other expenses (income), net	343	(136)	(17)	190	(620)	(37)	(13)	(670)
Net Revenues	$ –	$ –	$ –	$ –	$ –	$ –	$ –	$ –

CONDENSED STATEMENT OF CASH FLOWS

For the Years Ended:	December 31, 2006				December 31, 2005			
(in thousands)	Telecom	Distribution	Marketing	Telecom Project and Business Units	Telecom	Distribution	Marketing	Telecom Project and Business Units
Net cash provided by (used in) operating activities	$ 1,715	$201	$ 36	$ 1,952	$1,540	$ (74)	$(268)	$ 1,198
Net cash provided by (used in) investing activities	(1)	21	131	151	1,406	14	53	1,473
Net cash used in capital and related financing activities	(2,416)	(99)	–	(2,515)	(3,426)	(122)	(5)	(3,553)
Increase (decrease) in cash and cash equivalents	(702)	123	167	(412)	(480)	(182)	(220)	(882)
Cash and cash equivalents at beginning of year	2,971	437	653	4,061	3,451	619	873	4,943
Cash and cash equivalents at end of year	2,269	560	820	3,649	2,971	437	653	4,061
Other investment securities at end of year	95	–	–	95	7	–	–	7
Special funds at end of year	$ 2,364	$560	$820	$ 3,744	$2,978	$ 437	$ 653	$ 4,068

4. Telecommunications Project

(A) General Matters

As of December 31, 2006 and 2005, 32 of the 49 MEAG Power Electric Utility Participants (the "participants" for purposes of this Note) had contracts with Telecom, which commenced operations in 1997, to: (1) provide advanced internal telecommunications services to MEAG Power, (2) enhance the education proficiencies of the participants through the deployment of state-of-the-art telecommunications and (3) foster economic growth and development of the participants throughout Georgia by providing competitive access services in conjunction with local municipal fiber-optic networks.

(B) Master Agreement

MEAG Power has a Master Agreement with Georgia Public Web (GPW) under which all operational control of Telecom's fixed assets was transferred to GPW. GPW is a Georgia nonprofit corporation formed by the 32 participants. The Master Agreement also entitles GPW to derive revenue from the Telecom assets. In exchange for control of these assets, GPW assumed certain ongoing obligations of Telecom for the operation and maintenance of the Telecom assets. In addition, GPW pays Project One a monthly payment for use of rights-of-way.

(C) Revenues and Billings to Participants

Telecom's revenues are derived from contractual cost-recovery billings to participants, primarily related to costs of debt service and certain operating costs not assumed by GPW. Revenues are recognized as corresponding costs are incurred.

Billings to participants are designed to recover certain costs, as defined by the Telecom contracts, which principally include operating and scheduled debt service costs. In accordance with the Telecom contracts, a true-up of costs is performed annually. During 2006 and 2005, Telecom revenues exceeded expenses by approximately $365,000 and $355,000, respectively. These amounts are included in the Balance Sheet in current liabilities. Refunds to participants for 2006 will be processed in the second quarter of 2007. Timing differences between amounts billed and expenses determined in accordance with GAAP are charged or credited to net costs to be recovered from future billings to participants.

At December 31, 2006 and 2005, net costs to be recovered from future billings to participants consisted of the following (in thousands):

	2006	2005
Differences between amounts billed and expenses determined in accordance with GAAP:		
Depreciation expense of telecommunications plant	**$18,308**	$16,602
Billings to participants for debt principal	**(6,755)**	(5,740)
Other deferred costs	**290**	415
Billings to participants for telecommunications construction costs	**(3,715)**	(3,715)
Net costs to be recovered from future billings to participants	**8,128**	7,562
Other deferred debits	**395**	476
Total deferred debits	**$ 8,523**	$ 8,038

(D) Property, Plant and Equipment

As of December 31, 2006 and 2005, the Telecom fiber-optic network totaled 1,571 operational miles. Telecom has entered into agreements that convey the rights to the use of certain fiber-optic cable owned by others. Telecom's costs under these agreements have been recorded as capital lease assets.

Telecommunications property, plant and equipment activity for the years ended December 31, 2006 and 2005 was (in thousands):

Property, Plant and Equipment	As of December 31, 2004	Increases	Decreases	As of December 31, 2005	Increases	Decreases	**As of December 31, 2006**
Fiber-optic cable – owned	$10,557	$ 14	$ –	$10,571	$ –	$ –	**$10,571**
Fiber-optic cable – capital leases	6,397	–	–	6,397	–	–	**6,397**
Electronic systems	13,123	170	–	13,293	–	–	**13,293**
Other	1,057	(15)	–	1,042	17	–	**1,059**
Telecommunications plant in service	31,134	169	–	31,303	17	–	**31,320**
Less accumulated depreciation	(14,341)	(1,893)	228	(16,006)	(1,624)	–	**(17,630)**
Telecommunications depreciable plant, net	16,793	(1,724)	228	15,297	(1,607)	–	**13,690**
Construction work in progress	334	22	–	356	196	–	**552**
Total property, plant and equipment – net	$17,127	$(1,702)	$228	$15,653	$(1,411)	$ –	**$14,242**

Depreciation of telecommunications plant, which consists mainly of fiber-optic cable and network systems, is computed using the straight-line method over the expected life of the plant. The composite depreciation rates for both 2006 and 2005 were as follows:

Fiber-optic cable	4.0%
Electronic systems	20.0%
Other	4.0% – 33.3%

(E) Special Funds

Pursuant to the Telecommunications Bond Resolution (the Resolution), certain special funds listed below were established during 2003 in conjunction with the placement of Telecom Bonds as described below in "Long-Term Debt." Based on the requirements of the Resolution, special funds are considered restricted assets as defined by GASB Statement 34. The non-liened funds are not pledged to the bondholders. Special fund balances at December 31, 2006 and 2005 were as follows (in thousands):

Special funds	2006	2005
Construction fund:		
Liened	$ 394	$ 664
Non-liened	18	75
Revenue and operating fund:		
Liened	620	918
Non-liened	103	75
Debt service fund	1,229	1,246
Total Special funds	$2,364	$2,978

The Investment Policy also pertains to Telecom's investments, as do the various risk aspects discussed in Note 2 (L), "Special Funds and Supplemental Power Account." All of Telecom's investments are recorded and carried at fair value based on quoted market prices. Unrealized gains/losses on investment securities are reported in net change in the fair value of financial instruments. As of December 31, 2006:

- All of Telecom's investments in U.S. Government agencies were rated AAA by S&P, with investments in money market mutual funds rated AAAm by S&P and Aaa by Moody's.
- All of Telecom's investments mature in less than one year and were comprised of the following types of financial instruments (in thousands):

Investment Type	Fair Value
U.S. Government agency securities	$ 767
Money market mutual funds	1,559
Cash	38
Total	$2,364

Investments with one issuer that comprised 5% or more of Telecom's portfolio (excluding those issued or explicitly guaranteed by the U.S. Government, as well as mutual funds) as of December 31, 2006 were (in thousands):

Issuer	Fair Value	Percentage of Portfolio
Federal Home Loan Mortgage Corporation	$597	25.3%
Federal National Mortgage Association	$170	7.2%

(F) Long-Term Debt

As of December 31, 2006, MEAG Power had validated by court judgment $35 million of Telecommunications Project bonds for the purpose of acquisition and construction of the Telecommunications Project. Reference to "court judgment" indicates that MEAG Power is authorized to issue such bonds up to the validated amount. Telecom was initially financed through advances totaling $31.3 million under the Power Revenue Bond Resolution (Project One). The borrowings were used primarily for construction of network facilities and were repaid pursuant to the placement of $32.8 million of auction rate Telecommunications Project Revenue Bonds (the Telecom Bonds) in April 2003. In addition to repaying amounts owed to Project One, funds from this financing were also used to pay previously deferred costs of the Telecom project as well as the establishment of working capital funds.

The Telecom Bonds were issued to provide permanent financing for Telecom. Amounts payable by the participants for debt service under the Telecom contracts are on parity with amounts payable by the participants under their applicable power sales contracts with MEAG Power.

Changes in long-term debt during the years ended December 31, 2006 and 2005 are shown below (in thousands):

Long-Term Debt	Balance December 31, 2004	Additions	Principal Payments	Balance December 31, 2005	Additions	Principal Payments	**Balance December 31, 2006**	**Current Portion**
Revenue Bonds,								
Taxable Series 2003	$29,165	$ –	$2,030	$27,135	$ –	$1,200	**$25,935**	**$1,015**

At December 31, 2006, annual debt service costs to maturity of the Telecom Bonds are shown below (in thousands):

Year	Principal	Interest	Total
2007	$ 1,015	$ 89	$ 1,104
2008	2,315	1,102	3,417
2009	2,405	1,069	3,474
2010	2,460	888	3,348
2011	2,650	780	3,430
2012 – 2016	15,090	2,059	17,149
Total	$25,935	$5,987	$31,922

The Telecom Bonds were issued as variable rate debt. In conjunction with the bond placement, MEAG Power entered into an interest rate swap agreement with a counterparty which synthetically fixed the rate. This swap was for the same amount ($32.8 million) and through the same maturity (2015) as the Telecom Bonds. The mark-to-market adjustment on the swap agreement is included in other non-current liabilities on the Balance Sheet. It is adjusted monthly with the associated gain or loss recognized as a change in fair value of financial instruments and included in net costs to be recovered from future billings to participants. If the instrument is terminated before the end of the agreement's term, any gain or loss would be amortized over a period consistent with the underlying liability. MEAG Power pays a rate of 4.09% and receives LIBOR under the swap agreement.

5. Distribution Services Business Unit

(A) General Matters

The purpose of Distribution, which commenced operations in 1999, is to provide services to local government electric distribution systems that improve electric utility infrastructure, reduce costs through consolidation of resources and enhance service standards. These basic and premium services are provided to the Electric Utility Participants and non-Electric Utility Participants, both groups referred to as "participants" for purposes of this Note.

The basic services include technical support, joint purchasing, training and safety, and meter testing. These services are functionally unbundled so that each can be offered and provided independently of the other basic services. Premium services are offered primarily through the use of consultants and contractors, including tree trimming, pole inspection and padmount inspection services. Distribution establishes the parameters for joint contracting and functions primarily as the facilitator for such services. Similar to the basic services, each of the premium services can be offered and provided independently of the other premium services.

Distribution provided services to 50 participants in both 2006 and 2005. The contracts for these services are for an initial term of three years and are renewable annually thereafter. Distribution was established and is financed through borrowings from Project One.

(B) Revenues and Billings to Participants

Distribution revenues are primarily derived from billings to participants designed to recover the total cost of services provided. Revenues applicable to such billings are recognized as corresponding costs are incurred. Timing differences between amounts billed and expenses determined in accordance with GAAP are charged or credited to billings in excess of costs. In accordance with the Distribution contracts, a true-up of costs for each service is performed annually. Distribution collected revenues of approximately $66,000 and $14,000 in excess of costs during 2006 and 2005, respectively. Approximately $54,000 and $11,000 of the over collection amount that is to be refunded is included on the Balance Sheet in current liabilities as of December 31, 2006 and 2005, respectively. The remaining $12,000 and $3,000 as of December 31, 2006 and 2005, respectively, was reserved for future use and is reflected on the Balance Sheet in other non-current liabilities. At December 31, 2006 and 2005, billings in excess of costs consisted of the following (in thousands):

	2006	2005
Reserves applicable to future capital projects	$276	$340
Other reserves	330	385
Billings in excess of costs	$606	$725

(C) Property, Plant and Equipment

Property, plant and equipment activity for the years ended December 31, 2006 and 2005 is shown below (in thousands). Depreciation is computed on a straight-line basis over a three-year period.

Property, Plant and Equipment	Balance December 31, 2004	Increases	Decreases	Balance December 31, 2005	Increases	Decreases	**Balance December 31, 2006**
Computer, transportation and maintenance equipment	$ 518	$120	$ –	$ 638	$ 95	$ –	**$ 733**
Less accumulated depreciation	(178)	(96)	–	(274)	(126)	–	**(400)**
Total property, plant and equipment – net	$ 340	$ 24	$ –	$ 364	$ (31)	$ –	**$ 333**

(D) Advances from Project One

Included in other non-current liabilities is an obligation owed by Distribution to Project One. The interest rate on the borrowings outstanding at December 31, 2006 ranged from 3.43% to 5.84% during 2006. Changes in advances outstanding at December 31, 2006 and 2005 were (in thousands):

	Balance December 31, 2004	Additions	Principal Payments	Balance December 31, 2005	Additions	Principal Payments	**Balance December 31, 2006**
Advances from Project One	$170	$ –	$70	$100	$200	$ –	**$300**

At December 31, 2006, annual debt service costs of advances outstanding were as follows (in thousands):

Year	Principal	Interest	Total
2007	$219	$15	$234
2008	19	3	22
2009	20	2	22
2010	21	2	23
2011	21	1	22
Total	$300	$23	$323

6. Marketing Services Business Unit

The Marketing Services Business Unit (Marketing) commenced operations in 2000. The purpose of Marketing is to provide services to assist the Electric Utility Participants and non-Electric Utility Participants (both groups referred to as "participants" for purposes of this Note) in adding new customers, retaining existing customers and building partnerships that add value to that customer relationship. The services include pricing and sales support, energy services and major accounts. Additional services are offered through Hometown Connections, a subsidiary of the American Public Power Association.

In 2006 and 2005, Marketing provided services to 47 participants. Billings to the Electric Projects for services accounted for approximately 10% and 12% of Marketing's revenue for 2006 and 2005, respectively. As of December 31, 2006 and 2005, two participants comprised 21% and 18% of accounts receivable, respectively.

Marketing revenues are primarily derived from billings to participants designed to recover the total cost of services provided. Revenues applicable to such billings are recognized as corresponding costs are incurred. In accordance with the Marketing contracts, a true-up of costs for each service is performed annually. During 2006 and 2005, Marketing billed approximately $541,000 and $490,000, respectively, in excess of costs. Refunds to participants for 2006 will be processed in the second quarter of 2007. In both years, a corresponding liability was included in current liabilities.

Report of Independent Auditors

To the Board of Directors
Municipal Electric Authority of Georgia:

In our opinion, the accompanying balance sheets and the related statements of net revenues and of cash flows present fairly, in all material respects, the respective financial position of the Municipal Electric Authority of Georgia's Project One major fund (Power Revenue Bond Resolution Project), the General Resolution Projects major fund (General Power Revenue Bond Resolution Projects Two, Three and Four), the Combined Cycle Project major fund and the Trust Funds major fund (Municipal Competitive Trust and Deferred Lease Financing Trust) and the aggregate nonmajor funds (Telecommunications Project, Distribution Services and Marketing Services) (collectively, "MEAG Power") at December 31, 2006 and 2005, and the respective changes in financial position and cash flows for the years then ended in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of MEAG Power's management. Our responsibility is to express opinions on these financial statements based on our audits. We conducted our audits of these statements in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes 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 opinions.

The management's discussion and analysis on pages 14 through 23 is not a required part of the basic financial statements but is supplementary information required by accounting principles generally accepted in the United States of America. We have applied certain limited procedures, which consisted principally of inquiries of management regarding the methods of measurement and presentation of the required supplementary information. However, we did not audit the information and express no opinion on it.

PricewaterhouseCoopers LLP

May 14, 2007
Atlanta, Georgia

Corporate Information

Corporate Office
1470 Riveredge Parkway, NW
Atlanta, GA 30328-4686
1-800-333-MEAG
www.meagpower.org

General Counsel
Peter M. Degnan
Alston & Bird LLP
Atlanta, GA

Bond Counsel
Orrick, Herrington & Sutcliffe LLP
New York, NY

Financial Advisor
Public Financial Management, Inc.
Philadelphia, PA

Trustee
The Bank of New York
New York, NY

Consulting Engineer
R.W. Beck, Inc.
Orlando, FL

Independent Auditors
PricewaterhouseCoopers LLP
Atlanta, GA

Our Participants and employees merit the gratitude of MEAG Power as it is their cooperation, loyalty and dedication that keep us in the forefront of public power performance.

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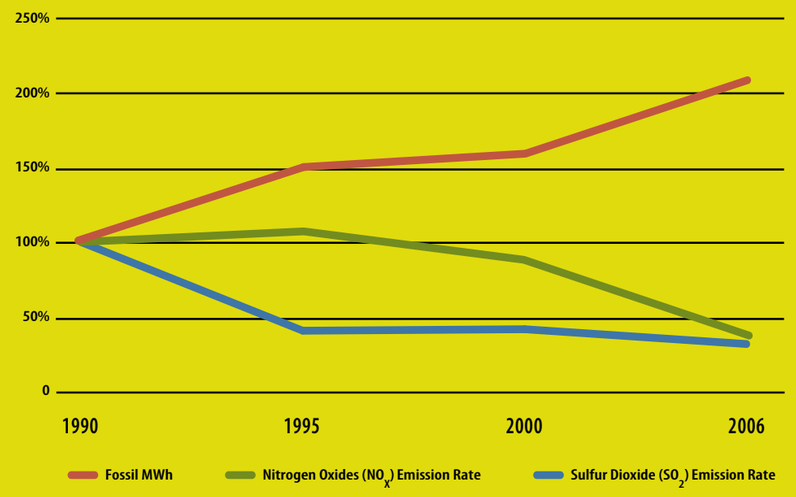
MEAG Power
1470 Riveredge Parkway, NW
Atlanta, Georgia 30328-4686

1-800-333-MEAG
www.meagpower.org

Our Fossil Fuel Generation Levels More Than Doubled From 1990 To 2006 To Meet Growing Demand, While Our SO_2 And NO_X Emission Rates Were Reduced By 69% And 64%, Respectively



These positive emission-control trends are the result of MEAG Power's significant investment in a state-of-the-art, high efficiency gas-fired plant and lower-emitting fuels at our coal plants. In the next decade, additional technology investments will reduce our emissions even further.

BUSINESS DESCRIPTION

The Municipal Electric Authority of Georgia (MEAG Power) exists for one primary reason: to generate and transmit reliable and economical wholesale electric power to our 49 Participants. We have addressed this requirement successfully in our three decades of service since being chartered by the Georgia General Assembly as a public power corporation. We provide power through our co-ownership of four generating plants, sole ownership of a combined cycle facility, ownership of over 1,300 miles of transmission lines with access to 17,500 miles, and the collective assistance of our Participants. In addition, as a business resource, MEAG Power provides our Participants with engineering services, technical consulting, pricing strategies, economic development assistance and political advocacy on energy issues.

MEAG Power is among the country's leading joint action agencies with one of the most diversified fuel portfolios. We were also one of the first public power organizations to extend our power sales contracts, thus providing for the continued operation and financing of our generation and transmission assets in the most efficient manner.

As a public power enterprise, MEAG Power was created to serve our Participants. It is for their benefit, not shareholders', that we exist; it is their decisions at the local level that drive our long-term operations; and it is by combining their voices into one that we help protect their interests as energy policies and legislation are discussed and enacted.

MEAG Power
1470 Riveredge Parkway, NW
Atlanta, Georgia 30328-4686

1-800-333-MEAG
www.meagpower.org

MEAGPOWER

First

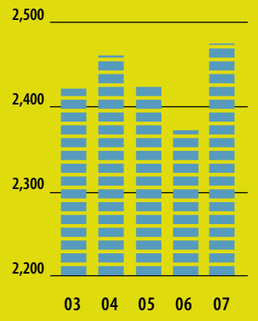
QUARTER REPORT 2007

MEAG POWER

Financial Highlights

TOTAL DELIVERED ENERGY

through March 31: (GWh)



First Quarter 2007 delivered energy increased 4.2% due to economic growth.

YEAR-TO-DATE REVENUES

through March 31: (in millions)

Total revenues through March 31 increased slightly from 2006 to 2007 due primarily to an increase in Participant billings for operating expenses, which was partially offset by a decrease in debt service billings.

Condensed Balance Sheet (UNAUDITED)

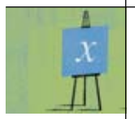
(in thousands)	March 31, 2007 Project One	General Resolution Projects	Combined Cycle Project	Trust Funds	Eliminations	Total Electric Projects	Telecom Project and Business Units	Total	March 31, 2006 Total
ASSETS									
Property, plant and equipment – net	$1,396,751	$435,594	$289,587	$ –	$ –	$2,121,932	$14,280	**$2,136,212**	$2,152,153
Other non-current assets	428,238	186,011	49,899	760,179	(180,206)	1,244,121	–	**1,244,121**	1,174,421
Current assets	412,899	89,854	44,810	255,976	(2,799)	800,740	4,117	**804,857**	721,404
Deferred debits	703,198	203,504	34,002	(482,257)	–	458,447	8,478	**466,925**	608,532
TOTAL ASSETS	$2,941,086	$914,963	$418,298	$533,898	$(183,005)	$4,625,240	$26,875	**$4,652,115**	$4,656,510
LIABILITIES									
Long-term debt	$2,405,755	$790,920	$387,140	$ –	$(180,206)	$3,403,609	$22,605	**$3,426,214**	$3,430,703
Lease finance obligation	–	–	–	277,063	–	277,063	–	**277,063**	265,086
Other non-current liabilities	280,813	44,795	4,840	897	–	331,345	(22)	**331,323**	348,592
Current portion of long-term debt	101,112	44,394	15,680	–	–	161,186	2,315	**163,501**	162,539
Flexible trust funds held for Participants	–	–	–	120,731	–	120,731	–	**120,731**	104,693
Other current liabilities	153,406	34,854	10,638	135,207	(2,799)	331,306	1,977	**333,283**	344,897
TOTAL LIABILITIES	$2,941,086	$914,963	$418,298	$533,898	$(183,005)	$4,625,240	$26,875	**$4,652,115**	$4,656,510

Condensed Statement of Net Revenues (UNAUDITED)

(in thousands)	Three months ended March 31, 2007 Project One	General Resolution Projects	Combined Cycle Project	Trust Funds	Total Electric Projects	Telecom Project and Business Units	Total	Three months ended March 31, 2006 Total
Revenues:								
Participant[1]	$ 86,782	$40,540	$13,355	$ –	$140,677	$1,845	**$142,522**	$140,927
Other	20,905	8,607	2,916	–	32,428	38	**32,466**	32,432
Total revenues	107,687	49,147	16,271	–	173,105	1,883	**174,988**	173,359
Operating expenses	71,684	33,448	10,135	18	115,285	1,441	**116,726**	112,581
Net operating revenues (loss)	36,003	15,699	6,136	(18)	57,820	442	**58,262**	60,778
Net interest expense (income)	30,893	8,297	3,168	(7,815)	34,543	469	**35,012**	33,431
Decrease (increase) in net costs to be recovered from future billings to Participants	5,110	7,402	2,968	7,797	23,277	(27)	**23,250**	27,347
Total other expenses (income), net	36,003	15,699	6,136	(18)	57,820	442	**58,262**	60,778
NET REVENUES	$ –	$ –	$ –	$ –	$ –	$ –	**$ –**	$ –

(1) Net of over (under)-recovery of $2.7 million and $(0.4) million for the three months ended March 31, 2007 and 2006, respectively. These amounts are included in other current liabilities and may not be indicative of future results. The final 2006 over-recovery has been distributed to the Participants.

These condensed financial statements, which include the accounts of the Power Revenue Bond Resolution (Project One), the General Power Revenue Bond Resolution (General Resolution Projects), the Combined Cycle Project Bond Resolution (Combined Cycle Project), the Municipal Competitive Trust and the Deferred Lease Financing Trust (Trust Funds), (collectively, the Electric Projects), the Telecommunications Project (Telecom), as well as the Distribution Services and the Marketing Services Business Units (Business Units), should be read in conjunction with MEAG Power's 2006 audited financial statements.



First Three Months' Performance

Revenue and Cost Analysis

Revenues: Participant revenues through March 31, 2007 were $142.5 million, a slight increase from $140.9 million for the same period of 2006. The higher revenues were due primarily to an increase in Participant billings for operating expenses, partially offset by a decrease in debt service billings. Other revenues of $32.5 million were comparable to the same period of 2006.

Operating Expenses: For the three months ended March 31, 2007, operating expenses increased 3.6% to $116.7 million compared to $112.6 million for the same period in 2006. An increase of $7.0 million in fuel was primarily due to coal price increases along with an increase in the quantity of coal burned as a result of timing of the planned outages for Plant Scherer. Purchased power expenses decreased $3.5 million mainly due to higher utilization of the coal plants during the First Quarter of 2007.

Interest Expense, Net: As of March 31, 2007, net interest expense, which includes stated interest expense and other related components such as amortization of debt discount and expense, interest income, net change in the fair value of financial instruments, and interest capitalized, totaled $35.0 million. This 4.8% increase, from the total of $33.4 million for the same period in 2006, is due primarily to a $5.1 million decrease in the fair value of financial instruments, which was partially offset by a $3.3 million increase in interest income due to higher short-term interest rates.

Financial

The weighted average interest rate of MEAG Power's debt was 4.75% and 4.64% for the three months ended March 31, 2007 and 2006, respectively, with the increase attributable to higher short-term interest rates. The weighted average interest rates exclude the impact of receipts and payments pertaining to interest rate swap agreements, as well as other related net interest expense components listed above.

As of March 31, 2007 and 2006, MEAG Power's investment portfolio included $1.2 billion in other non-current assets. In current assets, the portfolio totaled $658.1 million and $582.0 million as of March 31, 2007 and 2006, respectively.

Operations

Energy delivered to MEAG Power Participants for the first three months of 2007 increased 4.2% from the same period in 2006 due to economic growth.

Total power cost to the Participants, including energy purchased from the Southeastern Power Administration, was 5.86 cents/kWh for the first three months of 2007 compared to 5.92 cents/kWh for the same period in 2006. The decrease was due primarily to higher delivered energy.

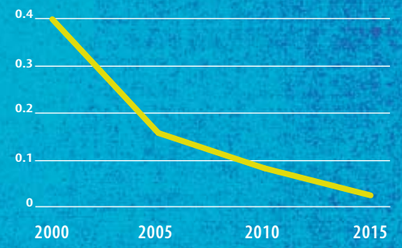
The nuclear units' capacity factor of 78.0% for the First Quarter 2007 decreased from the 80.3% factor for the first three months of 2006 due to slightly more maintenance outages. The First Quarter 2007 capacity factor of the coal units increased to 77.1% from 70.5% for the same period of 2006 due to reduced maintenance outages and elimination of coal conservation measures implemented in 2006 to build up inventory. During the First Quarter 2007, the Wansley Combined Cycle Facility's equivalent availability and starting reliability factors were both 100%, comparable to the same period in 2006.

Gas Agreement

MEAG Power has entered into an agreement with Petal Gas Storage, L.L.C. (Petal) providing for MEAG Power and Petal to enter into related storage and transportation agreements upon completion of the expansion of an existing natural gas storage facility in Petal, Mississippi. Petal has been authorized by the Federal Energy Regulatory Commission to expand the facility, and construction is under way with an expected completion date of April 1, 2008. The agreements will provide for storage and associated transportation of 200,000 mmBtus of natural gas for a term of 15 years. The agreements will also provide MEAG Power with access to a firm supply of natural gas for the Combined Cycle Project in the event of supply disruptions and will play a role in the daily management of gas supplies.

MEAG Power's Nitrogen Oxides Emission Rate Will Decline 89% Over The 2000-2015 Period

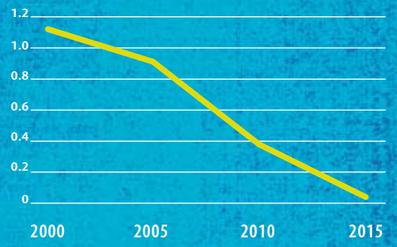
Pounds per Million BTU



100% Of MEAG Power's Coal Units Will Have Mercury Controls Installed By 2010

MEAG Power's Sulfur Dioxide Emission Rate Will Decline 97% Over The 2000-2015 Period

Pounds per Million BTU



BUSINESS DESCRIPTION

The Municipal Electric Authority of Georgia (MEAG Power) exists for one primary reason: to generate and transmit reliable and economical wholesale electric power to our 49 Participants. We have addressed this requirement successfully in our three decades of service since being chartered by the Georgia General Assembly as a public power corporation. We provide power through our co-ownership of four generating plants, sole ownership of a combined cycle facility, ownership of over 1,300 miles of transmission lines with access to 17,500 miles, and the collective assistance of our Participants. In addition, as a business resource, MEAG Power provides our Participants with engineering services, technical consulting, pricing strategies, economic development assistance and political advocacy on energy issues.

MEAG Power is among the country's leading joint action agencies with one of the most diversified fuel portfolios. We were also one of the first public power organizations to extend our power sales contracts, thus providing for the continued operation and financing of our generation and transmission assets in the most efficient manner.

As a public power enterprise, MEAG Power was created to serve our Participants. It is for their benefit, not shareholders', that we exist; it is their decisions at the local level that drive our long-term operations; and it is by combining their voices into one that we help protect their interests as energy policies and legislation are discussed and enacted.

MEAG Power
1470 Riveredge Parkway, NW
Atlanta, Georgia 30328-4686

1-800-333-MEAG
www.meagpower.org

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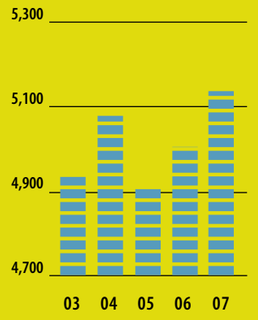
Financial Highlights

TOTAL DELIVERED ENERGY

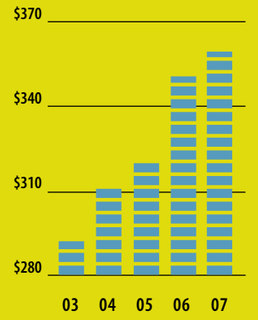
through June 30: (GWh)



Delivered energy through June 30, 2007 increased 2.6% over the same period in 2006 due to economic growth and an 8.6% increase in second quarter cooling degree hours.

YEAR-TO-DATE REVENUES

through June 30: (in millions)



A 2.7% increase in total revenues through June 30 from 2006 to 2007 is due primarily to an increase in Participant billings for operating expenses, partially offset by decreases in debt service billings and other revenues.

Condensed Balance Sheet (UNAUDITED)

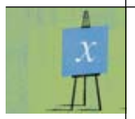
(in thousands)	June 30, 2007 Project One	General Resolution Projects	Combined Cycle Project	Trust Funds	Eliminations	Total Electric Projects	Telecom Project and Business Units	Total	June 30, 2006 Total
ASSETS									
Property, plant and equipment - net	$1,395,306	$436,003	$287,522	$ –	$ –	$2,118,831	$14,064	**$2,132,895**	$2,143,745
Other non-current assets	422,696	209,603	50,684	768,389	(183,045)	1,268,327	–	**1,268,327**	1,170,691
Current assets	305,963	103,586	56,441	238,792	(2,482)	702,300	4,172	**706,472**	806,181
Deferred debits	676,521	197,169	30,728	(487,160)	–	417,258	7,713	**424,971**	579,306
TOTAL ASSETS	$2,800,486	$946,361	$425,375	$520,021	$(185,527)	$4,506,716	$25,949	**$4,532,665**	$4,699,923
LIABILITIES									
Long-term debt	$2,292,242	$822,890	$386,820	$ –	$(183,045)	$3,318,907	$22,605	**$3,341,512**	$3,431,907
Lease finance obligation	–	–	–	280,107	–	280,107	–	**280,107**	267,998
Other non-current liabilities	271,684	45,213	8,713	1,197	–	326,807	(409)	**326,398**	351,279
Current portion of long-term debt	101,112	44,394	15,680	–	–	161,186	2,315	**163,501**	162,539
Flexible trust funds held for Participants	–	–	–	126,762	–	126,762	–	**126,762**	111,501
Other current liabilities	135,448	33,864	14,162	111,955	(2,482)	292,947	1,438	**294,385**	374,699
TOTAL LIABILITIES	$2,800,486	$946,361	$425,375	$520,021	$(185,527)	$4,506,716	$25,949	**$4,532,665**	$4,699,923

Condensed Statement of Net Revenues (UNAUDITED)

(in thousands)	Six months ended June 30, 2007 Project One	General Resolution Projects	Combined Cycle Project	Trust Funds	Total Electric Projects	Telecom Project and Business Units	Total	Six months ended June 30, 2006 Total
Revenues:								
Participant[1]	$176,163	$82,579	$28,297	$ –	$287,039	$3,774	**$ 290,813**	$278,465
Other	40,238	16,191	11,713	–	68,142	76	**68,218**	71,264
Total revenues	216,401	98,770	40,010	–	355,181	3,850	**359,031**	349,729
Operating expenses	144,599	67,378	26,891	85	238,953	2,862	**241,815**	227,876
Net operating revenues (loss)	71,802	31,392	13,119	(85)	116,228	988	**117,216**	121,853
Net interest expense (income)	43,601	19,121	7,440	(12,594)	57,568	190	**57,758**	74,217
Decrease in net costs to be recovered from future billings to Participants	28,201	12,271	5,679	12,509	58,660	798	**59,458**	47,636
Total other expenses (income), net	71,802	31,392	13,119	(85)	116,228	988	**117,216**	121,853
NET REVENUES	$ –	$ –	$ –	$ –	$ –	$ –	**$ –**	$ –

(1) Net of over-recovery of $8.0 million and $6.2 million for the six months ended June 30, 2007 and 2006, respectively. These amounts are included in other current liabilities and may not be indicative of future results. The final 2006 over-recovery has been distributed to the Participants.

These condensed financial statements, which include the accounts of the Power Revenue Bond Resolution (Project One), the General Power Revenue Bond Resolution (General Resolution Projects), the Combined Cycle Project Bond Resolution (Combined Cycle Project), the Municipal Competitive Trust and the Deferred Lease Financing Trust (Trust Funds), (collectively, the Electric Projects), the Telecommunications Project (Telecom), as well as the Distribution Services and the Marketing Services Business Units (Business Units), should be read in conjunction with MEAG Power's 2006 audited financial statements.



Six Months' Performance

Revenue and Cost Analysis

Revenues: Total revenues of $359.0 million through June 30, 2007 reflect a 2.7% increase compared to total revenues of $349.7 million for the first half of 2006. Participant revenues increased 4.4% to $290.8 million due primarily to an increase in billings for operating expenses, which was partially offset by a decrease in debt service billings. Other revenues decreased 4.3% to $68.2 million due mainly to a decrease in revenues related to the expiration of a long-term energy contract, as well as a decline in off-system energy sales related to price.

Operating Expenses: For the first six months of 2007, operating expenses increased 6.1% to $241.8 million from $227.9 million for the same period in 2006. Fuel expenses for coal increased $15.2 million due primarily to higher coal prices and quantity burned as a result of the elimination of coal conservation measures implemented in 2006 to build up inventory. The increase in coal costs was partially offset by a $3.0 million decrease in natural gas costs due to lower utilization of the Wansley Combined Cycle Facility related to market conditions. A $3.2 million decrease in purchased power expenses was mainly due to higher use of the coal plants.

Interest Expense, Net: Net interest expense, which includes stated interest expense and other related components such as amortization of debt discount and expense, interest income, net change in the fair value of financial instruments, and interest capitalized, totaled $57.8 million through June 30, 2007, compared to $74.2 million for the same period in 2006. This 22.1% decrease is due mainly to a $9.3 million increase in interest income due to higher average invested balances coupled with higher interest rates, as well as a $3.0 million improvement in the fair value of financial instruments. Interest expense also decreased $2.2 million due primarily to lower amounts of debt outstanding.

Financial

MEAG Power's debt had a weighted average interest rate of 4.84% and 4.75% for the six months ended June 30, 2007 and 2006, respectively. The increase was attributable to higher short-term interest rates. The weighted average interest rates exclude the impact of receipts and payments pertaining to interest rate swap agreements, as well as other related net interest expense components listed above.

As of June 30, 2007 and 2006, MEAG Power's investment portfolio included $1.3 billion and $1.2 billion in other non-current assets, as well as $545.5 million and $654.6 million, respectively, in current assets.

Operations

Energy delivered to MEAG Power Participants for the first half of 2007 increased 2.6% over the same period in 2006, due to economic growth and an 8.6% increase in second quarter cooling degree hours.

Through June 30, 2007, total power cost to the Participants, including energy purchased from the Southeastern Power Administration, was 5.73 cents/kWh compared to 5.69 cents/kWh for the same period in 2006, the slight increase attributable to higher Participant billings for operating expenses.

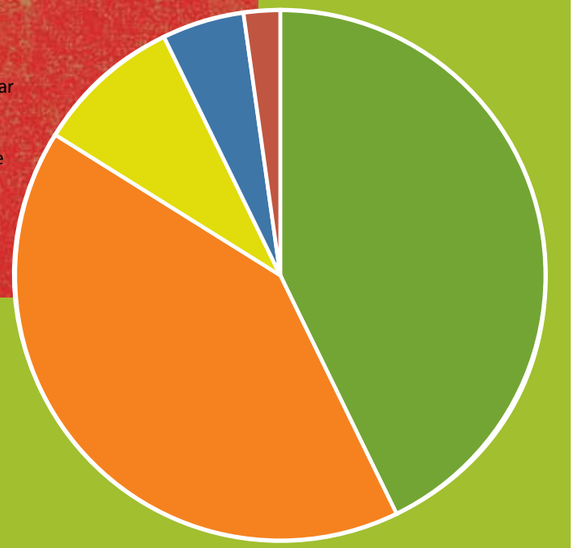
For the first six months of 2007, the nuclear units' capacity factor of 84.4% decreased from 88.0% for the same period in 2006 due to reduced availability of Plant Vogtle Unit 2 as a result of extending a planned outage. Due to a lower unplanned outage rate of Scherer Unit 1 and the elimination of coal conservation measures mentioned above, the coal units' capacity factor improved to 80.6% from 74.7% for the same period in 2006. The Combined Cycle Facility's equivalent availability factor through June 30, 2007 was 98.4%, and its starting reliability was 100.0%, compared to 2006 factors of 94.5% and 99.1%, respectively. The improvement in the equivalent availability factor was primarily due to fewer planned outage hours, as well as a decrease in maintenance and forced outage hours.

Environmental Improvements

In June 2007, MEAG Power issued $45.0 million of taxable subordinated bonds. Proceeds from these fixed rate bonds will be used to finance a portion of certain environmental improvements to the coal-fired generating units at Plants Scherer and Wansley. Beginning in 2007 and through 2014, MEAG Power plans to spend approximately $521 million at the coal units for equipment to reduce emissions of nitrogen oxides, sulfur dioxide, and mercury to comply with federal and Georgia air quality regulations.

MEAG Power's 2007 Energy Profile Illustrates Our Investment In Low- And Non-Emitting Sources

MEAG Power's communities have one of the best positions in nuclear and hydroelectric power in the Southeast, and we are evaluating the possible expansion of our nuclear generation capabilities.



DELIVERED ENERGY BY SOURCE
(AS OF NOVEMBER 30, 2007)

- Nuclear – 43%
- Coal – 41%
- Gas – 9%
- Hydro – 5%
- Purchases – 2%

BUSINESS DESCRIPTION

The Municipal Electric Authority of Georgia (MEAG Power) exists for one primary reason: to generate and transmit reliable and economical wholesale electric power to our 49 Participants. We have addressed this requirement successfully in our three decades of service since being chartered by the Georgia General Assembly as a public power corporation. We provide power through our co-ownership of two nuclear and two coal-fired generating plants, sole ownership of a combined cycle facility, as well as ownership of over 1,300 miles of high voltage transmission lines and nearly 200 substations. MEAG Power also monitors and advocates on energy issues at the state and federal levels on behalf of our Participants. In addition, through separate business units, MEAG Power offers our Participants technical support, training, pricing strategies, joint purchasing, energy services, meter testing and economic development assistance.

MEAG Power is among the country's leading joint action agencies with one of the most diversified fuel portfolios. We were also one of the first public power organizations to extend our power sales contracts, thus providing for the continued operation and financing of our generation and transmission assets in the most efficient manner.

As a public power enterprise, MEAG Power was created to serve our Participants. It is for their benefit, not shareholders', that we exist; it is their decisions at the local level that drive our long-term operations; and it is by combining their voices into one that we help protect their interests as energy policies and legislation are discussed and enacted.

MEAG Power
1470 Riveredge Parkway, NW
Atlanta, Georgia 30328-4686

1-800-333-MEAG
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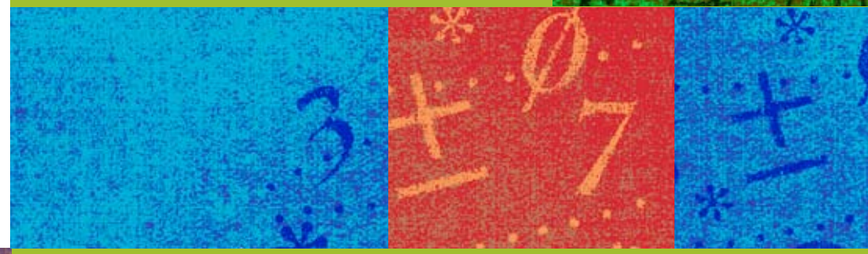
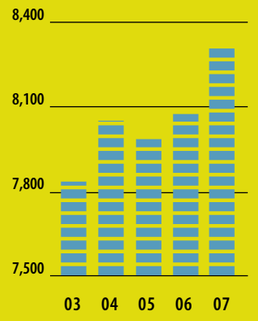


Financial Highlights

TOTAL DELIVERED ENERGY

through September 30: (GWh)



Delivered energy through September 30, 2007 increased 2.8% from the same period in 2006, due primarily to record-setting heat in August, as well as strong economic growth.

YEAR-TO-DATE REVENUES

through September 30: (in millions)

Total revenues through September 30 increased 3.2% from 2006 to 2007 due primarily to an increase in Participant billings for fuel, partially offset by a decrease in debt service billings.

Condensed Balance Sheet (UNAUDITED)

(in thousands)	September 30, 2007 Project One	General Resolution Projects	Combined Cycle Project	Trust Funds	Eliminations	Total Electric Projects	Telecom Project and Business Units	Total	September 30, 2006 Total
ASSETS									
Property, plant and equipment - net	$1,399,989	$437,978	$285,310	$ –	$ –	$2,123,277	$13,737	**$2,137,014**	$2,134,193
Other non-current assets	407,234	207,416	53,455	784,367	(185,971)	1,266,501	–	**1,266,501**	1,193,124
Current assets	312,684	111,521	60,663	211,783	(3,803)	692,848	5,043	**697,891**	800,914
Deferred debits	667,439	190,766	25,210	(499,676)	–	383,739	8,038	**391,777**	560,411
TOTAL ASSETS	$2,787,346	$947,681	$424,638	$ 496,474	$(189,774)	$4,466,365	$26,818	**$4,493,183**	$4,688,642
LIABILITIES									
Long-term debt	$2,294,194	$825,776	$386,499	$ –	$(185,971)	$3,320,498	$22,605	**$3,343,103**	$3,433,210
Lease finance obligation	–	–	–	283,218	–	283,218	–	**283,218**	270,975
Other non-current liabilities	282,988	46,508	4,208	1,494	–	335,198	228	**335,426**	365,877
Current portion of long-term debt	101,112	44,394	15,680	–	–	161,186	2,315	**163,501**	162,539
Flexible trust funds held for Participants	–	–	–	124,385	–	124,385	–	**124,385**	110,607
Other current liabilities	109,052	31,003	18,251	87,377	(3,803)	241,880	1,670	**243,550**	345,434
TOTAL LIABILITIES	$2,787,346	$947,681	$424,638	$ 496,474	$(189,774)	$4,466,365	$26,818	**$4,493,183**	$4,688,642

Condensed Statement of Net Revenues (UNAUDITED)

(in thousands)	Nine months ended September 30, 2007 Project One	General Resolution Projects	Combined Cycle Project	Trust Funds	Total Electric Projects	Telecom Project and Business Units	Total	Nine months ended September 30, 2006 Total
Revenues:								
Participant [1]	$265,943	$125,013	$53,158	$ –	$444,114	$5,605	**$449,719**	$434,362
Other	59,746	23,767	27,972	–	111,485	121	**111,606**	109,437
Total revenues	325,689	148,780	81,130	–	555,599	5,726	**561,325**	543,799
Operating expenses	218,111	101,910	60,265	138	380,424	4,226	**384,650**	360,753
Net operating revenues (loss)	107,578	46,870	20,865	(138)	175,175	1,500	**176,675**	183,046
Net interest expense (income)	74,838	28,926	10,230	(25,205)	88,789	1,012	**89,801**	113,793
Decrease in net costs to be recovered from future billings to Participants	32,740	17,944	10,635	25,067	86,386	488	**86,874**	69,253
Total other expenses (income), net	107,578	46,870	20,865	(138)	175,175	1,500	**176,675**	183,046
NET REVENUES	$ –	$ –	$ –	$ –	$ –	$ –	**$ –**	$ –

(1) Net of over-recovery of $17.6 million and $9.5 million for the nine months ended September 30, 2007 and 2006, respectively. These amounts are included in other current liabilities and may not be indicative of future results. The final 2006 over-recovery has been distributed to the Participants.

These condensed financial statements, which include the accounts of the Power Revenue Bond Resolution (Project One), the General Power Revenue Bond Resolution (General Resolution Projects), the Combined Cycle Project Bond Resolution (Combined Cycle Project), the Municipal Competitive Trust and the Deferred Lease Financing Trust (Trust Funds), (collectively, the Electric Projects), the Telecommunications Project (Telecom), as well as the Distribution Services and the Marketing Services Business Units (Business Units), should be read in conjunction with MEAG Power's 2006 audited financial statements.

Nine Months' Performance

Revenue and Cost Analysis

Revenues: Total revenues through September 30, 2007 were $561.3 million, a 3.2% increase from total revenues of $543.8 million for the same period of 2006. Participant revenues increased 3.5% to $449.7 million primarily due to an increase in Participant billings for fuel, partially offset by a decrease in debt service billings. Other revenues increased 2.0% to $111.6 million due primarily to a $5.2 million increase in off-system energy sales related to volume, which was partially offset by a $4.3 million decrease in revenues related to the expiration of a long-term energy contract.

Operating Expenses: Year-to-date operating expenses through September 30, 2007 increased 6.6% to $384.7 million, compared to $360.8 million for the same period in 2006. An increase of $16.4 million in coal cost was primarily due to higher quantity burned as a result of the elimination of coal conservation measures implemented in 2006 to build up inventory, as well as increased energy delivered related to record-setting heat as discussed below. Natural gas expense increased $5.6 million, which was also primarily attributable to the record temperatures. A $5.4 million increase in transmission expense was primarily due to a decline in revenues MEAG Power received from the co-owners of the Integrated Transmission System. Purchased power expenses decreased $2.3 million due mainly to higher output of the generating units.

Interest Expense, Net: As of September 30, 2007, net interest expense, which includes stated interest expense and other related components such as amortization of debt discount and expense, interest income, net change in the fair value of financial instruments, and interest capitalized, totaled $89.8 million. This 21.1% decrease from the total of $113.8 million for the same period in 2006 is due primarily to a $10.5 increase in interest income due to higher interest rates and higher average invested balances, as well as a $5.4 million improvement in the fair value of financial instruments. Interest expense decreased $4.7 million due primarily to lower amounts of debt outstanding.

Financial

The weighted average interest rate of MEAG Power's debt was 4.88% and 4.85% for the nine months ended September 30, 2007 and 2006, respectively. Such rates exclude the impact of receipts and payments pertaining to interest rate swap agreements, as well as other related net interest expense components listed above.

As of September 30, 2007 and 2006, MEAG Power's investment portfolio included $1.3 billion and $1.2 billion in other non-current assets, as well as $542.1 million and $663.2 million, respectively, in current assets.

Operations

Total power cost to the Participants, including energy purchased from the Southeastern Power Administration, was 5.46 cents/kilowatt-hour (kWh) for the nine months ended September 30, 2007, compared to 5.50 cents/kWh for the same period in 2006. The decrease was due primarily to an increase in kWh delivered.

The nuclear units' 2007 year-to-date capacity factor of 89.4% was comparable to the factor for the same period in 2006. The coal plants' capacity factor of 84.7% improved from 80.9% for the same period in 2006, primarily due to the elimination of coal conservation measures implemented in 2006 to build up inventory at Plant Scherer. The Combined Cycle facility achieved an equivalent availability factor of 97.0% and 94.5% for the nine months ended September 30, 2007 and 2006, respectively, with the improvement attributable to a decline in planned outage and maintenance hours. The facility's 99.5% starting reliability factor for the nine months ended September 30, 2007 was comparable to the factor for the same period in 2006.

Record Heat

Through September 30, 2007, energy delivered to MEAG Power Participants increased 2.8% from the same period in 2006, due primarily to a 7.2% increase in second and third quarter cooling degree hours from record-setting heat in August, as well as strong economic growth. August 2007 was the hottest month on record in the State of Georgia and the quarter ended September 30, 2007 was the third warmest in the past 30 years. The extreme heat led to record delivery of energy to the Participants in August and during the third quarter, as well as a record peak of 2,117 megawatts.

APPENDIX 1C

FINANCIAL STATEMENTS FOR THE BOARD OF WATER, LIGHT AND SINKING FUND COMMISSIONERS OF DALTON

(**NOTE**: This appendix consists of a 42-page stand-alone document, developed independent of standard COL application formatting.)

The Fund Commissioners of The City of Dalton, Georgia

Financial Statements as of and for the Years Ended December 31, 2006 and 2005, Supplemental Information for the Years Ended December 31, 2006 and 2005, and Independent Auditors' Report

THE BOARD OF WATER, LIGHT AND SINKING FUND COMMISSIONERS OF THE CITY OF DALTON, GEORGIA

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Deloitte & Touche LLP
Suite 1500
191 Peachtree Street NE
Atlanta, Georgia 30303
USA

Tel: +1 404 220 1500
www.deloitte.com

INDEPENDENT AUDITORS' REPORT

To the Board of Water, Light and Sinking Fund
Commissioners of the City of Dalton, Georgia:

We have audited the accompanying balance sheet of The Board of Water, Light and Sinking Fund Commissioners of the City of Dalton, Georgia (the "Company") as of December 31, 2006, and the related statements of revenues, expenses, and changes in fund net assets and cash flows for the year then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audit. The financial statements of the Company for the year ended December 31, 2005, were audited by other auditors whose report, dated April 11, 2006, expressed an unqualified opinion on those statements.

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

In our opinion, such financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2006, and the changes in its fund net assets and the cash flows for the year then ended in conformity with accounting principles generally accepted in the United States of America.

The Management's Discussion and Analysis on pages 3 to 9 and Schedule of Funding Progress on page 32 are not a required part of the basic financial statements but are supplementary information required by the Governmental Accounting Standards Board. This supplementary information is the responsibility of the Company's management. We have applied certain limited procedures, which consisted principally of inquiries of management regarding the methods of measurement and presentation of the supplementary information. However, we did not audit such information and we do not express an opinion on it.

Our audit was conducted for the purpose of forming an opinion on the basic 2006 financial statements taken as a whole. The other supplemental information listed in the table of contents on pages 34 to 39 are presented for the purpose of additional analysis and are not a required part of the basic financial statements. These schedules are the responsibility of the Company's management. Such 2006 schedules have been subjected to the auditing procedures applied in our audit of the basic financial statements and, in our opinion, are fairly stated in all material respects when considered in relation to the basic financial statements taken as a whole. The 2005 schedules were subjected to auditing procedures by other auditors

whose report dated April 11, 2006, referred to above, stated that such information is fairly stated in all material respects when considered in relation to the basic 2005 financial statements taken as a whole.

In accordance with *Government Auditing Standards*, we have also issued our report dated May 29, 2007, on our consideration of the Company's internal control over financial reporting and our tests of its compliance with certain provisions of laws, regulations, and other matters. The purpose of that report is to describe the scope of our testing of internal control over financial reporting and compliance and the results of that testing, and not to provide an opinion on the internal control over financial reporting or on compliance. That report is an integral part of an audit performed in accordance with *Government Auditing Standards* and should be considered in assessing the results of our audit.

Deloitte & Touche LLP

May 29, 2007

THE BOARD OF WATER, LIGHT AND SINKING FUND COMMISSIONERS OF THE CITY OF DALTON, GEORGIA

MANAGEMENT'S DISCUSSION AND ANALYSIS

FINANCIAL HIGHLIGHTS

	2006	2005	2004
	(In thousands of dollars)		
Operating revenues	$ 151,787	$ 145,585	$ 125,644
Operating expenses	151,416	149,418	134,140
Operating income (loss)	371	(3,833)	(8,496)
Other nonoperating revenues and (expenses)	(1,623)	10,111	9,204
Income (loss) before transfers	(1,252)	6,278	708
Cash transferred to the City of Dalton	(8,184)	(6,451)	(6,657)
Changes in fund net assets	(9,436)	(173)	(5,949)
Beginning of year net assets	608,723	608,896	614,845
End of year net assets	599,287	608,723	608,896
Plus: contribution in aid of construction	89,576	89,396	88,965
NET ASSETS	$ 688,863	$ 698,119	$ 697,861

	2006	2005	2004
	(In thousands of dollars)		
ASSETS			
Current assets	$ 56,104	$ 53,496	$ 55,576
Noncurrent assets	137,962	190,775	234,921
Capital assets — net	640,977	623,863	586,973
Unamortized Debt Expense	562	930	1,422
Regulatory assets	27,931	26,424	24,815
Department of Energy decommissioning assessment		124	239
TOTAL ASSETS	$ 863,536	$ 895,612	$ 903,946
LIABILITIES			
Current liabilities	$ 41,130	$ 43,356	$ 41,042
Noncurrent liabilities	133,543	154,137	165,043
Total liabilities	174,673	197,493	206,085
NET ASSETS	688,863	698,119	697,861
TOTAL LIABILITIES AND NET ASSETS	$ 863,536	$ 895,612	$ 903,946

2006 versus 2005

Operating revenues for 2006 versus 2005 increased $6.2 million or 4.3% primarily due to increased revenues in the following utility sectors:

- Electric operating revenues increased $4.8 million or 7.3%, primarily due to a 7% overall rate increase effective with January 2006 billing, partly offset by decreased consumption of 2.8% for all customer classes.

- Water operating revenues increased $2.4 million or 14.3%, primarily due to a 13.2% overall rate increase effective with January 2006 billing.

- Sewer operating revenues increased $4.2 million or 21.8%, primarily due to a 20% overall rate increase effective with January 2006 billing.

Operating expenses for 2006 versus 2005 increased $2.0 million or 1.3% due to changes in the following cost types:

- Production expenses were up $1.2 million or 3.4% primarily due to increased operating and maintenance (O&M) expenses at the Company's jointly owned electric generating facilities.

- Purchased electricity expenses were down $1.2 million or 3.1%.

    - Total kWh's purchased from Southeastern Power Administration ("SEPA") were down 23% while average cost per kWh increased 39%.

    - Total kWh's purchased from Southern Company under Dalton Utilities' Partial Requirements Service Agreement were down 5% while average cost per kWh increased 5%.

- Purchased gas expenses were down $1.4 million or 5.9% primarily due to decreased purchased gas volumes.

- Distribution expenses were down $0.9 million or 4.6%.

- Depreciation expenses were up $2.7 million or 10.8% primarily due to:

    - increased depreciation expenses related to asset additions associated with continuing customer growth of OptiLink

    - increased depreciation expense associated with the final phase water projects being closed to plant in service

- General and administrative expenses were up $1.7 million or 16.6% primarily due to increased expenses related to customer growth coupled with an increase in health care costs due to underlying healthcare inflation.

The operating income for 2006 versus 2005 increased $4.2 million or 109.7% (operating income of $0.4 million in 2006 vs. operating loss of $3.8 million in 2005). Dalton Utilities' operating income for the year ending December 31, 2006 is the result of the following operating margins in the various utility sectors.

- Operating loss in the Electric sector was $4.6 million. Average cost per kWh for jointly owned generation, SEPA and purchased power were all up 4%, 39% and 5%, respectively.

- Operating income in the Natural Gas sector was $0.8 million. The positive operating margin was the result of Dalton Utilities' market based index pricing coupled with Dalton Utilities' ability to purchase and/or store gas at less than the monthly index price of gas.

- Operating income in the Water sector was $0.9 million. The positive operating margin was the result of the 13.2% overall rate increase effective with January 2006 billing.

- Operating income in the Sewer sector was $5.5 million. The positive operating margin was the result of the 20% overall rate increase effective with January 2006 billing.

- Operating loss in the Information Technology sector was $2.2 million. The operating loss is primarily the result of the continued build out and increased market share for the OptiLink business sector.

The net of nonoperating revenues and expenses for 2006 versus 2005 decreased $11.7 million.

- Interest income was up $0.4 million or 6.9% due to the reinvestment of portfolio securities at higher interest rates. The amount of Dalton Utilities' restricted funds, available for investment, continues to decrease as they are used to fund Dalton Utilities' Renewals and Extensions ("Construction") budgets.

- Interest expense was down $0.9 million or 13%, primarily due to the decrease of the outstanding debt balance.

- Net increase in fair value of investments decreased by $13.0 million which includes $5.5 million of interest accretion on zero coupon bonds.

- Allowance for debt funds used during construction ("AFUDC") was down $0.6 million or 45% due to decreased construction activity.

- Miscellaneous income was up $0.5 million.

Net assets on the balance sheet for 2006 versus 2005 decreased $9.3 million.

- Net assets invested in capital assets, net of related debt, were up $38.8 million or 8.1% primarily due to increased net utility plant of $24 million coupled with a reduction in long-term debt of $14.2 million.

- Net assets restricted for capital projects were down $53.1 million or 39.7% due to dollars being taken out of Dalton Utilities' investment portfolio to pay for capital expenditures.

2005 versus 2004

Operating revenues for 2005 versus 2004 increased $19.9 million or 15.9% due to increased revenues in the following utility sectors:

- Electric operating revenues increased $6.6 million or 10.9%, primarily due to an overall increase of 2.9% in consumption and a 3% overall rate increase effective with January 2005 billing.

- Natural gas operating revenues increased $5.9 million or 23.5%, primarily due to increases in market based index prices that are the basis for rate pricing, partly offset by decreased consumption by industrial and transportation gas customers.

- Water operating revenues increased $1.8 million or 11.5%, primarily due to a 9% overall rate increase effective with January 2005 billing.

- Sewer operating revenues increased $2.7 million or 16.2%, primarily due to a 20% overall rate increase effective with January 2005 billing.

- Information Technology revenues increased $3.1 million or 34.5%, primarily due to continuing growth of OptiLink, a business sector with a true fiber to user offering enhanced telephony, entertainment, and internet.

Operating expenses for 2005 versus 2004 increased $15.2 million or 11.4% due to changes in the following cost types:

- Production expenses were up $1.9 million or 6.0% primarily due to increased operating and maintenance (O&M) expenses at the Company's jointly owned electric generating facilities.

- Purchased electricity expenses were up $7.0 million or 22.4%.

    - Total kWh's purchased from Southeastern Power Administration ("SEPA") were up 13% while average cost per kWh decreased 12%.

    - Total kWh's purchased from Southern Company under Dalton Utilities' Partial Requirements Service Agreement were up 7% while average cost per kWh increased 17%.

- Purchased gas expenses were up $3.6 million or 17.9% primarily due to an increase in the weighted average cost of purchased gas resulting from higher natural gas prices.

- Distribution expenses were down $1.3 million or 6.4%.

- Depreciation expenses were up $1.5 million or 6.6% primarily due to:

    - Increased depreciation expenses associated with continuing customer growth of OptiLink

    - Increased depreciation expense associated with the final phase water projects being closed to plant in service

- General and administrative expenses were up $2.5 million or 33.4% primarily due to increased expenses related to customer growth coupled with an increase in health care costs due to underlying healthcare inflation.

The operating loss for 2005 versus 2004 decreased $4.7 million or 54.9%. (operating loss of $3.8 million in 2005 vs. operating loss of $8.5 million in 2004) Dalton Utilities' operating loss for the year ended December 31, 2005, is the result of the following operating margins in the various utility sectors.

- Operating loss in the Electric sector was $9.2 million. Average cost per kWh for jointly owned generation and purchased power were up by 11% and 17%, respectively while average cost per kWh for SEPA was down 12%.

- Operating income in the Natural Gas sector was $4.0 million. The positive operating margin was the result of Dalton Utilities' market based index pricing coupled with Dalton Utilities' ability to purchase and/or store gas at less than the monthly index price of gas.

- Operating income in the Water sector was $2.1 million. The positive operating margin was the result of the 9% overall rate increase effective with January 2005 billing.

- Operating income in the Sewer sector was $2.5 million. The positive operating margin was the result of the 20% overall rate increase effective with January 2005 billing.

- Operating loss in the Information Technology sector was $3.2 million. The operating loss is primarily the result of the build out the OptiLink business sector.

The net of nonoperating revenues and expenses for 2005 versus 2004 increased $0.9 million.

- Interest income was down $4.1 million or 44.3% due to declining market interest rates as well as decreased investment balances. The amount of Dalton Utilities' restricted funds, available for investment, continues to decrease as they are used to fund Dalton Utilities' Renewals and Extensions (Construction) budgets.

- Interest expense was down $0.7 million or 9.3%, primarily due to the decrease of the outstanding debt balance.

- Net increase in fair value of investments increased by $5.0 million. Additionally, net increase in fair value of investments was up due to $8.3 million of interest accretion on zero coupon bonds.

- Investment income was down $0.3 million or 20.2% due to reduced investment in the Integrated Transmission System ("ITS").

- Allowance for debt funds used during construction ("AFUDC") was down $0.3 million or 18.2% due to decreased construction activity.

- Miscellaneous income was down $0.1 million due to a payment of $0.3 million to EPA by the Sewer sector.

Net assets on the balance sheet for 2005 versus 2004 increased $0.3 million.

- Net assets invested in capital assets, net of related debt, were up $48.9 million or 11.4% due to increased net utility plant of $50.4 million coupled with a reduction in long-term debt of $13.6 million.

- Net assets restricted for capital projects were down $48.2 million or 26.5% due to dollars being taken out of Dalton Utilities' investment portfolio to pay for capital expenditures.

Overview of the Financial Statements — In June 1999, the Governmental Accounting Standards Board (GASB) issued Statement No. 34, *Basic Financial Statements – Management's Discussion and Analysis — for State and Local Governments* ("GASB No. 34"). The objective of this Statement is to enhance the understandability and usefulness of the external financial reports of state and local governments to the citizenry, legislative and oversight bodies, investors and creditors.

Management's Discussion and Analysis — The purpose is to provide an objective and easily readable analysis of Dalton Utilities' financial activities based on currently known facts, decisions or conditions.

Balance Sheet — Assets and liabilities are presented to distinguish between current and long-term assets and liabilities.

Statements of Revenues, Expenses and Changes in Fund Net Assets — This statement provides the operating results of Dalton Utilities, broken into the various categories of operating revenue and expenses, nonoperating revenues and expenses, as well as transfer payments to the City.

Statement of Cash Flows — Using the direct method, sources and uses of cash from operating, investing and financing activities are shown. Also using the indirect method, changes in balance sheet accounts are shown.

Notes to the Financial Statements — The footnotes are used to explain the information in the financial statements and provide more detailed data.

Required Supplementary Information — Required Supplementary Information ("RSI") includes management's discussion and analysis and the schedule of funding progress of the Pension Plan. This information is not a required part of the basic financial statements but is supplementary information required by accounting principles generally accepted in the United States of America.

Other Supplementary Information — Other RSI includes the system financial statements. This information is presented for purposes of additional analysis and is not a required part of the basic financial statements.

Financial Policy Established in October 2003 — In order to ensure the long-term health of Dalton Utilities, the Board of Water, Light and Sinking Fund Commissioners approved a new financial policy at its October 2003 Board meeting, which will drive the creation of utility service rates in the future. This new policy sets annual rates based on each Utility's sector's economic cost to provide service by customer class. A significant element in the new financial policy is a formula, which allocates the interest earnings from the Utility's investment portfolio across the electric, water, and sewer sectors to benefit customers by offsetting their economic cost of service. Due to regulatory requirements, telecommunication services will not receive any interest subsidies. If the current rate is not sufficient to meet the amount owed after the interest subsidy is subtracted from the economic cost of service, then the rate will be increased. To protect customers from sudden increases in rates, the Board has restricted rate increases not to exceed 20% for any particular rate class in any given year.

Regulatory Matters — *Environmental Protection Agency ("EPA")/Environmental Protection Division ("EPD") — U.S. District Court Case* — March 28, 2001, a Consent Decree containing a settlement between Dalton Utilities and the U.S. Environmental Protection Agency and the State of Georgia was entered by the Court. Compliance with the terms of the Consent Decree required that Dalton Utilities undertake certain actions, all of which have been completed. After March 28, 2002, Dalton Utilities could request that some or all of the Consent Decree be terminated if certain prerequisites were met to the Court's satisfaction. Compliance with the Consent Decree proceeded smoothly. On September 10, 2004, the Court terminated three of four portions of the Consent Decree.

On November 16, 2005, the Court terminated the Consent Decree in its entirety. Dalton Utilities is no longer subject to the jurisdiction of the Court.

Capital Improvement Program — Dalton Utilities has a rolling five-year capital budget approximating $244 million which is a decrease of $8 million from its 2005 rolling-five year capital budget. As with past capital budgets, a large portion of the Utility's rolling five-year capital budget is directed to maintaining service delivery capability and regulated production capacity of the Utility's aging infrastructure, while complying with increasing environmental regulations. Additionally, substantial capital dollars will need to be expended in order to establish preventative maintenance, extension and expansion of the Utility's infrastructure.

While not precluding the possibility of future financing, Dalton Utilities currently does not have any plans for any additional debt financing. Consequently, it is probable that Dalton Utilities' five-year rolling capital budget will be funded internally, through a combination of cash generated by operation and investing activities as well as drawdowns of Dalton Utilities' Renewal and Extension (capital construction projects) Funds.

THE BOARD OF WATER, LIGHT AND SINKING FUND COMMISSIONERS OF THE CITY OF DALTON, GEORGIA

BALANCE SHEETS
AS OF DECEMBER 31, 2006 AND 2005
(In thousands of dollars)

ASSETS	2006	2005
CURRENT ASSETS:		
Cash and cash equivalents	$ 1,192	$ 1,431
Restricted funds:		
Customer deposit fund	2,703	2,163
Combined utilities sinking fund	17,507	17,124
Accounts receivable, less allowance for doubtful accounts of $876 and $522 in 2006 and 2005, respectively	15,591	18,817
Accrued interest receivable	2,484	1,787
Fuel stocks — at average cost	7,163	3,383
Materials and supplies inventory — at average cost	8,812	7,698
Deposits and prepaid expenses	652	1,093
Total current assets	56,104	53,496
NONCURRENT ASSETS:		
Restricted funds:		
Combined utilities renewals and extensions fund	80,793	133,911
Natural gas derivative	1,335	
Nuclear decommissioning fund	55,834	56,864
Total restricted funds	137,962	190,775
Capital assets:		
Utility plant	906,353	855,013
Less accumulated depreciation	(277,803)	(250,226)
Total utility plant — net	628,550	604,787
Construction work in progress	5,688	13,732
Nuclear fuel — at amortized cost	6,739	5,344
Total capital assets	640,977	623,863
Debt expense — Net of accumulated amortization	562	930
Regulatory asset	27,931	26,424
Department of energy decommissioning assessment		124
Total noncurrent assets	807,432	842,116
TOTAL	$ 863,536	$ 895,612

(Continued)

THE BOARD OF WATER, LIGHT AND SINKING FUND COMMISSIONERS OF THE CITY OF DALTON, GEORGIA

BALANCE SHEETS
AS OF DECEMBER 31, 2006 AND 2005
(In thousands of dollars)

LIABILITIES AND NET ASSETS	2006	2005
CURRENT LIABILITIES:		
Current maturities of long-term debt	$ 14,700	$ 13,930
Accrued interest on long-term debt	2,798	3,184
Customer deposits	2,612	2,532
Accounts payable and accrued expenses	21,020	23,710
Total current liabilities	41,130	43,356
NONCURRENT LIABILITIES:		
Deferred credit — TVA right of use	617	667
Long-term debt	86,856	101,818
Asset retirement obligations	26,910	34,585
Regulatory liability	19,160	17,067
Total noncurrent liabilities	133,543	154,137
Total liabilities	174,673	197,493
COMMITMENTS AND CONTINGENCIES		
NET ASSETS:		
Invested in capital assets — net of related debt	518,484	479,703
Restricted for debt service	17,507	17,124
Restricted for capital projects	80,793	133,911
Restricted for customer deposit fund, nuclear decommissioning, restricted cash, and natural gas derivative	59,872	59,027
Unrestricted	12,207	8,354
Total net assets	688,863	698,119
TOTAL	$ 863,536	$ 895,612
RECONCILIATION OF NET ASSETS:		
End of year total net assets	$ 688,863	$ 698,119
Less contribution in aid of construction	89,576	89,396
End of year fund net assets	$ 599,287	$ 608,723

See notes to financial statements. (Concluded)

THE BOARD OF WATER, LIGHT AND SINKING FUND COMMISSIONERS OF THE CITY OF DALTON, GEORGIA

STATEMENTS OF REVENUES, EXPENSES AND CHANGES IN FUND NET ASSETS FOR THE YEARS ENDED DECEMBER 31, 2006 AND 2005 (In thousands of dollars)

	2006	2005
OPERATING REVENUES:		
Electric	$ 71,339	$ 66,495
Natural gas	26,227	30,728
Water	19,595	17,150
Sewer	23,385	19,198
Information technology	11,241	12,014
Total operating revenues	151,787	145,585
OPERATING EXPENSES:		
Production	34,655	33,531
Purchased electricity	36,952	38,152
Purchased natural gas	22,445	23,854
Distribution	17,950	18,825
Depreciation of utility plant	27,800	25,094
General and administrative expenses	11,614	9,962
Total operating expenses	151,416	149,418
OPERATING INCOME (LOSS)	371	(3,833)
NONOPERATING REVENUES (EXPENSES):		
Interest:		
Income	5,548	5,188
Expense	(5,701)	(6,555)
Interest expense — net	(153)	(1,367)
Net increase (decrease) in fair value of investments	(3,977)	9,062
Investment income	1,126	1,025
Swap income	242	126
Allowance for debt funds used during construction	768	1,396
Miscellaneous income (expenses)	371	(131)
Total nonoperating revenues (expenses) — net	(1,623)	10,111
INCOME (LOSS) BEFORE TRANSFERS	(1,252)	6,278
CASH TRANSFERRED TO THE CITY OF DALTON	(8,184)	(6,451)
CHANGES IN FUND NET ASSETS	(9,436)	(173)
FUND NET ASSETS — Beginning of year	608,723	608,896
FUND NET ASSETS — End of year	$ 599,287	$ 608,723

See notes to financial statements.

THE BOARD OF WATER, LIGHT AND SINKING FUND COMMISSIONERS OF THE CITY OF DALTON, GEORGIA

STATEMENTS OF CASH FLOWS
FOR THE YEARS ENDED DECEMBER 31, 2006 AND 2005
(In thousands of dollars)

	2006	2005
CASH FLOWS FROM OPERATING ACTIVITIES:		
Cash received from customers	$ 155,013	$ 141,417
Cash paid to suppliers and employees	(128,654)	(121,875)
Net cash provided by operating activities	26,359	19,542
CASH FLOWS FROM INVESTING ACTIVITIES:		
Interest receipts	5,548	5,188
Sales and maturities of investment securities	304,493	169,806
Purchases of investment securities	(257,458)	(118,322)
Receipts from overparity investment in integrated transmission facilities	1,126	1,025
Net cash provided by investing activities	53,709	57,697
CASH FLOWS FROM NONCAPITAL FINANCING ACTIVITIES —		
Transfers to the City of Dalton	(8,184)	(7,108)
CASH FLOWS FROM CAPITAL AND RELATED FINANCING ACTIVITIES:		
Capital expenditures for utility plant	(52,123)	(60,302)
Principal and interest payments on long-term debt and other debt-related activities	(20,180)	(20,016)
Contributions in aid of construction	180	431
Net cash used in capital and related financing activities	(72,123)	(79,887)
NET CHANGE IN CASH AND CASH EQUIVALENTS	(239)	(9,756)
CASH AND CASH EQUIVALENTS — Beginning of year	1,431	11,187
CASH AND CASH EQUIVALENTS — End of year	$ 1,192	$ 1,431

(Continued)

THE BOARD OF WATER, LIGHT AND SINKING FUND COMMISSIONERS OF THE CITY OF DALTON, GEORGIA

STATEMENTS OF CASH FLOWS
FOR THE YEARS ENDED DECEMBER 31, 2006 AND 2005
(In thousands of dollars)

	2006	2005
Reconciliation of operating loss to net cash provided by operating activities:		
Operating income (loss)	$ 371	$ (3,833)
Adjustments to reconcile operating income (loss) to net cash provided by operating activities:		
Depreciation of utility plant	27,800	25,094
Amortization of nuclear fuel	2,151	2,050
Amortization of debt issuance costs	368	492
Miscellaneous income	371	(131)
Changes in assets and liabilities		
Accounts receivable — net	3,226	(4,168)
Accrued interest receivable	(697)	(133)
Fuel stocks	(3,780)	574
Materials and supplies inventory	(1,114)	(1,663)
Deposits and prepaid expenses	441	(562)
Deferred charges — DOE asset	124	115
Accounts payable and accrued expenses	(2,690)	2,261
Deferred credit — TVA right of use	(50)	(50)
Deferred charges — DOE liability		(120)
Other	(162)	(384)
Total adjustments	25,988	23,375
Net cash provided by operating activities	26,359	19,542
NONCASH INVESTING, CAPITAL AND FINANCING ACTIVITIES — Net increase (decrease) in fair value of investments	$ (3,977)	$ 9,062

See notes to financial statements. (Concluded)

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Reporting Entity — The Board of Water, Light and Sinking Fund Commissioners of the City of Dalton, Georgia ("Dalton Utilities") was established in 1913 by an act of the Georgia legislature for the purpose of constructing and operating the public utilities for the City of Dalton, Georgia (the "City"). Electric, natural gas, water, sewer, and information technology services are provided by Dalton Utilities to the City and certain other surrounding areas.

Rates charged to customers are established solely by the Board. As required by the Rate Covenant of the Combined Utilities Revenue Bond Indentures (the "Indentures") dated January 1, 1997 and November 1, 1999, electric, natural gas, water, and sewer customers are billed so that operating revenues and investment earnings shall be sufficient to meet operating and maintenance expenses, debt service, and certain reserve requirements. In addition, no funds obtained from the City of Dalton's ad valorem taxes are to be used for operating and maintenance expenses of Dalton Utilities.

System of Accounts — Dalton Utilities follows accounting principles generally accepted in the United States of America and governmental accounting standards issued by the Governmental Accounting Standards Board ("GASB") and also conforms to the provisions of Financial Accounting Standards Board (FASB) Statement No. 71, *Accounting for the Effects of Certain Types of Regulation*. In the event that a portion of Dalton Utilities' operations is no longer subject to the provisions of FASB Statement No. 71 as a result of a change in regulation or the effects of competition, Dalton Utilities would be required to determine any impairment to other assets and write down the assets to their fair values. Dalton Utilities' accounts are maintained separately for each system generally in accordance with the Uniform System of Accounts prescribed by the Federal Energy Regulatory Commission ("FERC") for the electric and natural gas sectors (with the exception of its property accounts, discussed below under Utility Plant) and generally in accordance with the Uniform System of Accounts prescribed by the National Association of Regulatory Utility Commissioners for the water, sewer, and information technology sectors (with the exception of its property accounts, discussed below under Utility Plant).

Utility Plant — Utility plant constructed or purchased by Dalton Utilities is stated at cost, which includes material and labor costs and applicable overheads. Property received as a contribution is recorded at its estimated fair value on the date received. The costs of maintenance, repairs, and minor replacements of property are charged to expense. The costs of renewals and betterments are capitalized. Detailed property records are not maintained for assets other than automobiles and electric transmission plant in service acquired prior to 1998. Property description and dollar amount from individual invoices are maintained in the fixed asset system for all post 1998 property records. The cost of property retired or otherwise disposed of in the normal course of business, together with removal costs, less salvage, is charged to accumulated depreciation at the time such property is removed from service.

The cost of property retired or disposed of in the normal course of business which does not have detailed property records is estimated by management. Property disposals and retirements for the years ended December 31, 2006 and 2005, were $2,726,000 and $3,793,000, respectively. The property retired or disposed of in the normal course of business approximates its original cost. Land used by or held for the use of Dalton Utilities is owned by the City.

In accordance with GASB Statement No. 42, *Accounting and Financial Reporting for Impairment of Capital Assets and for Insurance Recoveries*, Dalton Utilities evaluates the carrying value of capital assets. A capital asset is considered impaired when its service utility has declined significantly and unexpectedly. Dalton Utilities is required to evaluate prominent events or changes in circumstances affecting capital assets to determine whether impairment of a capital asset has occurred. Such events or changes in circumstances that may be indicative of impairment include evidence of physical damage, enactment or approval of laws or regulations or other changes in environmental factors, technological changes or evidence of obsolescence, changes in the manner or duration of use of a capital asset, and construction stoppage. A capital asset generally should be considered impaired if both (a) the decline in service utility of the capital asset is large in magnitude and (b) the event or change in circumstance is outside the normal life cycle of the capital asset. Impaired capital assets that will no longer be used by Dalton Utilities will be reported at the lower of carrying value or fair value.

Amortization of Nuclear Fuel — The cost of nuclear fuel, including a provision for the disposal of spent fuel, is amortized to fuel expense based on usage. Nuclear fuel expense, which is included in production expense in the accompanying statements of revenues, expenses and changes in fund net assets, totaled $2,151,000 and $2,050,000 in 2006 and 2005, respectively.

Depreciation and Nuclear Decommissioning — Depreciation of the major classes of utility plant is computed on additions when they are placed in service using rates computed under the composite straight-line method, which approximated 3.1% for 2006 and 2.9% for 2005, and are based on the following remaining useful lives:

Electric system	26–41 years
Natural gas system	33–44 years
Water system	50–67 years
Sewer system	30–50 years
Information technology system	5–20 years

The composite annual depreciation rate for nuclear production includes a factor to provide for Dalton Utilities' expected portion of the cost of decommissioning jointly owned nuclear generating plants based on the 2005 Nuclear Regulatory Commission's ("NRC") minimum external funding requirements.

The NRC requires all licensees operating commercial nuclear power reactors to establish a plan for providing, with reasonable assurance, funds for decommissioning. Dalton Utilities has an external trust fund to comply with the NRC's regulations (Note 5). The NRC's minimum external funding requirements are based on a generic estimate of the cost to decommission the radioactive portions of a nuclear unit based on the size and type of reactor. Dalton Utilities has transferred and will continue to transfer to this fund assets estimated to be sufficient to meet its responsibilities under the NRC's guidelines. Earnings on the trust fund are considered in determining decommissioning expense.

Site study cost is the estimate to decommission a specific facility as of the site study year. The estimated costs of decommissioning based on the most current study as of December 31, 2006, for Dalton Utilities' ownership interests in plants Hatch and Vogtle were as follows (in thousands of dollars):

	Plant Hatch	Plant Vogtle
Site study year	2006	2006
Decommissioning periods:		
Beginning year	2034	2027
Completion year	2061	2051
Cost of site study	$ 76,200	$76,200
Dalton Utilities' portion (%)	2.2 %	1.6 %
	$ 1,676	$ 1,219

The decommissioning cost estimates are based on prompt dismantlement and removal of the plant from service. The actual decommissioning costs may vary from the above estimates because of changes in the assumed date of decommissioning, changes in NRC requirements, or changes in the assumptions used in making these estimates.

Georgia Power Company ("GPC") has contracts with the U.S. Department of Energy ("DOE") that provide for the permanent disposal of spent nuclear fuel. The DOE failed to begin disposing of spent fuel in January 1998 as required by the contracts, and GPC is pursuing legal remedies against the U.S. government for breach of contract. Effective June 2000, the on-site dry storage facility for Plant Hatch became operational. Sufficient capacity is believed available to continue dry storage operations at Plant Hatch through the life of the plant. Sufficient fuel storage capacity currently is available at Plant Vogtle to maintain full-core discharge capability for both units into 2014. In addition, the Energy Policy Act of 1992 gave the DOE the authority to assess utilities for the decommissioning of its facilities used for the enrichment of uranium included in nuclear fuel costs. In order to decommission these facilities, the DOE estimates that it would need to charge utilities a total of $150,000,000 annually for 15 years based on enrichment services to date. The assessment began in 1993. Dalton Utilities' remaining pro-rata share of these total payments, estimated to be $0 and $124,000 as of December 31, 2006 and 2005, respectively, is recorded as a noncurrent asset in the accompanying balance sheets and will be recovered through the electric system rates as paid. The long-term portion of the related liability is included in noncurrent liabilities in the accompanying balance sheets.

Investments — Certain of Dalton Utilities' investments are included in the restricted revenue bond funds prescribed by the Indentures. The Indentures allow Dalton Utilities to invest the revenue bond funds in the following:

- Government obligations which are direct general obligations of the U.S. government or obligations which are unconditionally guaranteed by the U.S. government
- Obligations of the Federal Home Loan Bank which are senior debt obligations
- Repurchase agreements with a term of 30 days or less

- Certificates of deposit of national or state banks
- Securities of or other interests in any no-load, open-end management type investment company or investment trust registered under the Investment Company Act of 1940
- Investments in the local government investment pool
- Any other investments to the extent and at the time permitted by then applicable law for the investment of public funds

All investments are carried at fair value based on quoted market prices as required by GASB Statement No. 31, *Accounting and Reporting for Certain Investments and External Investment Pools* ("GASB No. 31"), GASB No. 31 requires that governmental entities report investments at fair value on the balance sheet and recognize all investment income, including changes in the fair value of investments, as revenue in the statement of revenues, expenses and changes in fund net assets.

Contributions in Aid of Construction — Contributions in aid of construction include amounts received or receivable for improvements and extensions, including the estimated fair value of property received from customers and government agencies. Such amounts have been capitalized and are included principally in the water and sewer utility plant accounts.

Revenue — Revenue is recorded when earned, usually when the customer is billed. Dalton Utilities accrues revenue for utility services provided but unbilled at the end of each fiscal year. Unbilled revenues included in accounts receivable and operating revenues in the accompanying financial statements were $5,511,000 and $6,685,000 for the years ended December 31, 2006 and 2005, respectively.

In its information technology sector, Dalton Utilities has adopted the industry standard of billing its customers in advance for the telecommunication services. Deferred revenues included in accounts receivable in the accompanying financial statements were $321,000 and $242,000 for the years ended December 31, 2006 and 2005, respectively.

Electricity that is generated and not used by Dalton Utilities is sold back to Southern Power Company, the wholesale power marketing subsidiary of the Southern Company. The credits for energy sale backs are co-mingled with economy energy purchases (purchases of electricity by Dalton Utilities from Southern Power Company when the cost of Southern Power Company's electricity is lower than the cost of Dalton Utilities' jointly owned generating units). Consequently, the economic impact of those sale backs is not obtainable. Since the cost of economy energy purchases are greater on a per unit basis than the credits from the sale backs on a per unit basis, the net effect is an expense to Dalton Utilities, despite the appearance of net MWh's being sold back to Southern Power Company. In 2006 and 2005, total MWh's sold back to Southern Power Company were 114,000 and 81,000, respectively.

Cash and Cash Equivalents — Dalton Utilities considers unrestricted cash and short-term investments purchased with a maturity of three months or less to be cash and cash equivalents for purposes of the statements of cash flows. The carrying amount is a reasonable estimate of fair value for such short-term instruments. GASB Statement No. 34, *Basic Financial Statements — and Management's Discussion and Analysis - for State and Local Governments*, requires cash and cash equivalents to be shown as either restricted or unrestricted. "Restricted" refers to those funds limited by law, regulations, or Board action as to their allowable disbursement. "Unrestricted" is all other funds not meeting the requirements of restricted.

Deferred Credit-Tennessee Valley Authority ("TVA") Right of Use — During 1999, Dalton Utilities granted a right of use over a portion of its integrated transmission system ("ITS") to TVA for $1,000,000. The agreement will be in effect for the next 20 years. Dalton Utilities recorded the payment as a deferred credit in the accompanying balance sheets and is recognizing the revenue from this agreement on a straight-line basis over the 20-year period.

Allowance for Funds Used During Construction ("AFUDC") — AFUDC represents the estimated debt costs of capital funds that are necessary to finance the construction of new facilities. While cash is not realized currently from such allowance, it increases the revenue requirement over the service life of the plant through a higher rate base and higher depreciation expense. The average AFUDC rate was 5.184% and 5.101% for the years ended December 31, 2006 and 2005, respectively.

Financial Instruments — Interest Rate Swap Agreement (the "Swap Agreement") — In March 2003, Dalton Utilities entered into the Swap Agreement with Salomon Smith Barney. The agreement stipulated that Dalton Utilities pays a weekly floating rate based on BMA index (municipal bond index), which was 3.91% and 3.51% on December 31, 2006 and 2005, respectively, on a $54,540,000 notional amount. Salomon Smith Barney pays a monthly floating rate on the same notional amount based on the sum of 68% of USD LIBOR-BBA and 0.4%, which was 5.32% and 4.39% on December 31, 2006 and 2005, respectively.

Dalton Utilities follows GASB Statement No. 31, *Accounting and Financial Reporting for Certain Investments and for External Investment Pools,* and FASB Statement No. 133, *Accounting for Derivative Instruments and Hedging Activities*, as amended. Income from the Swap Agreement has been recorded as a separate line item in the accompanying statement of revenues, expenses and changes in net assets for the years ended December 31, 2006 and 2005. The net amount received under the Swap Agreement was $242,000 and $126,000 for 2006 and 2005, respectively. The amount of change in fair market value was an increase of $402,000 and an increase of $76,000 as of December 31, 2006 and 2005, respectively. This Swap Agreement is to continue until the termination date of January 1, 2012.

Financial Instruments – Natural Gas Derivatives — In August of 2006, Dalton Utilities entered into forward sales agreements with Texican Natural Gas Company (Texican). The agreements stipulated that Dalton Utilities would agree to sell Texican 500,000 mmBtu's of natural gas at an average weighted price of $10.98 during the first quarter of 2007. As Dalton Utilities held physical natural gas in its storage facilities in August, it was able to lock in a margin that would remain unchanged regardless of whether natural gas prices increased or decreased. Rising gas prices would decrease the value of its forward sales agreement and increase the value of its natural gas inventories while falling gas prices would increase the value of its forward sales agreements and decrease the value of its natural gas inventories. The January 2007 forward sales agreement was settled in December 2006 with a realized gain of $888,000 and is included in the accompanying statement of revenues, expenses and changes in net assets for the year ended December 31, 2006, as net increase (decrease) in fair value of investments. The unrealized gain of $1,335,000 from the remaining February 2007 and March 2007 forward sales agreements are included in the accompanying statement of revenues, expenses and changes in net assets, as net increase (decrease) in fair value of investments. Additionally, they are reported in the accompanying balance sheet for the year ended December 31, 2006, as Natural Gas Derivative in the amount of $1,335,000.

Fair Values — Dalton Utilities' financial instruments for which the carrying amounts did not approximate fair value at December 31, 2006 and 2005, were as follows (in thousands of dollars):

	Carrying Amount	Fair Value
Long-term debt — December 31, 2006	$ 86,856	$ 106,052
Long-term debt — December 31, 2005	101,818	122,065

Fair values of debt have been determined through information obtained from independent third parties using market data available on the last business day of the respective year.

Interutility Sales — Dalton Utilities records sales of electricity, natural gas, water, sewer, and information technology (at rates charged to customers for similar services) among its utility services as revenue of the selling utility service and expense of the purchasing utility service. During the years ended December 31, 2006 and 2005, interutility sales were as follows (in thousands of dollars):

	2006	2005
Electric	$ 4,195	$ 3,629
Natural gas	22	21
Water	208	139
Sewer	138	93
Information technology	1,175	5,710
	$ 5,738	$ 9,592

Use of Estimates — The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements. Estimates also affect the reported amounts of revenues and expenses during the year. Actual results could differ from those estimates.

Major Customers — Sales to Shaw Industries were approximately 21% and 18% of total sales, and approximately 22% and 21% of total electricity sales for the years ended December 31, 2006 and 2005, respectively. Sales to Mohawk Industries were approximately 11% of total sales for the years ended December 31, 2006 and 2005, respectively. No other customer accounted for more than 10% of Dalton Utilities' sales during 2006 or 2005.

Reclassifications — Certain 2005 amounts have been reclassified to conform with the 2006 presentation, with no material impact on total assets, total liabilities, or operations at Dalton Utilities. Specifically, $3.1 million was moved from distribution expenses to general and administrative expenses for presentation purposes.

2. RECENT ACCOUNTING PRONOUNCEMENTS

During 2004, the GASB issued Statement No. 45, *Accounting and Financial Reporting by Employers for Postemployment Benefits Other Than Pensions,* which is effective for Dalton Utilities on January 1, 2007. This statement addresses certain reporting and accounting standards for health and other non-pension benefits offered to retirees and will not have a significant impact on Dalton Utilities' financial statements.

3. ASSET RETIREMENT OBLIGATIONS AND OTHER COSTS OF REMOVAL

In accordance with regulatory requirements, prior to January 2003, Dalton Utilities followed the industry practice of accruing for the ultimate cost of retiring most long-lived assets over the life of the related asset as part of the annual depreciation expense provision. Effective January 1, 2003, the Company adopted FASB Statement No. 143, *Accounting for Asset Retirement Obligations*. FASB Statement No. 143 established new accounting and reporting standards for legal obligations associated with the ultimate costs of retiring long-lived assets. The present value of the ultimate costs for an asset's future retirement must be recorded in the period in which the liability is incurred. The costs must be capitalized as part of the related long-lived asset and depreciated over the asset's useful life. Additionally, FASB Statement No. 143 does not permit the continued accrual of future retirement costs for long-lived assets that the company does not have a legal obligation to retire. However, Dalton Utilities currently accrues for removal costs on many of its regulated long-lived assets through depreciation expense as provided in rates.

The asset retirement liability recognized to retire long-lived assets under FASB Statement No. 143 primarily relates to Dalton Utilities' ownership interest in Georgia Power's plants Hatch and Vogtle. Dalton Utilities will continue to recognize in the income statement allowed removal costs in accordance with regulatory treatment. Any difference between costs recognized under FASB Statement No. 143 and those reflected in rates are recognized on the balance sheet as either a regulatory asset or liability. The Company has also identified retirement obligations related to certain transmission and distribution facilities and properly associated with the sewer system. However, liabilities for the removal of these assets have not been recorded because no reasonable estimate can be made regarding the timing of any related retirements.

Details of the asset retirement obligations included on the balance sheet are as follows (in thousands of dollars):

	2006	2005
Beginning Balance	$ 34,585	$33,094
Reduction in Estimated Cash Flows	(8,938)	
Accretion	1,263	1,491
Ending Balance	$ 26,910	$ 34,585

The reduction of estimated cash flows was a result of a downward estimate of future asset retirement costs, as well as a correction to the anticipated timing of cash flows expected to be incurred.

Participation in Electric Generation and Transmission Facilities — Dalton Utilities participates in the ownership of electric generation and transmission facilities to meet the present and future service demands of its customers. Dalton Utilities has entered into agreements with GPC for the construction, purchase, ownership, operation, and maintenance of the following facilities:

	Dalton Utilities' Ownership Percentage
Electric plant in service:	
Plant Hatch — Nuclear Units 1 and 2	2.2 %
Plant Vogtle — Nuclear Units 1 and 2	1.6
Plant Wansley — Coal-fired Units 1 and 2	1.4
Plant Scherer — Coal-fired Units 1 and 2	1.4

Dalton Utilities' proportionate share of direct expenses of joint operation of the above plants is included in the corresponding operating expense captions in the accompanying statements of revenues, expenses and changes in fund net assets.

4. INTEGRATED TRANSMISSION SYSTEM ("ITS") FACILITIES

Dalton Utilities is required, under the ITS agreement (the "ITS Agreement") with GPC, Georgia Transmission Corporation and the Municipal Electric Authority of Georgia, to maintain a specified level of investment (e.g., parity) in transmission facilities necessary to provide for the transporting of electric energy to customers within the state of Georgia, which is in proportion to Dalton Utilities' use of such system. Parity will therefore fluctuate in response to any changes in Dalton Utilities' load requirements, as well as any changes in the level of investment in transmission facilities made by the other participants in the ITS Agreement. As of December 31, 2006 and 2005, Dalton Utilities' investment in ITS facilities was greater than parity, as defined by the ITS Agreement. The required level of investment and the excess investment in the transmission facilities are included in the accompanying balance sheets as utility plant. The excess investment earns investment income from the other participants in the ITS Agreement. Dalton Utilities intends to remain in an overparity position to take advantage of favorable rates of return on this investment.

Dalton Utilities' total investment in ITS facilities at December 31, 2006 and 2005, was $65.0 million and $61.3 million, respectively.

5. INVESTMENTS

Dalton Utilities has investments in the restricted funds and nuclear decommissioning fund ("Nuclear Decommissioning Fund"). Restricted funds include the revenue bond funds prescribed by the Indentures, the fund for customer deposits, and other funds which are segregated from the operating funds at the direction of Dalton Utilities. The Nuclear Decommissioning Fund holds funds held in accordance with the NRC's guidelines. Investments in the restricted funds and Nuclear Decommissioning Fund are stated at fair market value.

Dalton Utilities invests in two categories of securities: U.S. government and government agency securities and repurchase agreements. As required by GASB Statement No. 3, *Deposits with Financial Institutions, Investments (Including Repurchase Agreements)*, *and Reverse Repurchase Agreements*, Dalton Utilities' investments are categorized below by level of risk. Category 1 includes the U.S. government and government agency securities that are registered and held by Dalton Utilities or its agent in Dalton Utilities' name. The contractual maturities of these securities can range from 6 months

to 50 years. Category 2 includes the securities collateralizing the repurchase agreements that are uninsured and unregistered and are not required to be insured or registered. Such securities are held by a bank's trust department or agent and are pledged in Dalton Utilities' name.

	Category 1	Category 2	Total Market
	(In thousands of dollars)		
December 31, 2006			
Customer Deposit Fund			
U.S. government and government agency securities	$ 2,703	$ -	$ 2,703
Total	$ 2,703	$ -	$ 2,703
Combined Utilities Sinking Fund			
Cash and cash equivalents*	$ -	$ 17,507	$ 17,507
Total	$ -	$ 17,507	$ 17,507
Combined Utilities Renewals and Extensions			
U.S. government and government agency securities	$ 80,793	$ -	$ 80,793
Total	$ 80,793	$ -	$ 80,793
Nuclear Decommissioning Fund			
U.S. government and government agency securities	$ 55,834	$ -	$ 55,834
Total	$ 55,834	$ -	$ 55,834

	Category 1	Category 2	Total Market
	(In thousands of dollars)		
December 31, 2005			
Customer Deposit Fund			
U.S. government and government agency securities	$ 2,163	$ -	$ 2,163
Total	$ 2,163	$ -	$ 2,163
Combined Utilities Sinking Fund			
Cash and cash equivalents*	$ -	$ 17,124	$ 17,124
Total	$ -	$ 17,124	$ 17,124
Combined Utilities Renewals and Extensions			
U.S. government and government agency securities	$ 133,911	$ -	$ 133,911
Total	$ 133,911	$ -	$ 133,911
Nuclear Decommissioning Fund			
U.S. government and government agency securities	$ 56,864	$ -	$ 56,864
Total	$ 56,864	$ -	$ 56,864

* Cash and cash equivalents include U.S. government and government agency securities and repurchase agreements purchased with a maturity of three months or less. Such securities are held by a trustee in accordance with Dalton Utilities' bond indenture.

The fair value analyses of the investments for the years ended December 31, 2006 and 2005, are as follows (in thousands of dollars):

	2006						
			Fair Value				
Fund Type	Cost	Beginning Fair Value at January 1, 2006	Purchases	Sales	Subtotal	Ending Fair Value at December 31, 2006	Change in Fair Value
Customer Deposit Fund	$ 5,124	$ 2,163	$ 2,595	$ 2,018	$ 2,740	$ 2,703	$ (37)
Combined Utilities R&E Fund	151,701	133,911	227,949	275,569	86,291	80,793	(5,498)
Nuclear Decommissioning Fund	33,667	56,864	26,914	26,906	56,872	55,805	(1,067)
	$ 190,492	$ 192,938	$ 257,458	$ 304,493	$ 145,903	$ 139,301	$ (6,602)

	2005						
			Fair Value				
Fund Type	Cost	Beginning Fair Value at January 1, 2005	Purchases	Sales	Subtotal	Ending Fair Value at December 31, 2005	Change in Fair Value
Customer Deposit Fund	$ 529	$ 750	$ 1,426	$ -	$ 2,176	$ 2,163	$ (13)
Combined Utilities R&E Fund	128,909	182,120	116,585	169,806	128,899	133,911	5,012
Nuclear Decommissioning Fund	33,382	52,801			52,801	56,864	4,063
	$ 162,820	$ 235,671	$ 118,011	$ 169,806	$ 183,876	$ 192,938	$ 9,062

* The change in fair value includes $5,464,000 and $8,349,000 in the years ended December 31, 2006 and 2005, respectively, relating to interest income accrued on the zero-coupon bonds.

CHANGE IN FAIR MARKET VALUE

	2006	2005
Fund Type		
Customer Deposit Fund	$ (37)	$ (13)
Combined Utilities R&E Fund	(1,067)	4,063
Nuclear Decommissioning Fund	(5,498)	4,936
Interest Rate Swap	402	76
Gas Derivatives:		
Realized gain	888	
Unrealized gain	1,335	
	$ (3,977)	$ 9,062

Investment Risk Disclosures — As of December 31, 2006, Dalton Utilities had the following investments and maturities (in thousands of dollars):

			Investment Maturities (in Years)			
	Credit Quality	Fair Value	Less Than 1	1–5	6–10	More Than 10
U.S. Treasury Bonds	-	$ 1,465	$ -	$ -	$ 1,465	$ -
Federal Home Loan Bank	-	1,990				1,990
Federal Home Loan Mortgage Corporation	AAA/Aaa	96,049			22,026	74,023
Federal National Mortgage Association	AAA/Aaa	15,845				15,845
Coupons (US Strip)	-	6,782			3,667	3,115
Coupons (Resolution Fund Corporation)	-	17,170				17,170
Repurchase agreements (1)	-	6	6			
Bond Repurchase agreements (2)	-	17,280	17,280			
Total		$ 156,587	$ 17,286	$ -	$ 27,158	$ 112,143

(1)

(2) Collateral for these repurchase agreements is held by the Federal Reserve Bank and is pledged to the account of Dalton Utilities.

(3) Collateral for these repurchase agreements, used in the Combined Utilities Sink Fund is held by a third part custodian.

Interest Rate Risk — Dalton Utilities does not have a formal investment policy that limits investment maturities as a means of managing its exposure to fair value losses arising from increasing interest rates.

Credit Risk — Dalton Utilities bond ordinance follows Georgia state law in restricting investments to obligations of the United States Government.

Custodial Credit Risk — Dalton Utilities does not incur custodial credit risk. All of its investments are held by an independent third party custodian except for repurchase agreements noted above as (1). Collateral for these repurchase agreements (1) is held by the Federal Reserve Bank and is pledged to the account of Dalton Utilities.

Concentration of Credit Risk — Dalton Utilities does not place a limit on the amount it may invest in any one issuer. More than 65% and 13% of its investments are in debentures of the Federal Home Loan Mortgage Corporation (FHLMC) and the Federal National Mortgage Association (FNMA), respectively.

Foreign Currency Risk — Dalton Utilities does not invest in foreign securities.

6. TRANSFERS TO THE CITY OF DALTON

In accordance with an arrangement between Dalton Utilities and the Mayor (the "Mayor") and the Council of the City of Dalton (the "Council"), transfers based on an agreed-upon formula are made to the City to be utilized for any purpose that the Mayor and the Council deem appropriate. Cash transferred to the City of Dalton during the years ended December 31, 2006 and 2005, was $8,184,000 and $7,108,000, respectively. Due to an accrual in 2004 of $657,000 for cash to be transferred in 2005, the 2005 transfer amount reflected is $6,451,000 in the statements of revenues, expenses and changes in fund net assets. Cash to be transferred in 2007 relating to 2006 operations is $8,265,000.

7. LONG-TERM DEBT

At December 31, 2006 and 2005, total long-term debt consisted of the following (in thousands):

	2006	2005
Term bonds, Series 1997, 4.865%, maturing in 2008; payable from combined utilities revenues, net of unamortized premium of $37 and $103 in 2006 and 2005, respectively	$ 19,247	$ 28,153
Term bonds, Series 1999, 5.36%, maturing in 2012; payable from combined utilities revenues, net of unamortized premium of $634 and $830 in 2006 and 2005, respectively	82,309	87,595
Less: current maturities/sinking fund redemptions	(14,700)	(13,930)
	$ 86,856	$ 101,818

Annual sinking fund installments and interest payments on long-term debt, as set forth in the Indentures, are as follows (in thousands of dollars):

Fiscal Year Ending December 31 (Due January 1 of the following year)	Sinking Fund Installments	Interest	Total Debt Service
2007	$ 15,430	$ 4,867	$ 20,297
2008	16,305	3,995	20,300
2009	17,170	3,127	20,297
2010	18,105	2,191	20,296
2011–2012	19,175	1,124	20,299
	$ 86,185	$ 15,304	$ 101,489

8. INCOME TAXES

The enterprise is exempt from federal and state income taxes. However, Dalton Utilities pays ad valorem taxes on its electric, gas, water, and sewer facilities in their residing counties outside of Whitfield County. Additionally, Dalton Utilities pays ad valorem taxes on its natural gas inventories stored out of the state of Georgia plus all applicable federal, state, and local taxes and fees on its telecommunications services. State sales taxes are collected from customers on electric, gas, and telecommunication services then paid to the state of Georgia.

9. DEFINED BENEFIT PENSION PLAN

Plan Description — Substantially all full-time employees that were hired before July 1, 2002, are covered by the City of Dalton Employees' Pension Plan (the "Pension Plan"), which is a cost-sharing plan under the Public Retirement Systems Standards Law (Georgia Code Section 47-20-10) (the "Public Retirement Systems"). All full-time employees who have completed six months of continuous service are eligible to participate in the Pension Plan. The Pension Plan provides pension benefits, deferred pension benefits, and survivor benefits.

Benefits fully vest after ten years of service. Employees who retire at the normal retirement date are entitled to monthly pension payments for the remainder of their lives equal to 0.15% of their final average monthly earnings times the months of credited service for which they were employed by an entity of the Pension Plan. These benefit payments may be subject to an annual cost-of-living adjustment. The final average earnings are the average of basic monthly earnings during 36 consecutive calendar months out of the last ten years which produce the highest average. Monthly pension benefits will be paid as a life annuity to the participant, with 120 payments guaranteed.

Pension provisions include deferred pension benefits whereby an employee may terminate his/her employment with Dalton Utilities after accumulating 15 years of service and reaching the age of 50.

Pension provisions include survivor benefits whereby the surviving spouse is entitled to receive annually an amount equal to 55% of the employee's pension benefit at the time of death, commencing after 120 payments of the full benefit amount have been received. The surviving spouse may receive survivor benefits for life as long as he/she does not remarry. Benefits are determined by the Pension Plan.

Funding Policy — The actuarial report covering the Pension Plan has been completed as of January 1, 2006. Combined contributions from both the employer and employee will be needed to adequately fund both the Pension Plan's ongoing cost and the 20-year amortization of the unfunded actuarial accrued liability from January 1, 1991.

The annual funding requirement for the plan consists of the following components:

- Normal Cost — the amount due to pay for the value of benefits earned in the plan year.

- Amortization of unrecognized liabilities — an annual recognition of costs due to past plan changes, assumption changes, initial unfunded liabilities, and actuarial gains/losses. As of January 1, 2006, all liabilities and gains of that date have been combined and were scheduled to be funded over 15-year periods.

These amounts are funded through Dalton Utilities' employee and employer contributions of 4% and 6%, respectively, of the employees' earnings. However, recent actuarial valuations have indicated that Dalton Utilities will need to fund at a level greater than 6%. The actuarial valuations of January 1, 2006, recommended that Dalton Utilities contribute at 11.4% and 9.7% for 2006 and 2005, respectively, of the employee's earnings. Dalton Utilities remitted 10.8% of the employee's earnings to the Pension Fund during both years of 2006 and 2005. Employer and employee contributions were made by the City of Dalton, of which Dalton Utilities and its employees contributed $1.7 million and $1.6 million for 2006 and 2005, respectively.

Related-Party Investments — During the years ended December 31, 2006 and 2005, the Pension Plan held no securities issued by Dalton Utilities or other related parties.

10. DEFINED CONTRIBUTION RETIREMENT PLAN

Employees with an employment commencement date, including former employees rehired after a severance, on or after July 1, 2002 will not be allowed to participate in the above described Pension Plan. Employees hired or rehired after July 1, 2002, will be covered by the City of Dalton Employee Retirement Plan (the "Retirement Plan"), which is a Combined Profit Sharing/Money Purchase Plan. All full-time employees who have completed six months of continuous service are eligible to participate in the Retirement Plan. This plan is considered a defined contribution plan in which the employer provides $1.00 for every $1.00 of deferred compensation the employee makes to the Retirement Plan. The employer will make this match up to the first 4% of the employee's compensation, up to an annual limit of $200,000. Employer matching contributions fully vest after one year of service. Participation is not mandatory; however, nonparticipating employees will not receive any matching employer contributions. Employer and employee contributions made by Dalton Utilities for the years ended December 31, 2006 and 2005, were $165,000 and $125,000, respectively.

11. COMMITMENTS AND CONTINGENCIES

Capital Expenditures — Dalton Utilities has a rolling five-year capital budget approximating $244,000,000. A large portion of this is directed to maintaining service delivery capability and regulated production capacity of Dalton Utilities' aged infrastructure, while complying with increasing environmental regulations. Additionally, substantial capital dollars will need to be expended in order to establish preventative maintenance, extension, and expansion of the Dalton Utilities' infrastructure.

Certain Environmental Contingencies and Litigation — Dalton Utilities is subject to present and developing environmental regulations by various federal, state, and local jurisdictions. To date, Dalton Utilities has received federal grants for a large portion of its capital expenditures for wastewater treatment facilities. Expenditures for additional wastewater treatment facilities and water treatment facilities are not expected to be covered by federal grants and will instead require expenditures to be borne by Dalton Utilities.

On May 25, 2001, Dalton Utilities paid a $6,000,000 fine to the United States Department of Justice. The $6,000,000 had been recorded as "EPA/EPD civil penalty" in the statement of revenues, expenses and changes in net assets for the year ended December 31, 1999. On March 28, 2001, a Consent Decree containing a settlement between Dalton Utilities and the U.S. Environmental Protection Agency and the State of Georgia was entered by the Court. Compliance with the terms of the Consent Decree required that Dalton Utilities undertake certain actions, all of which have been completed. After March 28, 2002, Dalton Utilities could request that some or all of the Consent Decree be terminated if certain prerequisites were met to the Court's satisfaction. Compliance with the Consent Decree proceeded smoothly. On September 10, 2004, the Court terminated three of four portions of the Consent Decree. On November 16, 2005, the Court terminated the Consent Decree in its entirety. Dalton Utilities is no longer subject to the jurisdiction of the Court.

Civil Action Against Georgia Power Company —During November 1999, the EPA brought a civil action in the U.S. District Court for the Northern District of Georgia against GPC. The complaint alleges violations of the prevention of significant deterioration and new source review provisions of the Clean Air Act with respect to coal-fired generating facilities at certain plants owned by GPC, including Plant Scherer. The civil action requests penalties and injunctive relief, including an order requiring the installation of the best available control technology at the affected units beginning at the point of the alleged violations. The Clean Air Act authorized civil penalties of up to $27,500 per day per violation at each generating unit. Prior to January 30, 1997, the penalty was $25,000 per day.

The EPA concurrently issued a notice of violation to GPC relating to the plants named in the complaint. In early 2000, the EPA filed a motion to amend its complaint to add the violations alleged in its notice of violation. The complaint and notice of violation are similar to those brought against and issued to several other electric utilities. The complaint and notice of violation allege that GPC failed to secure necessary permits or install additional pollution equipment when performing maintenance and construction at coal-burning plants constructed or under construction prior to 1978.

As discussed in Note 3, Dalton Utilities owns 1.4% of Plant Scherer and would therefore be liable based on its percentage ownership for any capital expenditures and penalties relating to Plant Scherer. An adverse outcome of this matter could require substantial capital expenditures that cannot be determined at this time and possibly require payment of substantial penalties.

New Source Review Reform Rules — On October 20, 2005, the EPA published a proposed rule clarifying the test for determining when an emissions increase is subject to the NSR requirements. On March 17, 2006, the U.S. Court of Appeals for the District of Columbia Circuit vacated the EPA's proposed rule which sought to clarify the scope of the existing routine maintenance, repair, and replacement exclusion. Because this rule was not yet in effect, the Court's ruling is not anticipated to have any impact on Georgia Power Company and its co-owners.

Five-Year Permit for Wastewater Treatment — During 1997, Dalton Utilities was issued a new five-year permit for its wastewater treatment systems by the Environmental Protection Division of the Georgia Department of Natural Resources ("EPD"). The new permit was contingent upon the undertaking by Dalton Utilities to make certain improvements to its wastewater treatment systems and included a

compliance schedule for those improvements. Dalton Utilities completed all improvements required under the 1997 permit. In March 2002, Dalton Utilities requested and received a two-year extension of the permit to allow time for a full watershed assessment to be performed. The assessment was completed on December 24, 2003, and a permit renewal application was submitted in accordance with the requirements of the existing permit. The permit was reissued on March 26, 2007.

Monroe County Board of Tax Assessors vs Dalton Utilities — The Monroe County Board of Tax Assessors has changed its apportioned share of the unitary value of Dalton Utilities' interest in Plant Scherer as provided by the Revenue Commissioner and approved by the State Board of Equalization. The result is higher ad valorem taxes levied on Dalton Utilities' interest in Plant Scherer. Dalton Utilities and the other owners are appealing the assessment and the actions of the Monroe County Board of Tax Assessors.

The Trial Court denied the motion for summary judgment in favor of Georgia Power Company (and other owners such as Dalton Utilities). However, the Court of Appeals reversed in a full court decision on March 30, 2007, in which it held that summary judgment should have been granted in favor of Georgia Power and the other owners. Monroe County has filed a Petition for Writ of Certiorari to the Supreme Court of Georgia seeking to reverse the decision of the Court of Appeals. Georgia Power has opposed this petition. This petition is now pending before the Georgia Supreme Court.

Risk Management — Dalton Utilities has transferred risk of property and casualty loss to commercial insurers for the majority of the risks for which it is exposed, except for the environmental liabilities discussed above. Dalton Utilities participates with other agencies in the City's Self-Insurance Fund (the "Fund"), a public-entity risk pool currently operating as a common risk management and insurance program for employees of the City. Dalton Utilities pays annual premiums to the Fund for its medical and workers' compensation coverage, and these premiums are used to pay related claims, claim reserves, and administrative costs. In addition, medical claims in excess of $150,000 per covered individual are covered through a commercial insurer. The amount accrued for claims incurred but not paid for the years ended December 31, 2006 and 2005, were $200,000 and $196,000, respectively.

Dalton Utilities maintains private insurance through its participation with GPC and agreements of indemnity with the NRC to cover third-party liability arising from a nuclear incident which might occur at the nuclear plants in which Dalton Utilities has an interest. In the event a public liability loss arising from a nuclear incident at a facility currently covered by government indemnification exceeds $300,000,000, under the current provisions of the Price-Anderson Act, the owners of a nuclear power plant could be assessed a deferred assessment of up to $100,590,000 per incident for each licensed reactor operated by it, but not more than $15,000,000 per reactor per incident to be paid in a calendar year. Dalton Utilities is liable for its share of any such deferred assessment. Based on its ownership percentage in nuclear plants as set forth in Note 3, Dalton Utilities maximum annual assessment would be $1,140,000.

GPC, on behalf of all co-owners of Plants Hatch and Vogtle, is a member of Nuclear Electric Insurance Limited ("NEIL"). NEIL is a mutual insurer established to provide insurance coverage against property damage to its members' nuclear generating facilities. In the event that losses exceed accumulated reserve funds, the members are subject to retroactive premium assessments in proportion to their participation in the mutual insurer. Dalton Utilities' maximum annual assessment would be $1,121,646 under current policies.

All retrospective assessments, whether generated for liability, property, or replacement power, may be subject to applicable state premium taxes.

Future Nuclear Plants — Dalton Utilities is in current discussions with Georgia Power Company in which Dalton Utilities has expressed an interest in pursuing a possible ownership purchase in the next generation of nuclear plants that Georgia Power Company may be building at the existing Plant Vogtle Nuclear Plant Site.

Fuel Commitments — Dalton Utilities, through O&M agreements with GPC for its co-owned generating facilities, is obligated for its pro-rata portion of fossil and nuclear fuel used at its jointly owned generating facilities. Additionally, Dalton Utilities is obligated to make fixed capacity payments in its natural gas sector of $5,400,000 per year to cover its transmission and storage services it receives from Southern Natural Gas, Texas Eastern Transmission Company, and East Tennessee. It is also obligated to make fixed capacity payments in its electric sector of $14,500,000 per year to Southern Company and SEPA to cover its firm electric requirements. These payments are consistent with those made during the years ended December 31, 2006 and December 31, 2005. Dalton Utilities purchases natural gas on a 30-day basis and does not have any long term contracts to purchase natural gas.

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REQUIRED SUPPLEMENTARY INFORMATION

THE BOARD OF WATER, LIGHT AND SINKING FUND COMMISSIONERS OF THE CITY OF DALTON, GEORGIA

REQUIRED SUPPLEMENTARY INFORMATION
SCHEDULE OF FUNDING PROGRESS

Actuarial Valuations — The following represents the funding progress of the Pension Plan based on the past seven actuarial valuations:

Actuarial Valuation Date	Actuarial Value of Assets	Actuarial Accrued Liability ("AAL")	Unfunded AAL ("UAAL")	Funded Ratio	Covered Payroll	UAAL as a Percentage of Covered Payroll
January 1, 2006	$ 54,466,921	$ 70,208,760	$ 15,741,839	77.6 %	$ 23,777,732	66.2 %
January 1, 2005	52,617,082	67,353,669	14,736,587	78.1	24,117,608	61.1
January 1, 2004	48,717,335	70,116,207	21,398,872	69.5	25,247,408	84.8
January 1, 2003	42,452,389	74,056,656	31,604,268	57.3	24,991,641	126.5
January 1, 2001	43,235,142	63,902,546	20,667,402	67.7	21,065,143	98.1
January 1, 1999	41,952,246	55,115,649	13,163,403	76.1	18,559,002	70.9
January 1, 1998	37,620,675	52,401,060	14,780,385	71.8	17,161,839	86.1

The actuarial values shown above include information for both the City of Dalton and Dalton Utilities.

OTHER SUPPLEMENTARY INFORMATION

THE BOARD OF WATER, LIGHT AND SINKING FUND COMMISSIONERS OF THE CITY OF DALTON, GEORGIA

SYSTEM BALANCE SHEET
DECEMBER 31, 2006
(In thousands of dollars)

ASSETS	Combined Systems	Electric System	Gas System	Water System	Sewer System	Information Technology System
CURRENT ASSETS:						
Cash and cash equivalents	$ 1,192	$ 560	$ 203	$ 155	$ 191	$ 83
Restricted cash						
Restricted funds:						
Customer deposit fund	2,703	1,379	514	378	432	
Combined utilities sinking fund	17,507	6,127	350	5,427	5,603	
Accounts receivable, less allowance for doubtful accounts of $876 and $522 in 2006 and 2005, respectively	15,591	7,667	2,856	2,105	2,405	558
Accrued interest receivable	2,484	1,178	320	369	425	192
Fuel stocks — at average cost	7,163	1,381	5,782			
Materials and supplies inventory — at average cost	8,812	6,252	298	554	89	1,619
Deposits and prepaid expenses	652	343	125	67	82	35
Total current assets	56,104	24,887	10,448	9,055	9,227	2,487
NONCURRENT ASSETS						
Restricted funds:						
Combined utilities renewals and extensions fund	80,793	29,893	1,616	19,390	20,198	9,696
Natural gas derivative	1,335		1,335			
Nuclear decommissioning fund	55,834	55,834				
	137,962	85,727	2,951	19,390	20,198	9,696
Capital assets:						
Utility plant	906,353	315,628	19,710	224,163	235,217	111,635
Less accumulated depreciation	(277,803)	(151,606)	(7,400)	(42,561)	(52,494)	(23,742)
Total utility plant — net	628,550	164,022	12,310	181,602	182,723	87,893
Construction work in progress	5,688	92	163	12	11	5,410
Nuclear fuel — at amortized cost	6,739	6,739				
Total capital assets	640,977	170,853	12,473	181,614	182,734	93,303
DEBT EXPENSE — Net of accumulated amortization	562	197	11	174	180	
REGULATORY ASSET	27,931	22,633				5,298
Total noncurrent assets	807,432	279,410	15,435	201,178	203,112	108,297
TOTAL	$ 863,536	$ 304,297	$ 25,883	$ 210,233	$ 212,339	$ 110,784

(Continued)

THE BOARD OF WATER, LIGHT AND SINKING FUND COMMISSIONERS OF THE CITY OF DALTON, GEORGIA

SYSTEM BALANCE SHEET
DECEMBER 31, 2006
(In thousands of dollars)

LIABILITIES AND NET ASSETS	Combined Systems	Electric System	Gas System	Water System	Sewer System	Information Technology System
CURRENT LIABILITIES:						
Current maturities of long-term debt	$ 14,700	$ 5,145	$ 294	$ 4,557	$ 4,704	$ -
Accrued interest on long-term debt	2,798	979	56	867	896	
Customer deposits	2,612	1,332	496	366	418	
Accounts payable and accrued expenses	21,020	11,768	2,350	2,144	2,681	2,077
Total current liabilities	41,130	19,224	3,196	7,934	8,699	2,077
Noncurrent liabilities:						
Deferred credit — TVA right of use	617				617	
Long-term debt	86,856	30,366	1,737	26,898	27,760	95
Asset retirement obligations	26,910	26,910				
Regulatory liability	19,160	6,885	351	4,735	4,735	2,454
Total noncurrent liabilities	133,543	64,161	2,088	31,633	33,112	2,549
Total liabilities	174,673	83,385	5,284	39,567	41,811	4,626
COMMITMENTS AND CONTINGENCIES						
NET ASSETS:						
Invested in capital assets — net of related debt	518,484	123,201	10,035	144,557	144,639	96,052
Restricted for debt service	17,507	6,127	350	5,427	5,603	
Restricted for capital projects	80,793	29,893	1,616	19,390	20,198	9,696
Restricted for customer deposit fund, nuclear decommissioning, restricted cash, and natural gas derivative	59,872	57,213	1,849	378	432	
Unrestricted	12,207	4,478	6,749	914	(344)	410
Total net assets	688,863	220,912	20,599	170,666	170,528	106,158
TOTAL	$863,536	$304,297	$25,883	$210,233	$212,339	$110,784

(Concluded)

THE BOARD OF WATER, LIGHT AND SINKING FUND COMMISSIONERS OF THE CITY OF DALTON, GEORGIA

SYSTEM BALANCE SHEET
DECEMBER 31, 2005
(In thousands of dollars)

ASSETS	Combined Systems	Electric System	Gas System	Water System	Sewer System	Information Technology System
CURRENT ASSETS:						
Cash and cash equivalents	$ 1,431	$ 658	$ 301	$ 172	$ 186	$ 114
Restricted funds:						
Customer deposit fund	2,163	1,082	497	281	303	
Combined utilities sinking fund	17,124	5,822	514	6,507	4,281	
Accounts receivable, less allowance for doubtful accounts of $876 and $522 in 2006 and 2005, respectively	18,817	9,258	4,259	2,407	2,592	301
Accrued interest receivable	1,787	798	197	315	310	167
Fuel stocks — at average cost	3,383	314	3,069			
Materials and supplies inventory — at average cost	7,698	5,682	274	623	95	1,024
Deposits and prepaid expenses	1,093	934	74	31	34	20
Total current assets	53,496	24,548	9,185	10,336	7,801	1,626
NONCURRENT ASSETS						
Restricted funds:						
Combined utilities renewals and extensions fund	133,911	48,208	4,017	32,139	34,817	14,730
Nuclear decommissioning fund	56,864	56,864				
	190,775	105,072	4,017	32,139	34,817	14,730
Capital assets:						
Utility plant	855,013	300,442	19,231	232,757	208,906	93,677
Less accumulated depreciation	(250,226)	(142,685)	(9,870)	(37,470)	(46,945)	(13,256)
Total utility plant — net	604,787	157,757	9,361	195,287	161,961	80,421
Construction work in progress	13,732	1,197		1,848	946	9,741
Nuclear fuel — at amortized cost	5,344	5,344				
Total capital assets	623,863	164,298	9,361	197,135	162,907	90,162
DEBT EXPENSE — Net of accumulated amortization	930	316	28	353	233	
REGULATORY ASSET (Note 3)	26,424	26,424				
DEPARTMENT OF ENERGY DECOMMISSIONING ASSESSMENT (Note 1)	124	124				
Total noncurrent assets	842,116	296,234	13,406	229,627	197,957	104,892
TOTAL	$895,612	$320,782	$22,591	$239,963	$205,758	$106,518

(Continued)

THE BOARD OF WATER, LIGHT AND SINKING FUND COMMISSIONERS OF THE CITY OF DALTON, GEORGIA

SYSTEM BALANCE SHEET
DECEMBER 31, 2005
(In thousands of dollars)

LIABILITIES AND NET ASSETS	Combined Systems	Electric System	Gas System	Water System	Sewer System	Information Technology System
CURRENT LIABILITIES:						
Current maturities of long-term debt	$ 13,930	$ 4,736	$ 279	$ 4,876	$ 4,039	$ -
Accrued interest on long-term debt	3,184	1,083	64	1,114	923	
Customer deposits	2,532	1,266	582	329	355	
Accounts payable and accrued expenses	23,710	13,305	3,460	2,173	2,754	2,018
Total current liabilities	43,356	20,390	4,385	8,492	8,071	2,018
Noncurrent liabilities:						
Deferred credit — TVA right of use	667				667	
Long-term debt	101,818	34,572	2,037	35,590	29,489	130
Asset retirement obligations	34,585	34,585				
Regulatory liability	17,067	6,102	309	4,633	3,861	2,162
Total noncurrent liabilities	154,137	75,259	2,346	40,223	34,017	2,292
Total liabilities	197,493	95,649	6,731	48,715	42,088	4,310
COMMITMENTS AND CONTINGENCIES						
NET ASSETS:						
Invested in capital assets — net of related debt	479,703	109,644	6,672	150,922	124,595	87,870
Restricted for debt service	17,124	5,822	514	6,507	4,281	
Restricted for capital projects	133,911	48,208	4,017	32,139	34,817	14,730
Restricted for customer deposit fund, nuclear decommissioning, restricted cash, and natural gas derivative	59,027	57,946	497	281	303	
Unrestricted	8,354	3,513	4,160	1,399	(326)	(392)
Total net assets	698,119	225,133	15,860	191,248	163,670	102,208
TOTAL	$895,612	$320,782	$22,591	$239,963	$205,758	$106,518

(Concluded)

THE BOARD OF WATER, LIGHT AND SINKING FUND COMMISSIONERS OF THE CITY OF DALTON, GEORGIA

SYSTEM STATEMENT OF REVENUES, EXPENSES AND CHANGES IN NET ASSETS
YEAR ENDED DECEMBER 31, 2006
(In thousands of dollars)

	Combined Systems	Electric System	Gas System	Water System	Sewer System	Information Technology System
OPERATING REVENUES:						
Electric	$ 71,339	$ 71,339	$ -	$ -	$ -	$ -
Natural gas	26,227		26,227			
Water	19,595			19,595		
Sewer	23,385				23,385	
Information technology	11,241					11,241
Total operating revenues	151,787	71,339	26,227	19,595	23,385	11,241
OPERATING EXPENSES:						
Production	34,655	21,931		4,176	8,548	
Purchased electricity	36,952	36,952				
Purchased natural gas	22,445		22,445			
Distribution	17,950	4,480	1,054	3,259	960	8,197
Depreciation of utility plant	27,800	10,168	783	6,110	6,541	4,198
General and administrative expenses	11,614	2,439	1,161	5,110	1,858	1,046
Total operating expenses	151,416	75,970	25,443	18,655	17,907	13,441
OPERATING INCOME (LOSS)	371	(4,631)	784	940	5,478	(2,200)
NONOPERATING REVENUES (EXPENSES):						
Interest:						
Income	5,548	2,371	105	1,210	1,254	608
Expense	(5,701)	(1,710)	(114)	(1,539)	(1,539)	(799)
Interest income (expense) — net	(153)	661	(9)	(329)	(285)	(191)
Net increase in fair value of investments	(3,977)	(1,357)	2,064	(1,842)	(1,920)	(922)
Investment income	1,126	1,126				
Swap income	242	114	41	31	39	17
Allowance for debt funds used during construction	768	67	1	156	91	453
Miscellaneous income	371	65	23	18	255	10
Total nonoperating revenues (expense) — net	(1,623)	676	2,120	(1,966)	(1,820)	(633)
INCOME (LOSS) BEFORE TRANSFERS	(1,252)	(3,955)	2,904	(1,026)	3,658	(2,833)
CASH TRANSFERRED TO THE CITY OF DALTON	(8,184)	(3,846)	(1,391)	(1,064)	(1,309)	(574)
CHANGES IN FUND NET ASSETS	(9,436)	(7,801)	1,513	(2,090)	2,349	(3,407)
FUND NET ASSETS — Beginning of year	608,723	309,071	24,946	160,456	109,143	5,107
FUND NET ASSETS — End of year	$599,287	$301,270	$26,459	$158,366	$111,492	$ 1,700

THE BOARD OF WATER, LIGHT AND SINKING FUND COMMISSIONERS OF THE CITY OF DALTON, GEORGIA

SYSTEM STATEMENT OF REVENUES, EXPENSES AND CHANGES IN NET ASSETS
YEAR ENDED DECEMBER 31, 2005
(In thousands of dollars)

	Combined Systems	Electric System	Gas System	Water System	Sewer System	Information Technology System
OPERATING REVENUES:						
Electric	$ 66,495	$ 66,495	$ -	$ -	$ -	$ -
Natural gas	30,728		30,728			
Water	17,150			17,150		
Sewer	19,198				19,198	
Information technology	12,014					12,014
Total operating revenues	145,585	66,495	30,728	17,150	19,198	12,014
OPERATING EXPENSES:						
Production	33,531	20,412		4,647	8,472	
Purchased electricity	38,152	38,152				
Purchased natural gas	23,854		23,854			
Distribution	18,825	5,818	1,555	3,500	1,141	6,811
Depreciation of utility plant	25,094	9,312	564	4,356	5,968	4,894
General and administrative expenses	9,962	2,002	759	2,554	1,104	3,543
Total operating expenses	149,418	75,696	26,732	15,057	16,685	15,248
OPERATING INCOME (LOSS)	(3,833)	(9,201)	3,996	2,093	2,513	(3,234)
NONOPERATING REVENUES (EXPENSES):						
Interest:						
Income	5,188	2,161	129	1,168	1,149	581
Expense	(6,555)	(2,229)	(131)	(2,294)	(1,901)	
Interest income (expense) — net	(1,367)	(68)	(2)	(1,126)	(752)	581
Net increase in fair value of investments	9,062	5,861	148	1,201	1,301	551
Investment income	1,025	1,025				
Swap income	126	58	26	15	16	11
Allowance for debt funds used during construction	1,396	61		804	60	471
Miscellaneous income (expenses)	(131)	78	35	20	(278)	14
Total nonoperating revenues — net	10,111	7,015	207	914	347	1,628
INCOME (LOSS) BEFORE TRANSFERS	6,278	(2,186)	4,203	3,007	2,860	(1,606)
CASH TRANSFERRED TO THE CITY OF DALTON	(6,451)	(2,967)	(1,355)	(774)	(839)	(516)
CHANGES IN FUND NET ASSETS	(173)	(5,153)	2,848	2,233	2,021	(2,122)
FUND NET ASSETS — Beginning of year	608,896	314,224	22,098	158,223	107,122	7,229
FUND NET ASSETS — End of year	$ 608,723	$ 309,071	$ 24,946	$ 160,456	$ 109,143	$ 5,107

APPENDIX 1D

VEGP UNITS 3 AND 4 DECOMMISSIONING FUND ESTIMATE REPORT

The NRC defines decommissioning as the safe removal of a nuclear facility from service and the reduction of residual radioactivity to a level that permits release of the site property and termination of the license (10 CFR 50). NRC regulation 10 CFR 50.82 specifies the regulatory actions that the NRC and a licensee must take to decommission a nuclear power facility. NRC regulation 10 CFR 20, Subpart E identifies the radiological criteria that must be met for license termination. These requirements apply to the existing fleet of power reactors and to advanced reactors such as the AP1000.

1D.1 DECOMMISSIONING FUNDING CALCULATION

The NRC minimum funding requirement for decommissioning provides reasonable assurance that funding will be available to remove a facility safely from service and reduce residual radioactivity to a level that permits release of the site property for unrestricted use and termination of the license. The NRC minimum funding requirement for decommissioning does not include the cost of removal and disposal of spent fuel or nonradioactive structures and materials beyond that necessary to terminate the license. The purpose of this calculation is to determine the NRC minimum decommissioning funding requirement for the Vogtle Electric Generating Plant (VEGP) in accordance with the requirements of 10 CFR 50.75(c). The calculation for proposed VEGP Units 3 and 4 is based on the Westinghouse AP1000 pressurized water reactor (PWR) that is being licensed based upon the referenced DCD. This design has a thermal power rating of 3400 MW_t.

The methodology used to determine the NRC minimum funding requirement in January 1986 dollars for PWRs is specified by 10 CFR 50.75(c)(1)(i). For PWRs with a thermal power greater than or equal to 3400 MW_t, the NRC minimum funding requirement is $105 million (January 1986 dollars).

Regulation 10 CFR 50.75(c)(2) requires that the following adjustment factor be applied to the January 1986 minimum decommissioning funding requirement to reflect escalation of labor (L), energy (E), and radioactive waste burial (B) as follows:

$$0.65\ L + 0.13\ E + 0.22\ B$$

The escalation factors for labor and energy are based on regional data from the U.S. Department of Labor Bureau of Labor Statistics (Reference 1D-1) and are determined as

described below. The escalation factor for burial is taken directly from NRC report NUREG–1307, “Report of Waste Burial Charges” (Reference 1D-2), for the Barnwell, South Carolina facility.

As described in NUREG-1307, the escalation factor for energy associated with PWRs is determined as follows:

$$E = 0.58\ P + 0.42\ F$$

where P and F are the escalation factors for electric power and light fuel oil, respectively.

The escalation factors for labor, electric power, and light fuel oil for any given year are determined by dividing the respective December index for the previous year by the corresponding January 1986 index. For example, the escalation factor used to determine the 1990 NRC minimum is calculated by dividing the December 1989 indices for labor, electric power, and light fuel oil by the corresponding January 1986 index.

As described in NUREG-1307, the NRC provides two options for the disposal of radioactive material during decommissioning which significantly affect the NRC minimum funding requirement for decommissioning. In the calculation performed for 2007, the escalation factors B, E, F, L and P are as follows:

B = 23.030 (Option 1) or 8.683 (Option 2)

E = 1.469

F = 2.444

L = 2.045

P = 1.879

Based on the results of this calculation, the 2007 NRC minimum funding requirement for each proposed unit at the VEGP is $697,239,000 (Option 1 – Direct Disposal – 2006 dollars) and $365,823,000 (Option 2 – Direct Disposal with Vendors – 2006 dollars).

1D.2 VEGP DECOMMISSIONING FUNDING MECHANISM

Because they recover the estimated total cost of decommissioning through rates established by "cost of service" or similar ratemaking regulation, the Owners of proposed VEGP Units 3 and 4 are authorized by 10 CFR § 50.75(e)(1)(ii)(A) to use the external sinking fund method as the exclusive mechanism for providing financial assurance of decommissioning funds. Accordingly,

the Owners will deposit funds for the decommissioning of VEGP Units 3 and 4 using the external sinking fund as described in 10 CFR 50.75(e)(1)(ii). In accordance with 10 CFR 50.75 (e)(3), SNC will submit a report for each proposed unit, no later than thirty (30) days after the NRC publishes notice in the Federal Register under 10 CFR 52.103(a), containing certification that financial assurance for decommissioning is provided in the amount specified in SNC's most recent updated certification, including a copy of the financial instrument to be used.

1D.3 DECOMMISSIONING COSTS AND FUNDING – STATUS REPORTING

In accordance with 10 CFR 50.75(e)(3), two years before, and one year before, the scheduled date for initial loading of fuel for each proposed unit, SNC will submit a report to the NRC containing a certification updating the information described in Section 1D.1, including a copy of the financial instrument to be used. Additionally, in accordance with 10 CFR 50.75(f)(1), SNC will periodically report on the status of decommissioning funding for proposed VEGP Units 3 and 4; however, this reporting will not begin until the date that the NRC has made the finding under 10 CFR 52.103(g).

1D.4 RECORDKEEPING PLANS RELATED TO DECOMMISSIONING FUNDING

In accordance with 10 CFR 50.75(g), SNC will retain records, until the termination of the license, of information important to safe and effective decommissioning.

1D.5 REFERENCES

1D-1 U.S. Department of Labor Bureau of Labor Statistics website (http://data.bls.gov/cgi-bin/srgate), Series IDs - CIU2010000000220I (Labor Indexes– Total compensation, private industry, South region), wpu0543 (Producer Price Indexes - Industry electric power), wpu0573 (Producer Price Indexes - Light fuel oils).

1D-2 U.S. Nuclear Regulatory Commission, "Report on Waste Burial Charges," NUREG-1307, Revisions 12.

1D-3 Southern Nuclear Operating Company, "Vogtle Electric Generating Plant, Financial Assurance Requirements for Decommissioning Nuclear Power Plants (10 CFR 50.75(f)(1))," SNC letter NL-07-0680, dated March 26, 2007 [ADAMS Accession No. ML070860488].