ORIGINAL

NEW APPLICATION

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April 7, 2009

VIA OVERNIGHT MAIL

Docket Control Center
Arizona Corporation Commission
1200 West Washington Street
Phoenix, Arizona 85007-2927

T-20667A-09-0179

Re: Application and Petition of AGL Networks, LLC for a Certificate of Convenience and Necessity to Provide Intrastate Telecommunications Services (the "Application")

Dear Sir or Madam:

Enclosed are the original and fourteen (14) copies of AGL Networks, LLC 's Application. Please file the Application in your usual fashion and return one (1) file-stamped copy to us in the enclosed envelope.

If you have any questions or comments, please call the undersigned.

Sincerely,

Kennard B Woods

Kennard B. Woods
Attorney for AGL Networks, LLC

KBW/jh
Enc.
cc: AGL Networks, LLC
(*with enclosure*)
Norman B. Gerry, Esq.
(*without enclosure*)

Arizona Corporation Commission
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DOCKET CONTROL

ARIZONA CORPORATION COMMISSION

Application and Petition for Certificate of Convenience and Necessity to Provide Intrastate Telecommunications Services

Mail original plus 13 copies of completed application to:

For Docket Control Only:
(Please Stamp Here)

Docket Control Center
Arizona Corporation Commission
1200 West Washington Street
Phoenix, Arizona 85007-2927

Please indicate if you have current applications pending in Arizona as an Interexchange reseller, AOS provider, or as the provider of other telecommunication services.

~~Type of Service: **Applicant has no current applications pending.**~~

Docket No.: _____ Date: _____ Date Docketed: _____

Type of Service: **Applicant has no current applications pending.**

Docket No.: _____ Date: _____ Date Docketed: _____

A. COMPANY AND TELECOMMUNICATION SERVICE INFORMATION

(A-1) Please indicate the type of telecommunications services that you want to provide in Arizona and mark the appropriate box(s).

Resold Long Distance Telecommunications Services (Answer Sections A, B).

☐ Resold Local Exchange Telecommunications Services (Answer Sections A, B, C).

☐ Facilities-Based Long Distance Telecommunications Services (Answer Sections A, B, D).

☐ Facilities-Based Local Exchange Telecommunications Services (Answer Sections A, B, C, D, E)

☐ Alternative Operator Services Telecommunications Services (Answer Sections A, B)

X Other **Please see Attachment "E".** (Please attach complete description)

(A-2) The name, address, telephone number (including area code), facsimile number (including area code), e-mail address, and World Wide Web address (if one is available for consumer access) of the Applicant:

Response:

AGL Networks, LLC
Ten Peachtree Place
Suite 1000
Atlanta, Georgia 30309
Telephone: 404-584-4917
Facsimile: 404-584-3375
Email: wharris@aglresources.com
http://www.aglnetworks.com/

(A-3) The d/b/a ("Doing Business As") name if the Applicant is doing business under a name different from that listed in Item (A-2):

Response: **None**

(A-4) The name, address, telephone number (including area code), facsimile number (including area code), and E-mail address of the Applicant's Management Contact:

Response:

W. Andy Harrison
Managing Director of Business Operations
AGL Networks, LLC
Ten Peachtree Place
Suite 1000
Atlanta, Georgia 30309
Telephone: 404-584-4917
Facsimile: 404-584-3375
Email: wharris@aglresources.com

(A-5) The name, address, telephone number (including area code), facsimile number (including area code), and E-mail address of the Applicant's Attorney and/or Consultant:

Response:

Norman B. Gerry, Esq.
Kennard B. Woods, Esq.
Friend, Hudak & Harris, LLP
Three Ravinia Drive
Suite 1450
Atlanta, Georgia 30346-2117
Telephone: 770-399-9500
Facsimile: 770-395-0000
Email: ngerry@fh2.com
kwoods@fh2.com

(A-6) The name, address, telephone number (including area code), facsimile number (including area code), and E-mail address of the Applicant's Complaint Contact Person:

Response:

W. Andy Harrison
Managing Director of Business Operations
AGL Networks, LLC
Ten Peachtree Place
Suite 1000
Atlanta, Georgia 30309
Telephone: 404-584-4917
Facsimile: 404-584-3375
Email: wharris@aglresources.com

(A-7) What type of legal entity is the Applicant? Mark the appropriate box(s) and category.

☐ Sole proprietorship

Partnership: ____ Limited, ____ General, ____ Arizona, ____ Foreign

X Limited Liability Company: ____ Arizona, X Foreign

☐ Corporation: ____ "S", ____ "C", ____ Non-profit

☐ Other, specify: _____

(A-8) Please include "Attachment A":

Attachment "A" must include the following information:

1. A copy of the Applicant's Certificate of Good Standing as a domestic or foreign corporation, LLC, or other entity in Arizona.
2. A list of the names of all owners, partners, limited liability company managers (or if a member managed LLC, all members), or corporation officers and directors (specify).
3. ~~Indicate percentages of ownership of each person listed in A-8.2.~~

Response: **Please see Attachment "A".**

(A-9) Include your Tariff as "Attachment B".

Your Tariff must include the following information:

1. Proposed Rates and Charges for each service offered (reference by Tariff page number).
2. Tariff Maximum Rate and Prices to be charged (reference by Tariff page number).
3. Terms and Conditions Applicable to provision of Service (reference by Tariff page number).
4. Deposits, Advances, and/or Prepayments Applicable to provision of Service (reference by Tariff page number).
5. The proposed fee that will be charged for returned checks (reference by Tariff page number).

Response: **Please see Attachment "B".**

(A-10) Indicate the geographic market to be served:

X Statewide. (Applicant adopts statewide map of Arizona provided with this application).

☐ Other. Describe and provide a detailed map depicting the area.

Please see Attachment "H"

(A-11) Indicate if the Applicant or any of its officers, directors, partners, or managers has been or are currently involved in any formal or informal complaint proceedings pending before any state or federal regulatory commission, administrative agency, or law enforcement agency.

Describe in detail any such involvement. Please make sure you provide the following information:

1. States in which the Applicant has been or is involved in proceedings.
2. Detailed explanations of the Substance of the Complaints.
3. Commission Orders that resolved any and all Complaints.
4. Actions taken by the Applicant to remedy and/or prevent the Complaints from re-occurring.

Response: **On October 1, 2002, the Missouri Public Service Commission ("MPSC"), in its *Order Approving Interexchange and Nonswitched Local Exchange Certificates of Service Authority*, in Case No. XA-2003-0060, granted AGL Networks, LLC certificates of service authority to provide interexchange and nonswitched local exchange telecommunications services.**

On January 29, 2004 the Staff of the MPSC filed a complaint against Applicant, alleging that it was subject to penalties for failing to file an annual report for 2002. On June 17, 2004, the MPSC entered its *Determination on Pleading and Order Directing General Counsel to Seek Penalties*, in Case No. TC-2004-0314. The order authorized and directed the General Counsel of the MPSC to seek penalties against Applicant in Circuit Court for failure to file an annual report for 2002. On November 8, 2004, the General Counsel's office issued a letter stating that, notwithstanding the MPSC's June 17, 2004 order, the parties had agreed that Applicant had never exercised authority pursuant to its certification, that the MPSC in subsequent cases had found that companies that never exercised their certificate of service authority were not responsible for submitting annual reports, and that in such cases the MPSC had denied Staff's complaints. Accordingly, the General Counsel's office advised Applicant that the General Counsel's office would not pursue any penalty action against the company.

On January 11, 2005 the Staff of the MPSC filed a motion in Case No. XD-2005-0222, requesting the MPSC to find that the certificate of service authority issued to AGL Networks, LLC was null and void, since, according to Staff, Applicant did not have an approved tariff in Missouri, and Applicant had stated in the aforesaid complaint action that it had not provided telecommunications services in Missouri at any time. Applicant also requested that the MPSC find its certificate null and void. On February 16, 2005, the MPSC issued its *Order Finding Certificate Is Null and Void and Directing Staff to Remove Company From Its Record of Certificated Companies*. The order also stated that Staff noted that Applicant did not owe the MPSC any assessments, and that Applicant had submitted all outstanding annual reports.

On March 24, 2008, AGL Networks, LLC requested certificate of service authority from the MPSC. On April 30, 2008, the MPSC, in its Order *Approving Interexchange and Nonswitched Local Exchange Certificate of Service Authority*, in Case No. CA-2008-0306, granted Applicant certificates of service authority to provide interexchange and nonswitched local exchange telecommunications services. Applicant has filed its annual report for 2008 and the other compliance reports required by the MPSC, and also has submitted a tariff to the MPSC for approval to provide telecommunications services. Accordingly, the circumstances described in the complaint and motion proceedings described above should not recur.

(A-12) Indicate if the Applicant or any of its officers, directors, partners, or managers has been or are currently involved in any civil or criminal investigation, or had judgments entered in any civil matter, judgments levied by any administrative or regulatory agency, or been convicted of any criminal acts within the last ten (10) years.

Describe in detail any such judgments or convictions. Please make sure you provide the following information:

1. States involved in the judgments and/or convictions.

2. Reasons for the investigation and/or judgment.

3. Copy of the Court order, if applicable.

Response: **On or about December 29, 2008, Southwest Gas Corporation filed a Complaint in the Superior Court of Maricopa County, Arizona, against the City of Tempe, AGL Networks, LLC, Speedy Gonzalez Construction, Inc., Does 1-10, and Roe Corporations I-X, in Case No. CV2008-032658. The Complaint seeks damages that allegedly resulted from breakage of a 24-inch water main by a contractor for Applicant. The Complaint is pending; therefore, no judgment has been entered in the case. However, Applicant and Speedy Gonzalez Construction, Inc. have filed a cross claim and third party complaint against the City of Tempe for its failure to properly locate and mark underground utilities in an amount equal to the claim against Applicant. The Arizona Corporation Commission found that Speedy Gonzalez Construction, Inc. followed all applicable underground facility laws and the City of Tempe had not properly identified the 24-inch water main line, and the Commission issued the City of Tempe a Notice of Violation because an "owner of underground facility failed to properly identify or mark underground facility."**

~~(A-13) Indicate if the Applicant's customers will be able to access alternative toll service providers or resellers~~ via 1+101XXXX access.

~~Yes~~ ~~X No~~

Response: **Applicant is not seeking authority to provide switched services. Please see Attachment "E".**

(A-14) Is Applicant willing to post a Performance Bond? Please check appropriate box(s).

☐ For Long Distance Resellers, a $10,000 bond will be recommended for those resellers who collect advances, prepayments or deposits.

Yes X No

If "No", continue to question (A-15).

☐ For Local Exchange Resellers, a $25,000 bond will be recommended.

Yes X No

If "No", continue to question (A-15).

☐ For Facilities-Based Providers of Long Distance, a $100,000 bond will be recommended.

Yes X No

If "No", continue to question (A-15).

☐ For Facilities-Based Providers of Local Exchange, a $100,000 bond will be recommended.

Yes X No

If any box in (A-14) is marked "No", continue to question (A-15).

Note: Amounts are cumulative if the Applicant is applying for more than one type of service.

(A-15) If any box in (A-14) is marked "No", provide the following information. Clarify and explain the Applicant's deposit policy (reference by tariff page number). Provide a detailed explanation of why the Applicant's superior financial position limits any risk to Arizona consumers.

Response: **Applicant is not seeking authority to provide switched services. Please see Attachment "E".**

Please also see Attachment "B". Applicant's deposit policy is set forth in Section 2.13 commencing at page 26 of Applicant's Tariff No. 1.

In further explanation: Applicant is a wholly-owned subsidiary of AGL Resources Inc., which is a publicly traded company (NYSE – AGL). During the 2008 calendar year, AGL Resources Inc. generated approximately $2.8 billion in operating revenues and, as of December 31, 2008, AGL Resources Inc. had in excess of $6.7 billion in assets. Applicant, as an AGL Resources Inc. operating subsidiary, has AGL Resources Inc.'s complete support of its Arizona operations. AGL Resources Inc.'s immense financial capability serves as adequate protection for Applicant's Arizona customers.

(A-16) Submit copies of affidavits of publication that the Applicant has, as required, published legal notice of the Application in all counties where the Applicant is requesting authority to provide service.

Note: For Resellers, the Applicant must complete and submit an Affidavit of Publication Form as Attachment "C" before Staff prepares and issues its report. Refer to the Commission's website for Legal Notice Material (Newspaper Information, Sample Legal Notice and Affidavit of Publication). For Facilities-Based Service Providers, the Hearing Division will advise the Applicant of the date of the hearing and the publication of legal notice. Do not publish legal notice or file affidavits of publication until you are advised to do so by the Hearing Division.

Response: **Applicant is applying for facilities-based authority. Therefore, no affidavits are required to be published or filed until Applicant has been advised to do so by the Hearing Division.**

(A-17) Indicate if the Applicant is a switchless reseller of the type of telecommunications services that the Applicant will or intends to resell in Arizona:

Yes X No

If "Yes", provide the name of the company or companies whose telecommunications services the Applicant resells

(A-18) List the States in which the Applicant has had an application approved or denied to offer telecommunications services similar to those that the Applicant will or intends to offer in Arizona:

Note: If the Applicant is currently approved to provide telecommunications services that the Applicant intends to provide in Arizona in less than six states, excluding Arizona, list the Public Utility Commission ("PUC") of each state that granted the authorization. For each PUC listed provide the name of the contact person, their phone number, mailing address including zip code, and e-mail address.

Response:

Applicant has had applications approved to offer telecommunications services similar to those that the Applicant will or intends to offer in Arizona, in the following states:

(1) Georgia: Georgia Public Service Commission ("GPSC"), Leon Bowles, Director, Telecommunications, 244 Washington Street, SW, Atlanta, Georgia 30334, 404-656-0949, leonb@psc.state.ga.us

(2) Nevada: Public Service Commission of Nevada, Bing Young, Administrative Attorney, 1150 E. William Street, Carson City, Nevada 89701, 775-684-6173, lcm@puc.state.nv.us

(3) Missouri: Missouri Public Service Commission, John Van Eschen, Manager, Telecommunications Department, 200 Madison Street, Jefferson City, Missouri 65101, 573-751-5525, john.vaneschen@psc.mo.gov

(4) North Carolina: North Carolina Utilities Commission, John Garrison, Director, Communications Division, North Carolina Public Staff, 4326 Mail Service Center, Raleigh, North Carolina 27699-4326, 919-733-2810, John.Garrison@ncmail.net

Applicant has not had an application denied to offer telecommunications services similar to those that the Applicant will or intends to offer in Arizona.

As described in response to item A-11, prior to Applicant's current certification by the MPSC, which was granted on April 30, 2008, Applicant had been certificated by that commission to offer telecommunications services similar to those that the Applicant will or intends to offer in Arizona. Subsequent to such prior certification, the staff of the MPSC requested the MPSC to find that the certificate issued to AGL Networks, LLC was null and void, since AGL Networks, LLC had not filed a tariff in Missouri and was not providing any telecommunications services in Missouri. AGL Networks, LLC also requested that the MPSC find its certificate null and void. On February 16, 2005, the MPSC issued an *Order Finding Certificate Is Null and Void and Directing Staff to Remove Company From Its Record of Certificated Companies*. Subsequent to the February 16, 2005 order, Applicant again sought certificate of service authority from the MPSC, which was granted as described in response to item A-11.

(A-19) List the States in which the Applicant currently offers telecommunications services similar to those that the Applicant will or intends to offer in Arizona.

Note: If the Applicant currently provides telecommunication services that the Applicant intends to provide in Arizona in six or more states, excluding Arizona, list the states. If the Applicant does not currently provide telecommunications services that the Applicant intends to provide in Arizona in five or less states, list the key personnel employed by the Applicant. Indicate each employee's name, title, position, description of their work experience, and years of service in the telecommunications services industry.

Response: **Georgia, Missouri, Nevada and North Carolina. Applicant's key personnel are described in Attachment "F".**

(A-20) List the names and addresses of any alternative providers of the service that are also affiliates of the telecommunications company, as defined in R14-2-801.

Response: **None of Applicant's affiliates, as defined in R14-2-801, is an alternative provider of Applicant's services in Arizona.**

(A-21) Check here if you wish to adopt as your petition a statement that the service has already been classified as competitive by Commission Decision:

- ☐ Decision # 64178 Resold Long Distance
- ☐ Decision # 64178 Resold LEC
- ☐ Decision # 64178 Facilities Based Long Distance
- ☐ Decision # 64178 Facilities Based LEC

Response: **Applicant seeks the classification of itself and its services as competitive pursuant to Article 11 of the Commission's rules, so that all telecommunications services to be offered pursuant to the certification to be granted by the Commission in approving this Application, are and will be competitive telecommunications services. In support of Applicant's request: there are alternatives to Applicant's services; Applicant will have to convince customers to purchase its services; Applicant has no ability to adversely affect the local exchange, interexchange, or point-to-point dedicated data service market; and Applicant will have no market power in those local exchange, interexchange, or point-to-point dedicated data service markets where alternative providers of telecommunications services exist.**

B. FINANCIAL INFORMATION

(B-1) Indicate if the Applicant has financial statements for the two (2) most recent years.

X Yes ☐ No

If "No," explain why and give the date on which the Applicant began operations.

Response:

(B-2) Include "Attachment D".

Provide the Applicant's financial information for the two (2) most recent years.

1. A copy of the Applicant's balance sheet.
2. A copy of the Applicant's income statement.
3. A copy of the Applicant's audit report.
4. ~~A copy of the Applicant's retained earnings balance.~~
5. A copy of all related notes to the financial statements and information.

~~Note: Make sure "most recent years" includes current calendar year or current year reporting period.~~

Response: **Please see Attachment "D"**

(B-3) Indicate if the Applicant will rely on the financial resources of its Parent Company, if applicable.

Response: **Applicant has significant financial resources of its own, and currently owns and operates a substantial dark fiber network in Chandler, Mesa, Paradise Valley, Phoenix, Scottsdale and Tempe pursuant to franchise and/or license agreements with those municipalities. Additionally, Applicant has the assurance of its parent, AGL Resources Inc., that Applicant will be provided with any additional financial resources necessary to operate on a continuous basis in the State of Arizona. Applicant if necessary will obtain financing directly from AGL Resources Inc. to support Applicant's initiation of services in Arizona, and, if necessary, its procurement of any systems or facilities. Applicant anticipates commencing the provision of service within a reasonable period of time after approval of this Application, and Applicant believes that the revenues that it will derive from its customers will provide adequate financing to support its ongoing operations.**

(B-4) The Applicant must provide the following information.

1. Provide the projected total revenue expected to be generated by the provision of telecommunications services to Arizona customers for the first twelve months following certification, adjusted to reflect the maximum rates for which the Applicant requested approval. Adjusted revenues may be calculated as the number of units sold times the maximum charge per unit.
2. Provide the operating expenses expected to be incurred during the first twelve months of providing telecommunications services to Arizona customers following certification.
3. Provide the net book value (original cost less accumulated depreciation) of all Arizona jurisdictional assets expected to be used in the provision of telecommunications service to Arizona customers at the end of the first twelve months of operation. Assets are not limited to plant and equipment. Items such as office equipment and office supplies should be included in this list.
4. If the projected value of all assets is zero, please specifically state this in your response.
5. If the projected fair value of the assets is different than the projected net book value, also provide the corresponding projected fair value amounts.

Response: **Please see Attachment "G".**

C. RESOLD AND/OR FACILITIES-BASED LOCAL EXCHANGE TELECOMMUNICATIONS SERVICES

(C-1) Indicate if the Applicant has a resale agreement in operation,

☐ Yes ☒ No

If "Yes", please reference the resale agreement by Commission Docket Number or Commission Decision Number.

Response:

D. FACILITIES-BASED LONG DISTANCE AND/OR FACILITIES BASED LOCAL EXCHANGE TELECOMMUNICATIONS SERVICES

(D-1) Indicate if the Applicant is currently selling facilities-based long distance telecommunications services AND/OR facilities-based local exchange telecommunications services in Arizona. This item applies to an Applicant requesting a geographic expansion of their CC&N:

☐ Yes ☒ No

If "Yes," provide the following information:

1. The date or approximate date that the Applicant began selling facilities-based long distance telecommunications services AND/OR facilities-based local exchange telecommunications services in Arizona.
2. Identify the types of facilities-based long distance telecommunications services AND/OR facilities-based local exchange telecommunications services that the Applicant sells in Arizona.

If "No," indicate the date when the Applicant will begin to sell facilities-based long distance telecommunications AND/OR facilities-based local exchange telecommunications services in Arizona.

Response: **Applicant does not intend to provide switched services, including "local exchange service" as that term is defined by Commission Rule R14-2-1102. Applicant intends to provide only various non-switched services, as described in Attachment "E". Applicant anticipates commencing the provision of service within a reasonable period of time after approval of this Application.**

E. FACILITIES-BASED LOCAL EXCHANGE TELECOMMUNICATIONS SERVICES

(E-1) Indicate whether the Applicant will abide by the quality of service standards that were approved by the Commission in Commission Decision Number 59421:

☒ Yes ☐ No

Response: **Applicant will abide by the quality of service standards that were approved by the Commission in Decision Number 59421 to the extent they are applicable to non-switched competitive services. However, Applicant has been unable to find any Commission decisions applying the standards approved in Decision Number 59421 to providers of only competitive non-switched services. Applicant does not have a history of service quality problems, and therefore the penalty provisions set forth by that Decision would not appear to apply in any event.**

(E-2) Indicate whether the Applicant will provide all customers with 911 and E911 service, where available, and will coordinate with incumbent local exchange carriers ("ILECs") and emergency service providers to provide this service:

☐ Yes X No

Response: **Applicant is not seeking authority to provide switched or voice services of any kind. Applicant intends to provide only non-switched services, as described in Attachment "E", and, as such, is not required by federal or state law to provide 911 and E911 service.**

(E-3) Indicate that the Applicant's switch is "fully equal access capable" (i.e., would provide equal access to facilities-based long distance companies) pursuant to A.A.C. R14-2-1111 (A):

☐ Yes X No

Response: **Applicant is not seeking authority to provide switched services, and will not deploy any switch. Please see Attachment "E".**

I certify that if the applicant is an Arizona corporation, a current copy of the Articles of Incorporation is on file with the Arizona Corporation Commission and the applicant holds a Certificate of Good Standing from the Commission. If the company is a foreign corporation or partnership, I certify that the company has authority to transact business in Arizona. I certify that all appropriate city, county, and/or State agency approvals have been obtained. Upon signing of this application, I attest that I have read the Commission's rules and regulations relating to the regulations of telecommunications services (A.A.C. Title 14, Chapter 2, Article 11) and that the company will abide by Arizona state law including the Arizona Corporation Commission Rules. I agree that the Commission's rules apply in the event there is a conflict between those rules and the company's tariff, unless otherwise ordered by the Commission. I certify that to the best of my knowledge the information provided in this Application and Petition is true and correct.

AGL NETWORKS, LLC

James A. Gillis
President and Manager

March 23, 2009
Date

SUBSCRIBED AND SWORN to before me this 23 day of March, 2009

NOTARY PUBLIC

My Commission Expires Khalilah Henderson
Notary Public Cobb County, Georgia
My Commission Expires December 6, 2011

ATTACHMENT "A"

1. Applicant's Certificate of Good Standing is attached hereto.

2. Applicant is a limited liability company, and is a wholly-owned subsidiary of AGL Resources Inc. The managers of AGL Networks, LLC are as described in Attachment "F".

3. Applicant is a wholly-owned subsidiary of AGL Resources Inc.

STATE OF ARIZONA

Office of the
CORPORATION COMMISSION

CERTIFICATE OF GOOD STANDING

To all to whom these presents shall come, greeting:

I, Michael P. Kearns, Interim Executive Director of the Arizona Corporation Commission, do hereby certify that

******AGL NETWORKS, LLC******

a foreign limited liability company organized under the laws of the jurisdiction of Delaware did obtain a Certificate of Registration in Arizona on the 30th day of April 2002.

I further certify that according to the records of the Arizona Corporation Commission, as of the date set forth hereunder, the said limited liability company has not had its Certificate of Registration revoked for failure to comply with the provisions of A.R.S. section 29-601 et seq., the Arizona Limited Liability Company Act; and that the said limited liability company has not filed a Certificate of Cancellation as of the date of this certificate.

This certificate relates only to the legal authority of the above named entity as of the date issued. This certificate is not to be construed as an endorsement, recommendation, or notice of approval of the entity's condition or business activities and practices.

IN WITNESS WHEREOF, I have hereunto set my hand and affixed the official seal of the Arizona Corporation Commission. Done at Phoenix, the Capital, this 3rd Day of March, 2003, A.D.

Interim Executive Director

By: Jeffrey A. Barlin

SEAL OF THE ARIZONA CORPORATION COMMISSION
DITAT DEUS
1912

ATTACHMENT "B"

Applicant's proposed tariff is attached hereto.

B.1 Proposed Rates and Charges for each service offered (reference by Tariff page number).

Metro Ethernet Virtual Private Line Service Rates	**Page 47**
Link Connectible Transport Service Basic Channel Systems Rates	**Pages 59 - 61**
LCT Service Internodal or Interoffice Channels Rates	**Pages 62 - 66**
Dark Fiber Leasing Rates	**Page 69**

B.2 Tariff Maximum Rate and Prices to be charged (reference by Tariff page number).

Metro Ethernet Virtual Private Line Service Rates	**Page 47**
Link Connectible Transport Service Basic Channel Systems Rates	**Pages 59 - 61**
LCT Service Internodal or Interoffice Channels Rates	**Pages 62 - 66**
Dark Fiber Leasing Rates	**Page 69**

B.3 Terms and Conditions Applicable to provision of Service (reference by Tariff page number).

Metro Ethernet Virtual Private Line Service	**Pages 41 - 47**
Link Connectible Transport Service	**Pages 48 - 58**
Dark Fiber Leasing	**Pages 68 - 73**

B.4 Deposits, Advances, and/or Prepayments Applicable to provision of Service (reference by Tariff page number).

Deposits	**Pages 26 - 27**
Advance Payments	**Page 26**

B.5 The proposed fee that will be charged for returned checks (reference by Tariff page number).

Returned Check Charge	**Page 30**

AGL NETWORKS, LLC

TARIFF APPLICABLE TO SERVICES AND FACILITIES
PROVIDED WITHIN THE STATE OF ARIZONA

This Tariff applies to services and facilities furnished by AGL Networks, LLC in the State of Arizona. This Tariff is on file with the Arizona Corporation Commission and copies may be inspected during Normal Business Hours, as defined herein, at the principal offices of AGL Networks, LLC, Ten Peachtree Place, Atlanta, Georgia 30309.

Issued By:
W. Andy Harrison
Managing Director of Business Operations
AGL Networks, LLC
Ten Peachtree Place
Atlanta, Georgia 30309

CONTACT INFORMATION FOR INQUIRIES BY THE PUBLIC REGARDING RATES AND OTHER INFORMATION

The public may contact the person below for information regarding rates and other information:

W. Andy Harrison
Managing Director of Business Operations
AGL Networks, LLC
Ten Peachtree Place
Suite 1000
Atlanta, Georgia 30309
Telephone: 404-584-4917
Email: wharris@aglresources.com

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SYMBOLS

The following are the only symbols used for the purposes indicated below:

(D)	Delete or Discontinue
(I)	Change Resulting in an Increase to a Customer's Bill
(M)	Moved from Another Tariff Location
(N)	New
(R)	Change Resulting in a Reduction to a Customer's Bill
(T)	Change in Text or Regulation but no Change in Rate or Charge

TARIFF FORMAT

A. **Sheet Numbering** - Page numbers appear in the upper right corner of the sheet. Pages are numbered sequentially. However, new pages are occasionally added to the Tariff. When a new page is added between existing pages with whole numbers, a decimal is added. For example, a new page added between pages 14 and 15 would be page 14.1.

B. **Sheet Revision Numbering** - Revision numbers also appear in the upper right corner of the page. These numbers are used to determine the most current page version on file with the Arizona Corporation Commission. For example, 4th Revised Page 14 cancels the 3rd Revised Page 14.

C. **Paragraph Numbering Sequence** - There are nine levels of paragraph coding. Each level of coding is subservient to its next higher level:

2
2.1
2.1.1
2.1.1.(A)
2.1.1.(A).(1)
2.1.1.(A).(1).a.
2.1.1.(A).(1).a.I
2.1.1.(A).(1).a.I.(i)
2.1.1.(A).(1).a.I.(i).(1)

APPLICATION OF TARIFF

This Tariff sets forth the offerings, rates and terms and conditions of services applicable to the furnishing of Non-Switched Telecommunications Services and Dark Fiber Services, as defined herein, provided by AGL Networks, LLC to Customers within the State of Arizona.

1. DEFINITIONS AND ABBREVIATIONS

1.1 DEFINITIONS

Certain terms used generally throughout this Tariff are described below.

Advance Payment
Part or all of a payment required before the start of Service.

Attaching Party
A provider of telecommunication services or of a cable television system, or such other party as may be authorized by law to provide communication services that installs facilities in Conduit provided by the Company.

Attachment
Any cable, equipment, facilities, apparatus or appurtenances, used or useful in communication networks or in a cable television system, installed in or attached to Duct Structure.

Authorized User(s) or User(s)
A person, firm or corporation which is authorized by the Customer to be connected to the Service provided by the Company to the Customer.

Cable
The bundle of fiber optic strands contained in a cable sheath (including Dark Fibers), and any other communications transmission media which may be included in the Network and associated splicing connections and splice boxes located in the Network.

Carrier or Company or AGL
AGL Networks, LLC, the issuer of this Tariff.

Commission
The Arizona Corporation Commission.

Company Optical Fiber Termination Point, Central Office or "CO"
Any Company owned, controlled or designated node, facility, structure or other connection point located at, on, or connected to a Company fiber optic ring.

Credit or Credit Allowance
An allowance provided to Customer for Interruption(s) and Performance Failure(s)as set forth in Sections 2.15 and 3.2.1 hereof.

1.1 DEFINITIONS (CONT'D)

Cross-connect
Fiber jumpers that will be installed by the Company from the fiber optic termination panel to the demarcation point.

Customer
The Person which orders service and is responsible for the payment of charges and compliance with the Company's regulations.

Customer Contract
The legally binding written agreement executed by Customer and Company that governs the terms of the provision of Service.

Dark Fiber
Strands of fiber optic cable that connect two points within the Company's Network but which strands have not been activated through connection to the electronics that "light" that fiber thereby enabling it to carry communication services.

Dark Fiber Service
Service in which Dark Fiber is provided to a Customer, including by leasing, renting or granting indefeasible rights to use the same.

Disconnect
To render inoperable or to disable circuitry thus preventing outgoing and incoming communications service.

Duct Structure
Conduit and separate Innerducts.

End User(s)
Any person or entity that obtains the Company's Services provided under this Tariff, regardless of whether such person or entity is so authorized by the Customer.

1.1 DEFINITIONS (CONT'D)

Ethernet Services / Metro EVPLS

Communications service consisting of (i) Ethernet Virtual Private Line Service ("EVPLS") which will provide point-to-point connectivity between diverse locations within a metropolitan area with Ethernet based transport, (ii) Ethernet Virtual Private LAN Service ("EVLAN") will provide point to multipoint, or any point to any point connectivity across multiple diverse locations within a metropolitan area with Ethernet based transport, and (iii) Ethernet Internet Access Service ("EIA") will provide a connection with a bandwidth profile from 1Mbps to 1,000 Mbps to the Internet backbone. EIA provides Customer only with access to the Company's backbone network that serves as a transmission conduit through which Customer may connect its data servers to the Internet. The Company does not operate, process or control the information, services, opinions or other content of the Customer's data servers or the information, services, opinions or other content of the Internet; nor does the Company engage in any protocol or information processing or conversion in connection therewith. EVPLS, EVLAN, and EIA are hereinafter referred to as Metro Ethernet Virtual Private Line Service ("Metro EVPLS").

Exchange

A geographical area for the administration of telecommunications services, established and described by the tariff of a telecommunications company providing local exchange service.

Gbps

One thousand million bits per second.

Holiday

For the purposes of this Tariff, New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day.

Individual Case Basis (ICB)

An arrangement for Services or facilities in which the Regulations, rates and charges are developed based on the specific circumstances of the case.

IntraLATA Telecommunications Service

Interexchange telecommunications service between points within the same local access and transportation area.

Interexchange Telecommunications Service

Telecommunications service between points in two or more exchanges.

1.1 DEFINITIONS (CONT'D)

Mbps
One million bits per second.

Network
The Company's facilities, equipment, and services provided under this Tariff.

Normal Business Hours
The hours of 8:00 a.m. to 5:00 p.m., Monday through Friday, excluding Holidays.

OC3
Optical Carrier, level 3. A SONET channel capable of transmitting data at 155.52 Mbps.

OC12
Optical Carrier, level 12. A SONET channel capable of transmitting data at 622.08 Mbps.

OC48
Optical Carrier, level 48. A SONET channel capable of transmitting data at 2.488 Gbps.

OC192
Optical Carrier, level 192. A SONET channel capable of transmitting data at 9.953 Gbps.

Performance Failure
Any disruption, degradation, or failure of Service, including without limitation any Interruption (but excluding Scheduled Interruptions), any installation failure or delay, or any mistake, delay, omissions, errors or other defects in the Services or in the provision thereof.

Person
Any natural person, corporation, partnership, limited liability company, business trust, joint venture, association, company or Governmental Authority.

Premises
The space occupied by a Customer in a building, in adjoining buildings occupied entirely by that Customer, or on contiguous property occupied by the Customer separated only by a public thoroughfare, a railroad right of way, or a natural barrier.

Rates or Charges
Money, fees or other assessments billed to Customers for Services or facilities.

1.1 DEFINITIONS (CONT'D)

Regulation(s)

Any and all law(s), rule(s), regulation(s) (including without limitation those set forth in this Tariff), order(s), policy or policies, ruling(s), judgment(s), decree(s) or other determination(s) which are made by the Commission or any other Governmental Authority or which arise under any federal, state, or local statute, utility code, or ordinance, and which are applicable to the Services or to any provision of this Tariff.

Scheduled Interruption

"Scheduled Interruption" means an Interruption which has been scheduled by the Company in advance for maintenance, testing, or other administrative purposes.

Service or Services

~~(i) Telecommunications Services provided by the Company pursuant to this Tariff, consisting of one-~~ way and/or two-way transmission paths for the delivery of electronic or photonic signals; (ii) the provision of Dark Fiber Services by the Company pursuant to this Tariff, (iii) the provision of Metro ~~EVPLS pursuant to this Tariff or (iv)) the provision of other one-way and/or two-way transmission~~ paths for the delivery of electronic or photonic signals between two (2) or more points . "Service" and "Services" are used interchangeably herein.

Service Commencement Date

The first date on which the Company notifies the Customer that the requested Service or facility is available for use, unless extended by the Customer's refusal to accept Service which does not conform to standards set forth in the Service Order or this Tariff, in which case the Service Commencement Date is the date of the Customer's acceptance. The Company and the Customer may mutually agree on a substitute Service Commencement Date. If the Company does not have an executed Service Order from a Customer, the Service Commencement Date will be the first date on which the Service or facility was used by a Customer.

Service Order

The written request for Services executed by the Customer and the Company in the format devised by the Company.

Shared

A facility or equipment system or subsystem that can be used simultaneously by several Customers.

1.1 DEFINITIONS (CONT'D)

Tariff

This AGL Networks, LLC Arizona Corporation Commission Tariff No. 1.

Telecommunications Company

A public service corporation, as defined in the Arizona Constitution, Article 15, § 2, that provides telecommunications services within the state of Arizona and over which the Commission has jurisdiction.

Telecommunications Service

Any transmission of interactive switched and non-switched signs, signals, writing, images, sounds, messages, data, or other information of any nature by wire, radio, lightwave, or any other electromagnetic means (including access services), which originate and terminate in this state and are offered to or for the public, or some portion thereof, for compensation.

Terminal Equipment

Customer supplied telephone instruments, including pay telephone equipment, the common equipment of large and small key and PBX systems and other devices and apparatus, and associated wiring, which are intended to be connected electrically, acoustically, or inductively to the Network.

2. RULES AND REGULATIONS

2.1 Undertaking of the Company

2.1.1 Scope

The Company undertakes to exercise its commercially reasonable efforts to install, operate, maintain and furnish Services to Customers in accordance with the terms and conditions set forth in this Tariff.

2.1.2 Terms and Conditions

(A) Services may be used by Customer, Authorized Users and End Users for any lawful purpose, subject to the terms and conditions set forth herein and in any applicable Service Order. Service is provided on the basis of a minimum period of at least one (1) month, twenty-four (24) hours per day. For the purpose of computing charges in this Tariff, a month is considered to have thirty (30) days.

(B) A Customer may be required to enter into a Service Order and/or an ICB which contains or references a description of the Services ordered, the Rates, the duration of the Services, and other terms and conditions. A Customer may also be required to execute any other documents as may be reasonably requested by the Company. In the event of a conflict or inconsistency between the terms of a Service Order or ICB, and the terms otherwise set forth in this Tariff, the terms of the Tariff shall govern. In the event of a conflict or inconsistency between the terms of a Service Order or ICB, the terms and conditions of the ICB shall govern.

(C) When authorized by the Customer, the Company may act as the Customer's agent for ordering facilities provided by other carriers or entities to allow connection of a Customer's location to the Network. The Customer shall be responsible for all Charges due for such service arrangements.

(D) Should any provision or portion of this Tariff be held by a court or administrative agency of competent jurisdiction to be illegal, invalid, or unenforceable, the remaining provisions of this Tariff will remain in full force and effect.

(E) Customer shall cooperate with the Company to the extent necessary for the Company to discharge its obligations hereunder and as reasonably requested by the Company.

(F) The non-ICB rates and charges set forth in this Tariff are reasonable, and constitute the maximum and the initially offered rates and charges for Services that will apply in the absence of ICB arrangements.

(G) This Tariff shall be interpreted and governed by the laws of the State of Arizona regardless of its choice of laws provision.

2.2 Limitations of Service

2.2.1 Service is offered subject to the availability of Conduit, Innerduct, Dark Fiber, Network and other Company facilities and equipment, and the provisions of this Tariff. The Company may limit communications, refuse to provide Services or discontinue Services when necessary because of the lack of transmission medium, transmission capacity or any other facilities or equipment, the lack of interconnection with the services or facilities of other service providers, when the Service is being used in violation of the law or the provisions of or otherwise authorized by this Tariff, or because of any causes beyond the Company's control.

2.2.2 Service shall not be used in such a manner as to interfere unreasonably with the use of service by any other Users. The Company may require applicants for Services to confirm that their use of Services complies with relevant laws, regulations, governmental approvals, authorizations, licenses, consents, orders and permits. The Company may require a Customer to immediately discontinue its transmission if such transmission is causing interference to others.

2.2.3 The Customer is responsible for payment of all Charges for Services provided under this Tariff furnished to the Customer, Authorized Users or End Users. This responsibility is not changed due to any use, misuse, or abuse of the Service or Customer-provided equipment by Users or other third parties, the Customer's employees, or the public.

2.2.4 The Customer is liable for all costs incurred as a result of unauthorized use of the Company's Services, Network or facilities, including service charges, any direct, indirect, special, incidental, reliance, consequential, exemplary, or punitive damages, and any charges related to the suspension and/or termination of service, and any charges for reconnection of Service, incurred as a result of unauthorized use of the Network.

2.2.5 The use of Services without payment, or attempting to avoid payment for Service by fraudulent means or devices, false or invalid numbers, or false calling or credit cards, is prohibited.

2.2.6 Services may be denied for nonpayment of Charges or for other violations of the terms and conditions set forth in this Tariff.

2.2.7 The use of Services to make Calls which might reasonably be expected to frighten, abuse, torment, or harass another is prohibited.

2.2.8 Service is subject to transmission limitations caused by natural (including atmospheric, geographic or topographic) or artificial conditions adversely affecting transmission.

2.2.9 Service may be temporarily interrupted or curtailed due to equipment modifications, upgrades, relocations, repairs and similar activities necessary for proper or improved operations.

2.2 Limitations of Service (cont'd.)

2.2.10 A Customer or Authorized User may not assign or transfer the Service or any rights associated therewith without the express written consent of the Company.

2.3 Limitations on Liability

2.3.1 Except as otherwise stated in this Section, the liability of the Company with respect to any action, claim, judgment, damages, demand or expense (including without limitation reasonable attorney's fees) (1) brought or incurred by any Customer or by any other party in connection with the installation, provision, preemption, termination, maintenance, repair or restoration of Service; or (2) arising from any Performance Failure, whether caused by acts or omission, shall be limited to the extension of Credits or Credit Allowances to the Customer for Interruptions in Service as set forth in this Tariff.

2.3.2 To the extent permitted by any applicable Regulation, the Company's liability for negligence will also be limited to the amounts described in Section 2.3.1 hereof.

2.3.3 To the extent permitted by any applicable Regulation, the Company's liability for gross negligence will also be limited to the amounts described in Section 2.3.1 hereof.

2.3.4 In no event will the Company be liable to a Customer or to any third party for any direct, indirect, special, incidental, reliance, consequential, exemplary or punitive damages, including, but not limited to, loss of revenue or profits (even if the Company has been advised of the possibility of such loss), for any reason whatsoever, including, but not limited to, any act or omission, failure to perform, delay, Interruption, failure to provide any service or any failure in or breakdown of facilities associated with the Service.

2.3.5 Except for the issuance of Credits or Credit Allowances to the Customer for Interruptions or Performance Failures as set forth in this Tariff, the liability of the Company for errors in billing that result in overpayment by the Customer shall be limited to a Credit equal to the dollar amount erroneously billed or, in the event that payment has been made and Service has been discontinued, to a refund of the amount erroneously billed.

2.3.6 Except as caused by its willful misconduct, the Company will not be liable for defacement of or damages to Customer's Premises or for any personal injury or death arising, directly or indirectly, from the furnishing of Services, including without limitation the installation or removal of any facilities, equipment or wiring associated therewith. Customer is solely responsible for connecting any and all apparatus, equipment and associated wiring on Customer's Premises to the Services, and no other carrier or third party engaged in such activity shall be deemed to be an agent or employee of the Company.

2.3 Limitations on Liability (cont'd)

2.3.7 The Company shall not be liable for any claims for loss or damages involving:

(A) Any act or omission of: (1) the Customer; (2) any other entity furnishing service, equipment or facilities for use in conjunction with Services or facilities provided by the Company; or (3) common carriers or warehousemen;

(B) Any delay or failure of performance or equipment due to causes beyond the Company's control, including but not limited to, acts of God, fires, floods, earthquakes, hurricanes, or other catastrophes; national emergencies, insurrections, riots, wars or other civil commotions; strikes, lockouts, work stoppages or other labor difficulties; criminal actions taken against the Company; unavailability, failure or malfunction of equipment, services or facilities provided by the Customer, other service providers or other third parties; and any law, order, regulation or other action of any governing authority or agency thereof;

(C) Any unlawful or unauthorized use of the Company's facilities and Services;

(D) Libel, slander, indecency, obscenity, invasion of privacy, or infringement of patents, trade secrets, copyrights, or other intellectual property rights of any third party, arising from or in connection with the transmission of communications by means of Company-provided facilities or services; or by means of the combination of Company-provided facilities or services with Customer-provided facilities or services;

(E) Breach in the privacy or security of communications transmitted over the Company's facilities;

(F) Changes in any of the facilities, operations or procedures of the Company that render any equipment, facilities or services provided by the Customer obsolete, or require modification or alteration of such equipment, facilities or services, or otherwise affect their use or performance, except where reasonable notice is required by the Company and is not provided to the Customer, in which event the Company's liability is limited as set forth in this Tariff.

(G) Defacement of or damage to Customer Premises resulting from the furnishing of Services or equipment on such Premises or the installation or removal thereof;

2.3 Limitations on Liability (cont'd)

(H) Injury to property or injury or death to persons, including claims for payments made under Workers' Compensation law or under any plan for employee disability or death benefits, arising out of, or caused by, any act or omission of the Customer, or the construction, installation, maintenance, presence, use or removal of the Customer's facilities or equipment connected, or to be connected to the Company's facilities;

(I) Any intentional or wrongful act of a Company employee when such act is not within the scope of the employee's responsibilities for the Company and/or is not authorized by the Company; or

(J) Any representations made by Company employees that do not comport, or that are inconsistent, with the provisions of this Tariff.

2.3.8 Any action or claim against the Company arising from any of its alleged acts or omissions in connection with this Tariff will be deemed waived if not brought or made in writing within sixty (60) days from the date that the alleged act or omission occurred.

2.3.9 The Company does not guarantee nor make any warranty with respect to installations provided by it for use in an explosive atmosphere. The Company shall be indemnified, defended and held harmless by the Customer from and against any and all claims, loss, demands, suits, or other action, or any liability whatsoever, including attorney's fees, whether suffered, made, instituted, or asserted by the Customer or by any other party, for any personal injury to or death of any person or persons, and for any loss, damage, or destruction of any property, including environmental contamination, whether owned by the Customer or by any other party, caused or claimed to have been caused directly or indirectly by the installation, operation, failure to operate, maintenance, presence, condition, location, use, or removal of any equipment or facilities or the service.

2.3.10 Because the Company does not undertake to provide switched services, but offers the use of its Service when available, and has no control of the communications content transmitted over its system, and because of the possibility of errors incident to the provision and use of Service, the Company shall not be liable for failure to establish or maintain connections.

2.3.11 The Company is not liable to Customer or Users for Interruptions or delays in transmission, or errors or defects in transmission, or failure to transmit when caused by or as a result of acts of God, fire, flood, earthquakes, wind or other catastrophes, war, riots, national emergencies, government or military authorities, strikes, lock-outs, work stoppages or other labor difficulties, or causes beyond the Company's control, except as set forth in this Section and allowances for Interruptions set forth in this Tariff.

2.3 Limitations on Liability (cont'd)

2.3.12 The Company assumes no responsibility for the availability or performance of any cable, satellite systems or other facilities under the control of other entities that are used to provide service to Customer, even if the Company has acted as the Customer's agent in arranging for such facilities or services. The Company shall have no liability associated with the installation, operation or maintenance of facilities, equipment or services of the Customer, Authorized User or third parties. The responsibility of the Company shall be limited to the furnishing of Services under this Tariff and to the maintenance and operation of such Services as set forth herein. Subject to this responsibility, the Company shall not be responsible for: (1) the through transmission of signals generated by Customer-provided equipment or for the quality of, or defects in, such transmission; (2) the reception of signals by Customer-provided equipment; or (3) network control signaling where such signaling is performed by Customer-provided network control signaling equipment.

2.3.13 The Customer shall reimburse the Company for all costs, expenses and fees (including reasonable attorneys' fees and costs) incurred by the Company in its defense against Claims set forth in Section 2.3.9.

2.3.14 Any liability of the Company for loss or damages arising out of mistakes, omissions, interruptions, delays, errors or defects in Service, the transmission of Service, or of any entity furnishing service, equipment or facilities for use in conjunction with Services or facilities provided by the Company, or any misrepresentations regarding Service, or failures or defects in facilities furnished by the Company, occurring in the course of furnishing Service shall in no event exceed an amount equivalent to the proportionate monthly charge to the Customer for Service, during the period of time in which such mistakes, omissions, interruptions, delays, errors or defects in Service, its transmission or failure or defect in facilities furnished by the Company occurred.

2.3.15 **EXCEPT AS EXPRESSLY SET FORTH IN THIS TARIFF, THE COMPANY DISCLAIMS ALL REPRESENTATIONS AND WARRANTIES, EXPRESS OR IMPLIED, INCLUDING WITHOUT LIMITATION, ANY IMPLIED WARRANTY OF MERCHANTABILITY OR FITNESS FOR A PARTICULAR PURPOSE FOR OR IN CONNECTION WITH THE PROVISION OF SERVICES HEREUNDER.**

2.4 Testing and Adjusting

Upon no less than twenty four (24) hours advance notice, the Company may Schedule Interruptions to make such tests, adjustments, and inspections as may be necessary to maintain the Company's facilities in satisfactory operating condition. No Credits or Credit Allowances will be provided to the Customer for a Scheduled Interruption.

2.5 Provision of Equipment and Facilities

2.5.1 Except as otherwise indicated, Customer-provided equipment at the Customer's premises or elsewhere for use in conjunction with Service shall be so constructed, maintained, and operated as to work satisfactorily with the facilities of the Company.

2.5.2 The Company shall not be responsible for the installation, operation, or maintenance of any Customer-provided communications equipment or other CPE. Where such equipment or CPE is connected to Service furnished pursuant to this Tariff, the responsibility of the Company shall be limited to the furnishing of Services under this Tariff and to the maintenance and operation of such Services in the proper manner. The Company shall not be responsible for:

(A) The through transmission of signals generated by Customer-provided equipment or for the quality of, or defects in, such transmission; or

(B) The reception of signals by Customer-provided equipment; or

(C) Network control signaling where such signaling is performed by Customer-provided network control signaling equipment.

2.6 Special Construction

2.6.1 Subject to the agreement of the Company and to all of the Regulations, special construction of facilities may be undertaken on an ICB basis at the request of the Customer. Special construction is that construction undertaken:

(A) Where facilities are not presently available, and there is no other requirement for the facilities so constructed;

(B) Of a type other than that which the Company would normally utilize in the furnishing of its Services;

(C) Over a route other than that which the Company would normally utilize in the furnishing of its Services;

(D) In a quantity greater than that which the Company would normally construct;

(E) On an expedited basis;

(F) On a temporary basis until permanent facilities are available;

(G) Involving abnormal costs; or

(H) In advance of its normal construction planned by the Company.

Special construction charges will be determined pursuant to Section 3.4.

2.7 Ownership of Facilities

Title to all facilities provided in accordance with this Tariff remains in the Company, its agents, contractors, or suppliers.

2.8 Indemnification by Customer

The Customer shall defend, indemnify, and hold the Company and its employees, directors, subcontractors, and agents (collectively "Indemnitees") harmless from and against any and all actions, claims, judgments, damages, demands, liabilities, costs and expenses, (including without limitation reasonable attorney's fees (collectively "Claims"), whether made, suffered, instituted, or asserted by Customer or any other Person for:

(A) Injury to or death of any person or persons (including injury to or death of their employees);

2.8 Indemnification by Customer (cont'd)

(B) Any loss of or damage to or destruction of tangible real or tangible personal property or to the environment, to the extent that such injury, death, loss or damage was caused by any act or omission on the part of Customer, any Authorized User or any End User or their respective agents, employees, subcontractors or assignees, in connection with use of the Services;

(C) The Company must notify the Customer promptly of written Claims or demands for which the Customer is responsible hereunder, except where failure to do so will not prejudice Customer's obligation under this Section 2.8. The Company and the Customer, shall cooperate fully with the other in the course of such indemnification, and the Customer shall control such defense and the right to litigate, settle, appeal (provided it pays the cost of any required appeal bond), compromise or otherwise deal with any such claim or resulting judgment, provided that such settlement, compromise or other resolution of said Claim does not result in any liability to any Indemnitee;

(D) Libel or slander or invasion of privacy resulting from Customer's use of the Services;

(E) Infringement of any patent, copyright, trademark, trade name or trade secret or other intellectual property right of any third party arising from: (1) the transmission of any material transmitted (a) by any Customer or (b) by any other Person using the Services provided to any Customer or Customer location; or (2) from the combination of Customer's use of Services with CPE or with other Customer-provided facilities or services;

(F) The transmission of any indecent, obscene, or otherwise unlawful content by the user of the Services; or

(G) Except as otherwise provided by applicable Regulation, any unauthorized, unlawful, or fraudulent use of or access to the Services provided to Customers.

2.9 Prohibited Uses

2.9.1 The Services the Company offers shall not be used for any unlawful purpose or for any use for which the Customer has not obtained all required governmental approvals, authorization, licenses, consents, and permits.

2.9.2 The Company may require applicants for Service who intend to use the Company's offering for resale and/or for shared use to file a letter with the Company confirming that their use of the Company's offering complies with relevant laws and regulations, policies, orders, and decisions.

2.9 Prohibited Uses (cont'd)

2.9.3 The Company may immediately shut down the Service provided to any Authorized User if the use thereof is causing interference to others. The Company shall exercise reasonable commercial efforts to restore such services once the Interruption has ceased.

2.9.4 A Customer, joint user, or Authorized User may not assign, or transfer in any manner, the Service or any rights associated with the Service without the written consent of the Company.

2.10 Obligations of the Customer

2.10.1 Customer Premises Provisions

(A) The Customer is responsible for placing any necessary orders, complying with this Tariff, ensuring that Users comply with this Tariff's regulations, and payment of Charges for Service originated at the Premises or otherwise by or through Customer's equipment, including by any remote access, by any person. The Customer shall ensure compliance with any applicable laws, regulations, orders or other requirements of any governmental entity relating to Services provided by the Company to the Customer or made available by the Customer to another User.

(B) Customer or User-provided equipment at the Premises or elsewhere for use in conjunction with Services shall be so constructed, maintained, and operated as to be compatible with and work satisfactorily with the facilities and Services of the Company. Such equipment shall be provided by and maintained at the expense of the Customer, Authorized User, or joint user, and as authorized by the Company. The magnitude and character of the voltages and currents impressed on Company-provided equipment and wiring by the connection, operation, or maintenance of such equipment and wiring shall be such as not to cause damage to the Company-provided equipment and wiring or injury to the Company's employees or to other Persons. Any additional protective equipment required to prevent such damage or injury shall be provided by the Company at the Customer's expense.

(C) The Customer shall provide the personnel, power, and space required to operate all facilities and associated equipment installed on the premises of the Customer. Facilities furnished under this Tariff may be connected to Customer-provided terminal equipment in accordance with the provisions of this Tariff. Customer provided terminating equipment such as multiplexers and other terminating equipment may, at the Customer's request, be provided by the Customer, at the Customer's expense. The Company makes no guarantees or warranties as to the performance of Customer-provided equipment.

2.10.1 Customer Premises Provisions (cont'd)

(D) In order to protect the Company's facilities and personnel and the Services furnished to other Customers by the Company from potentially harmful effects, the signals applied to Services shall be such as not to cause damage to the facilities of the Company. Any special interface equipment necessary to achieve the compatibility between facilities of the Company and the channels or facilities of others shall be provided at the Customer's expense.

(E) If the protective requirements in connections with Customer-provided equipment are not being complied with, the Company may take such action as necessary to protect its facilities and personnel and will promptly notify the Customer of the need for protective action. In the event that the Customer fails to advise the Company within ten (10) days after such notice is received or within the time specified in the notice that corrective action has been taken, the Company may take whatever additional action is deemed necessary, including canceling Service, to protect its facilities and personnel from harm. The Company will upon request twenty-four (24) hours in advance provide Customer with a statement of technical parameters that the Customer's equipment must meet.

(F) Customer shall cooperate with the Company to the extent necessary for the Company to discharge its obligations hereunder and as reasonably requested by the Company. The Customer is responsible for arranging access to its Premises at times mutually agreeable to the Company and the Customer when required for Company personnel to install, repair, maintain, program, inspect or remove equipment associated with the provision of the Company's services. The Company may, upon notification to the Customer, make such tests and inspections as may be necessary to determine that the requirements regarding the equipment and interconnections are being complied with in respect to the installation, operation and maintenance of Customer-provided equipment and in the wiring of the connection of Customer channels to Company-owned facilities. The Customer shall be responsible for providing Company personnel access to Premises at any reasonable hour for the purpose of testing, maintaining or repairing the facilities or equipment of the Company and to make such tests, adjustments and inspections as may be necessary to maintain the Company's facilities in satisfactory operating condition.

2.11 Liability of the Customer

2.11.1 The Customer will be liable for damages to the facilities of the Company and for all incidental and consequential damages caused by the negligent or intentional acts or omissions of the Customer, its officers, employees, agents, invitees, or contractors where such acts or omissions are not caused by the Company's negligence or intentional misconduct.

2.11.2 To the extent caused by any negligent or intentional act of the Customer as described in Section 2.11.1, preceding, the Customer shall indemnify, defend, and hold harmless the Company from and against all claims, actions, damages, liabilities, costs and expenses, including reasonable attorneys' fees, for (1) any loss, destruction, or damage to property of any third party, (2) the death of or injury to persons, including, but not limited to, employees or invitees of either party, and (3) any liability incurred by the Company to any third party pursuant to this or any other tariff of the Company, or otherwise, for any interruption of, interference to, or other defect in any service provided by the Company to such third party.

2.11.3 The Customer shall not assert any Claim against any other customer or user of the Company's Services for damages resulting in whole or in part from or arising in connection with the furnishing of Service under this Tariff including but not limited to mistakes, omissions, interruptions, delays, errors, or other defects or misrepresentations, whether or not such other customer or user contributed in any way to the occurrence of the damages, unless such damages were caused solely by the negligent or intentional act or omission of the other customer or user and not by any act or omission of the Company. Nothing in this Tariff is intended either to limit or to expand Customer's right to assert any claims against third parties for damages of any nature other than those described in the preceding sentence.

2.12 Customer Equipment and Channels

2.12.1 Interconnection of Facilities

(A) Customer Provided Equipment

Customer provided terminating equipment such as CSUs, multiplexers, and other terminating equipment may, at the Customer's request, be provided by the Company, at the Customer's expense. Company makes no guarantees or warranties as to the performance of Customer provided equipment.

(B) In order to protect the Company's facilities and personnel and the Services furnished to other Customers by the Company from potentially harmful effects, the signals applied to the Company's Service shall be such as not to cause damage to the facilities of the Company. Any special interface equipment necessary to achieve the compatibility between facilities of the Company and the channels or facilities of others shall be provided at the Customer's expense.

2.12.1 Interconnection of Facilities (cont'd)

(C) The Customer or other Authorized User is responsible for ensuring that Customer-provided equipment connected to Company equipment and facilities is compatible with such equipment and facilities. The magnitude and character of the voltages and currents impressed on Company-provided equipment and wiring by the connection, operation, or maintenance of such equipment and wiring shall be such as not to cause damage to the Company-provided equipment and wiring or injury to the Company's employees or to other persons. Any additional protective equipment required to prevent such damage or injury shall be provided by the Company at the Customer's expense.

2.12.2 Inspections

(A) The Company may, upon notification to the Customer, at a reasonable time, make such tests and inspections as may be necessary to determine that the requirements regarding the equipment and interconnections are being complied with in respect to the installation, operation and maintenance of Customer-provided equipment and in the wiring of the connection of Customer channels to Company-owned facilities.

(B) If the protective requirements in connection with Customer provided equipment are not being complied with, the Company may take such action as necessary to protect its facilities and personnel and will promptly notify the Customer by registered mail in writing of the need for protective action. In the event that the Customer fails to advise the Company within ten (10) days after such notice is received or within the time specified in the notice that corrective action has been taken, the Company may take whatever additional action is deemed necessary, including canceling service, to protect its facilities and personnel from harm. The Company will upon request twenty-four (24) hours in advance provide Customer with a statement of technical parameters that the Customer's equipment must meet.

2.13 Customer Deposits and Advance Payments

2.13.1 Advance Payments

To safeguard its interests, the Company may require a Customer to make an Advance Payment before Services and facilities are furnished. Except as provided in Section 3.4 hereof, the Advance Payment will not exceed an amount up to two (2) months of estimated monthly usage charges. In addition, where special construction is involved, the Advance Payment may also include an amount equal to the estimated nonrecurring charges for the special construction and recurring charges (if any) for a period to be set between the Company and the Customer. The Advance Payment will first be credited to the Customer's initial bill. An Advance Payment may be required in addition to a deposit. The sum of the advanced payment (exclusive of special construction) and deposit will not exceed 2.5 times of a Customer's estimated monthly charges.

2.13.2 Deposits

(A) To safeguard its interests, the Company may require the Customer to make a deposit to be held as a guarantee for the payment of charges. A deposit does not relieve the Customer of the responsibility for the prompt payment of bills on presentation. The deposit will not exceed an amount equal to:

(1) Two and a half (2½) months' charges for a service or facility which has a minimum payment period of one (1) month;

(2) The charges that would apply for the minimum payment period for a Service or facility which has a minimum payment period of more than one (1) month; except that the deposit may include an additional amount in the event that a Termination Charge is applicable; or

(3) Such other amounts as the Commission may prescribe.

(B) A deposit may be required in addition to an Advance Payment. The sum of the advanced payment (exclusive of special construction) and deposit will not exceed two and a half (2½) times of a Customer's estimated monthly charges.

(C) When a Service or facility is discontinued, the amount of a deposit, if any, will be applied to the Customer's account and any credit balance remaining will be refunded. Before the service or facility is discontinued, the Company may, at its option, return the deposit or credit it to the Customer's account. If the amount of the deposit is insufficient to cover the balance due to the Customer's account, the Company retains the right to collect any amounts owing after the deposit has been applied plus any costs related to the collection of any remaining balance.

2.13.2 Deposits (cont'd)

(D) When a Service or facility is discontinued, the amount of a deposit, if any, will be applied to the Customer's account and any credit balance remaining will be refunded. Before the Service or facility is discontinued, the Company may, at its option, return the deposit or credit it to the Customer's account. If the amount of the deposit is insufficient to cover the balance due to the Customer's account, the Company retains the right to collect any amounts owing after the deposit has been applied plus any costs related to the collection of any remaining balance.

2.13.3 Credit

Company may require Customer to provide information pertaining to its financial ability to pay for service. Company may deny Service to Customers who do not provide the requested information or who fail to meet Company's financial criteria, unless the Customer is willing to pay a deposit based on the rules contained in this Tariff. If Service was discontinued for non-payment of charges, the Company may request additional information from the Customer, and reserves the right to collect an Advance Payment and/or deposit, in addition to the unpaid balance due the Company, prior to re-establishing Service.

2.14. Payment Arrangements

2.14.1 Payment for Service

The Customer is responsible for the payment of all charges for facilities and Services furnished to the Customer or other Users.

(A) Taxes, Impositions, and Other Governmental Charges

(1) In addition to charges for the Services, the Customer is also responsible for payment of any sales, use, gross receipts, excise, or other local, state and federal taxes, charges, franchise fees or surcharges or any kind and character (however designated) (excluding taxes on the Company's net income) imposed on or based upon the provision, sale, or use of the Services and facilities. If Customer provides Company with a duly authorized exemption certificate, Company will exempt Customer in accordance with law, effective on the date Company receives the exemption certificate. If Customer does not give Company written notice of a dispute with respect to Company charges or application of taxes within six (6) months of the date of an invoice, such invoice shall be deemed to be correct and binding on Customer.

(2) Any assessments, franchise fees, access, ingress or egress fees or charges for use of real property, privilege, license, occupation or excise taxes or fees or other similar taxes or fees, whether in lump sum or at a flat rate, or based on receipts, or based on poles, wire or other utility property units, imposed upon Company by any governmental authority may be added pro rata, insofar as practical, in amounts which in the aggregate for the Company's Customers of any political entity shall be equal to the amount of any such tax upon the Company. The Company may, so long as any such tax or fee is in effect, add to the bills of the Customers in such political entity pro rata on the basis of the revenue derived by the Company from each such Customer, an amount sufficient to recover any such tax or fee.

(3) Unless otherwise specified in this Tariff, any such taxes, charges, assessments, surcharges and fees are in addition to Rates as quoted in the Tariff and are included as separate line items on the Customer's bill.

2.14.1 Payment for Service (cont'd)

(A) Taxes, Impositions, and Other Governmental Charges (cont'd)

(4) Company may adjust its Rates and Charges or impose additional Rates and Charges in order to recover amounts it is required or permitted by governmental or quasi-governmental authorities to collect from or pay to others in support of statutory or regulatory programs ("Governmental Charges"). Examples of such Governmental Charges include, but are not limited to, Universal Service funding.

(5) If Customer provides the Company with a duly authorized exemption certificate, the Company will exempt Customer in accordance with law, effective on the date the Company receives the exemption certificate.

(B) Third Party Charges

(1) Unless otherwise expressly specified in this Tariff, the Rates set forth in this Tariff do not include any charges imposed by third parties.

2.14.2 Billing and Collection of Charges

(A) Nonrecurring charges are due and payable within thirty (30) days after the date of the invoice.

(B) The Company shall present invoices for recurring charges monthly to the Customer, in advance of the month in which service is provided, and Recurring Charges shall be due and payable within thirty (30) days after the date of the invoice. When billing is based upon Customer usage, usage charges will be billed monthly for the preceding billing period. Payments of all amounts less than $25,000 by Customer may be made by either wire transfer or by Customer check of immediately available funds payable to the Company. All payments made by Customer in excess of $25,000 shall be made solely by wire transfer of immediately available funds in accordance with wire instructions provided by the Company.

(C) When Service does not begin on the first day of the month, or end on the last day of the month, the charge for the fraction of the month in which service was furnished will be calculated on a pro rata basis. For this purpose, every month is considered to have thirty (30) days.

2.14.2 Billing and Collection of Charges (cont'd)

(D) Billing of the Customer by the Company will begin on the Service Commencement Date, which is the day on which the Company notifies the Customer that the service or facility is available for use, except that the Service Commencement Date may be postponed by mutual agreement of the parties, or if the Service or facility does not conform to standards set forth in this Tariff or the Service Order. Billing accrues through and includes the day that the service, circuit, arrangement, or component is discontinued.

(E) If any portion of the payment is received by the Company after the date due, or if any portion of the payment is received by the Company in funds which are not immediately available upon presentment, then a late payment penalty shall be due to the Company. The late payment penalty shall be the portion of the payment not received by the date due, multiplied by a late factor. The late factor shall be the lesser of:

(1) A rate of one and one half percent (1½%) per month; or

(2) The highest interest rate which may be applied under Arizona state law for commercial transactions.

(F) The Customer will be assessed a charge of Two Hundred Fifty dollars ($250.00) for each check submitted by the Customer to the Company which a financial institution refuses to honor.

(G) If Service is disconnected by the Company in accordance with Section 2.14.4 and later reinstalled, Service will be subject to all applicable installation charges. If Service is suspended by the Company and later restored, service will be subject to all applicable restoration charges.

2.14.3 Billing Disputes

(A) General

All invoices are presumed accurate, final and shall be binding on the Customer unless a valid notice of the disputed charge(s) is received by the Company within ninety (90) days after the date on the invoice. For the purposes of this Section, "valid notice" is defined as Customer's written notice to the Company, containing sufficient documentation to investigate the dispute, including the account number under which the invoice has been rendered, the date of the invoice, and the specific items on the invoice being disputed, and Customer's specific reasons for disputing a charge.

2.14.3 Billing Disputes (cont'd)

(B) Late Payment Charge

(1) The undisputed portions of the bill must be paid by the payment due date to avoid assessment of a late payment charge on the undisputed amount as provided in this Tariff.

(2) In the event that a billing dispute is resolved by the Company in favor of the Customer, any disputed amount withheld pending resolution of the billing dispute shall not be subject to the late payment charge.

(3) In the event that a billing dispute is resolved in favor of the Company, the Customer shall pay the late payment charge.

(C) Adjustments or Refunds to the Customer

(1) In the event that the Company resolves the billing dispute in favor of a Customer who has withheld payment of the disputed amount pending resolution of the disputed bill, the Company will credit the Customer's account for the disputed amount in the billing period following the resolution of the dispute.

(2) In the event that the Company resolves the billing dispute in favor of a Customer who has paid the total amount of the disputed bill, the Company will credit the Customer's account for any overpayment by the Customer in the billing period following the resolution of the dispute.

(3) In the event that the Company resolves the billing dispute in favor of a Customer who has paid the total amount of the disputed bill but canceled the service, the Company will issue a refund of any overpayment by the Customer.

(4) All adjustments or refunds provided by the Company to the Customer at the Customer's request, or provided by the Company to the Customer by way of compromise of a billing dispute, and which are accepted by the Customer, are final and constitute full satisfaction, settlement, and/or compromise of all of the Customer's claims for the billing period for which the adjustment or refund was issued.

2.14.3 Billing Disputes (cont'd)

(D) Unresolved Billing Disputes

In the case of a billing dispute between the Customer and the Company for Service furnished to the Customer, which cannot be settled to the mutual satisfaction of the Customer and the Company, the Customer has up to ninety (90) days (commencing five (5) days after such bills have been mailed or otherwise rendered per the Company's normal course of business) to take the following course of action.

(1) First, the Customer may request and the Company will provide an in-depth review of the disputed amount.

(2) Second, if after investigation and review by the Company, a disagreement remains as to the disputed amount, the Customer may file an appropriate complaint with:

Arizona Corporation Commission
1200 West Washington Street
Phoenix, Arizona 85007-2927

(E) If Customer does not give Company written notice of a dispute with respect to Company's charges or application of taxes within six (6) months of the date of an invoice, such invoice shall be deemed to be correct and binding on Customer.

2.14.4 Discontinuance of Service and Termination of Agreement for Cause

(A) Upon nonpayment of any amounts owing to the Company more than twenty-nine (29) days from the due date of the bill, the Company may, by giving at least five (5) days prior written notice to the Customer, discontinue, suspend or terminate the affected Service and Service Orders without incurring any liability.

(B) Upon breach of any of the other Regulations or material terms or conditions of this Tariff or for furnishing Service the Company may, after giving Customer written notice of such breach and Customer's failure to cure such breach within thirty (30) days thereafter, by giving twenty-four (24) hours written notice to the Customer, discontinue, suspend or terminate the affected Service and Service Orders without incurring any liability if such violation continues during that period.

(C) Upon condemnation of any material portion of the facilities used by the Company to provide Service to a Customer or if a casualty renders all or any material portion of such facilities, the Company, by written notice to the Customer, may immediately discontinue or suspend the affected Service without incurring any liability.

(D) Upon the Customer's insolvency, assignment for the benefit of creditors, filing for bankruptcy or reorganization, or failing to discharge an involuntary petition within the time permitted by law, the Company may immediately discontinue or suspend Service without incurring any liability.

(E) Upon any governmental prohibition or required alteration of the Services to be provided, or any violation by Customer of an applicable law or regulation, the Company may immediately discontinue Service without incurring any liability.

(F) In the event of fraudulent or unauthorized use of the Company's network or the Services, the Company may without notice discontinue, suspend or terminate the affected Service and Service Orders. The Customer will be liable for all related costs. The Customer will also be responsible for payment of any reconnection charges.

(G) Upon the Company's discontinuance of Service to the Customer under this Section, the Company, in addition to all other remedies that may be available to the Company at law or in equity or under any other provision of this Tariff, may declare all future monthly and other charges which would have been payable by the Customer during the remainder of the term for which such Services would have otherwise been provided to the Customer to be immediately due and payable (discounted to present value at six percent (6%)).

2.14.5 Customer Overpayment

The Company will pay interest on a Customer overpayment. Customer overpayment shall mean a payment to the Company in excess of the correct charges for Service when caused by erroneous billing by the Company. The rate of interest shall be the unadjusted interest rate paid on Customer deposits or the late payment penalty rate, whichever is greater. Interest shall be paid from the date when the Customer overpayment was made, adjusted for any changes in the deposit interest rate or late payment penalty rate, and compounded monthly, until the date when the overpayment is refunded. No interest shall be paid on Customer overpayments that are refunded within thirty (30) days after such overpayment is received by the Company.

2.14.6 Cancellation of Application for Service

(A) The Customer may cancel an application for service prior to installation of the equipment provided that the Customer immediately pay the Company any out of pocket expenses incurred by the Company plus a cancellation fee of two (2) times the applicable monthly recurring service charge.

(B) Out of pocket expenses include but are not limited to the cost of the equipment, facilities, and material, the cost of installation, engineering, labor, and supervision, general and administrative expense, other disbursements, depreciation, maintenance, taxes, provision for return on investment, and any other costs associated with the special construction or arrangements.

2.15. Allowances for Interruptions in Service

2.15.1 General

(A) If the Customer reports any Service, facility, or circuit to be interrupted but declines to release it for testing and repair, the Service, facility or circuit is considered to be impaired but not interrupted. No Credit Allowances will be made for a Service, facility, or circuit considered by the Company to be impaired.

(B) A Credit Allowance will be given when there is an Interruption of Service or Performance Failure, except as specified below.

(C) An Interruption period or Performance Failure begins when the Customer reports a Service, facility or circuit to be inoperative and, if necessary, releases it for testing and repair. An Interruption period or Performance Failure ends when the Service, facility or circuit is operative.

2.15. Allowances for Interruptions in Service (cont'd)

2.15.2 Limitations of Allowances

No credit allowance will be made for any Interruption in or Performance Failure of any Service:

(A) Due to the negligence of or noncompliance with the provisions of this Tariff by any Person other than the Company, including but not limited to the Customer, User or other common carriers connected to the service of the Company;

(B) Due to the failure of power, equipment, systems, connections, or services not provided by the Company;

(C) Due to circumstances or causes beyond the control of the Company or any Force Majeure;

(D) During any period in which the Company is not given full and free access to its facilities and equipment for the purposes of investigating and correcting Interruptions;

(E) During any period in which the Customer continues to use the Service on an impaired basis;

(F) During any period when the Customer has released Service to the Company for maintenance purposes or for implementation of a Customer order for a change in service arrangements;

(G) That occurs or continues due to the Customer's failure to authorize replacement of any element of special construction;

(H) That was not reported to the Company within thirty (30) days of the date that Service was affected; and

(I) Service outage attributable to the installation of a new circuit.

2.15. Allowances for Interruptions in Service (cont'd)

2.15.3 Use of Another Means of Communications

If the Customer elects to use another means of communications during the period of Interruption, the Customer must pay the charges for the alternative service used.

2.15.4 Application of Credits for Interruptions in Service

(A) Credits for Interruptions in Service that is provided and billed on a flat rate basis for a minimum period of at least one (1) month, beginning on the date that billing becomes effective, shall in no event exceed an amount equivalent to the proportionate charge to the Customer for the period of Service during which the event that gave rise to the claim for a Credit occurred. A Credit Allowance is applied on a pro rata basis against the Rates specified hereunder and is dependent upon the length of the Interruption. Only those facilities on the interrupted portion of the circuit will receive a Credit.

(B) For calculating Credit Allowances, every month is considered to have thirty (30) days.

(C) Only if requested by Customer in writing, a Credit Allowance will be given for Interruptions in Service of thirty (30) minutes or more. Two (2) or more interruptions of thirty (30) minutes or more during any one (1) twenty-four (24) hour period shall be considered as one (1) Interruption.

(D) Interruptions of 24 Hours or Less

Length of Interruption	Interruption Period To Be Credited
Less than 30 minutes	None
30 minutes up to but not including 3 hours	1/10 Day
3 hours up to but not including 6 hours	1/5 Day
6 hours up to but not including 9 hours	2/5 Day
9 hours up to but not including 12 hours	3/5 Day
12 hours up to but not including 15 hours	4/5 Day
15 hours up to but not including 24 hours	One Day

2.15.4 Application of Credits for Interruptions in Service (cont'd)

(E) Continuous Interruption Over Twenty-four (24) Hours and Less Than Seventy-two (72) Hours

Interruptions over twenty-four (24) hours and less than seventy-two (72) hours will be credited one-fifth ($1/5^{th}$) day for each three (3) hour period or fraction thereof that occurs following the expiration of the initial twenty-four (24) hour period. No more than one (1) full day's Credit will be allowed for any period of twenty-four (24) hours.

(F) Interruptions Over Seventy-two (72) Hours

Interruptions over seventy-two (72) hours will be credited two (2) days for each full 24-hour period that occurs following the expiration of the initial seventy-two (72) hour period. No more than thirty (30) days Credit will be allowed for any one (1) month period.

(G) Notwithstanding the foregoing, Credits for Metro EVPLS and LCT Service shall be as provided in Sections 2.15.5 and 3.2.1 (L).

2.15.5 Application of Credits for Performance Failure(s) of Metro EVPLS.

(A) In the event that the Company is unable to restore a portion of the Metro EVPLS as required hereunder, or in the event of a Metro EVPLS Performance Failure, Customer shall be entitled to a Credit against the monthly recurring charges prorated for the affected circuits for the unplanned Performance Failure of Metro EVPLS in excess of fifteen (15) continuous minutes. The Company will deduct any Credit Allowance from future charges payable by the Customer. If two more or more Performance Failure(s) in excess of thirty (30) continuous minutes occur in one calendar month, and the cause of the Performance Failure(s) is determined to be in Company's Network, the affected Metro EVPLS will be deemed a trouble service. If a third Performance Failure(s) of thirty (30) continuous minutes occurs within fifteen, (15) days after the second thirty, (30) minute Performance Failure(s), Customer may disconnect the affected Metro EVPLS without incurring any Termination Liability Charges.

2.15.5 Application of Credits for Performance Failure(s) of Metro EVPLS (cont'd)

(B) A Metro EVPLS Performance Failure begins when the Company is notified or becomes aware of the interruption, whichever occurs first. A Metro EVPLS Performance Failure ends when the affected line and/or associated Company facilities and equipment are operational. Any delay time associated with the Company or its agents' inability to access the Metro EVPLS equipment at the Customer's Premise shall not be included in the duration of the Performance Failure. If the Customer reports any Service, equipment, facility or circuit to be inoperative, but declines to release it for testing and repair, it is considered to be impaired, but shall not be deemed a Metro EVPLS Performance Failure.

(C) Customer must request a Credit Allowance for a Performance Failure within thirty (30) days after the Performance Failure occurs or any claim for an allowance is waived. Unless otherwise specifically stated, Performance Failure(s) are not aggregated for purposes of determining the Credit Allowance.

(D) The Metro EVPLS Credit Allowance is calculated per circuit according to the following table:

METRO EVPLS Performance Failure Duration	**Credit Per Circuit**
15 minutes or less	None
Between 15 Minutes and 1 Hour	2% of Company' monthly recurring charge for the affected circuit
Each Hour above 1 Hour	An additional 3% of the Company's monthly recurring charge for the affected circuit, capped at 75% of the Company's monthly recurring charge for any single Metro EVPLS Performance Failure, with a maximum Credit equal to 100% of the Company's monthly recurring charge for all Metro EVPLS Performance Failures to that same circuit in any month

2.16 Cancellation of Service/Termination Liability Charges

2.16.1 Customers desiring to terminate a Service Order or Service shall provide Company no less than thirty (30) days written notice thereof. If a Customer cancels a Service Order or terminates Services for any reason whatsoever before the completion of the term set forth in the applicable Service Order, Customer agrees to pay to Company Termination Liability Charges. These charges shall become due and owing as of the effective date of the cancellation or termination and be payable within the period for payment of invoices set forth in this Tariff.

2.16 Cancellation of Service/Termination Liability Charges (cont'd)

2.16.2 Termination Liability Charges

Unless otherwise expressly provided in this Tariff, Customer's Termination Liability Charges shall be equal to:

(A) All unpaid nonrecurring charges reasonably expended by Company to establish Service to Customer, plus;

(B) Pro rata refund of all concessions and Credits issued and all waived installation and other nonrecurring charges, plus;

(C) Any disconnection, early cancellation or termination charges reasonably incurred and paid to third parties by Company on behalf of Customer, plus;

(D) An amount equal to fifty percent (50%) of all recurring charges specified in the applicable Service Order for the balance of the then current term for all elements of the Service which include without limit all Nodes, Channel Interfaces, and Internodal Channels.

2.16.3 The Customer is responsible for payment of all bills for Service furnished until the termination date regardless of which party terminates the Service. The Customer shall reimburse the Company for all costs, expenses and fees (including reasonable attorneys' fees and costs) incurred by the Company in collecting such amounts.

2.17 Customer Liability for Unauthorized Use of the Network

2.17.1 Unauthorized Use of the Network

(A) Unauthorized use of the Network occurs when: (1) a person or entity that does not have actual, apparent, or implied authority to use the Network, obtains the Company's Services provided under this Tariff; or (2) a person or entity that otherwise has actual, apparent, or implied authority to use the Network, makes fraudulent use of the Network to obtain the Company's services provided under this Tariff, or uses specific services that are not authorized.

2.17.1 Unauthorized Use of the Network (cont'd)

(B) The following activities constitute fraudulent use:

(1) Using the Network to transmit a message, locate a person, or otherwise give or obtain information, without payment for the service;

(2) Using or attempting to use the Network with the intent to avoid payment, either in whole or part, of any of the Company's tariffed charges by either rearranging, tampering with, or making connections not authorized by this Tariff to any service components used to furnish the Company's Services or using fraudulent means or devices, tricks, schemes, false or invalid numbers, false credit devices or electronic devices;

(3) Using fraudulent means or devices, tricks, schemes, false or invalid numbers, false credit devices or electronic devices to defraud or mislead callers.

(C) Customers are advised that use of telecommunications equipment and services, including that provided under this Tariff, carries a risk of various forms of telecommunications fraud (including, but not limited to, toll and PBX fraud perpetrated by Users who gain access to a Customer's facilities, account numbers, security, or authorization codes, etc.). Customers should take all necessary steps to restrict access to their facilities, including the equipment and services provided hereunder, and to detect and prevent unauthorized use of the equipment and Services provided by the Company under this Tariff.

2.17.2 Liability for Unauthorized Use

(A) Except as provided for elsewhere in this Tariff, the Customer is responsible for payment of all charges for Services provided under this Tariff furnished to the Customer or User. This responsibility is not changed due to any use, misuse, or abuse of the Customer's Service or Customer-provided equipment by Users or other third parties, the Customer's employees, or the public.

(B) The Customer is liable for all costs incurred as a result of unauthorized use of the Network, including service charges and any direct, indirect, special, incidental, reliance, consequential, exemplary, or punitive charges.

(C) The Customer is responsible for payment of any charges related to the suspension and/or termination of Service, and any charges for reconnection of Service, incurred as a result of unauthorized use of the Network.

3. SERVICE DESCRIPTIONS AND RATES

3.1 Metro Ethernet Virtual Private Line Service ("Metro EVPLS")

Metro EVPLS is a common carrier service subject to the regulations set forth in this Tariff. The Company, upon request, shall exercise commercially reasonable efforts to provide Metro EVPLS to Customer pursuant to the terms and conditions of this Tariff.

3.1.1 General

(A) Metro EVPLS permits a Customer to extend the range of their Ethernet communication from their local area network ("LAN") to a wide area network.

(B) With Metro EVPLS, Customers' Ethernet transmissions are encapsulated at OSI Layer 2, using standard IEEE 802.3 protocol, and delivered over the AGL supplied optical backbone network to a designated remote site. Metro EVPLS thus can deliver IP ("Internet Protocol") or other data packets between two (2) specified points using Ethernet frames. Each Ethernet circuit will have a total Bandwidth Profile, which indicates its maximum data throughput. Metro EVPLS is transparent to Layer 3 protocols, including IP, IPX, and AppleTalk. Connectivity is available (initially) at a discrete bit rate from 1 Mbps to 1000 Mbps (in increments of 1 Mbps or 10 Mbps). Metro EVPLS thus permits Customers to transmit any information content of their choosing, and delivers the Customer's Ethernet communications without change in form or content from the Customer's premises to a specified destination (remote site, data center, or other carrier's point of presence ("POP")).

(C) Metro EVPLS is suitable for data transmission and VOIP.

(D) Metro EVPLS provided under this Tariff is available for intrastate service use only.

(E) Metro EVPLS is available at the rates set forth herein where facilities are available. Where special construction is required, additional charges under a Special Pricing Arrangement, as described in Section 3.4 may apply.

3.1.2 Metro EVPLS Regulations

(A) Explanation of Terms

(1) Customer Premises Equipment ("CPE"): Customer supplied equipment used to attach its Ethernet LAN to an Edge Device.

(2) Edge Device: A Company supplied termination device placed on the Customer's premises that permits Customers to attach their CPE. The Edge Device is part of the Company's regulated network, with the demarcation point (as defined in 47 C.F.R. Section 68.3) being the interface between the Edge Device and the Customer's CPE.

3.1.2 Metro EVPLS Regulations (cont'd)

(A) Explanation of Terms (cont'd)

(3) Ethernet LAN: A type of LAN conforming to IEEE Standard 802.3 (and related standards). Ethernet protocol (CMSA/CD) permits workstations on a LAN to communicate with one another, at speeds starting at 1 Mbps up to 1 Gbps. Technical specifications are available from:

American National Standards Institute
11 West 42nd Street
New York, NY 10036

(B) Regulations

(1) Customer may not suspend Metro EVPLS.

(2) Metro EVPLS is available 24 hours per day, 7 days per week, except for periods of scheduled maintenance.

(3) Metro EVPLS is available for lawful use only. Company may suspend Metro EVPLS if it reasonably suspects that (i) unlawful or fraudulent use is occurring or (ii) Customer supplied CPE is interfering with the proper operation or other customers' use of the Company's Network.

(4) CPE attachment to the Company's Network (at the Customer's side of the Edge Device) is permitted, subject to compliance with applicable Electrical Institute of America or other interface specifications (available from the Company upon request). The Customer is responsible for installation, operation and maintenance of any and all CPE.

(5) Responsibilities of the Company:

(a) The Company's obligations to provide Metro EVPLS are expressly conditioned upon the availability of facilities (including without limitation, services provided by local exchange carriers and access to rights-of-way, poles, conduit, easements, and other carriers' facilities), under economically and technically feasible conditions, all as determined by the Company in its sole, reasonable discretion.

(b) The Company will provide the Customer with information regarding the Edge Device specifications as reasonably necessary for the Customer to attach its LAN CPE.

3.1.2 Metro EVPLS Regulations (cont'd)

(B) Regulations (cont'd)

(5) Responsibilities of the Company: (cont'd)

(c) The Company reserves the right to change its equipment vendors should equipment availability, price or technological advantages make such a change attractive or necessary. In such circumstances, the Company will give the Customer as much advance notice as reasonably possible, to allow the Customer sufficient time to make any necessary changes to CPE, and schedule cooperative testing for cutover if required.

(d) The Company will exercise reasonable commercial efforts to timely install Metro EVPLS by either the installation date set forth in a Service Order (defined hereunder) or, if no date is specified therein as soon as practicable after execution of a Service Order, subject to Customer's compliance with all regulations set forth in this Tariff. In the event Company fails to substantially complete such installation within thirty (30) days of the agreed upon installation date in the Service Order, Customer, as its sole remedy, may cancel the Service Order without penalty.

(6) Responsibilities of the Customer:

(a) The Customer must be prepared to initiate testing of the Metro EVPLS in a timely manner on the negotiated date, providing testing equipment and personnel to support installation requirements, as may be necessary.

(b) Customer will be responsible for selecting its own CPE, which must be compatible with the Company provided Edge Devices.

(c) The Customer shall be solely responsible for providing at its sole cost, (i) space and racks to house Company supplied Edge Devices, connector panels, splice boxes, media converters and (ii) a suitable power supply to all Company supplied equipment (including any Edge Devices) and for Customer's own CPE connected thereto.

(d) The Customer shall arrange for, and shall be solely responsible for securing all permits, approval, and for completing all site preparation as required, for Company supplied Edge Devices to be placed on the Customer premises, together with suitable heating, air conditioning and environmental conditions for the Edge Devices as prescribed by and all at no charge to the Company.

3.1.2 Metro EVPLS Regulations (cont'd)

(B) Regulations (cont'd)

(6) Responsibilities of the Customer: (cont'd)

(e) The Customer must obtain a building entrance agreement permitting AGL to bring its lateral connection or other Network facility into the building, if at the time of placing the Service Order Company does not then have access to the building.

(f) The Customer will be responsible for selecting its own CPE, which must be compatible with the AGL supplied Edge Devices. Company, upon request and as mutually agreed, may provide CPE to Customer on a case by case basis.

(g) Except as otherwise agreed, Customer is responsible for the installations and all costs for the wiring from Customer's CPE to Company's point of demarcation for the building. Customer is responsible for any and all additional costs that may be incurred by Company due to delays caused, in whole or in part, by Customer.

(h) The Customer must provide Company with timely access to all Customer location(s) where Company equipment is located for authorized Company personnel and/or its agents to perform routine and emergency maintenance, and/or for removal of Company equipment at the termination, cancellation or expiration of the Service Term.

(i) The operation of Metro EVPLS in accordance with the Company accepted Service Order and this Tariff.

(j) Submission of a Service Order to Company for the Metro EVPLS ordered, which Service Order is subject to Company's acceptance.

(k) The Company's obligations (but not Customer's payment) to install or provide Metro EVPLS shall be excused to the extent affected by Customer's failure to comply with this Section 3.1.2(B)(6).

3.1.2 Metro EVPLS Regulations (cont'd)

(B) Regulations (cont'd)

(6) Responsibilities of the Customer: (cont'd)

(l) The Company's obligations hereunder are expressly conditioned upon Customer, at its sole expense, securing a switched, local telephone circuit for purposes of "remote dial-in" and a modem for each Customer location, and making such dial-in line and modem available at all times for the Company's use during installation, maintenance and repairs to the service ordered by Customer. The Company will have no liability whatsoever for (nor will the SLAs apply during the period of) any failure of Metro EVPLS arising from or caused by, directly or indirectly, the operation or failure of said dial-in line and/or modem.

(7) Trouble Resolutions

The Company will assist the Customer in resolving any installation or Metro EVPLS problems. However, the Company does not assume responsibility for the compatibility or suitability of the Customer's CPE. Company dispatches of personnel to the Customer premises to resolve problems caused, directly or indirectly, by CPE (or other Customer supplied devices or equipment) will result in additional charges to the Customer, based on the Company's then effective rates on a time and materials basis.

(8) Service Orders

Customer may order Metro EVPLS by executing a Service Order. In addition to the Service Order, Customer shall also execute such other documents as the Company may reasonably require. In the event of a conflict or inconsistency between (i) the terms of a Service Order (or of any other document executed by the Customer) and (ii) those of this Tariff, the latter shall govern.

3.1.3 Metro EVPLS Service Level Agreement ("SLAs")

The Company shall undertake commercially reasonable efforts to achieve the following performance goals and to make available the following network capabilities for Metro EVPLS Customers:

(A) Network Performance Goals ("SLAs")

SLAs will vary, depending upon Customer's network configuration and specific service agreements entered into by the parties. Generally speaking, EVPLS is intended to operate according to the following SLAs:

(1) EVPLS Availability: 99.5% - 99.99%

(2) Network Restoration: 200ms – 1000ms

(B) SLA Description Metrics

(1) Bandwidth Guarantee: the Company guarantees that for periods when EVPLS is available, full port-to-port Circuit bandwidth is available for the Customer's use at all times.

(2) Response and Repair Times:

In the event of a Performance Failure in Metro EVPLS, excluding events as defined in Section 2.15.2, the Company will respond after receiving notification of the EVPLS Performance Failure from either internal network monitoring or Customer. After receiving notification of the EVPLS Performance Failure, the Company shall restore EVPLS on its failed system as follows:

(i) Electronic Restoration
In the event of an electronic failure, the Company shall use reasonable commercial efforts to restore the affected Metro EVPLS electronics within eight (8) hours of arrival of maintenance personnel on site. Such repairs may be temporary.

(ii) Cable Restoration
In the event of a cable failure of Company supplied cables, the Company shall use reasonable commercial efforts to effect repairs on the cable within eight (8) hours after of arrival of maintenance personnel on site. Such repairs may be temporary.

3.1.3 Metro EVPLS Service Level Agreement ("SLAs") (cont'd)

(B) SLA Description Metrics (cont'd)

(2) Response and Repair Times: (cont'd)

(iii) Permanent Restoration
Within one (1) business day after completing any temporary repair or restoration, Company shall commence planning permanent repair. Company shall notify Customer of its permanent repair plans and implement such repairs within an appropriate time thereafter. Company shall strive to repair "in-use" fibers first and repair those fibers not currently in-use during permanent restoration activities.

3.1.4 Metro EVPLS Rates

	1 to 9 Mbps	10 to 99 Mbps	100 to 1000 Mbps
Installation	$6,000.00	$10,000.00	$20,000.00
MRC	ICB based on Committed Bandwidth, Special Construction Costs and Distance between Network Connections	ICB based on Committed Bandwidth, Special Construction Costs and Distance between Network Connections	ICB based on Committed Bandwidth, Special Construction Costs and Distance between Network Connections
Service Term	ICB	ICB	ICB

3.1.5 Termination Liability Charges

In the event that, prior to the end of the period of time for which the Metro EVPLS was ordered , Customer terminates the Service or in the event that the delivery of Service is terminated by Company due to a failure of Customer to comply with the of this Tariff, Customer shall pay Termination Liability Charge(s) as specified in Section 2.16 of this Tariff.

3.2 Link Connectable Transport ("LCT") Service

3.2.1 General

(A) LCT service is an intraLATA fiber optic based, digital service which provides channelization capability for the customer in packages based on systems consisting of DS1, DS3, STS-1, OC-3, OC-12, OC-48 and OC-192 channels. It will provide local channels in the following system sizes:

(1) Synchronous - STS-1, OC-3, OC-12, OC-48 and OC-192 service

Synchronous systems are capable of transporting all channels. The capacity of each LCT service system is shown in the following table:

LCT System	DS1	DS3	STS-1	OC-3	OC-12	OC-48
LCT STS-1	28		1			
LCT OC-3	84	3	3	1		
LCT OC-12	336		12	12	4	1
LCT OC-48	1344	48	48	16	4	1
LCT OC-192	5376	192	192	64	16	4

3.2.1 General (cont'd)

(B) Channelization is provided by LCT service systems which furnish point to point fiber optic transport from or to the Company's Optical Fiber Termination Point (a node, facility, structure or other connection point located at or on a Company fiber optic ring), or from or to customer designated Premises or POPs. Channel interfaces are offered to provide individual DS1, DS3, STS-1, OC-3, OC-12 and OC-48 channels. The Customer may channelize all or part of a LCT service package to activate data facilities for interconnection with the exchange network, voice grade and data facilities for private line channels, as well as other LCT services. The Customer may also choose not to channelize all or part of a LCT service package allowing direct connection to other Company services as provided in this Tariff. (OC-12, OC-48 and higher LCT service local channel systems are only available as channelized.)

(C) Channel interface availability varies with system size and transport architecture. The following table lists the channel interfaces available with each LCT service system.

Local Channel Systems:

			Synchronous		
Customer Channel Interfaces	**STS-1**	**OC-3**	**OC-12**	**OC-48**	**OC-192**
DS1	Yes	Yes	No	No	No
DS3	Yes	Yes	Yes	Yes	No
STS-1	Yes	Yes	Yes	Yes	No
OC-3	No	Yes	Yes	Yes	Yes
OC-12	No	No	No	Yes	Yes
OC-48	No	No	No	No	Yes

3.2.1 General (cont'd)

(C) (cont'd)

Local Channel Systems: **CO Channel Interfaces**	**STS-1**	**OC-3**	**OC-12**	**OC-48**	**OC-192**
DS1	Yes	Yes	No	No	No
DS3	No	Yes	Yes	Yes	No
STS-1	Yes	Yes	Yes	Yes	No
OC-3	No	Yes	Yes	Yes	Yes
OC-12	No	No	No	Yes	Yes
OC-48	No	No	No	No	Yes
28 DS1 Channel System	No	No	Yes	Yes	No
STS-1 Channel System	No	No	Yes	Yes	No
OC-3 Channel System	No	No	Yes	Yes	Yes
OC-12 Channel System	No	No	No	No	Yes
OC-48 Channel System	No	No	No	No	Yes

3.2.1 General (cont'd)

(D) LCT service systems may have an optical physical interface at either the CO or the Customer termination location. Where a Customer elects to order a LCT service with optical termination at the Customer's location, the Customer's termination equipment must be compatible with Company equipment. Customers are also required to utilize compatible channel interface combinations to function with Company provided CO channel interfaces. The Company reserves the right to determine the equipment it employs for Service.

(E) This Service is available within a LATA where appropriate optical facilities can be made available as determined by the Company. Service inquiries will be necessary to determine availability interval.

(F) All LCT services in a Customer's package must be channelized in a single equipment location on a Customer's Premises, i.e., a package cannot be split between premises, or multiple locations within a Premises. Standard network interfaces will be provided by the Company for digital services consistent with existing practices for single channel services.

(G) Individual channels within a LCT service package may be connected with service offered in other sections of this Tariff as appropriate. The regulations and Rates in this Tariff are applicable for the LCT service component of the Customer's end-to-end service. Single channel service components (non-LCT service links) are subject to the regulations and Rates in their respective Tariff sections.

(H) The Customer may activate any number or combination of channels within a LCT service package within the capacity limits of the basic system. Channels may be activated coincident with installation or at any time subsequent to basic system installation. Once activated, a channel is subject to a minimum service period in accordance with the contract period. Features (channels) activated under month-to-month rates will have a minimum service period of one (1) month.

(I) Synchronous channels, automatic protection switching capability is provided via the synchronous Customer or CO channel 4-fiber interfaces. These 4-fiber interfaces provide 1+1 optical card protection of the interface. The specifications for these interfaces are contained in BellSouth Telecommunications, Inc. Technical Reference #73501.

3.2.1 General (cont'd)

(J) The termination of channelization equipment will be in a single equipment location on a Customer's Premises. The Customer must provide suitable floor space, controlled environment, and a source of non-switched 120 volt, 60 Hz AC power to support this Service.

(K) Channelization of DS3 (electrical) data rates on a Customer's Premises may also be provided by the Customer. Joint provisioning of channelized services introduces joint responsibilities between the Customer and the Company.

(1) Responsibilities of the Company:

a. The Company will endeavor to activate its portion of joint service in a timely manner on the negotiated date to support installation requirements.

b. The Company will provide the Customer with information regarding the type and the manufacturer of CO channelization equipment to be used in each application.

c. The Company will limit its selection of CO equipment to avoid operational and administrative difficulties associated with a multi-vendor environment.

d. The Company reserves the right to change its equipment vendors should equipment availability, price or technological advantages make such a change attractive or necessary.

e. The Company will notify the Customer, generally a minimum of three (3) months in advance, of any need to change its CO equipment to allow the Customer sufficient time to respond, make any necessary changes, and schedule cooperative testing for cutover if required.

f. Digital synchronization timing for LCT services will be provided by the Company.

3.2.1 General (cont'd)

(K) (cont'd)

(2) Responsibilities of the Customer:

a. The Customer must be prepared to activate its portion of joint service in a timely manner on the negotiated date, providing testing equipment and personnel to support installation requirements, as may be necessary.

b. The Customer will be responsible for selecting its own equipment. Customer equipment must be compatible with the Company provided channelization.

c. The Customer must provide suitable power for its own equipment. Simplex powering will not be provided by the Company for a Customer's channel service units due to the serving arrangements associated with fiber optic facilities.

d. If the Customer wishes the Company to locate Company equipment at the Customer's Premises or POP and the Company agrees to place such equipment, Customer shall provide, at no charge to Company, suitable space, power and environmental conditions for the equipment.

(3) Trouble resolutions:

The Company will assist the Customer in resolving any installation or day to day channel service problems. However, the Company does not assume responsibility for the compatibility or suitability of the Customer's equipment. Dispatches to Customer Premises caused by Customer equipment troubles will result in additional charges to the Customer.

3.2.1 General (cont'd)

(L) Credit Allowance

When an Interruption to LCT service occurs due to causes other than negligence of the Customer, or to the failure of facilities or equipment furnished by the Customer or third person, a Credit Allowance will be made upon request for the portion of Service affected. Where Service Interruptions of one (1) minute or more per occasion occur, the Credit applied shall be at the per minute rate of 1/1440 of the monthly charges for the LCT service. All Credit Allowances shall begin from the time of notice by the Customer to the Company, and will end when Company determines that the LCT service is operative. A Customer must report the outage in order to receive service outage Credit. The total Credit received in any month shall not exceed the monthly Charges for the LCT service.

(M) The technical specifications and standard network interfaces for LCT service, DS3, DS1 and associated channelization are contained in BellSouth Technical Reference #73501.

3.2.2 Application of Rates

(A) Monthly Rates as specified in Section 3.2.4 following apply for each LCT service, and are the maximum rates that will apply to standard LCT Service purchased under this Tariff other than on an ICB. These Rates apply regardless of the number of circuit equivalents within each package that are actually activated by the Customer at a point in time. Access, egress (or related charges) or any other charges of third parties are not included in the Rates specified in Section 3.2.4 following.

(1) Channel systems furnished between a CO and the Customer's Premises are distance sensitive. Basic Channel systems include the transport common equipment, and first half route mile of channel facilities at Rates specified in Section 3.4.4(A) following.

(B) All usual and applicable Service Connection Charges and Nonrecurring Charges as specified in the tariffs apply to the activation, move or change of channel equivalents within LCT service packages as well as for installation of the basic system. Suspension of service is not permitted with LCT service.

(C) Channel interfaces are required for LCT service based upon the following guidelines:

(1) Channel interfaces are required at both the Customer's location and the CO, or another Customer location, for LCT service local channel systems, except as specified in (2) following.

3.2.2 Application of Rates (cont'd)

(2) A LCT service CO channel interface is not required for a LCT service channel system with optical termination at a CO. A LCT service local channel system with optical termination in the CO may connect in one (1) of the following ways:

a. To another LCT service local channel at the compatible optical level;

b. To a Self-Healing Ring service channel interface ("CI") at the compatible optical level; or

c. To a compatible optical level channel interface from a higher level LCT service local channel.

(3) LCT service channel interfaces are only offered in conjunction with a LCT service System.

(4) Company provided DS1 Customer channel interfaces are offered only with LCT STS-1 and LCT OC-3 Basic Systems.

(5) OC-12 and OC-48 LCT service channel systems require a 28 DS1, STS-1, or OC-3 channel system in addition to DS1 channel interfaces in the CO, or Customer location to derive DS1 channels. OC-192 LCT service local channel systems require an OC-3 channel system in addition to DS1 channel interfaces to terminate DS1 channels in the CO, or Customer location.

(6) OC-192 LCT service local channel systems require an OC-3, OC-12 or OC-48 channel system in addition to DS3 or STS-1 channel interfaces to terminate DS3 or STS-1 channels in the CO or Customer location.

(7) OC-3 LCT service channel systems which require a DS3 termination at one (1) location and DS1 terminations at the other, have two (2) options available:

a. A DS3 channel interface at the Customer location and a 28 DS1 channel system in addition to DS1 channel interfaces at the CO, or

b. A DS3 (asymmetrical with DS1) interface at one (1) termination point and DS1 channel interfaces at the other termination point.

3.2.2 Application of Rates (cont'd)

(D) LCT service channel mileage Rates are distance sensitive. They are measured per half route mile or fraction thereof from the Customer's designated Premises to the Company origination location. Fractional mileage shall be rounded up to the next half (½) mile.

(E) LCT service Systems are available under contract only for variable rate periods with Rates based on lengths of 24 to 48 months, 49 to 72 months, or 73 to 96 months under conditions specified in Section 3.2 except as modified following. Contract rate increases are subject to the stipulations of (F) following. All elements of a contract will expire at the same time (be coterminous).

(1) LCT service Systems are available only under contract as specified preceding. Month to month rates are only available at the end of a contract rate period ("Term"). Customer channel interfaces are available on a month to month basis or under contract.

(2) All rate elements associated with a LCT service local channel must be provided under the same payment plan; provided however, that channel interfaces may be activated on month-to-month Rates or a shorter payment period if desired.

(F) LCT service Rates under contract will not be increased by Company initiative until the contract period expires. Those monthly Rates for LCT service in effect at the time the Service is installed and/or as of the Service Order application date, will be applicable until the contract expires. At the expiration date of the Customer's payment period option, the Customer may select a new payment period option at current contract rates or revert to current Rates on a month-to-month basis.

3.2.3 Digital Architecture and Definitions

(A) Digital Architecture

(1) LCT services differ in provisioning method and numbering format from single channel services. These services will be available from the Company on a link (partial channel) basis rather than as an end-to-end service. This architecture is intended to promote more efficient connectivity of analog and digital networks in the future.

Many LCT service channels will be available on a digital basis at the network interface on a Customer's Premises. Traditional analog services, like tie lines and off-premises stations can be provided on a digital basis to a premises by the Company when a Customer desires them encoded in a DS1 bit stream. Under those conditions, they will be provided as DS0 channels by the Company. Both the Company and the Customer have joint responsibilities to ensure the proper transmission of the provided services. Normal analog channel network interface specifications will be superseded by the electrical specifications of the 1.544 Mbps (DS1) channel which is actually terminated. Each DS0 channel provided will have identity only as a "time slot" within a DS1 channel. Compatible digital to analog conversion equipment must be provided by the Customer to derive the desired analog services. Any Channel Service Units ("CSUs") necessary for digital services are the responsibility of the Customer.

(B) Definitions

CHANNEL SERVICE UNIT (CSU)
This denotes network channel terminating equipment provided by the Customer to terminate digital channel facilities on a Customer's or User's premises.

DSO
This denotes a channel service expressed in terms of its digitally encoded data bit rate in accordance with the North American hierarchy of digital signal levels. It is generally referred to as having a 64 kbps transmission data rate signal. The required format and interface specifications are referenced in BellSouth Technical Reference #73501.

3.2.3 Digital Architecture and Definitions (cont'd)

(B) Definitions (cont'd)

DS1
This denotes a channel service expressed in terms of its digitally encoded data bit rate in accordance with the North American hierarchy of digital signal levels. It has a 1.544 Mbps transmission data rate, and provides for the two-way simultaneous transmission of isochronous timed, Bipolar Return-to-Zero (BPRZ) bit stream format, except where intentional bipolar violations are introduced by Bipolar with 8 Zero Substitution (B8ZS) format. Unframed signal formats are not permitted or compatible with Company equipment. The required format and interface specifications are contained in BellSouth Technical Reference #73501.

DS3
This denotes a channel service expressed in terms of its digitally encoded data bit rate in accordance with the North American hierarchy of digital signal levels. It has a 44.736 Mbps transmission data rate, and provides for two-way simultaneous transmission of randomized Non-Return-to-Zero (NRZ) signals with a B3ZS format. The required format and interface specifications are contained in BellSouth Technical Reference #73501.

SYNCHRONOUS LCT SERVICES
LCT service is available in the following synchronous systems: STS-1, OC-3, OC-12, OC-48 and higher levels LCT. These offerings are intended to be a very flexible, link connectable transport service for large Customers. They have the capability of connecting with individual exchange and private line services, Self-Healing Sonet Ring service and/or other LCT services. Appropriate electrical and optical signals will be provided in accordance with the specifications of BellSouth Technical Reference #73501.

SYNCHRONOUS OPTICAL NETWORK (SONET)
SONET defines a progressive hierarchy of optical signal and line rates. The basic building block is the STS-1 (Synchronous Transport Signal at level 1), operating at 51.840 Mbps. All higher rate signals (STS-N) are multiples of the basic STS-1 signal rate. The optical counterpart of a STS-N is the OC-N, operating at the same rate as the corresponding STS-N. The required format and interface specifications are contained in BellSouth Technical Reference #73501.

3.2.4 Rates and Charges

(A) LCT service Basic Channel Systems

The Basic System includes photonic common equipment and first one-half route mile of 1 channel fiber optic facilities.

	Nonrecurring Charge	Month to Month	24 to 48 Months	49 to 72 Months	73 to 96 Months	USOC
1. LCT STS-1 Basic System[1]						
(a) Per System	700.00	2,070.00	1,590.00	1,440.00	1,290.00	HFST1
2. LCT OC-3 Basic System[1]						
(a) Per System	700.00	3,700.00	3,100.00	2,800.00	2,500.00	HFSO3
(b) Per System with Optical Customer Termination	700.00	2,432.00	1,968.00	1,776.00	1,584.00	HFSOC
3. LCT OC-12 Basic System[1]						
(a) Per System	700.00	5,500.00	5,100.00	4,600.00	4,150.00	HFS12
(b) Per System with Optical Customer Termination	700.00	3,840.00	3,504.00	3,200.00	2,880.00	HFS1C
4. LCT OC-48 Basic System[1]						
(a) Per System	700.00	13,000.00	11,000.00	10,000.00	9,000.00	HFS48
(b) Per System with Optical Customer Termination	700.00	8,000.00	7,040.00	6,400.00	5,760.00	HFS4C
5. LCT OC-192 Basic System[1]						
(a) Per System	700.00	26,000.00	22,000.00	20,000.00	18,000.00	HFST2

[1] Month to month rates are only available at the end of a contract rate period.

3.2.4 Rates and Charges (cont'd)

(A) LCT service Basic Channel Systems (cont'd)

6. CO Interfaces	Nonrecurring Charge	Month to Month	24 to 48 Months	49 to 72 Months	73 to 96 Months	USOC
(a) Per DS1	$125.00	$24.00	$20.00	$17.00	$16.00	1PQE8
(b) Per DS3	125.00	115.00	95.00	90.00	85.00	1PQE3
(c) Per STS-1	125.00	175.00	140.00	130.00	120.00	1PQE4
(d) Per OC-3 (2 Fiber)	200.00	240.00	190.00	175.00	160.00	1PQE5
(e) Per OC-3 (4 Fiber)	200.00	425.00	330.00	300.00	270.00	1PQE6
(f) Per OC-12 (2 Fiber)	360.00	640.00	495.00	450.00	405.00	1PQEE
(g) Per OC-12 (4 Fiber)	400.00	1,280.00	990.00	900.00	810.00	1PQED
(h) Per OC-48 (2 Fiber)	500.00	1,600.00	1,325.00	1,215.00	1,050.00	1PQEO
(i) Per OC-48 (4 Fiber)	500.00	3,200.00	2,650.00	2,430.00	2,100.00	1PQEF
(j) Per 28 DS1 Channel System	125.00	600.00	490.00	465.00	450.00	MQ3CO
(k) Per DS1 on 28 DS1 Channel System	125.00	15.00	8.00	7.00	6.00	1PQEA
(l) Per STS-1 Channel System	125.00	600.00	490.00	465.00	450.00	1PQE7
(m) Per OC-3 Channel System	125.00	1,325.00	1,100.00	1,000.00	900.00	1PQE9
(n) Per OC-12 Channel System	125.00	2,650.00	2,200.00	2,000.00	1,800.00	1PQ12
(o) Per OC-48 Channel System	125.00	5,490.00	4,410.00	4,050.00	3,510.00	1PQ48

3.2.4 Rates and Charges (cont'd)

(A) LCT service Basic Channel Systems (cont'd)

7. Customer Channel Interfaces	Nonrecurring Charge	Month to Month	24 to 48 Months	49 to 72 Months	73 to 96 Months	USOC
(a) Per DS1	170.00	24.00	20.00	17.00	16.00	1PQF1
(b) Per DS3	125.00	115.00	95.00	90.00	85.00	1PQF3
(c) Per STS-1	125.00	240.00	195.00	185.00	175.00	1PQF4
(d) Per OC-3 (2 Fiber)	125.00	240.00	190.00	175.00	160.00	1PQF5
(e) Per OC-3 (4 Fiber)	125.00	475.00	380.00	350.00	320.00	1PQF6
(f) Per OC-12 (2 Fiber)	275.00	715.00	570.00	525.00	480.00	1PQF8
(g) Per OC-12 (4 Fiber)	275.00	1,430.00	1,140.00	1,050.00	960.00	1PQF7
(h) Per OC-48 (2 Fiber)	300.00	1,600.00	1,325.00	1,215.00	1,050.00	1PQF2
(i) Per OC-48 (4 Fiber)	300.00	3,200.00	2,650.00	2,430.00	2,100.00	1PQFO

3.2.4 Rates and Charges (cont'd)

(B) LCT service Internodal or Interoffice Channels (These channels are furnished between Customer Premises or POPs and other Customer Premises or POPs or Company COs. Rates are based upon route miles.[1]

	Nonrecurring Charge	Month to Month	24 to 48 Months	49 to 72 Months	73 to 96 Months	USOC
1. LCT STS-1 Service[1]						
a. Per STS-1						
(1) 0-8 miles						
(a) Fixed	190.00	1,430.00	975.00	775.00	625.00	1LPS8
(b) Per Mile	-	130.00	70.00	60.00	50.00	1LPE8
(2) 9-25 miles						
(a) Fixed	190.00	1,600.00	1,125.00	925.00	775.00	1LPS9
(b) Per Mile	-	130.00	70.00	60.00	50.00	1LPE9
(3) Over 25 miles						
(a) Fixed	190.00	1,870.00	1,325.00	1,125.00	925.00	1LPS6
(b) Per Mile	-	130.00	70.00	60.00	50.00	1LPE6

1 Month to month rates are only available at the end of a contract rate period.

3.2.4 Rates and Charges (cont'd)

(B) LCT service Internodal or Interoffice Channels (cont'd)

2. LCT OC-3 Service[1]	**Nonrecurring Charge**	**Month to Month**	**24 to 48 Months**	**49 to 72 Months**	**73 to 96 Months**	**USOC**
a. Per OC-3						
(1) 0-8 miles						
(a) Fixed	190.00	2,100.00	1,475.00	1,225.00	1,025.00	1LPS8
(b) Per Mile	-	225.00	155.00	140.00	125.00	1LPE8
(2) 9-25 miles						
(a) Fixed	190.00	2,600.00	2,150.00	2,000.00	1,900.00	1LPS9
(b) Per Mile	-	225.00	155.00	140.00	125.00	1LPE9
(3) Over 25 miles						
(a) Fixed	190.00	3,600.00	3,150.00	2,900.00	2,700.00	1LPS6
(b) Per Mile	-	225.00	155.00	140.00	125.00	1LPE6

[1] Month to month rates are only available at the end of a contract rate period.

3.2.4 Rates and Charges (cont'd)

(B) LCT service Internodal or Interoffice Channels (cont'd)

3. LCT OC-12 Service[1]	Nonrecurring Charge	Month to Month	24 to 48 Months	49 to 72 Months	73 to 96 Months	USOC
a. Per OC-12						
(1) 0-8 miles						
(a) Fixed	190.00	4,000.00	3,300.00	3,000.00	2,700.00	1LPS8
(b) Per Mile	-	400.00	320.00	290.00	260.00	1LPE8
(2) 9-25 miles						
(a) Fixed	190.00	5,500.00	4,800.00	4,500.00	4,200.00	1LPS9
(b) Per Mile	-	400.00	320.00	290.00	260.00	1LPE9
(3) Over 25 miles						
(a) Fixed	190.00	7,200.00	6,500.00	6,200.00	5,900.00	1LPS6
(b) Per Mile	-	400.00	320.00	290.00	260.00	1LPE6

[1] Month to month rates are only available at the end of a contract rate period.

3.2.4 Rates and Charges (cont'd)

(B) LCT service Internodal or Interoffice Channels (cont'd)

4. LCT OC-48 Service[1]	**Nonrecurring Charge**	**Month to Month**	**24 to 48 Months**	**49 to 72 Months**	**73 to 96 Months**	**USOC**
a. Per OC-48						
(1) 0-8 miles						
(a) Fixed	190.00	7,800.00	6,500.00	5,800.00	5,200.00	1LPS8
(b) Per Mile	-	600.00	500.00	450.00	400.00	1LPE8
(2) 9-25 miles						
(a) Fixed	190.00	8,700.00	7,300.00	6,700.00	6,100.00	1LPS9
(b) Per Mile	-	600.00	500.00	450.00	400.00	1LPE9
(3) Over 25 miles						
(a) Fixed	190.00	10,000.00	8,600.00	7,900.00	7,100.00	1LPS6
(b) Per Mile	-	600.00	500.00	450.00	400.00	1LPE6

[1] Month to month rates are only available at the end of a contract rate period.

3.2.4 Rates and Charges (cont'd)

(B) LCT service Internodal or Interoffice Channels (cont'd)

5. LCT OC-192 Service[1]	**Nonrecurring Charge**	**Month to Month**	**24 to 48 Months**	**49 to 72 Months**	**73 to 96 Months**	**USOC**
a. Per OC-192						
(1) 0-8 miles						
(a) Fixed	190.00	19,000.00	16,500.00	14,800.00	13,500.00	1LPS8
(b) Per Mile	-	600.00	500.00	450.00	400.00	1LPE8
(2) 9-25 miles						
(a) Fixed	190.00	19,900.00	16,900.00	15,200.00	13,700.00	1LPS9
(b) Per Mile	-	600.00	500.00	450.00	400.00	1LPE9
(3) Over 25 miles						
(a) Fixed	190.00	22,000.00	18,700.00	16,800.00	15,100.00	1LPS6
(b) Per Mile	-	600.00	500.00	450.00	400.00	1LPE6

[1] Month to month rates are only available at the end of a contract rate period.

3.2.4 Rates and Charges (cont'd)

(C) Moves

(1) A move involves a change in the physical location of one of the following:

a. The point of interface at the Customer Premises; or

b. The Customer's premises.

(2) When the move is to a new location in Company territory within the same state, the charge for the move is equal to the sum of all nonrecurring charges applicable to a new LCT service arrangement at the new location.

When the move is to a new location in Company territory in a different state, the move will be treated as a discontinuance and start of service. The Customer will be responsible for satisfying all outstanding minimum period charges for the discontinued service. All applicable nonrecurring charges at the new location will apply.

3.3 Dark Fiber Leasing

3.3.1 General

(A) The Company will make available Dark Fibers owned or controlled by Company for the placement of the Attaching Party's Attachments.

(B) It is expressly understood that the Company is and will at all times remain the sole owner and holder of title to any Dark Fiber leased by Customer pursuant to this Tariff. Nothing in this Tariff or any documents shall be construed as conveying to Customer any right, title or interest in any Dark Fiber leased by Customer pursuant to this Tariff, except for the mere license and right to use the same pursuant to this Tariff.

(C) The Company will provide Dark Fiber to Customers pursuant to terms of service that are negotiated between the Customer and Company and set forth in the Customer Contract. Dark Fiber provided under this Tariff shall not be used for any unlawful purpose and may not be furnished if any law enforcement or regulatory agency, acting within its jurisdiction, determines that such services are being used in violation of the law. Any Dark Fiber provided under this Tariff is subject to and dependent upon all applicable law and prior property interests

3.3.2 Regulations for Dark Fiber Leasing

(A) Description of Service

The provision of Dark Fiber to a Customer, including by leasing, renting or granting indefeasible rights to use the same.

(B) Lease Term

Dark Fiber leases have a minimum twenty (20) year term.

(C) Full Route Mileage Lease

All Dark Fiber must be leased over the full route mileage of the continuous Dark Fiber, such mileage and continuous route as defined and calculated solely by the Company.

(D) Inventory of Dark Fiber

All Dark Fiber is offered on an "as is" basis with no conditioning offered. Dark Fiber available for leasing does not include maintenance spares, defective fibers or fibers subscribed to by other parties.

3.3.2 Regulations for Dark Fiber Leasing (cont'd)

(E) Ordering of Dark Fiber.

Upon completion of a Dark Fiber inquiry, if the Company determines that Dark Fiber is available, the prospective Customer may place a request for access to the Dark Fiber. The minimum number of fiber strands that can be ordered is two (2). All Dark Fiber must be ordered in multiples of two (2) fiber strands.

(F) Demarcation Points for Dark Fiber.

The demarcation points for Dark Fiber will be in a Company-approved splitter shelf. To allow for non-intrusive testing, Company will install demarcations and place fiber jumpers from the fiber optic termination panel to the demarcation point. The Customer will run its fiber jumpers from the demarcation point (1x2, 90-10 optical splitter) to the Customer's equipment.

(G) Rates and Charges

		Nonrecurring Charge	**Annual Charge**
Inquiry Charge		$200.00	
Administrative Charge			
Installation	per order	$50.00	
Disconnection	per order	$50.00	
Connection Charge			
Installation	per strand	$1,000.00	
Disconnection	per strand	$1,000.00	
Termination	per strand		$100.00
Mileage	per strand per route mile		$7500.00
Cross Connect	per cross connect		$60.00

Dark Fiber Leasing is also available on a month-to-month basis, under variable rate periods, and also subject to an ICB in accordance with Section 3.4.

3.3.2 Regulations for Dark Fiber Leasing (cont'd)

H. Response and Repair Times

In the event of a Cable or Dark Fiber failure, excluding events as defined in Section 2.15.2, the Company will respond after receiving notification of such failure from either internal network monitoring or Customer. After receiving such notification, the Company shall repair and restore its failed system as follows:

(i) Electronic Restoration
In the event of an electronic failure, the Company shall use reasonable commercial efforts to restore the affected electronics within eight (8) hours of arrival of maintenance personnel on site. Such repairs may be temporary.

(ii) Cable Restoration
In the event of a Cable, Dark Fiber, Innerduct or Conduit failure, the Company shall use reasonable commercial efforts to effect repairs within eight (8) hours after of arrival of maintenance personnel on site. Such repairs may be temporary.

(iii) Permanent Restoration
Within one (1) business day after completing any temporary repair or restoration, Company shall commence planning permanent repair. Company shall notify Customer of its permanent repair plans and implement such repairs within an appropriate time thereafter. Company shall strive to repair "in-use" fibers first and repair those fibers not currently in-use during permanent restoration activities.

3.4 Contract Rates - Special Pricing Arrangements - SPA

3.4.1 In lieu of the rates, terms and charges otherwise set forth in this Tariff, rates, terms and charges, including minimum usage, installation, special construction, maintenance, repair and recurring and non-recurring charges for Company's Services, may be established at negotiated rates on an ICB basis, taking into account the nature of the facilities and Services, the costs of construction and operation, the volume of traffic, the length of service commitment by the Customer, and use of facilities by other customers. Such arrangements shall be considered Special Pricing Arrangements ("SPA"),all of the terms of which will be set forth in individual Customer contracts. However, unless otherwise expressly specified to the contrary in such Contract, all of the terms, conditions, obligations and regulations set forth in this Tariff shall be deemed to be incorporated into, and become a part of, said contract, and shall be binding on Company and Customer

3.4.2 In addition to charges for the Services, the Customer is also responsible for payment of any sales, use, gross receipts, excise, or other local, state and federal taxes, charges, franchise fees or surcharges or any kind and character (however designated) (excluding taxes on the Company's net income) imposed on or based upon the provision, sale, or use of the Services and facilities. If Customer provides Company with a duly authorized exemption certificate, Company will exempt Customer in accordance with law, effective on the date Company receives the exemption certificate. If Customer does not give Company written notice of a dispute with respect to Company charges or application of taxes within six (6) months of the date of an invoice, such invoice shall be deemed to be correct and binding on Customer;

3.4.3 Any assessments, franchise fees, access, ingress or egress fees or charges for use of real property, privilege, license, occupation or excise taxes or fees or other similar taxes or fees, whether in lump sum or at a flat rate, or based on receipts, or based on poles, wire or other utility property units, imposed upon Company by any governmental authority may be added pro rata, insofar as practical, in amounts which in the aggregate for the Company's Customers of any political entity shall be equal to the amount of any such tax upon the Company. The Company may, so long as any such tax or fee is in effect, add to the bills of the Customers in such political entity pro rata on the basis of the revenue derived by the Company from each such Customer, an amount sufficient to recover any such tax or fee.

3.4.4 Customer shall pay taxes, surcharges, access charges, any recurring or nonrecurring charges imposed by local exchange telephone companies or interexchange carriers incurred by or on behalf of the Customer in establishing and maintaining service. Such charges may be billed by Company or directly by the local exchange company or interexchange carrier, at Company's option

3.4 Contract Rates - Special Pricing Arrangements - SPA (cont'd)

3.4.5 Specialized Rates or Charges will be made available to similarly situated Customers on a non-discriminatory basis. However, such a Customer must not (i) be receiving Services under another SPA, (ii) be in breach of any Company agreement or obligation, nor (iii) have any outstanding past due balances with Company, in order to request Services under the terms of another customer's SPA.

3.4.6 Requests for Services available under a another Customer's SPA must be made in writing and received by Company within the period of availability for the original SPA and must contain evidence that demonstrates, in Company's sole discretion, that the request is being made by a similarly situated Customer. If a written request is received during the availability period, Company will, subject to the deposit and other requirements hereof, provide the Customer with an SPA. SPA contracts may not be requested after the period of availability has expired. In order to purchase Services under an SPA, the SPA must be signed and returned to Company within fifteen (15) days.

3.4.7 Each Customer requesting a SPA will be required to establish credit. Any Customer whose credit has not been duly established to the sole and exclusive satisfaction of Company may be required to make a deposit, to be held as a guarantee of payment of charges. The deposit must be made by Customer prior to commencement of any Services. In addition, an existing Customer may be required to make a deposit or increase a deposit presently held.

The Company will accept Bank Letters of Credit instead of cash deposits. The deposit may be held for as long as the Company, in its sole discretion, deems appropriate. A deposit will not exceed Customer's estimated charges for six (6) months' Service plus installation, construction costs, and other non-recurring charges.

If the deposit is not posted with five (5) days of receipt of deposit notice, Service to the Customer may be discontinued without further notice.

3.4.8 A deposit will be returned: (a) if the SPA is not consummated. The deposit will be applied to any charges applicable in accordance with the base service schedules and the excess portion of the deposit will be returned; or (b) upon the discontinuance of all Services. The Company will refund the Customer's deposit or the balance in excess of all outstanding charges, including all termination liabilities.

The fact that a deposit has been made in no way relieves the Customer from complying with the Regulations with respect to deposits and the prompt payment of invoices.

ATTACHMENT "C"

AFFIDAVIT OF PUBLICATION FORM
(NOT REQUIRED)

ATTACHMENT "D"

Applicant is a wholly-owned subsidiary of AGL Resources Inc., an energy services holding company whose principal business is the distribution of natural gas in six (6) states: Georgia, Virginia, Tennessee, Maryland, New Jersey and Florida. AGL Networks, LLC reports all financial information under AGL Resources Inc.'s annual report. The audited financial statements and accompanying notes of AGL Resources Inc. for the years 2008 and 2007 are attached hereto.

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

(Mark One)

☑ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended December 31, 2008

OR

☐ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from to

Commission File Number 1-14174

AGL RESOURCES INC.

(Exact name of registrant as specified in its charter)

Georgia	**58-2210952**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
Ten Peachtree Place NE, Atlanta, Georgia 30309	**404-584-4000**
(Address and zip code of principal executive offices)	(Registrant's telephone number, including area code)

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Common Stock, $5 Par Value	**New York Stock Exchange**

Securities registered pursuant to Section 12(g) of the Act: **None**

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 under the Securities Act.
Yes ☑ No ☐

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Securities Act.
Yes ☐ No ☑

Indicate by check mark whether the registrant: (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months, and (2) has been subject to such filing requirements for the past 90 days.
Yes ☑ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer or a non-accelerated filer, or a smaller reporting company

Large accelerated filer ☑ Accelerated filer ☐ Non-accelerated filer ☐ Smaller reporting company ☐
(Do not check if smaller reporting company)

Indicate by check mark whether the registrant is a shell company (as defined in Exchange Act Rule 12b-2). Yes ☐ No ☑

The aggregate market value of the registrant's voting and non-voting common equity held by non-affiliates of the registrant, computed by reference to the price at which the registrant's common stock was last sold as of the last business day of the registrant's most recently completed second fiscal quarter, was $2,651,161,320.

The number of shares of the registrant's common stock outstanding as of January 30, 2009 was 76,902,777.

DOCUMENTS INCORPORATED BY REFERENCE:

Portions of the Proxy Statement for the 2009 Annual Meeting of Shareholders ("Proxy Statement") to be held April 29, 2009, are incorporated by reference in Part III.

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GLOSSARY OF KEY TERMS

Atlanta Gas Light	Atlanta Gas Light Company
AGL Capital	AGL Capital Corporation
AGL Networks	AGL Networks, LLC
AGSC	AGL Services Company, a service company established in accordance with SEC regulations
AIP	Annual Incentive Plan
Bcf	Billion cubic feet
Chattanooga Gas	Chattanooga Gas Company
Compass Energy	Compass Energy Services, Inc.
Credit Facilities	$1.0 billion and $140 million credit agreements of AGL Capital
Deregulation Act	1997 Natural Gas Competition and Deregulation Act
Dominion Ohio	Dominion East of Ohio, a Cleveland, Ohio based natural gas company; a subsidiary of Dominion Resources, Inc.
EBIT	Earnings before interest and taxes, a non-GAAP measure that includes operating income, other income, minority interest in SouthStar's earnings and gain on sales of assets and excludes interest and income tax expense; as an indicator of our operating performance, EBIT should not be considered an alternative to, or more meaningful than, operating income or net income as determined in accordance with GAAP
EITF	Emerging Issues Task Force
Energy Act	Energy Policy Act of 2005
ERC	Environmental remediation costs associated with our distribution operations segment which are recoverable through rates mechanisms
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
Fitch	Fitch Ratings
Florida Commission	Florida Public Service Commission
FSP	FASB Staff Position
GAAP	Accounting principles generally accepted in the United States of America
Georgia Commission	Georgia Public Service Commission
Golden Triangle Storage	Golden Triangle Storage, Inc.
Heating Degree Days	A measure of the effects of weather on our businesses, calculated when the average daily actual temperatures are less than a baseline temperature of 65 degrees Fahrenheit.
Heating Season	The period from November to March when natural gas usage and operating revenues are generally higher because more customers are connected to our distribution systems when weather is colder
Jefferson Island	Jefferson Island Storage & Hub, LLC
LIBOR	London interbank offered rate
LNG	Liquefied natural gas
LOCOM	Lower of weighted average cost or current market price
Louisiana DNR	Louisiana Department of Natural Resources
Magnolia	Magnolia Enterprise Holdings, Inc.
Maryland Commission	Maryland Public Service Commission
Marketers	Marketers selling retail natural gas in Georgia and certificated by the Georgia Commission
Medium-term notes	Notes issued by Atlanta Gas Light with scheduled maturities between 2012 and 2027 bearing interest rates ranging from 6.6% to 9.1%
MGP	Manufactured gas plant
MMBtu	NYMEX equivalent contract units of 10,000 million British thermal units
Moody's	Moody's Investors Service
New Jersey Commission	New Jersey Board of Public Utilities
NUI	NUI Corporation - an acquisition which was completed in November 2004
NYMEX	New York Mercantile Exchange, Inc.
OCI	Other comprehensive income
Operating margin	A measure of income, calculated as revenues minus cost of gas, that excludes operation and maintenance expense, depreciation and amortization, taxes other than income taxes, and the gain or loss on the sale of our assets; these items are included in our calculation of operating income as reflected in our statements of consolidated income.
OTC	Over-the-counter
Piedmont	Piedmont Natural Gas
Pivotal Propane	Pivotal Propane of Virginia, Inc.
Pivotal Utility	Pivotal Utility Holdings, Inc., doing business as Elizabethtown Gas, Elkton Gas and Florida City Gas
PP&E	Property, plant and equipment
PRP	Pipeline replacement program for Atlanta Gas Light
S&P	Standard & Poor's Ratings Services
Saltville	Saltville Gas Storage Company
SEC	Securities and Exchange Commission
Sequent	Sequent Energy Management, L.P.
SFAS	Statement of Financial Accounting Standards
SNG	Southern Natural Gas Company, a subsidiary of El Paso Corporation
SouthStar	SouthStar Energy Services LLC
Tennessee Commission	Tennessee Regulatory Authority
VaR	Value at risk is defined as the maximum potential loss in portfolio value over a specified time period that is not expected to be exceeded within a given degree of probability
Virginia Natural Gas	Virginia Natural Gas, Inc.
Virginia Commission	Virginia State Corporation Commission
WACOG	Weighted average cost of goods
WNA	Weather normalization adjustment

REFERENCED ACCOUNTING STANDARDS

APB 25	APB Opinion No. 25, "Accounting for Stock Issued to Employees"
EITF 98-10	EITF Issue No. 98-10, "Accounting for Contracts Involved in Energy Trading and Risk Management Activities"
EITF 99-02	EITF Issue No. 99-02, "Accounting for Weather Derivatives"
EITF 00-11	EITF Issue No. 00-11, "Lessor's Evaluation of Whether Leases of Certain Integral Equipment Meet the Ownership Transfer Requirements of FASB Statement No. 13, *Accounting for Leases*, for Leases of Real Estate"
EITF 02-03	EITF Issue No. 02-03, "Issues Involved in Accounting for Contracts under EITF Issue No. 98-10, 'Accounting for Contracts Involved in Energy Trading and Risk Management Activities'"
FIN 39	FASB Interpretation No. (FIN) 39 "Offsetting of Amounts Related to Certain Contracts"
FSP FIN 39-1	FASB Staff Position 39-1 "Amendment of FIN 39"
FIN 46 & FIN 46R	FIN 46, "Consolidation of Variable Interest Entities"
FIN 48	FIN 48, "Accounting for Uncertainty in Income Taxes, an interpretation of SFAS Statement No. 109"

FSP EITF 03-6-1	FSP EITF 03-6-1, "Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities"
FSP EITF 06-3	FSP EITF 06-3, "How Taxes Collected from Customers and Remitted to Governmental Authorities Should be Presented in the Income Statement (That Is, Gross versus Net Presentation)"
FSP FAS 133-1	FSP No. FAS 133-1, "Disclosures about Credit Derivatives and Certain Guarantees: An Amendment of FASB Statement No. 133"
FSP FAS 140-R and FIN 46R-8	FSP No. FAS 140-R and FIN 46R-8, "Disclosures by Public Entities (Enterprises) about Transfers of Financial Assets and Interests in Variable Interest Entities"
FSP FAS 157-3	FSP No. FAS 157-3, "Determining the Fair Value of a Financial Asset When the Market for That Asset Is Not Active"
SFAS 5	SFAS No. 5, "Accounting for Contingencies"
SFAS 13	SFAS No. 13, "Accounting for Leases"
SFAS 66	SFAS No. 66, "Accounting for Sales of Real Estate"
SFAS 71	SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation"
SFAS 87	SFAS No. 87, "Employers' Accounting for Pensions"
SFAS 106	SFAS No. 106, "Employers' Accounting for Postretirement Benefits Other Than Pensions"
SFAS 109	SFAS No. 109, "Accounting for Income Taxes"
SFAS 123 & SFAS 123R	SFAS No. 123, "Accounting for Stock-Based Compensation"
SFAS 133	SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities"
SFAS 140	SFAS No. 140, "Accounting for Transfers and Servicing Financial Assets and Extinguishments of Liabilities"
SFAS 141	SFAS No. 141, "Business Combinations"
SFAS 142	SFAS No. 142, "Goodwill and Other Intangible Assets"
SFAS 148	SFAS No. 148, "Accounting for Stock-Based Compensation – Transition and Disclosure"
SFAS 149	SFAS No. 149, "Amendment of SFAS 133 on Derivative Instruments and Hedging Activities"
SFAS 157	SFAS No. 157, "Fair Value Measurements"
SFAS 158	SFAS No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans"
SFAS 160	SFAS No. 160, "Noncontrolling Interests in Consolidated Financial Statements"
SFAS 161	SFAS No. 161, "Disclosure about Derivative Instruments and Hedging Activities, an amendment of SFAS 133"

PART I

ITEM 1. BUSINESS

Nature of Our Business

Unless the context requires otherwise, references to "we," "us," "our," the "company" and "AGL Resources" are intended to mean consolidated AGL Resources Inc. and its subsidiaries.

We are an energy services holding company whose principal business is the distribution of natural gas in six states - Florida, Georgia, Maryland, New Jersey, Tennessee and Virginia. Our six utilities serve more than 2.2 million end-use customers, making us the largest distributor of natural gas in the southeastern and mid-Atlantic regions of the United States based on customer count. We are also involved in several related and complementary businesses, including retail natural gas marketing to end-use customers primarily in Georgia; natural gas asset management and related logistics activities for each of our utilities as well as for nonaffiliated companies; natural gas storage arbitrage and related activities; and the development and operation of high-deliverability natural gas storage assets. We also own and operate a small telecommunications business that constructs and operates conduit and fiber infrastructure within select metropolitan areas.

We manage these businesses through four operating segments and a nonoperating corporate segment. Operating revenues, operating margin, operating expenses and EBIT for each of our business segments are presented in the following table for the last three years.

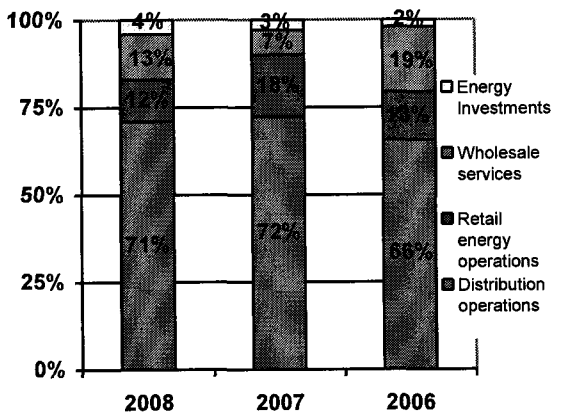
In millions	Operating revenues	Operating margin (1)	Operating expenses	EBIT (1)
2008				
Distribution operations	$1,768	$818	$493	$329
Retail energy operations	987	149	73	57
Wholesale services	170	122	62	60
Energy investments	55	50	31	19
Corporate (2)	(180)	7	9	(1)
Consolidated	$2,800	$1,146	$668	$464
2007				
Distribution operations	$1,665	$820	$485	$338
Retail energy operations	892	188	75	83
Wholesale services	83	77	43	34
Energy investments	42	40	25	15
Corporate (2)	(188)	-	8	(7)
Consolidated	$2,494	$1,125	$636	$463
2006				
Distribution operations	$1,624	$807	$499	$310
Retail energy operations	930	156	68	63
Wholesale services	182	139	49	90
Energy investments	41	36	26	10
Corporate (2)	(156)	1	9	(9)
Consolidated	$2,621	$1,139	$651	$464

(1) These are non-GAAP measurements. A reconciliation of operating margin and EBIT to our operating income, earnings before income taxes and net income is contained in "Results of Operations" in Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations."
(2) Includes intercompany eliminations

Over the last three years, on average, we have derived 84% of our operating segments' EBIT from our regulated natural gas distribution business and the sale of natural gas to retail customers primarily in Georgia through our affiliate SouthStar. This statistic is significant because it represents the portion of our earnings that directly results from the underlying business of supplying natural gas to retail customers. SouthStar, which is subject to a different regulatory framework from our utilities, is an integral part of the retail framework for providing natural gas service to end-use customers in Georgia.

We derived our remaining operating EBIT for the last three years principally from businesses that are complementary to our natural gas distribution business. We engage in natural gas asset management and the operation of high-deliverability natural gas underground storage as ancillary activities to our utility franchises. These businesses allow us to be opportunistic in capturing incremental value at the wholesale level and provide us with deepened business insight about natural gas market dynamics.

The following chart provides each operating segment's percentage contribution to the total operating EBIT for the last three years.



Distribution Operations

Our distribution operations segment is the largest component of our business and includes six natural gas local distribution utilities. These utilities construct, manage and maintain intrastate natural gas pipelines and distribution facilities and include:

- Atlanta Gas Light in Georgia
- Chattanooga Gas in Tennessee

- Elizabethtown Gas in New Jersey
- Elkton Gas in Maryland
- Florida City Gas in Florida
- Virginia Natural Gas in Virginia

Regulatory Environment

Each utility operates subject to regulations of the state regulatory agencies in its service territories with respect to rates charged to our customers, maintenance of accounting records and various service and safety matters. Rates charged to our customers vary according to customer class (residential, commercial or industrial) and rate jurisdiction. Rates are set at levels that generally should allow recovery of all prudently incurred costs, including a return on rate base sufficient to pay interest on debt and provide a reasonable return for our shareholders. Rate base generally consists of the original cost of utility plant in service, working capital and certain other assets; less accumulated depreciation on utility plant in service and net deferred income tax liabilities, and may include certain other additions or deductions.

In 2009 and 2010, we expect to file base rate cases in four of our six jurisdictions. Over the past several years our utilities have been fulfilling their long-term commitments to rate freezes, which begin expiring in 2009. As these rate cases are filed, we will be seeking rate reforms that encourage conservation and "decoupling." In traditional rate designs, our utilities' recovery of a significant portion of their fixed customer service costs is tied to assumed natural gas volumes used by our customers. We believe separating, or decoupling, the recovery of these fixed costs from the natural gas deliveries will align the interests of our customers and utilities by encouraging energy conservation and ensuring stable returns for our shareholders.

For our largest utility, Atlanta Gas Light, the natural gas market was deregulated in 1997 with the Deregulation Act. Prior to this act, Atlanta Gas Light was the supplier and seller of natural gas to its customers. Today, Marketers sell natural gas to end-use customers in Georgia and handle customer billing functions. The Marketers file their rates monthly with the Georgia Commission. Atlanta Gas Light's role includes:

- distributing natural gas for Marketers
- constructing, operating and maintaining the gas system infrastructure, including responding to customer service calls and leaks
- reading meters and maintaining underlying customer premise information for Marketers
- planning and contracting for capacity on interstate transportation and storage systems

Atlanta Gas Light recognizes revenue under a straight-fixed-variable rate design whereby it charges rates to its customers based primarily on monthly fixed charges that are periodically adjusted. The Marketers bill these charges directly to their customers. This mechanism minimizes the seasonality of Atlanta Gas Light's revenues since the monthly fixed charge is not volumetric or directly weather dependent. However, weather indirectly influences the number of customers that have active accounts during the heating season, and this has a seasonal impact on Atlanta Gas Light's revenues since generally more customers are connected in periods of colder weather than in periods of warmer weather.

All of our utilities, excluding Atlanta Gas Light, are authorized to use a natural gas cost recovery mechanism that allows them to adjust their rates to reflect changes in the wholesale cost of natural gas and to ensure they recover 100% of the costs incurred in purchasing gas for their customers. Since Atlanta Gas Light does not sell natural gas directly to its end-use customers, it does not need or utilize a natural gas cost recovery mechanism.

Regulatory Agreements In 2007, we filed a joint FERC application with SNG, which was approved in 2008, which obtained an undivided interest in pipelines connecting our Georgia service territory to the Elba Island LNG facility. Under the project, we would purchase the undivided interest and, in turn, lease the interest to SNG. Atlanta Gas Light would then subscribe to the associated supply capacity from SNG. The project is expected to be completed in 2009. We along with SNG have undertaken this pipeline project in an effort to diversify our sources of natural gas by gaining more access to natural gas supplies from SNG's Elba Island LNG facility located on Georgia's Atlantic coast near Savannah. We currently receive the majority of our natural gas supply from a production region in and around the Gulf of Mexico and generally, demand for this natural gas is growing faster than supply.

In July 2008, Virginia Natural Gas filed a Conservation and Ratemaking Efficiency Plan with the Virginia Commission. The plan was filed pursuant to the Natural Gas Conservation and Ratemaking Efficiency Act passed by the State of Virginia in March 2008. The act allows natural gas utilities to implement conservation programs and alternative rate designs that would allow the utilities to recover the cost of providing safe and reliable service based on normal customer usage. In October 2008, Virginia Natural Gas filed with the Virginia Commission a motion for approval of the proposed plan; which was approved by the Virginia Commission in December 2008. As part of this plan, Virginia Natural Gas intends to invest approximately $7 million over three

years in new conservation programs and to implement an accompanying decoupled rate design mechanism that will help to mitigate the impact of declining usage due to conservation and provide the utility with an opportunity to recover its fixed costs.

In December 2007, the Florida Commission approved our request to include the amortization of certain components of the purchase price we paid for Florida City Gas in our calculation of return on equity. The costs will not be amortized for financial reporting purposes in accordance with GAAP, but will be amortized over a period of 5 to 30 years for our regulatory reporting to the Florida Commission in connection with the Florida Commission's review of Florida City Gas' return on equity. Additionally and under the same order, the Florida Commission approved a five-year base rate stay-out beginning October 2007, whereby base rates will not be increased, except for certain unforeseen acts beyond our control. The five-year stay-out provision does not preclude the Florida Commission from initiating over-earning or other proceedings that may result in rate reductions.

A November 2004 agreement between Elizabethtown Gas and the New Jersey Commission approved our acquisition of NUI. This agreement included, among other things, a base rate freeze for Elizabethtown Gas for a five-year period with new rates, if approved, to go into effect no later than January 2010. Beginning with the December 2007 annual measurement period, 75% of Elizabethtown Gas' earnings in excess of an 11% return on equity are shared with rate payers in the fourth and fifth years of the base rate stay-out period.

The following table provides certain regulatory information for our largest utilities.

	Atlanta Gas Light	Elizabethtown Gas	Virginia Natural Gas	Florida City Gas	Chattanooga Gas
Current rates effective until	Q2 2010	Q4 2009 - Q1 2010	Q3 2011	N/A	Q1 2011
Authorized return on rate base (1)	8.53%	7.95%	9.24%	7.36%	7.89%
Estimated 2008 return on rate base (2) (3)	8.38%	6.86%	8.24%	5.63%	6.52%
Authorized return on equity (1)	10.90%	10.00%	10.90%	11.25%	10.20%
Estimated 2008 return on equity (2) (3)	10.59%	7.67%	9.61%	7.09%	7.14%
Authorized rate base % of equity (1)	47.9%	53.0%	52.4%	36.8%	44.8%
Rate base included in 2008 return on equity (in millions) (3) (4)	$1,312	$471	$378	$152	$108
Performance based rates (5)		✓	✓		
Weather normalization (6)		✓	✓		✓
Decoupled or straight-fixed variable rate design (7)	✓		✓		
State regulator	Georgia Commission	New Jersey Commission	Virginia Commission	Florida Commission	Tennessee Commission

(1) The authorized return on rate base, return on equity, and percentage of equity reflected above were those authorized as of December 31, 2008.
(2) Estimates based on principles consistent with utility ratemaking in each jurisdiction, and are not necessarily consistent with GAAP returns.
(3) Florida City Gas includes the impacts of the acquisition adjustment, as approved by the Florida Commission in December 2007, in its rate base, return on rate base and return on equity calculations.
(4) Estimated based on 13-month average.
(5) Involves frozen rates for a determined period, and or allows for sharing of earnings with customers when returns on equity or rate base exceeds agreed upon amounts.
(6) Involves regulatory mechanisms that allow us to recover our costs in the event of unseasonal weather, but are not direct offsets to the potential impacts of weather and customer consumption on earnings. These mechanisms are designed to help stabilize operating results by increasing base rate amounts charged to customers when weather is warmer than normal and decreasing amounts charged when weather is colder than normal.
(7) Decoupled and straight-fixed variable rate designs allow for the recovery of fixed customer service costs separately from assumed natural gas volumes used by our customers.

Customer Demand

All of our utilities face competition from other energy products. Our principal competition is from electric utilities and oil and propane providers serving the residential and commercial markets throughout our service areas and the potential displacement or replacement of natural gas appliances with electric appliances. The primary competitive factors are the prices for competing sources of energy as compared to natural gas and the desirability of natural gas heating versus alternative heating sources.

Competition for space heating and general household and small commercial energy needs generally occurs at the initial installation phase when the customer or builder makes decisions as to which types of equipment to install. Customers generally continue to use the chosen energy source for the life of the equipment. Customer demand for natural gas could be affected by numerous factors, including:

- changes in the availability or price of natural gas and other forms of energy
- general economic conditions
- energy conservation
- legislation and regulations
- the capability to convert from natural gas to alternative fuels
- weather, and
- new housing starts.

Due to the general economic downturn and the decline in the housing markets in the areas we serve, we experienced lower than expected customer growth throughout 2008, a trend we expect to continue through 2009. The reduction in customer growth is primarily a result of much slower growth in the residential housing markets throughout our service territories. This trend has been offset slightly by growth in the commercial customer segment in certain areas, primarily as a result of conversions to natural gas from other fuel sources. In addition, we continue to experience some customer loss because of higher natural gas prices and competition from alternative fuel sources, including incentives offered by the local electric utilities to switch to electric alternatives.

We continue to use a variety of targeted marketing programs to attract new customers and to retain existing customers. These efforts include working to add residential customers, multifamily complexes and commercial customers who use natural gas for purposes other than space heating. In addition, we partner with numerous entities to market the benefits of gas appliances and to identify potential retention options early in the process for those customers who might consider converting to alternative fuels.

Collective Bargaining Agreements

The following table provides information about the collective bargaining agreements to which our natural gas utilities are parties. This represents approximately 12% of our total employees.

	Approximate # of Employees	Contract Expiration Date
Elizabethtown Gas		
Utility Workers Union of America (Local No. 424)	160	Nov. 2009
Virginia Natural Gas		
International Brotherhood of Electrical Workers (Local No. 50)	126	May 2010
Total	286	

Retail Energy Operations

Our retail energy operations segment consists of SouthStar, a joint venture owned 70% by our subsidiary, Georgia Natural Gas Company, and 30% by Piedmont. SouthStar markets natural gas and related services under the trade name Georgia Natural Gas to retail customers on an unregulated basis, primarily in Georgia as well as to commercial and industrial customers, principally in Florida, Ohio, Tennessee, North Carolina, South Carolina and Alabama. Based on its market share, SouthStar is the largest Marketer of natural gas in Georgia, with average customers in excess of 525,000 over the last three years.

SouthStar is governed by an executive committee, which is comprised of six members, three representatives from AGL Resources and three from Piedmont. Under a joint venture agreement, all significant management decisions require the unanimous approval of the SouthStar executive committee; accordingly, our 70% financial interest is considered to be noncontrolling. Although our ownership interest in the SouthStar partnership is 70%, under an amended and restated joint venture agreement executed in March 2004, SouthStar's earnings are allocated 75% to us and 25% to Piedmont except for earnings related to customers in Ohio and Florida, which are allocated 70% to us and 30% to Piedmont. We record the earnings allocated to Piedmont as a minority interest in our consolidated statements of income, and we record Piedmont's portion of SouthStar's capital as a minority interest in our consolidated balance sheets.

The restated agreement includes a series of options granting us the evergreen opportunity to purchase all or a portion of Piedmont's ownership interest in SouthStar. We have the right to exercise an option to purchase on or before November of each year, with the purchase being effective as of January 1, of the following year. The option, effective November 1, 2009, allows us to purchase 100% of Piedmont's ownership interest. If we were to exercise any option to purchase less than 100% of Piedmont's ownership interest in SouthStar, Piedmont, at its discretion, could require us to purchase their entire ownership interest. The purchase price, in any exercise of our option, would be based on the then current fair market value of SouthStar.

SouthStar's operations are sensitive to customer consumption patterns similar to those affecting our utility operations. SouthStar uses a variety of hedging strategies, such as futures, options, swaps, weather derivative instruments and other risk management tools, to mitigate the potential effect of these issues and commodity price risk on its operations. For more information on SouthStar's energy marketing and risk management activities, see Item 7a, "Quantitative and Qualitative Disclosures About Market Risk - Commodity Price Risk."

Competition SouthStar competes with other energy marketers to provide natural gas and related services to customers in Georgia and the Southeast. SouthStar's operation in Georgia is currently in direct competition with other Marketers to provide natural gas to customers in Georgia. In addition, similar to our distribution operations, SouthStar faces competition based on customer preferences for natural gas compared to other energy products and the comparative prices of those products. Also, price volatility in the wholesale natural gas commodity market and related significant increases in the cost of natural gas billed to SouthStar's customers have contributed to an increase in competition for residential and commercial customers.

Operating margin SouthStar generates operating margin primarily in three ways. The first is through the sale of natural gas to residential, commercial and industrial customers, primarily in Georgia where SouthStar captures a spread between wholesale and retail natural gas prices. The second is through the collection of monthly service fees and customer late payment fees.

SouthStar evaluates the combination of these two retail price components to ensure such pricing is structured to cover related retail customer costs, such as bad debt expense, customer service and billing, and lost and unaccounted-for gas, and to provide a reasonable profit, as well as being competitive to attract new customers and maintain market share. SouthStar's operating margin is affected by seasonal weather, natural gas prices, customer growth and their related market share in Georgia, which has historically been in excess of approximately 34%, based on customer count. SouthStar employs strategies to attract and retain a higher credit-quality customer base. These strategies result not only in higher operating margin, as these customers tend to utilize higher volumes of natural gas, but also help to mitigate bad debt expense due to the higher credit-quality of these customers.

The third way SouthStar generates operating margin is through its commercial operations of optimizing storage and transportation assets and effectively managing commodity risk, which enables SouthStar to maintain competitive retail prices and operating margin. SouthStar is allocated storage and pipeline capacity that is used to supply natural gas to its customers in Georgia. Through hedging transactions, SouthStar manages exposures arising from changing commodity prices using natural gas storage transactions to capture operating margin from natural gas pricing differences that occur over time. SouthStar's risk management policies allow the use of derivative instruments for hedging and risk management purposes but prohibit the use of derivative instruments for speculative purposes.

SouthStar accounts for its natural gas inventories at the LOCOM price. SouthStar evaluates the weighted average cost of its natural gas inventories against market prices and determines whether any declines in market prices below the weighted average cost are other than temporary. For declines considered to be other than temporary, SouthStar records adjustments to the cost of gas (LOCOM adjustments) in our consolidated statement of income to reduce the weighted average cost of the natural gas inventory to the current market price. SouthStar recorded the following LOCOM adjustments.

	For the years ended Dec. 31,		
In millions	2008	2007	2006
LOCOM adjustments	$24	$-	$6

SouthStar also enters into weather derivative instruments to stabilize operating margin profits in the event of warmer-than-normal and colder-than-normal weather in the winter months. These contracts are accounted for using the intrinsic value method under EITF 99-02. The weather derivative contracts contain settlement provisions based on cumulative heating degree days for the covered periods. SouthStar entered into weather derivatives (swaps and options) for the last three heating seasons. The net gains or losses on these weather derivatives were largely offset by corresponding decreases or increases in operating margin due to the warmer or colder weather the hedges were designed to protect against.

Wholesale Services

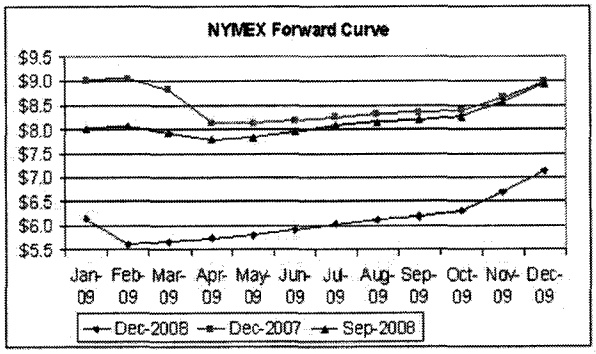
Our wholesale services segment consists primarily of Sequent, our subsidiary involved in asset management and optimization, storage, transportation, producer and peaking services and wholesale marketing. Sequent seeks asset optimization opportunities, which focus on capturing the value from idle or underutilized assets, typically by participating in transactions to take advantage of pricing differences between varying markets and time horizons within the natural gas supply, storage and transportation markets to generate earnings. These activities are generally referred to as arbitrage opportunities.

Sequent's profitability is driven by volatility in the natural gas marketplace. Volatility arises from a number of factors such as weather fluctuations or the change in supply of, or demand for, natural gas in different regions of the country. Sequent seeks to capture value from the price disparity across geographic locations and various time horizons (location and seasonal spreads). In doing so,

Sequent also seeks to mitigate the risks associated with this volatility and protect its margin through a variety of risk management and economic hedging activities.

Sequent provides its customers with natural gas from the major producing regions and market hubs in the U.S. and Canada. Sequent acquires transportation and storage capacity to meet its delivery requirements and customer obligations in the marketplace. Sequent's customers benefit from its logistics expertise and ability to deliver natural gas at prices that are advantageous relative to other alternatives available to its customers.

Storage inventory outlook The following graph presents the NYMEX forward natural gas prices as of December 31, 2008, December 31, 2007 and September 30, 2008, for the period of January 2009 through December 2009, and reflects the prices at which Sequent could buy natural gas at the Henry Hub for delivery in the same time period. The Henry Hub is the largest centralized point for natural gas spot and futures trading in the United States. The NYMEX uses the Henry Hub as the point of delivery for its natural gas futures contracts. Many natural gas marketers also use the Henry Hub as their physical contract delivery point or their price benchmark for spot trades of natural gas.



Sequent's expected natural gas withdrawals from physical salt dome and reservoir storage are presented in the following table along with the operating revenues expected at the time of withdrawal. Sequent's expected operating revenues are net of the estimated impact of regulatory sharing and reflect the amounts that are realizable in future periods based on the inventory withdrawal schedule and forward natural gas prices at December 31, 2008. Sequent's storage inventory is economically hedged with futures contracts, which results in an overall locked-in margin, timing notwithstanding.

	Withdrawal schedule *(in Bcf)*		
	Salt dome (WACOG $5.67)	**Reservoir** (WACOG $5.68)	**Expected operating revenues** *(in millions)*
2009			
First quarter	-	8	$(0.4)
Second quarter	-	-	-
Third quarter	1	1	0.4
Total	1	9	$-

Due to the storage hedge gains and LOCOM adjustments reported in 2008, Sequent expects no additional operating revenue in 2009 from storage withdrawals of existing inventory. Expected operating revenues will change in the future as Sequent injects natural gas into inventory, adjusts its injection and withdrawal plans in response to changes in market conditions in future months and as forward NYMEX prices fluctuate. For more information on Sequent's energy marketing and risk management activities, see Item 7a, "Quantitative and Qualitative Disclosures About Market Risk - Commodity Price Risk."

Competition Sequent competes for asset management contracts with other energy wholesalers, often through a competitive bidding process.

Asset Management Transactions Sequent's asset management customers include affiliated utilities, nonaffiliated utilities, municipal utilities, power generators and large industrial customers. These customers, due to seasonal demand or levels of activity, may have contracts for transportation and storage capacity, which may exceed their actual requirements. Sequent enters into structured agreements with these customers, whereby Sequent, on behalf of the customer, optimizes the transportation and storage capacity during periods when customers do not use it for their own needs. Sequent may capture incremental operating margin through optimization, and either share margins with the customers or pay them a fixed amount.

The FERC recently issued Order 712, which clarifies capacity release rules for asset management relationships. As Order 712 has removed uncertainties associated with certain aspects of some asset management services, we expect there may be an increase in customers seeking these services during 2009. This could provide us with additional opportunities in this portion of Sequent's business. Until the market further develops under the requirements of Order 712, we are unable to predict what impact this may have on our wholesale business.

Sequent is actively negotiating the renewal of its remaining affiliate asset management agreement with Virginia Natural Gas scheduled to expire in 2009. The following table provides information on Sequent's asset management agreements with affiliated utilities.

			Profit sharing / fees payments		
In millions	**Expiration date**	**% Shared**	**2008**	**2007**	**2006**
Virginia Natural Gas	Mar 2009	(A)	$2	$7	$2
Chattanooga Gas	Mar 2011	50% (B)	4	2	4
Elizabethtown Gas	Mar 2011	(A) (B)	5	6	4
Atlanta Gas Light	Mar 2012	up to 60% (B)	9	9	6
Florida City Gas	Mar 2013	50%	1	1	-
Total			$21	$25	$16

(A) Shared on a tiered structure.
(B) Includes aggregate annual minimum payments of $12 million.

Transportation Transactions Sequent contracts for natural gas transportation capacity and participates in transactions that manage the natural gas commodity and transportation costs in an attempt to achieve the lowest cost to serve its various markets. Sequent seeks to optimize this process on a daily basis as market conditions change by evaluating all the natural gas supplies, transportation alternatives and markets to which it has access and identifying the lowest-cost alternatives to serve the various markets. This enables Sequent to capture geographic pricing differences across these various markets as delivered natural gas prices change.

As Sequent executes transactions to secure transportation capacity, it often enters into forward financial contracts to hedge its positions and lock-in a margin on future transportation activities. The hedging instruments are derivatives, and Sequent reflects changes in the derivatives' fair value in its reported operating results in the period of change, which can be in periods prior to actual utilization of the transportation capacity. The following table lists Sequent's reported unrealized gains associated with transportation capacity hedges. In prior years, these amounts have been realized as these positions settle in subsequent periods, and this is expected to be the case for unrealized gains in 2008.

	For the year ended December 31,		
In millions	2008	2007	2006
Unrealized gains	$7	$5	$12

During 2008, Sequent negotiated an agreement for 40,000 dekatherms per day of transportation capacity for a period of 25 years beginning in August 2009. Upon execution of this agreement, we will include approximately $89 million of future demand payments associated with this capacity within our unrecorded contractual obligations and commitment disclosures. As with its other transportation capacity agreements, Sequent has and will identify opportunities to lock-in economic value associated with this capacity through the use of financial hedges. Since the duration of this agreement will be significantly longer than the average duration of Sequent's portfolio, the hedging of the capacity has increased our exposure to hedge gains and losses as well as potentially increasing VaR once the contract is executed. During the third quarter of 2008, we began executing hedging transactions related to this transportation capacity, and recorded associated hedge gains of $9 million during 2008 associated with this capacity; however there was no significant impact to VaR due to the effect of other positions in the portfolio.

Producer Services Sequent's producer services business primarily focuses on aggregating natural gas supply from various small and medium-sized producers located throughout the natural gas production areas of the United States. Sequent provides producers with certain logistical and risk management services that offer them attractive options to move their supply into the pipeline grid.

Park and Loan Transactions Sequent routinely enters into park and loan transactions with various pipelines, which allow Sequent to park gas on, or borrow gas from, the pipeline in one period and reclaim gas from, or repay gas to, the pipeline in a subsequent period. The economics of these transactions are evaluated and price risks are managed in much the same way traditional reservoir and salt dome storage transactions are evaluated and managed.

Sequent enters into forward NYMEX contracts to hedge its park and loan transactions. While the hedging instruments mitigate the price risk associated with the delivery and receipt of natural gas, they can also result in volatility in Sequent's reported results during the period before the initial delivery or receipt of natural gas. During this period, if the forward NYMEX prices in the months of delivery and receipt do not change in equal amounts, Sequent will report a net unrealized gain or loss on the hedges.

Sequent's results were affected by unrealized hedge gains on park and loan activities of $9 million during

2008, but Sequent had no significant gains or losses on park and loan hedges during 2007 or 2006.

Mark-to-Market Versus Lower of Average Cost or Market Sequent purchases natural gas for storage when the current market price it pays plus the cost for transportation and storage is less than the market price it anticipates it could receive in the future. Sequent attempts to mitigate substantially all of the commodity price risk associated with its storage portfolio and uses derivative instruments to reduce the risk associated with future changes in the price of natural gas. Sequent sells NYMEX futures contracts or OTC derivatives in forward months to substantially lock in the operating revenue it will ultimately realize when the stored gas is actually sold.

We view Sequent's trading margins from two perspectives. First, we base our commercial decisions on economic value, which is defined as the locked-in operating revenue to be realized at the time the physical gas is withdrawn from storage and sold and the derivative instrument used to economically hedge natural gas price risk on that physical storage is settled. Second is the GAAP reported value both in periods prior to and in the period of physical withdrawal and sale of inventory. The GAAP amount is affected by the process of accounting for the financial hedging instruments in interim periods at fair value between the period when the natural gas is injected into storage and when it is ultimately withdrawn and the financial instruments are settled. The change in the fair value of the hedging instruments is recognized in earnings in the period of change and is recorded as unrealized gains or losses. The actual value, less any interim recognition of gains or losses on hedges and adjustments for LOCOM, is realized when the natural gas is delivered to its ultimate customer.

Sequent accounts for natural gas stored in inventory differently than the derivatives Sequent uses to mitigate the commodity price risk associated with its storage portfolio. The natural gas that Sequent purchases and injects into storage is accounted for at the lower of average cost or current market value. The derivatives that Sequent uses to mitigate commodity price risk are accounted for at fair value and marked to market each period. This difference in accounting treatment can result in volatility in Sequent's reported results, even though the expected operating revenue is essentially unchanged from the date the transactions were initiated. These accounting differences also affect the comparability of Sequent's period-over-period results, since changes in forward NYMEX prices do not increase and decrease on a consistent basis from year to year.

During the first half of 2008, the reported results were negatively affected by sharp increases in forward NYMEX prices, but in the second half of 2008 forward NYMEX prices dropped to below 2007 levels. The overall result was more significant unrealized gains during 2008, which contributed to the favorable variance between 2008 and 2007. During most of 2007 and 2006, Sequent's reported results were positively affected by decreases in forward NYMEX prices, which resulted in the recognition of unrealized gains; however, the effect was more significant for 2006. As a result the more significant unrealized gains during 2006 increased the unfavorable variance between 2007 and 2006.

Energy Investments

Our energy investments segment includes a number of businesses that are related and complementary to our primary business. The most significant of these businesses is our natural gas storage business, which develops, acquires and operates high-deliverability salt-dome and other storage assets in the Gulf Coast region of the United States. While this business also can generate additional revenue during times of peak market demand for natural gas storage services, the majority of our storage services are covered under a portfolio of short, medium and long-term contracts at a fixed market rate.

Jefferson Island This wholly owned subsidiary operates a salt dome storage and hub facility in Louisiana, approximately eight miles from the Henry Hub. The storage facility is regulated by the Louisiana DNR and by the FERC, which has limited regulatory authority over storage and transportation services. Jefferson Island provides storage and hub services through its direct connection to the Henry Hub via the Sabine Pipeline and its interconnection with eight other pipelines in the area. Jefferson Island's entire portfolio is under firm subscription for the current heating season.

In August 2006, the Office of Mineral Resources of the Louisiana DNR informed Jefferson Island that its mineral lease – which authorizes salt extraction to create two new storage caverns – at Lake Peigneur had been terminated. The Louisiana DNR identified two bases for the termination: (1) failure to make certain mining leasehold payments in a timely manner, and (2) the absence of salt mining operations for six months.

In September 2006, Jefferson Island filed suit against the State of Louisiana, in the 19th Judicial District Court in Baton Rouge, to maintain its lease to complete an ongoing natural gas storage expansion project in Louisiana. The project would add two salt dome storage caverns under Lake Peigneur to the two caverns currently owned and operated by

Jefferson Island. In its suit, Jefferson Island alleges that the Louisiana DNR accepted all leasehold payments without reservation and never provided Jefferson Island with notice and opportunity to cure the alleged late payments, as required by state law. In its answer to the suit, the State denied that anyone with proper authority approved late payments. As to the second basis for termination, the suit contends that Jefferson Island's lease with the State of Louisiana was amended in 2004 so that mining operations are no longer required to maintain the lease. The State's answer denies that the 2004 amendment was properly authorized. In March 2008, Jefferson Island served discovery requests on the State of Louisiana and sought a trial date in this lawsuit. Jefferson Island also asserted additional claims against the State seeking to obtain a declaratory ruling that Jefferson Island's surface lease, under which it operates its existing two storage caverns, authorizes the creation of the two new expansion caverns separate and apart from the mineral lease challenged by the State.

In addition, in June 2008, the State of Louisiana passed legislation restricting water usage from the Chicot aquifer, which is a main source of fresh water required for the expansion of our Jefferson Island capacity. We contend that this legislation is unconstitutional and have sought to amend the pending litigation to seek a declaration that the legislation is invalid and cannot be enforced. Even if we are not successful on those grounds, we believe the legislation does not materially impact the feasibility of the expansion project. During 2008 and early 2009 we aggressively pursued our litigation. However, we are not able to predict the outcome of the litigation. As of January 2009, our current estimate of costs incurred that would be considered unusable if the Louisiana DNR was successful in terminating our lease and causing us to cease the expansion project is approximately $6 million.

Golden Triangle Storage In December 2006, we announced that our wholly-owned subsidiary, Golden Triangle Storage, plans to build a natural gas storage facility in the Beaumont, Texas area in the Spindletop salt dome. The project will initially consist of two underground salt dome storage caverns approximately a half-mile to a mile below ground that will hold about 12 Bcf of working natural gas storage capacity initially, or a total cavern capacity of approximately 17 Bcf. The facility potentially can be expanded to a total of five caverns with 38 Bcf of working natural gas storage capacity in the future based on customer interest. Golden Triangle Storage also intends to build an approximately nine-mile dual 24" natural gas pipeline to connect the storage facility with three interstate and three intrastate pipelines. In May 2007, Golden Triangle Storage held a non-binding open season for service offerings at the proposed facility, which resulted in indications of market support for the facility.

In December 2007, Golden Triangle Storage received an order from the FERC granting a Certificate of Public Convenience and Necessity to construct and operate the storage facility and approving market-based rates for services to be provided. We accepted this FERC order in January 2008. The FERC will serve as the lead agency overseeing the participation of a number of other federal, state and local agencies in reviewing and permitting the facility. In May 2008, Golden Triangle Storage started construction on the first cavern. Hurricanes Gustav and Ike caused some damage and minor delays in September 2008, but our timelines associated with commencement of commercial operations remain on schedule.

We previously estimated, based on then current prices for labor, materials and pad gas, that costs to construct the facility would be approximately $265 million. However, prices for labor and materials have risen significantly in the ensuing months, increasing the current estimated construction cost by approximately 10% to 20%. The actual project costs depend upon the facility's configuration, materials, drilling costs, financing costs and the amount and cost of pad gas, which includes volumes of non-working natural gas used to maintain the operational integrity of the cavern facility. The costs for approximately 64% of these items have not been fixed and are subject to continued variability during construction. Further, since we are not able to predict whether these costs of construction will continue to increase, moderate or decrease from current levels, we believe that there could be continued volatility in the construction cost estimates.

AGL Networks This wholly owned subsidiary provides telecommunications conduit and available for use or "dark" fiber optic cable. AGL Networks leases and sells its fiber to a variety of customers in the Atlanta, Georgia and Phoenix, Arizona metropolitan areas, with a small presence in other cities in the United States. Its customers include local, regional and national telecommunications companies, internet service providers, educational institutions and other commercial entities. AGL Networks typically provides underground conduit and dark fiber to its customers under leasing arrangements with terms that vary from one to twenty years. In addition, AGL Networks offers telecommunications construction services to its customers. AGL Networks' competitors are any entities that have laid or will lay conduit and fiber on the same route as AGL Networks in the respective metropolitan areas.

Corporate

Our corporate segment includes our nonoperating business units, including AGSC and AGL Capital. AGL Capital, our wholly owned subsidiary, provides for our ongoing financing needs through a commercial paper program, the issuance of various debt and hybrid securities, and other financing arrangements.

We allocate substantially all of AGSC's operating expenses and interest costs to our operating segments in accordance with state regulations. Our corporate segment also includes intercompany eliminations for transactions between our operating business segments. Our EBIT results include the impact of these allocations to the various operating segments.

Our corporate segment also includes Pivotal Energy Development, which coordinates among our related operating segments the development, construction or acquisition of assets, such as storage facilities, related and complementary to our primary businesses within the southeastern, mid-Atlantic and northeastern regions in order to extend our natural gas capabilities and improve system reliability while enhancing service to our customers in those areas. The focus of Pivotal Energy Development's commercial activities is to improve the economics of system reliability and natural gas deliverability in these targeted regions.

Employees

As of January 31, 2009, we employed a total of 2,389 employees, and we believe that our relations with them are good.

Additional Information

For additional information on our segments, see Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations" under the caption "Results of Operations" and "Note 9, Segment Information," set forth in Item 8, "Financial Statements and Supplementary Data."

Information on our environmental remediation efforts, is contained in "Note 7, Commitments and Contingencies," set forth in Item 8, "Financial Statements and Supplementary Data."

Hedges

Changes in commodity prices subject a significant portion of our operations to earnings variability. Our nonutility businesses principally use physical and financial arrangements to reduce the risks associated with both weather-related seasonal fluctuations in market conditions and changing commodity prices. In addition, because these economic hedges may not qualify, or are not designated for hedge accounting treatment, our reported earnings for the wholesale services and retail energy operations segments reflect changes in the fair values of certain derivatives. These values may change significantly from period to period and are reflected as gains or losses within our operating revenues or our OCI for those derivative instruments that qualify and are designated as accounting hedges.

Elizabethtown Gas utilizes certain derivatives in accordance with a directive from the New Jersey Commission to create a hedging program to hedge the impact of market fluctuations in natural gas prices. These derivative products are accounted for at fair value each reporting period. In accordance with regulatory requirements, realized gains and losses related to these derivatives are reflected in purchased gas costs and ultimately included in billings to customers. Unrealized gains and losses are reflected as a regulatory asset or liability, as appropriate, in our condensed consolidated balance sheets.

Seasonality

The operating revenues and EBIT of our distribution operations, retail energy operations and wholesale services segments are seasonal. During the heating season, natural gas usage and operating revenues are generally higher because more customers are connected to our distribution systems and natural gas usage is higher in periods of colder weather than in periods of warmer weather. Occasionally in the summer, Sequent's operating revenues are impacted due to peak usage by power generators in response to summer energy demands. Seasonality also affects the comparison of certain balance sheet items such as receivables, unbilled revenue, inventories and short-term debt across quarters. However, these items are comparable when reviewing our annual results.

Approximately 65% of these segments' operating revenues and 72% of these segments' EBIT for the year ended December 31, 2008 were generated during the first and fourth quarters of 2008, and are reflected in our statements of consolidated income for the quarters ended March 31, 2008 and December 31, 2008. Our base operating expenses, excluding cost of gas, interest expense and certain incentive compensation costs, are incurred relatively equally over any given year. Thus, our operating results can vary significantly from quarter to quarter as a result of seasonality.

Available Information

Detailed information about us is contained in our annual reports on Form 10-K, quarterly reports on

Form 10-Q, current reports on Form 8-K, proxy statements and other reports, and amendments to those reports, that we file with, or furnish to, the SEC. These reports are available free of charge at our website, www.aglresources.com, as soon as reasonably practicable after we electronically file such reports with or furnish such reports to the SEC. However, our website and any contents thereof should not be considered to be incorporated by reference into this document. We will furnish copies of such reports free of charge upon written request to our Investor Relations department. You can contact our Investor Relations department at:

AGL Resources Inc.
Investor Relations - Dept. 1071
P.O. Box 4569
Atlanta, GA 30309-4569
404-584-3801

In Part III of this Form 10-K, we incorporate by reference from our Proxy Statement for our 2009 annual meeting of shareholders certain information. We expect to file that Proxy Statement with the SEC on or about March 16, 2009, and we will make it available on our website as soon as reasonably practicable. Please refer to the Proxy Statement when it is available.

Additionally, our corporate governance guidelines, code of ethics, code of business conduct and the charters of each of our Board of Directors committees are available on our website. We will furnish copies of such information free of charge upon written request to our Investor Relations department.

ITEM 1A. RISK FACTORS

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

Certain expectations and projections regarding our future performance referenced in this report, in other materials we file with the SEC or otherwise release to the public, and on our website are forward-looking statements. Senior officers may also make verbal statements to analysts, investors, regulators, the media and others that are forward-looking. Forward-looking statements involve matters that are not historical facts, such as statements in "Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations" and elsewhere regarding our future operations, prospects, strategies, financial condition, economic performance (including growth and earnings), industry conditions and demand for our products and services. We have tried, whenever possible, to identify these statements by using words such as "anticipate," "assume," "believe," "can," "could," "estimate," "expect," "forecast," "future," "goal," "indicate," "intend," "may," "outlook," "plan," "potential," "predict," "project," "seek," "should," "target," "would," and similar expressions.

You are cautioned not to place undue reliance on our forward-looking statements. Our forward-looking statements are not guarantees of future performance and are based on currently available competitive, financial and economic data along with our operating plans. While we believe that our expectations for the future are reasonable in view of the currently available information, our expectations are subject to future events, risks and inherent uncertainties, as well as potentially inaccurate assumptions, and there are numerous factors - many beyond our control - that could cause results to differ significantly from our expectations. Such events, risks and uncertainties include, but are not limited to those set forth below and in the other documents that we file with the SEC. We note these factors for investors as permitted by the Private Securities Litigation Reform Act of 1995. There also may be other factors that we cannot anticipate or that are not described in this report, generally because we do not perceive them to be material, which could cause results to differ significantly from our expectations.

Forward-looking statements are only as of the date they are made, and we do not undertake any obligation to update these statements to reflect subsequent circumstances or events. You are advised, however, to review any further disclosures we make on related subjects in our Form 10-Q and Form 8-K reports to the SEC.

Risks Related to Our Business

Risks related to the regulation of our businesses could affect the rates we are able to charge, our costs and our profitability.

Our businesses are subject to regulation by federal, state and local regulatory authorities. In particular, at the federal level our businesses are regulated by the FERC. At the state level, our businesses are regulated by the Georgia, Tennessee, New Jersey, Florida, Virginia and Maryland Commissions.

These authorities regulate many aspects of our operations, including construction and maintenance of facilities, operations, safety, rates that we charge customers, rates of return, the authorized cost of capital, recovery of pipeline replacement and environmental remediation costs, relationships with our affiliates, and carrying costs we charge Marketers selling retail natural gas in Georgia for gas held in storage for their customer accounts. Our ability to obtain rate increases and rate supplements to maintain our current rates of return and recover regulatory assets and liabilities recorded in

accordance with SFAS 71 depends on regulatory discretion, and there can be no assurance that we will be able to obtain rate increases or rate supplements or continue receiving our currently authorized rates of return including the recovery of our regulatory assets and liabilities. In addition, if we fail to comply with applicable regulations, we could be subject to fines, penalties or other enforcement action by the authorities that regulate our operations, or otherwise be subject to material costs and liabilities.

Deregulation in the natural gas industry is the separation of the provision and pricing of local distribution gas services into discrete components. Deregulation typically focuses on the separation of the gas distribution business from the gas sales business and is intended to cause the opening of the formerly regulated sales business to alternative unregulated suppliers of gas sales services.

In 1997, the Georgia legislature enacted the Deregulation Act. To date, Georgia is the only state in the nation that has fully deregulated gas distribution operations, which ultimately resulted in Atlanta Gas Light exiting the retail natural gas sales business while retaining its gas distribution operations. Marketers, including our majority-owned subsidiary, SouthStar, then assumed the retail gas sales responsibility at deregulated prices. The deregulation process required Atlanta Gas Light to completely reorganize its operations and personnel at significant expense. It is possible that the legislature could reverse or amend portions of the deregulation process.

Our business is subject to environmental regulation in all jurisdictions in which we operate, and our costs to comply are significant. Any changes in existing environmental regulation could affect our results of operations and financial condition.

Our operations and properties are subject to extensive environmental regulation pursuant to a variety of federal, state and municipal laws and regulations. Such environmental legislation imposes, among other things, restrictions, liabilities and obligations in connection with storage, transportation, treatment and disposal of hazardous substances and waste and in connection with spills, releases and emissions of various substances into the environment. Environmental legislation also requires that our facilities, sites and other properties associated with our operations be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. Our current costs to comply with these laws and regulations are significant to our results of operations and financial condition. Failure to comply with these laws and regulations and failure to obtain any required permits and licenses may expose us to fines, penalties or interruptions in our operations that could be material to our results of operations.

In addition, claims against us under environmental laws and regulations could result in material costs and liabilities. Existing environmental regulations could also be revised or reinterpreted, new laws and regulations could be adopted or become applicable to us or our facilities, and future changes in environmental laws and regulations could occur. With the trend toward stricter standards, greater regulation, more extensive permit requirements and an increase in the number and types of assets operated by us subject to environmental regulation, our environmental expenditures could increase in the future, particularly if those costs are not fully recoverable from our customers. Additionally, the discovery of presently unknown environmental conditions could give rise to expenditures and liabilities, including fines or penalties, which could have a material adverse effect on our business, results of operations or financial condition.

We may be exposed to certain regulatory and financial risks related to climate change.

Climate change is receiving ever increasing attention from scientists and legislators alike. The debate is ongoing as to the extent to which our climate is changing, the potential causes of this change and its potential impacts. Some attribute global warming to increased levels of greenhouse gases, including carbon dioxide, which has led to significant legislative and regulatory efforts to limit greenhouse gas emissions.

The international treaty relating to global warming (commonly known as the Kyoto Protocol) would have required reductions in emissions of greenhouse gases, primarily carbon dioxide and methane. The Kyoto Protocol became effective (without ratification by the U.S.) in February 2005. Presently there are no federally mandated greenhouse gas reduction requirements in the U.S. as current policy favors voluntary reductions, increased operating efficiency and continued research and technology development. The likelihood of any federal mandatory carbon dioxide emissions reduction program being adopted in the near future and the specific requirements of any such program is uncertain. However, President Obama has stated that to combat global warming he will propose reducing greenhouse gas emissions to 1990 levels by 2020 and further reduce levels an additional 80% by 2050. He is also expected to push an economic stimulus package that is heavily weighted towards the energy sector.

There are a number of other legislative and regulatory proposals to address greenhouse gas emissions, which are in various phases of discussion or implementation. The outcome of federal and state actions to address global climate change could result in a variety of regulatory programs including potential new regulations, additional charges to fund energy efficiency activities, or other regulatory actions. These actions could:

- result in increased costs associated with our operations
- increase other costs to our business
- affect the demand for natural gas, and
- impact the prices we charge our customers.

Because natural gas is a fossil fuel with low carbon content, it is possible that future carbon constraints could create additional demand for natural gas, both for production of electricity and direct use in homes and businesses.

Any adoption by federal or state governments mandating a substantial reduction in greenhouse gas emissions could have far-reaching and significant impacts on the energy industry. We cannot predict the potential impact of such laws or regulations on our future consolidated financial condition, results of operations or cash flows.

Our infrastructure improvement and customer growth may be restricted by the capital-intensive nature of our business.

We must construct additions to our natural gas distribution system to continue the expansion of our customer base. We may also need to construct expansions of our existing natural gas storage facilities or develop and construct new natural gas storage facilities. The cost of this construction may be affected by the cost of obtaining government and other approvals, development project delays, adequacy of supply of diversified vendors, or unexpected changes in project costs. Weather, general economic conditions and the cost of funds to finance our capital projects can materially alter the cost, and projected construction schedule and completion timeline of a project. Our cash flows may not be fully adequate to finance the cost of this construction. As a result, we may be required to fund a portion of our cash needs through borrowings or the issuance of common stock, or both. For our distribution operations segment, this may limit our ability to expand our infrastructure to connect new customers due to limits on the amount we can economically invest, which shifts costs to potential customers and may make it uneconomical for them to connect to our distribution systems. For our natural gas storage business, this may significantly reduce our earnings and return on investment from what would be expected for this business, or may impair our ability to complete the expansions or development projects.

Transporting and storing natural gas involves numerous risks that may result in accidents and other operating risks and costs.

Our gas distribution and storage activities involve a variety of inherent hazards and operating risks, such as leaks, accidents and mechanical problems, which could cause substantial financial losses. In addition, these risks could result in loss of human life, significant damage to property, environmental pollution and impairment of our operations, which in turn could lead to substantial losses to us. In accordance with customary industry practice, we maintain insurance against some, but not all, of these risks and losses. The location of pipelines and storage facilities near populated areas, including residential areas, commercial business centers and industrial sites, could increase the level of damages resulting from these risks. The occurrence of any of these events not fully covered by insurance could adversely affect our financial position and results of operations.

We face increasing competition, and if we are unable to compete effectively, our revenues, operating results and financial condition will be adversely affected which may limit our ability to grow our business.

The natural gas business is highly competitive, and we are facing increasing competition from other companies that supply energy, including electric companies, oil and propane providers and, in some cases, energy marketing and trading companies. In particular, the success of our investment in SouthStar is affected by the competition SouthStar faces from other energy marketers providing retail natural gas services in the Southeast. Natural gas competes with other forms of energy. The primary competitive factor is price. Changes in the price or availability of natural gas relative to other forms of energy and the ability of end-users to convert to alternative fuels affect the demand for natural gas. In the case of commercial, industrial and agricultural customers, adverse economic conditions, including higher gas costs, could also cause these customers to bypass or disconnect from our systems in favor of special competitive contracts with lower per-unit costs.

Our wholesale services segment competes with national and regional full-service energy providers, energy merchants and producers and pipelines for sales based on our ability to aggregate competitively priced commodities with transportation and storage capacity. Some of our competitors are larger and

better capitalized than we are and have more national and global exposure than we do. The consolidation of this industry and the pricing to gain market share may affect our operating margin. We expect this trend to continue in the near term, and the increasing competition for asset management deals could result in downward pressure on the volume of transactions and the related operating margin available in this portion of Sequent's business.

The continuation of recent economic conditions could adversely affect our customers and negatively impact our financial results.

The slowdown in the U.S. economy, along with increased mortgage defaults, and significant decreases in new home construction, home values and investment assets, has adversely impacted the financial well-being of many U.S. households. We cannot predict if the administrative and legislative actions to address this situation will be successful in reducing the severity or duration of this recession. As a result, our customers may use less gas in future heating seasons and it may become more difficult for them to pay their natural gas bills. This may slow collections and lead to higher than normal levels of accounts receivables, bad debt and financing requirements.

A significant portion of our accounts receivable is subject to collection risks, due in part to a concentration of credit risk in Georgia and at Sequent.

We have accounts receivable collection risk in Georgia due to a concentration of credit risk related to the provision of natural gas services to Marketers. At December 31, 2008, Atlanta Gas Light had 11 certificated and active Marketers in Georgia, four of which (based on customer count and including SouthStar) accounted for approximately 31% of our consolidated operating margin for 2008. As a result, Atlanta Gas Light depends on a concentrated number of customers for revenues. The provisions of Atlanta Gas Light's tariff allow it to obtain security support in an amount equal to no less than two times a Marketer's highest month's estimated bill in the form of cash deposits, letters of credit, surety bonds or guaranties. The failure of these Marketers to pay Atlanta Gas Light could adversely affect Atlanta Gas Light's business and results of operations and expose it to difficulties in collecting Atlanta Gas Light's accounts receivable. AGL Resources provides a guarantee to Atlanta Gas Light as security support for SouthStar. Additionally, SouthStar markets directly to end-use customers and has periodically experienced credit losses as a result of severe cold weather or high prices for natural gas that increase customers' bills and, consequently, impair customers' ability to pay.

Sequent often extends credit to its counterparties. Despite performing credit analyses prior to extending credit and seeking to effectuate netting agreements, Sequent is exposed to the risk that it may not be able to collect amounts owed to it. If the counterparty to such a transaction fails to perform and any collateral Sequent has secured is inadequate, Sequent could experience material financial losses. Further, Sequent has a concentration of credit risk, which could subject a significant portion of its credit exposure to collection risks. Approximately 63% of Sequent's credit exposure is concentrated in its top 20 counterparties. Most of this concentration is with counterparties that are either load-serving utilities or end-use customers that have supplied some level of credit support. Default by any of these counterparties in their obligations to pay amounts due Sequent could result in credit losses that would negatively impact our wholesale services segment.

The asset management arrangements between Sequent and our local distribution companies, and between Sequent and its nonaffiliated customers, may not be renewed or may be renewed at lower levels, which could have a significant impact on Sequent's business.

Sequent currently manages the storage and transportation assets of our affiliates Atlanta Gas Light, Chattanooga Gas, Elizabethtown Gas, Elkton Gas, Florida City Gas, and Virginia Natural Gas and shares profits it earns from the management of those assets with those customers and their respective customers, except at Elkton Gas where Sequent is assessed annual fixed-fees payable in monthly installments. Entry into and renewal of these agreements are subject to regulatory approval and one is subject to renewal in 2009. In addition, Sequent has asset management agreements with certain nonaffiliated customers. Sequent's results could be significantly impacted if these agreements are not renewed or are amended or renewed with less favorable terms.

We are exposed to market risk and may incur losses in wholesale services and retail energy operations.

The commodity, storage and transportation portfolios at Sequent and the commodity and storage portfolios at SouthStar consist of contracts to buy and sell natural gas commodities, including contracts that are settled by the delivery of the commodity or cash. If the values of these contracts change in a direction or manner that we do not anticipate, we could experience financial losses from our trading activities. Based on a 95% confidence interval and

employing a 1-day holding period for all positions, Sequent's and SouthStar's portfolio of positions as of December 31, 2008 had a 1-day holding period VaR of $2.5 million and less than $0.1 million, respectively.

Our accounting results may not be indicative of the risks we are taking or the economic results we expect for wholesale services.

Although Sequent enters into various contracts to hedge the value of our energy assets and operations, the timing of the recognition of profits or losses on the hedges does not always correspond to the profits or losses on the item being hedged. The difference in accounting can result in volatility in Sequent's reported results, even though the expected operating margin is essentially unchanged from the date the transactions were initiated.

Changes in weather conditions may affect our earnings.

Weather conditions and other natural phenomena can have a large impact on our earnings. Severe weather conditions can impact our suppliers and the pipelines that deliver gas to our distribution system. Extended mild weather, during either the winter or summer period, can have a significant impact on demand for and cost of natural gas.

We have a WNA mechanism for Elizabethtown Gas and Chattanooga Gas that partially offsets the impact of unusually cold or warm weather on residential and commercial customer billings and our operating margin. At Elizabethtown Gas we could be required to return a portion of any WNA surcharge to its customers if Elizabethtown Gas' return on equity exceeds its authorized return on equity of 10%.

Additionally, Virginia Natural Gas has a WNA mechanism for its residential customers that partially offsets the impact of unusually cold or warm weather. In September 2007, the Virginia Commission approved Virginia Natural Gas' application for an Experimental Weather Normalization Adjustment Rider (the Rider) for its commercial customers. The Rider applies to the 2007 and 2008 heating seasons, with an opportunity for Virginia Natural Gas to extend the Rider for additional years.

These WNA regulatory mechanisms are most effective in a reasonable temperature range relative to normal weather using historical averages. The protection afforded by the WNA depends on continued regulatory approval. The loss of this continued regulatory approval could make us more susceptible to weather-related earnings fluctuations.

Changes in weather conditions may also impact SouthStar's earnings. As a result, SouthStar uses a variety of weather derivative instruments to stabilize the impact on its operating margin in the event of warmer or colder than normal weather in the winter months. However, these instruments do not fully protect SouthStar's earnings from the effects of unusually warm or cold weather.

A decrease in the availability of adequate pipeline transportation capacity could reduce our revenues and profits.

Our gas supply depends on the availability of adequate pipeline transportation and storage capacity. We purchase a substantial portion of our gas supply from interstate sources. Interstate pipeline companies transport the gas to our system. A decrease in interstate pipeline capacity available to us or an increase in competition for interstate pipeline transportation and storage service could reduce our normal interstate supply of gas.

Our profitability may decline if the counterparties to Sequent's asset management transactions fail to perform in accordance with Sequent's agreements.

Sequent focuses on capturing the value from idle or underutilized energy assets, typically by executing transactions that balance the needs of various markets and time horizons. Sequent is exposed to the risk that counterparties to our transactions will not perform their obligations. Should the counterparties to these arrangements fail to perform, we might be forced to enter into alternative hedging arrangements, honor the underlying commitment at then-current market prices or return a significant portion of the consideration received for gas. In such events, we might incur additional losses to the extent of amounts, if any, already paid to or received from counterparties.

We could incur additional material costs for the environmental condition of some of our assets, including former manufactured gas plants.

We are generally responsible for all on-site and certain off-site liabilities associated with the environmental condition of the natural gas assets that we have operated, acquired or developed, regardless of when the liabilities arose and whether they are or were known or unknown. In addition, in connection with certain acquisitions and sales of assets, we may obtain, or be required to provide, indemnification against certain environmental liabilities. Before natural gas was widely available, we manufactured gas from coal and other fuels. Those manufacturing operations were known as MGPs, which we ceased operating in the 1950s.

We have identified ten sites in Georgia and three in Florida where we own all or part of an MGP site. We

are required to investigate possible environmental contamination at those MGP sites and, if necessary, clean up any contamination. As of December 31, 2008, the soil and sediment remediation program was complete for all Georgia sites, although groundwater cleanup continues. As of December 31, 2008, projected costs associated with the MGP sites associated with Atlanta Gas Light were $38 million. For elements of the MGP program where we still cannot provide engineering cost estimates, considerable variability remains in future cost estimates.

In addition, we are associated with former sites in New Jersey, North Carolina and other states. Material cleanups of these sites have not been completed nor are precise estimates available for future cleanup costs and therefore considerable variability remains in future cost estimates. For the New Jersey sites, cleanup cost estimates range from $58 million to $116 million. Costs have been estimated for only one of the non-New Jersey sites, for which current estimates range from $10 million to $20 million.

Inflation and increased gas costs could adversely impact our ability to control operating expenses, increase our level of indebtedness and adversely impact our customer base.

Inflation has caused increases in certain operating expenses that have required us to replace assets at higher costs. We attempt to control costs in part through implementation of best practices and business process improvements, many of which are facilitated through investments in information systems and technology. We have a process in place to continually review the adequacy of our utility gas rates in relation to the increasing cost of providing service and the inherent regulatory lag in adjusting those gas rates. Historically, we have been able to budget and control operating expenses and investments within the amounts authorized to be collected in rates, and we intend to continue to do so. However, any inability by us to control our expenses in a reasonable manner would adversely influence our future results.

Rapid increases in the price of purchased gas cause us to experience a significant increase in short-term debt because we must pay suppliers for gas when it is purchased, which can be significantly in advance of when these costs may be recovered through the collection of monthly customer bills for gas delivered. Increases in purchased gas costs also slow our utility collection efforts as customers are more likely to delay the payment of their gas bills, leading to higher-than-normal accounts receivable. This situation results in higher short-term debt levels and increased bad debt expense. Should the price of purchased gas increase significantly during the upcoming heating season, we would expect increases in our short-term debt, accounts receivable and bad debt expense during 2009.

Finally, higher costs of natural gas in recent years have already caused many of our utility customers to conserve in the use of our gas services and could lead to even more customers utilizing such conservation methods or switching to other competing products. The higher costs have also allowed competition from products utilizing alternative energy sources for applications that have traditionally used natural gas, encouraging some customers to move away from natural gas fired equipment to equipment fueled by other energy sources.

The cost of providing pension and postretirement health care benefits to eligible employees and qualified retirees is subject to changes in pension fund values and changing demographics and may have a material adverse effect on our financial results.

We have defined benefit pension and postretirement health care plans for the benefit of substantially all full-time employees and qualified retirees. The cost of providing these benefits to eligible current and former employees is subject to changes in the market value of our pension fund assets, changing demographics, including longer life expectancy of beneficiaries, changes in health care cost trends, and an expected increase in the number of eligible former employees over the next five years.

Any sustained declines in equity markets and reductions in bond yields may have a material adverse effect on the value of our pension funds. In these circumstances, we may be required to recognize an increased pension expense or a charge to our other comprehensive income to the extent that the pension fund values are less than the total anticipated liability under the plans. Market declines in the second half of 2008 resulted in significant losses in the value of our pension fund assets. As a result, based on the current funding status of the plans, we would be required to make a minimum contribution to the plans of approximately $7 million in 2009. We are planning to make additional contributions in 2009 up to $61 million, for a total of up to $68 million, in order to preserve the current level of benefits under the plans and in accordance with the funding requirements of the Pension Protection Act. As of December 31, 2008 our pension plans assets represented 54% or our total pension plan obligations.

For more information regarding some of these obligations, see Item 7, "Management's Discussion

and Analysis of Financial Condition and Results of Operations" under the caption "Contractual Obligations and Commitments" and the subheading "Pension and Postretirement Obligations" and Note 3 to our consolidated financial statements.

Natural disasters, terrorist activities and the potential for military and other actions could adversely affect our businesses.

Natural disasters may damage our assets. The threat of terrorism and the impact of retaliatory military and other action by the United States and its allies may lead to increased political, economic and financial market instability and volatility in the price of natural gas that could affect our operations. In addition, future acts of terrorism could be directed against companies operating in the United States, and companies in the energy industry may face a heightened risk of exposure to acts of terrorism. These developments have subjected our operations to increased risks. The insurance industry has also been disrupted by these events. As a result, the availability of insurance covering risks against which we and our competitors typically insure may be limited. In addition, the insurance we are able to obtain may have higher deductibles, higher premiums and more restrictive policy terms.

Risks Related to Our Corporate and Financial Structure

We depend on our ability to successfully access the capital and financial markets. Any inability to access the capital or financial markets may limit our ability to execute our business plan or pursue improvements that we may rely on for future growth.

We rely on access to both short-term money markets (in the form of commercial paper and lines of credit) and long-term capital markets as a source of liquidity for capital and operating requirements not satisfied by the cash flow from our operations. If we are not able to access financial markets at competitive rates, our ability to implement our business plan and strategy will be negatively affected, and we may be forced to postpone, modify or cancel capital projects. Certain market disruptions may increase our cost of borrowing or affect our ability to access one or more financial markets. Such market disruptions could result from:

- adverse economic conditions
- adverse general capital market conditions
- poor performance and health of the utility industry in general
- bankruptcy or financial distress of unrelated energy companies or Marketers
- significant decrease in the demand for natural gas
- adverse regulatory actions that affect our local gas distribution companies and our natural gas storage business
- terrorist attacks on our facilities or our suppliers, or
- extreme weather conditions.

The continued disruption in the credit markets could limit our ability to access capital and increase our cost of capital.

The global credit markets have been experiencing significant disruption and volatility in recent months. In some cases, the ability or willingness of traditional sources of capital to provide financing has been reduced.

Historically, we have accessed the commercial paper markets to finance our short-term working capital requirements, but the disruption in the credit markets has limited our access to the commercial paper markets at reasonable interest rates. Consequently, we have borrowed directly under our Credit Facilities for our working capital needs. As of December 31, 2008, we had $273 million in commercial paper outstanding and $500 million outstanding under our Credit Facilities. During 2008, our borrowings under these facilities along with our commercial paper were used primarily to purchase natural gas inventories for the current winter heating season. The amount of our working capital requirements in the near-term will depend primarily on the market price of natural gas and weather. Higher natural gas prices may adversely impact our accounts receivable collections and may require us to increase borrowings under our credit facilities to fund our operations.

While we believe we can meet our capital requirements from our operations and the sources of financing available to us, we can provide no assurance that we will continue to be able to do so in the future, especially if the market price of natural gas increases significantly in the near-term. The future effects on our business, liquidity and financial results of a continuation of current market conditions could be material and adverse to us, both in the ways described above, or in ways that we do not currently anticipate.

If we breach any of the financial covenants under our various credit facilities, our debt service obligations could be accelerated.

Our existing Credit Facilities and the SouthStar line of credit contain financial covenants. If we breach any of the financial covenants under these agreements, our debt repayment obligations under them could be accelerated. In such event, we may

not be able to refinance or repay all our indebtedness, which would result in a material adverse effect on our business, results of operations and financial condition.

A downgrade in our credit rating could negatively affect our ability to access capital.

Our senior unsecured debt is currently assigned a rating of BBB+ by S&P, Baa1 by Moody's and A- by Fitch. Our commercial paper currently is rated A2 by S&P, P2 by Moody's and F2 by Fitch. If the rating agencies downgrade our ratings, particularly below investment grade, it may significantly limit our access to the commercial paper market and our borrowing costs would increase. In addition, we would likely be required to pay a higher interest rate in future financings and our potential pool of investors and funding sources would likely decrease.

Additionally, if our credit rating by either S&P or Moody's falls to non-investment grade status, we will be required to provide additional support for certain customers of our wholesale business. As of December 31, 2008, if our credit rating had fallen below investment grade, we would have been required to provide collateral of approximately $12 million to continue conducting our wholesale services business with certain counterparties.

We are vulnerable to interest rate risk with respect to our debt, which could lead to changes in interest expense and adversely affect our earnings.

We are subject to interest rate risk in connection with the issuance of fixed-rate and variable-rate debt. In order to maintain our desired mix of fixed-rate and variable-rate debt, we may use interest rate swap agreements and exchange fixed-rate and variable-rate interest payment obligations over the life of the arrangements, without exchange of the underlying principal amounts. See Item 7A, "Quantitative and Qualitative Disclosures About Market Risk." We cannot ensure that we will be successful in structuring such swap agreements to manage our risks effectively. If we are unable to do so, our earnings may be reduced. In addition, higher interest rates, all other things equal, reduce the earnings that we derive from transactions where we capture the difference between authorized returns and short-term borrowings.

We are a holding company and are dependent on cash flow from our subsidiaries, which may not be available in the amounts and at the times we need.

A portion of our outstanding debt was issued by our wholly-owned subsidiary, AGL Capital, which we fully and unconditionally guarantee. Since we are a holding company and have no operations separate from our investment in our subsidiaries, we are dependent on cash in the form of dividends or other distributions from our subsidiaries to meet our cash requirements. The ability of our subsidiaries to pay dividends and make other distributions is subject to applicable state law. Refer to Item 5, "Market for the Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities" for additional dividend restriction information.

The use of derivative contracts in the normal course of our business could result in financial losses that negatively impact our results of operations.

We use derivatives, including futures, forwards and swaps, to manage our commodity and financial market risks. We could recognize financial losses on these contracts as a result of volatility in the market values of the underlying commodities or if a counterparty fails to perform under a contract. In the absence of actively quoted market prices and pricing information from external sources, the valuation of these financial instruments can involve management's judgment or use of estimates. As a result, changes in the underlying assumptions or use of alternative valuation methods could adversely affect the value of the reported fair value of these contracts.

As a result of cross-default provisions in our borrowing arrangements, we may be unable to satisfy all our outstanding obligations in the event of a default on our part.

Our Credit Facilities under which our debt is issued contains cross-default provisions. Accordingly, should an event of default occur under some of our debt agreements, we face the prospect of being in default under other of our debt agreements, obliged in such instance to satisfy a large portion of our outstanding indebtedness and unable to satisfy all our outstanding obligations simultaneously.

ITEM 1B. UNRESOLVED STAFF COMMENTS

We do not have any unresolved comments from the SEC staff regarding our periodic or current reports under the Securities Exchange Act of 1934, as amended.

ITEM 2. PROPERTIES

We consider our properties to be well maintained, in good operating condition and suitable for their intended purpose. The following provides the location and general character of the materially important properties that are used by our segments.

Distribution and transmission assets

This property primarily includes assets used by our distribution operations and energy investment segments for the distribution of natural gas to our customers in our service areas, and includes approximately 45,000 miles of underground distribution and transmission mains. These mains are located on easements or rights-of-way which generally provide for perpetual use.

Storage assets

We have approximately 7 Bcf of LNG storage capacity in five LNG plants located in Georgia, New Jersey and Tennessee. In addition, we own three propane storage facilities in Virginia and Georgia that have a combined storage capacity of approximately 0.5 Bcf. These LNG plants and propane facilities are used by distribution operations to supplement the natural gas supply during peak usage periods.

We also own a high-deliverability natural gas storage and hub facility in Louisiana. This facility is operated by a subsidiary within our energy investments segment and includes two salt dome gas storage caverns with approximately 10 Bcf of total capacity and about 7 Bcf of working gas capacity. Our energy investments segment also owns a propane storage facility in Virginia with approximately 0.3 Bcf of storage capacity. This facility supplements the natural gas supply to our Virginia utility during peak usage periods.

Telecommunications assets

AGL Networks, a subsidiary within our energy investments segment, owns and operates telecommunications conduit and fiber property in public rights-of-way that are leased to our customers primarily in Atlanta and Phoenix. This includes over 129,000 fiber miles, a 36,000 mile increase compared to 2007. Approximately 40% of our dark fiber in Atlanta and 22% of our dark fiber in Phoenix has been leased.

Offices

All of our segments own or lease office, warehouse and other facilities throughout our operating areas. We expect additional or substitute space to be available as needed to accommodate expansion of our operations.

ITEM 3. LEGAL PROCEEDINGS

The nature of our business ordinarily results in periodic regulatory proceedings before various state and federal authorities. In addition, we are party, as both plaintiff and defendant, to a number of lawsuits related to our business on an ongoing basis. Management believes that the outcome of all regulatory proceedings and litigation in which we are currently involved will not have a material adverse effect on our consolidated financial condition or results of operations. For more information regarding some of these proceedings, see Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations" under the caption "Results of Operations" and the heading "Commitments and Contingencies" and Note 7 to our consolidated financial statements under the caption "Litigation" and "Review of Compliance with FERC Regulation."

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

No matters were submitted to a vote of our security holders during the fourth quarter ended December 31, 2008.

EXECUTIVE OFFICERS OF THE REGISTRANT

Set forth below are the names, ages and positions of our executive officers along with their business experience during the past five years. All officers serve at the discretion of our Board of Directors. All information is as of the date of the filing of this report.

Name, age and position with the company	Periods served
John W. Somerhalder II, Age 53 (1)	
Chairman, President and Chief Executive Officer	October 2007 – Present
President and Chief Executive Officer	March 2006 – October 2007
Ralph Cleveland, Age 46	
Executive Vice President, Engineering and Operations	December 2008 – Present
Senior Vice President, Engineering and Operations	February 2005 – December 2008
Vice President, Engineering, Construction and Chief Engineer – Atlanta Gas Light	January 2003 – February 2005
Andrew W. Evans, Age 42	
Executive Vice President and Chief Financial Officer	May 2006 – Present
Senior Vice President and Chief Financial Officer	September 2005 – May 2006
Vice President and Treasurer	April 2002 – September 2005
Henry P. Linginfelter, Age 48	
Executive Vice President, Utility Operations	June 2007 – Present
Senior Vice President, Mid-Atlantic Operations	November 2004– June 2007
President, Virginia Natural Gas.	October 2000 – November 2004
Kevin P. Madden, Age 56 (2)	
Executive Vice President, External Affairs	November 2005 – Present
Executive Vice President, Distribution and Pipeline Operations	April 2002 – November 2005
Melanie M. Platt, Age 54	
Senior Vice President, Human Resources	September 2004 – Present
Senior Vice President and Chief Administrative Officer	November 2002 – September 2004
Douglas N. Schantz, Age 53	
President, Sequent	May 2003 – Present
Paul R. Shlanta, Age 51	
Executive Vice President, General Counsel and Chief Ethics and Compliance Officer	September 2005 – Present
Senior Vice President, General Counsel and Chief Corporate Compliance Officer	September 2002 – September 2005

(1) Mr. Somerhalder was executive vice president of El Paso Corporation (NYSE: EP) from 2000 until May 2005, and he continued service under a professional services agreement from May 2005 until March 2006.
(2) On November 5, 2008, Mr. Madden announced his retirement, which is effective March 1, 2009.

PART II

ITEM 5. MARKET FOR THE REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Holders of Common Stock, Stock Price and Dividend Information

Our common stock is listed on the New York Stock Exchange under the symbol ATG. At January 30, 2009, there were 9,819 record holders of our common stock. Quarterly information concerning our high and low stock prices and cash dividends paid in 2008 and 2007 is as follows:

	Sales price of common stock		Cash dividend per common
Quarter ended:	High	Low	share
2008			
March 31, 2008	$39.13	$33.45	$0.42
June 30, 2008	36.50	33.46	0.42
September 30, 2008	35.44	30.60	0.42
December 31, 2008	32.07	24.02	0.42
			$1.68
2007			
March 31, 2007	$42.99	$38.20	$0.41
June 30, 2007	44.67	39.52	0.41
September 30, 2007	41.51	35.24	0.41
December 31, 2007	41.16	35.42	0.41
			$1.64

We have historically paid dividends to common shareholders four times a year: March 1, June 1, September 1 and December 1. We have paid 244 consecutive quarterly dividends beginning in 1948. Our common shareholders may receive dividends when declared at the discretion of our Board of Directors. See Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations – Liquidity and Capital Resources – Cash Flow from Financing Activities – Dividends on Common Stock." Dividends may be paid in cash, stock or other form of payment, and payment of future dividends will depend on our future earnings, cash flow, financial requirements and other factors, some of which are noted below. In certain cases, our ability to pay dividends to our common shareholders is limited by the following:

- our ability to satisfy our obligations under certain financing agreements, including debt-to-capitalization covenants
- our ability to satisfy our obligations to any future preferred shareholders

Under Georgia law, the payment of cash dividends to the holders of our common stock is limited to our legally available assets and subject to the prior payment of dividends on any outstanding shares of preferred stock. Our assets are not legally available for paying cash dividends if, after payment of the dividend:

- we could not pay our debts as they become due in the usual course of business, or
- our total assets would be less than our total liabilities plus, subject to some exceptions, any amounts necessary to satisfy (upon dissolution) the preferential rights of shareholders whose preferential rights are superior to those of the shareholders receiving the dividends

Issuer Purchases of Equity Securities

The following table sets forth information regarding purchases of our common stock by us and any affiliated purchasers during the three months ended December 31, 2008. Stock repurchases may be made in the open market or in private transactions at times and in amounts that we deem appropriate. However, there is no guarantee as to the exact number of additional shares that may be repurchased, and we may terminate or limit the stock repurchase program at any time. We will hold the repurchased shares as treasury shares.

Period	Total number of shares purchased (1) (2) (3)	Average price paid per share	Total number of shares purchased as part of publicly announced plans or programs (3)	Maximum number of shares that may yet be purchased under the publicly announced plans or programs (3)
October 2008	-	$-	-	4,950,951
November 2008	4,800	29.35	-	4,950,951
December 2008	433	34.81	-	4,950,951
Total fourth quarter	5,233	$29.80	-	

(1) The total number of shares purchased includes an aggregate of 433 shares surrendered to us to satisfy tax withholding obligations in connection with the vesting of shares of restricted stock and/or the exercise of stock options.

(2) On March 20, 2001, our Board of Directors approved the purchase of up to 600,000 shares of our common stock in the open market to be used for issuances under the Officer Incentive Plan (Officer Plan). We purchased 4,800 any shares for such purposes in the fourth quarter of 2008. As of December 31, 2008, we had purchased a total 312,367 of the 600,000 shares authorized for purchase, leaving 287,633 shares available for purchase under this program.

(3) On February 3, 2006, we announced that our Board of Directors had authorized a plan to repurchase up to a total of 8 million shares of our common stock, excluding the shares remaining available for purchase in connection with the Officer Plan as described in note (2) above, over a five-year period.

The information required by this item regarding securities authorized for issuance under our equity compensation plans will be set forth under the caption "Executive Compensation – Equity Compensation Plan Information" in the Proxy Statement for our 2009 Annual Meeting of Shareholders or in a subsequent amendment to this report. All such information will be incorporated by reference from the Proxy Statement in Item 12, "Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters" hereof or set forth in such amendment to this report.

ITEM 6. SELECTED FINANCIAL DATA

Selected financial data about AGL Resources for the last five years is set forth in the table below. You should read the data in the table in conjunction with the consolidated financial statements and related notes set forth in Item 8, "Financial Statements and Supplementary Data."

Dollars and shares in millions, except per share amounts	2008	2007	2006	2005	2004
Income statement data					
Operating revenues	$2,800	$2,494	$2,621	$2,718	$1,832
Cost of gas	1,654	1,369	1,482	1,626	995
Operating margin (1)	1,146	1,125	1,139	1,092	837
Operating expenses					
Operation and maintenance	472	451	473	477	377
Depreciation and amortization	152	144	138	133	99
Taxes other than income taxes	44	41	40	40	29
Total operating expenses	668	636	651	650	505
Operating income	478	489	488	442	332
Other income (expense)	6	4	(1)	(1)	-
Minority interest	(20)	(30)	(23)	(22)	(18)
Earnings before interest and taxes (EBIT) (1)	464	463	464	419	314
Interest expense	115	125	123	109	71
Earnings before income taxes	349	338	341	310	243
Income taxes	132	127	129	117	90
Net income	$217	$211	$212	$193	$153
Common stock data					
Weighted average shares outstanding basic	76.3	77.1	77.6	77.3	66.3
Weighted average shares outstanding diluted	76.6	77.4	78.0	77.8	67.0
Total shares outstanding (2)	76.9	76.4	77.7	77.8	76.7
Average daily trading volumes	0.59	0.50	0.37	0.32	0.23
Earnings per share - basic	$2.85	$2.74	$2.73	$2.50	$2.30
Earnings per share - diluted	$2.84	$2.72	$2.72	$2.48	$2.28
Dividends declared per share	$1.68	$1.64	$1.48	$1.30	$1.15
Dividend payout ratio	59%	60%	54%	52%	50%
Dividend yield (3)	5.4%	4.4%	3.8%	3.7%	3.5%
Book value per share (4)	$21.48	$21.74	$20.72	$19.27	$18.04
Price-earnings ratio (5)	11.0	13.7	14.3	13.9	14.5
Stock price market range	$24.02 - $39.13	$35.24- $44.67	$34.40- $40.09	$32.00- $39.32	$26.50- $33.65
Market value per share (6)	$31.35	$37.64	$38.91	$34.81	$33.24
Market value (2)	$2,411	$2,876	$3,023	$2,708	$2,551
Balance sheet data (2)					
Total assets	$6,710	$6,258	$6,123	$6,310	$5,637
Property, plant and equipment – net	3,816	3,566	3,436	3,333	3,178
Working capital	59	163	156	73	(20)
Total debt	2,541	2,255	2,161	2,137	1,957
Common shareholders' equity	1,652	1,661	1,609	1,499	1,385
Cash flow data					
Net cash provided by operating activities	$227	$377	$351	$80	$287
Property, plant and equipment expenditures	372	259	253	267	264
Net borrowings and (payments) of short-term debt	286	52	6	188	(480)
Financial ratios (2)					
Total debt	61%	58%	57%	59%	59%
Common shareholders' equity	39%	42%	43%	41%	41%
Total	100%	100%	100%	100%	100%
Return on average common shareholders' equity	13.1%	12.9%	13.6%	13.4%	13.1%

(1) These are non-GAAP measurements. A reconciliation of operating margin and EBIT to our operating income, earnings before income taxes and net income is contained in Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations - AGL Resources-Results of Operations."
(2) As of the last day of the fiscal period.
(3) Dividends declared per share divided by market value per share.
(4) Common shareholders' equity divided by total outstanding common shares as of the last day of the fiscal period.
(5) Market value per share divided by basic earnings per share.
(6) Closing price of common stock on the New York Stock Exchange as of the last trading day of the fiscal period.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Overview

We are an energy services holding company whose principal business is the distribution of natural gas in six states - Florida, Georgia, Maryland, New Jersey, Tennessee and Virginia. Our six utilities serve more than 2.2 million end-use customers, making us the largest distributor of natural gas in the southeastern and mid-Atlantic regions of the United States based on customer count. We are involved in various related businesses, including retail natural gas marketing to end-use customers primarily in Georgia; natural gas asset management and related logistics activities for our own utilities as well as for nonaffiliated companies; natural gas storage arbitrage and related activities; and the development and operation of high-deliverability underground natural gas storage assets. We also own and operate a small telecommunications business that constructs and operates conduit and fiber infrastructure within select metropolitan areas. We manage these businesses through four operating segments – distribution operations, retail energy operations, wholesale services and energy investments – and a nonoperating corporate segment.

The distribution operations segment is the largest component of our business and is subject to regulation and oversight by agencies in each of the six states we serve. These agencies approve natural gas rates designed to provide us the opportunity to generate revenues to recover the cost of natural gas delivered to our customers and our fixed and variable costs such as depreciation, interest, maintenance and overhead costs, and to earn a reasonable return for our shareholders. With the exception of Atlanta Gas Light, our largest utility, the earnings of our regulated utilities can be affected by customer consumption patterns that are a function of weather conditions, price levels for natural gas and general economic conditions that may impact their ability to pay for gas consumed. Various mechanisms exist that limit our exposure to weather changes within typical ranges in all of our jurisdictions. Our retail energy operations segment, which consists of SouthStar, also is weather sensitive and uses a variety of hedging strategies, such as weather derivative instruments and other risk management tools, to mitigate potential weather impacts. Our Sequent subsidiary within our wholesale services segment is temperature insensitive, but generally has greater opportunity to capture operating margin due to price volatility as a result of extreme weather .Our energy investments segment's primary activity is our natural gas storage business, which develops, acquires and operates high-deliverability salt-dome storage assets in the Gulf Coast region of the United States. While this business also can generate additional revenue during times of peak market demand for natural gas storage services, the majority of our storage services are covered under medium to long-term contracts at a fixed market rate.

Executive Summary

Customer growth We continue to see challenging economic conditions in all of the areas we serve and, as a result, have experienced lower than expected customer growth in our distribution operations and retail energy operations segments throughout 2008, a trend we expect to continue through 2009.

For the year ended December 31, 2008, our consolidated utility customer growth rate was 0.1%, compared to 0.9% for 2007. We anticipated customer growth in 2008 of about 0.5%. The lower levels of customer growth are primarily a result of much slower growth in the residential housing markets throughout our service territories. This trend has been offset slightly by growth in the commercial customer segment in certain areas, primarily as a result of conversions to natural gas from other fuel sources.

We continue to use a variety of targeted marketing programs to attract new customers and to retain existing ones. These programs generally emphasize natural gas as the fuel of choice for customers and seek to expand the use of natural gas through a variety of promotional activities.

We have seen a 3% decline in average customer count at SouthStar for the year ended December 31, 2008, as compared to 2007. This decline reflects some of the same economic conditions that have affected our utility businesses; as well as a more competitive retail pricing market for natural gas in Georgia.

Natural gas prices Increased energy and transportation prices are expected to impact a significantly larger portion of consumer household incomes during the current winter heating season. As a result, we may incur additional bad debt expense, as well as lower operating margins, due to increased customer conservation. While these factors could adversely impact our results of operations, we expect regulatory and operational mechanisms in place in most of our jurisdictions will help to mitigate some of our exposure to these factors.

The risks of increased bad debt expense and decreased operating margins from conservation are minimized at our largest utility, Atlanta Gas Light, as a result of its straight-fixed variable rate structure. In addition, customers in Georgia buy their natural gas

from Marketers rather than from Atlanta Gas Light. Our credit exposure at Atlanta Gas Light is primarily related to the provision of services to the Marketers, but that exposure is mitigated, as we obtain security support in an amount equal to a minimum of no less than two times a Marketer's highest month's estimated bill. At our other utilities, while customer conservation could adversely impact our operating margins, we utilize measures to collect delinquent accounts and continue to be rigorous in monitoring and mitigating the impact of these expenses. We do, however, expect that our bad debt expense for the current winter heating season will be higher than the prior year.

We worked with regulators and state agencies in each of our jurisdictions to educate customers about higher energy costs in advance of the winter heating season, in particular to ensure that those qualified for the Low Income Home Energy Assistance Program and other similar programs receive any needed assistance.

SouthStar may also be affected by the conservation and bad debt trends, but its overall exposure is partially mitigated by the high credit quality of SouthStar's customer base, disciplined collection practices and the unregulated pricing structure in Georgia.

The rising commodity prices during the first six months of 2008, along with reduced opportunities related to the management of storage and transportation assets throughout 2008 negatively affected SouthStar's operating margin. More favorable market conditions and decreasing natural gas prices in the first six months of 2007 as compared to rising prices during the same time frame in 2008 enabled SouthStar to recognize higher operating margins for 2007 as compared to 2008. SouthStar's reported results were also negatively impacted during 2008 by the significant decrease in natural gas prices during the second half of the year as SouthStar was required to record $24 million of LOCOM adjustments to reduce its natural gas inventory to market value.

Due to the rising commodity price environment and the widening of transportation basis spreads during the first six months of 2008, Sequent recorded $70 million in losses on the financial instruments it used to hedge its storage and transportation positions. The natural gas market remained volatile with significant decreases in prices and narrowing of basis spreads during the second half of 2008. Consequently Sequent recognized gains on hedging instruments of $52 million for 2008. This is a $35 million net increase compared to 2007. In addition to the increase in hedge gains, Sequent's commercial activity improved by $25 million for 2008 over 2007, due to more favorable business opportunities presented by the greater volatility in the marketplace. In addition, the decrease in forward prices caused Sequent to be subject to a LOCOM adjustment on its natural gas inventory. The increase in the impact of the adjustment, net of estimated hedging recoveries, was $15 million for 2008 from the prior year. These changes resulted in Sequent reporting operating margin that was $45 million higher for 2008, as compared to 2007.

Results of Operations

Revenues We generate nearly all our operating revenues through the sale, distribution and storage of natural gas. We include in our consolidated revenues an estimate of revenues from natural gas distributed, but not yet billed, to residential and commercial customers from the latest meter reading date to the end of the reporting period. The following table provides more information regarding the components of our operating revenues.

In millions	2008	2007	2006
Residential	$1,194	$1,143	$1,127
Commercial	500	500	460
Transportation	482	401	434
Industrial	280	250	310
Other	344	200	290
Total operating revenues	$2,800	$2,494	$2,621

Operating margin and EBIT We evaluate the performance of our operating segments using the measures of operating margin and EBIT. We believe operating margin is a better indicator than operating revenues for the contribution resulting from customer growth in our distribution operations segment since the cost of gas can vary significantly and is generally billed directly to our customers. We also consider operating margin to be a better indicator in our retail energy operations, wholesale services and energy investments segments since it is a direct measure of operating margin before overhead costs. We believe EBIT is a useful measurement of our operating segments' performance because it provides information that can be used to evaluate the effectiveness of our businesses from an operational perspective, exclusive of the costs to finance those activities and exclusive of income taxes, neither of which is directly relevant to the efficiency of those operations.

Our operating margin and EBIT are not measures that are considered to be calculated in accordance with GAAP. You should not consider operating margin or EBIT an alternative to, or a more meaningful indicator of, our operating performance than operating income or net income as determined in accordance with GAAP. In addition, our operating margin and EBIT measures may not be comparable to similarly titled measures of other companies. The table below sets forth a reconciliation of our operating margin and EBIT to our operating income, earnings before income taxes and net income, together with other consolidated financial information for the last three years.

In millions, except per share amounts	**2008**	**2007**	**2006**
Operating revenues	$2,800	$2,494	$2,621
Cost of gas	1,654	1,369	1,482
Operating margin	1,146	1,125	1,139
Operating expenses			
Operation and maintenance	472	451	473
Depreciation and amortization	152	144	138
Taxes other than income	44	41	40
Total operating expenses	668	636	651
Operating income	478	489	488
Other income (expense)	6	4	(1)
Minority interest	(20)	(30)	(23)
EBIT	464	463	464
Interest expense	115	125	123
Earnings before income taxes	349	338	341
Income taxes	132	127	129
Net income	$217	$211	$212
Earnings per common share:			
Basic	$2.85	$2.74	$2.73
Diluted	$2.84	$2.72	$2.72
Weighted average number of common shares outstanding:			
Basic	76.3	77.1	77.6
Diluted	76.6	77.4	78.0

In 2008 our net income increased by $6 million from the prior year primarily due to increased EBIT from wholesale services and energy investments largely due to higher operating margin. This was offset by decreased EBIT at distribution operations and retail energy operations due to lower operating margins as compared to 2007. Additionally, distribution operations' EBIT contribution decreased due to higher operating expenses as compared to 2007. Our basic earnings per share increased by $0.11 and our diluted earnings per share increased by $0.12, primarily due to our increased earnings and the reduction in the average number of shares outstanding as a result of purchases made under our share repurchase program during 2007.

In 2007 our net income decreased by $1 million from 2006 primarily due to decreased EBIT from wholesale services largely due to lower operating margin. This was offset by increased EBIT at distribution operations, retail energy operations and energy investments due to higher operating margins as compared to 2006. Additionally, distribution operations' EBIT contribution increased due to lower operating expenses as compared to 2006. Our basic earnings per share increased by $0.01, primarily due to the reduction in the average number of shares outstanding as a result of our share repurchase program. Our diluted earnings per share were unchanged from 2006.

Operating metrics Selected weather, customer and volume metrics for 2008, 2007 and 2006, which we consider to be some of the key performance indicators for our operating segments, are presented in the following tables. We measure the effects of weather on our business through heating degree days. Generally, increased heating degree days result in greater demand for gas on our distribution systems. However, extended and unusually mild weather during the heating season can have a significant negative impact on demand for natural gas. Our marketing and customer retention initiatives are measured by our customer metrics which can be impacted by natural gas prices, economic conditions and competition from alternative fuels. Volume metrics for distribution operations and retail energy operations present the effects of weather and our customers' demand for natural gas. Wholesale services' daily physical sales represent the daily average natural gas volumes sold to its customers.

Weather Heating degree days (1)	Year ended December 31,				2008 vs. 2007 colder (warmer)	2007 vs. 2006 colder (warmer)	2008 vs. normal colder (warmer)	2007 vs. normal colder (warmer)	2006 vs. normal colder (warmer)
	Normal	2008	2007	2006					
Florida	496	416	326	468	28%	(30)%	(16)%	(34)%	(6)%
Georgia	2,608	2,746	2,366	2,455	16%	(4)%	5%	(9)%	(6)%
Maryland	4,705	4,521	4,621	4,205	(2)%	10%	(4)%	(2)%	(11)%
New Jersey	4,654	4,647	4,777	4,074	(3)%	17%	-	3%	(12)%
Tennessee	2,991	3,179	2,722	2,892	17%	(6)%	6%	(9)%	(3)%
Virginia	3,151	3,031	3,077	2,870	(1)%	7%	(4)%	(2)%	(9)%

	Quarter ended December 31,				2008 vs. 2007 colder (warmer)	2007 vs. 2006 colder (warmer)	2008 vs. normal colder (warmer)	2007 vs. normal colder (warmer)	2006 vs. normal colder (warmer)
	Normal	2008	2007	2006					
Florida	160	201	45	111	347%	(59)%	26%	(72)%	(31)%
Georgia	1,021	1,092	877	955	25%	(8)%	7%	(14)%	(6)%
Maryland	1,673	1,693	1,558	1,493	9%	4%	1%	(7)%	(11)%
New Jersey	1,623	1,729	1,605	1,372	8%	17%	7%	(1)%	(15)%
Tennessee	1,184	1,291	969	1,193	33%	(19)%	9%	(18)%	1%
Virginia	1,096	1,151	965	993	19%	(3)%	5%	(12)%	(9)%

(1) Obtained from the National Oceanic and Atmospheric Administration, National Climatic Data Center. Normal represents the ten-year averages from January 1999 to December 2008.

Customers	Year ended December 31,			2008 vs. 2007	2007 vs. 2006
	2008	2007	2006	% change	% change
Distribution Operations					
Average end-use customers (in thousands)					
Atlanta Gas Light	1,557	1,559	1,546	(0.1)%	0.8%
Chattanooga Gas	62	61	61	1.6	-
Elizabethtown Gas	273	272	269	0.4	1.1
Elkton Gas	6	6	6	-	-
Florida City Gas	104	104	104	-	-
Virginia Natural Gas	271	269	264	0.7	1.9
Total	2,273	2,271	2,250	0.1%	0.9%
Operation and maintenance expenses per customer	$145	$145	$156	-	(7)%
EBIT per customer	$145	$149	$138	(3)%	8%
Retail Energy Operations					
Average customers (in thousands)	526	540	533	(3)%	1%
Market share in Georgia	34%	35%	35%	(3)%	-

Volumes In billion cubic feet (Bcf)	Year ended December 31,			2008 vs. 2007	2007 vs. 2006
	2008	2007	2006	% change	% change
Distribution Operations					
Firm	219	211	199	4%	6%
Interruptible	104	108	117	(4)%	(8)
Total	323	319	316	1%	1%
Retail Energy Operations					
Georgia firm	41	39	37	5%	5%
Ohio and Florida	7	5	1	40%	400%
Wholesale Services					
Daily physical sales (Bcf / day)	2.60	2.35	2.20	11%	7%

Segment information Operating revenues, operating margin, operating expenses and EBIT information for each of our segments are contained in the following tables for the last three years.

In millions	Operating revenues	Operating margin(1)	Operating expenses	EBIT (1)
2008				
Distribution operations	$1,768	$818	$493	$329
Retail energy operations	987	149	73	57
Wholesale services	170	122	62	60
Energy investments	55	50	31	19
Corporate (2)	(180)	7	9	(1)
Consolidated	$2,800	$1,146	$668	$464
2007				
Distribution operations	$1,665	$820	$485	$338
Retail energy operations	892	188	75	83
Wholesale services	83	77	43	34
Energy investments	42	40	25	15
Corporate (2)	(188)	-	8	(7)
Consolidated	$2,494	$1,125	$636	$463
2006				
Distribution operations	$1,624	$807	$499	$310
Retail energy operations	930	156	68	63
Wholesale services	182	139	49	90
Energy investments	41	36	26	10
Corporate (2)	(156)	1	9	(9)
Consolidated	$2,621	$1,139	$651	$464

(1) These are non-GAAP measurements. A reconciliation of operating margin, earnings before income taxes and EBIT to our operating income and net income is contained in "Results of Operations" herein.
(2) Includes intercompany eliminations

Operating margin Our operating margin in 2008 increased by $21 million or 2% compared to 2007 primarily due to higher operating margins at wholesale services and energy investments segments, partially offset by decreased operating margin at our retail energy operations segment. In 2007 our operating margin decreased $14 million or 1% compared to 2006 primarily due to lower operating margin at our wholesale services segment.

Distribution operations The 2008 operating margin for distribution operations decreased by $2 million, compared to 2007, primarily due to lower customer growth and use of natural gas, offset by an increase in revenues from Atlanta Gas Light's pipeline replacement program (PRP).

Distribution operations' 2007 operating margin increased $13 million or 2% compared to 2006 primarily due to an increase in customers and slightly overall higher customer use of natural gas. The following table indicates the significant changes in distribution operations' operating margin for 2008 and 2007.

In millions	2008	2007
Operating margin for prior year	$820	$807
(Decreased) increased customer growth and use of natural gas	(4)	8
Higher PRP revenues at Atlanta Gas Light	6	2
Base rate increase at Chattanooga Gas	-	2
Other	(4)	1
Operating margin for year	$818	$820

Retail energy operations The 2008 operating margin for retail energy operations decreased $39 million or 21% compared to 2007. This was primarily due to a reduction of customers in Georgia, lower contributions from the optimization and management of storage and transportation assets and a $24 million LOCOM adjustment. Retail energy operations did not record a similar LOCOM adjustment in 2007. While 2008 was 16% colder than 2007, and 2007 was 4% warmer than 2006, retail energy operations use of weather derivatives largely offset the effects of weather in operating margin.

Retail energy operations' 2007 operating margin increased $32 million or 21% compared to 2006. This was primarily due to an increase in customer use of natural gas in Georgia and the combination of retail price spreads and contributions from the optimization of storage and transportation assets and commodity risk management activities. The following table indicates the significant changes in retail energy operations' operating margin for 2008 and 2007.

In millions	2008	2007
Operating margin for prior year	$188	$156
Inventory LOCOM	(24)	6
(Decreased) increased contributions from management and optimization of storage and transportation assets, and from retail price spreads	(9)	12
(Decreased) increased average number of customers	(8)	2
Pricing settlement with the Georgia Commission	(3)	-
Increased operating margins in Ohio and Florida	2	3
Increased customer use of natural gas	1	8
Increased late payment fees	-	2
Other	2	(1)
Operating margin for year	$149	$188

Wholesale services The 2008 operating margin for wholesale services increased $45 million or 58% compared to 2007. This increase was due to a $35 million increase in reported hedge gains and a $25 million increase in commercial activity, due in part to increased inventory storage and transportation spreads and higher volatility in the marketplace. These increases were partially offset by a $36 million increase in the required LOCOM adjustments to natural gas inventories for the year ended December

31, 2008, net of $21 million in estimated hedging recoveries.

Wholesale services' 2007 operating margin decreased $62 million or 45% compared to 2006. This decrease was due to a reduction in hedge gains and commercial activity, due in part to reduced inventory storage spreads and lower volatility in the marketplace.

The following table indicates the significant changes in wholesale services' operating margin for 2008 and 2007.

In millions	2008	2007
Operating margin for prior year	$77	$139
Increased (decreased) commercial activity	25	(46)
Increased (decreased) hedge gains	35	(36)
Inventory LOCOM, net of hedging recoveries	(15)	20
Operating margin for year	$122	$77

For more information on Sequent's expected operating revenues from its storage inventory in 2009 and discussion of increased commercial activity in 2008 compared to 2007, see the description of the wholesale services business in Item 1 "Business" beginning on page 10.

Energy investments The 2008 operating margin for energy investments increased $10 million or 25% compared to 2007. Its 2007 operating margin increased $4 million or 11% from the prior year, primarily due to a larger customer base and customer construction projects at AGL Networks and increased revenues at Jefferson Island as a result of increased interruptible margin opportunities. The following table indicates the significant changes in energy investments' operating margin for 2008 and 2007.

In millions	2008	2007
Operating margin for prior year	$40	$36
Increased customers and expansion projects at AGL Networks	7	2
Increased revenues at Jefferson Island	3	2
Operating margin for year	$50	$40

Operating expenses Our operating expenses in 2008 increased $32 million or 5% from 2007, which decreased $15 million or 2% from 2006. The following table indicates the significant changes in our operating expenses.

In millions	2008	2007
Operating expenses for prior year	$636	$651
Increased (decreased) incentive compensation costs at distribution operations	11	(14)
Increased (decreased) incentive compensation costs at wholesale services due to higher (lower) operating margin	6	(13)
Increased (decreased) bad debt expense at retail energy operations	3	(3)
Increased incentive compensation costs at retail energy operations due to growth and improved operations	-	3
Increased bad debt expense at distribution operations	5	-
Increased depreciation and amortization	8	6
Increased payroll and other operating costs at wholesale services due to continued expansion	13	7
(Decreased) increased costs at retail energy operations from customer care, marketing and payroll	(5)	5
Increased (decreased) costs at energy investments due to expansion costs at AGL Networks, business development costs and depreciation and legal expenses at Jefferson Island	6	(1)
Other, net primarily at distribution operations due to pension, outside services and reduction in marketing and customer service expenses	(15)	(5)
Operating expenses for year	$668	$636

Other income (expenses) Our 2008 other income (expenses) increased by $2 million compared to 2007 primarily from increased capitalization for regulatory allowances for funds used during distribution operations' construction projects. Our 2007 other income increased by $5 million as compared to 2006 primarily due to lower charitable contributions at distribution operations and retail energy operations.

Interest expense The decreased interest expense of $10 million or 8% in 2008 as compared to 2007 was due primarily to lower short-term interest rates partially offset by higher average debt outstanding and a $3 million premium paid for the early redemption of the $75 million notes payable to AGL Capital Trust I, which was recorded as interest expense in 2007.

The increased interest expense of $2 million or 2% in 2007 compared to 2006 was primarily due to higher short-term interest rates and the $3 million premium previously discussed. The following table provides additional detail on interest expense for the last three years and the primary items that affect year-over-year change.

In millions	2008	2007	2006
Interest expense	$115	$125	$123
Average debt outstanding (1)	$2,156	$1,967	$2,023
Average rate (2)	5.3%	6.4%	6.1%

(1) Daily average of all outstanding debt.
(2) Excluding $3 million premium paid for early redemption of debt, average rate in 2007 would have been 6.2%.

Income tax expense The increase in income tax expense of $5 million or 4% in 2008 compared to 2007 was primarily due to higher consolidated earnings and a slightly higher effective tax rate of 37.8% in 2008 compared to an effective tax rate of 37.6% in 2007.

The decrease in income tax expense of $2 million or 2% in 2007 compared to 2006 was primarily due to lower consolidated earnings and a slightly lower effective tax rate of 37.6% in 2007 compared to an effective tax rate of 37.8% in 2006. For more information on our income taxes, including a reconciliation between the statutory federal income tax rate and the effective rate, see Note 8.

Liquidity and Capital Resources

Overview Our primary sources of liquidity are cash provided by operating activities, short-term borrowings under our commercial paper program (which is supported by our Credit Facilities), borrowings from our Credit Facilities and borrowings under our Sequent and SouthStar lines of credit. Additionally from time to time, we raise funds from the public debt and equity capital markets through our existing shelf registration statement to fund our liquidity and capital resource needs.

Our issuance of various securities, including long-term and short-term debt, is subject to customary approval or authorization by state and federal regulatory bodies including state public service commissions and the SEC. Furthermore, a substantial portion of our consolidated assets, earnings and cash flow is derived from the operation of our regulated utility subsidiaries, whose legal authority to pay dividends or make other distributions to us is subject to regulation.

We believe the amounts available to us under our Credit Facilities and the issuance of debt and equity securities together with cash provided by operating activities will continue to allow us to meet our needs for working capital, pension contributions, construction expenditures, anticipated debt redemptions, interest payments on debt obligations, dividend payments, common share repurchases and other cash needs through the next several years. Nevertheless, our ability to satisfy our working capital requirements and debt service obligations, or fund planned capital expenditures, will substantially depend upon our future operating performance (which will be affected by prevailing economic conditions), and financial, business and other factors, some of which are beyond our control.

We will continue to evaluate our need to increase available liquidity based on our view of working capital requirements, including the impact of changes in natural gas prices, liquidity requirements established by rating agencies and other factors. See Item 1A, "Risk Factors," for additional information on items that could impact our liquidity and capital resource requirements. The following table provides a summary of our operating, investing and financing activities for the last three years.

In millions	2008	2007	2006
Net cash provided by (used in):			
Operating activities	$227	$377	$351
Investing activities	(372)	(253)	(248)
Financing activities	142	(122)	(118)
Net (decrease) increase in cash and cash equivalents	$(3)	$2	$(15)

Cash Flow from Operating Activities We prepare our statement of cash flows using the indirect method. Under this method, we reconcile net income to cash flows from operating activities by adjusting net income for those items that impact net income but may not result in actual cash receipts or payments during the period. These reconciling items include depreciation and amortization, changes in risk management assets and liabilities, undistributed earnings from equity investments, deferred income taxes and changes in the consolidated balance sheet for working capital from the beginning to the end of the period.

Our operations are seasonal in nature, with the business depending to a great extent on the first and fourth quarters of each year. As a result of this seasonality, our natural gas inventories are usually at their highest levels in November each year, and largely are drawn down in the heating season, providing a source of cash as this asset is used to satisfy winter sales demand. The establishment and price fluctuations of our natural gas inventories, which meet customer demand during the winter heating season, can cause significant variations in our cash flow from operations from period to period and are reflected in changes to our working capital.

Year-over-year changes in our operating cash flows are attributable primarily to working capital changes within our distribution operations, retail energy operations and wholesale services segments resulting from the impact of weather, the price of natural gas, the timing of customer collections, payments for natural gas purchases and deferred gas cost recoveries as our business has grown and

prices for natural gas have increased. The increase in natural gas prices directly impacts the cost of gas stored in inventory.

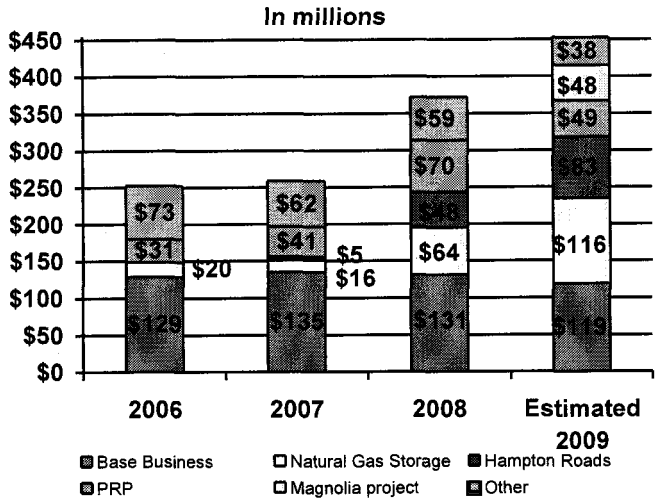
2008 compared to 2007 In 2008, our net cash flow provided from operating activities was $227 million, a decrease of $150 million or 40% from 2007. This decrease was primarily a result of increased working capital requirements of $104 million, principally driven by increased cash used for inventory purchases which were impacted by rising natural gas prices during the first half of 2008.

2007 compared to 2006 In 2007, our net cash flow provided from operating activities was $377 million, an increase of $23 million or 6% from 2006. The increase was due to higher realized gains on our energy marketing and risk management assets and liabilities and lower cash requirements for our natural gas inventories due to price and inventory volume fluctuations. This was offset by increased cash payments for income taxes due to realized gains on our energy marketing and risk management activities and higher working capital requirements.

Cash Flow from Investing Activities Our net cash used in investing activities consisted primarily of PP&E expenditures. The majority of our PP&E expenditures are within our distribution operations segment, which includes our investments in new construction and infrastructure improvements.

Our estimated PP&E expenditures of approximately $453 million in 2009 and actual expenditures of $372 million in 2008, $259 million in 2007 and $253 million in 2006 are shown within the following categories and are presented in the chart below.

- **Base business** – new construction and infrastructure improvements at our distribution operations segment
- **Natural gas storage** – salt-dome cavern expansions at Golden Triangle Storage and Jefferson Island
- **Hampton Roads** – Virginia Natural Gas' pipeline project, which will connect its northern and southern systems
- **PRP** – Atlanta Gas Light's program to replace all bare steel and cast iron pipe in its Georgia system
- **Magnolia project** –pipelines acquired from Southern Natural Gas connecting our Georgia service territory to the Elba Island LNG facility
- **Other** – primarily includes information technology, building and leasehold improvements and AGL Networks' telecommunication expenditures



In 2008, our PP&E expenditures were $113 million or 44% higher than in 2007. This was primarily due to an increase in our natural gas storage project expenditures of $48 million as we began construction of our Golden Triangle Storage facility, $43 million in increased expenditures for the Hampton Roads project and increased expenditures of $29 million for PRP as we replaced larger-diameter pipe in more densely populated areas. This was offset by decreased expenditures of $7 million on our base business and other projects.

In 2007, our PP&E expenditures were $6 million or 2% higher than in 2006. This was primarily due to an increase in PRP expenditures of $10 million as we replaced larger-diameter pipe in more densely populated areas and $5 million in expenditures for the Hampton Roads project. This was offset by decreased expenditures of $4 million on our storage projects and $5 million on our base business and other projects.

Our estimated expenditures for 2009 include discretionary spending for capital projects principally within the base business and natural gas storage categories. We continually evaluate whether to proceed with these projects, reviewing them in relation to factors including our authorized returns on rate base, other returns on invested capital for projects of a similar nature, capital structure and credit ratings, among others. We will make adjustments to these discretionary expenditures as necessary based upon these factors.

In October 2008, the New Jersey Governor presented a Comprehensive Economic Stimulus Plan for New Jersey that is intended to enhance the State's business climate and support short-term employment growth and long-term economic prospects. Recognizing that the State's natural gas utilities play a crucial role in both improving the

State's economic condition and encouraging energy efficiency, the Governor's stimulus package included provisions for energy companies to invest in programs for utility customers that will encourage energy efficiency, generate jobs and strengthen the local economy. In accordance with the Governor's plan, in January 2009 Elizabethtown Gas filed a two-year utility infrastructure enhancement program and gas cost recovery mechanism that, if approved, would require an additional $20 million in capital expenditures in 2009.

Cash Flow from Financing Activities Our capitalization and financing strategy is intended to ensure that we are properly capitalized with the appropriate mix of equity and debt securities. This strategy includes active management of the percentage of total debt relative to total capitalization, appropriate mix of debt with fixed to floating interest rates (our variable debt target is 20% to 45% of total debt), as well as the term and interest rate profile of our debt securities.

As of December 31, 2008, our variable-rate debt was $1,026 million or 40% of our total debt, compared to $840 million or 37% as of December 31, 2007. This increase was principally due to borrowings under our Credit Facilities and commercial paper borrowings. As of December 31, 2008, our Credit Facilities and commercial paper borrowings were $773 million or 37% higher than the same time last year, primarily a result of higher working capital requirements, driven by higher natural gas prices during the inventory injection season and increased PP&E expenditures of $113 million. For more information on our debt, see Note 6.

Credit Ratings We strive to maintain or improve our credit ratings on our debt to manage our existing financing cost and enhance our ability to raise additional capital on favorable terms. Factors we consider important in assessing our credit ratings include our balance sheet leverage, capital spending, earnings, cash flow generation, available liquidity and overall business risks. We do not have any trigger events in our debt instruments that are tied to changes in our specified credit ratings or our stock price and have not entered into any agreements that would require us to issue equity based on credit ratings or other trigger events. The following table summarizes our credit ratings as of December 31, 2008.

	S&P	Moody's	Fitch
Corporate rating	A-		
Commercial paper	A-2	P-2	F-2
Senior unsecured	BBB+	Baa1	A-
Ratings outlook	Stable	Stable	Stable

A credit rating is not a recommendation to buy, sell or hold securities. The highest investment grade credit rating for S&P is AAA, Moody's is Aaa and Fitch is AAA. Our credit ratings may be subject to revision or withdrawal at any time by the assigning rating organization, and each rating should be evaluated independently of any other rating. We cannot ensure that a rating will remain in effect for any given period of time or that a rating will not be lowered or withdrawn entirely by a rating agency if, in its judgment, circumstances so warrant. If the rating agencies downgrade our ratings, particularly below investment grade, it may significantly limit our access to the commercial paper market and our borrowing costs would increase. In addition, we would likely be required to pay a higher interest rate in future financings, and our potential pool of investors and funding sources would decrease.

Default Events Our debt instruments and other financial obligations include provisions that, if not complied with, could require early payment, additional collateral support or similar actions. Our most important default events include maintaining covenants with respect to a maximum leverage ratio, insolvency events, nonpayment of scheduled principal or interest payments, and acceleration of other financial obligations and change of control provisions.

Our Credit Facilities' financial covenants require us to maintain a ratio of total debt to total capitalization of no greater than 70%; however, our goal is to maintain this ratio at levels between 50% and 60%. Our ratio of total debt to total capitalization calculation contained in our debt covenant includes minority interest, standby letters of credit, surety bonds and the exclusion of other comprehensive income pension adjustments. Our debt-to-equity calculation, as defined by our Credit Facilities, was 59% at December 31, 2008 and 58% at December 31, 2007. These amounts are within our required and targeted ranges. The components of our capital structure, as calculated from our consolidated balance sheets, as of the dates indicated, are provided in the following table.

In millions	December 31, 2008		December 31, 2007	
Short-term debt	$866	21%	$580	15%
Long-term debt	1,675	40	1,675	43
Total debt	2,541	61	2,255	58
Common shareholders' equity	1,652	39	1,661	42
Total capitalization	$4,193	100%	$3,916	100%

We are currently in compliance with all existing debt provisions and covenants. We believe that accomplishing these capitalization objectives and maintaining sufficient cash flow are necessary to maintain our investment-grade credit ratings and to allow us access to capital at reasonable costs.

Short-term Debt Our short-term debt is composed of borrowings and payments of commercial paper, lines of credit and payments of the current portion of our capital leases. Our short-term debt financing generally increases between June and December because our payments for natural gas and pipeline capacity are generally made to suppliers prior to the collection of accounts receivable from our customers. We typically reduce short-term debt balances in the spring because a significant portion of our current assets are converted into cash at the end of the winter heating season.

In June 2008 we extended Sequent's $25 million unsecured line of credit bearing interest at the federal funds rate plus 0.75% through June 2009. In September 2008 Sequent extended its $20 million second line of credit that bears interest at the LIBOR rate plus 1.0% to September 2009. In December 2008 the terms of this line of credit were decreased to $5 million bearing interest at the LIBOR rate plus 3.0%. Sequent's lines of credit are used solely for the posting of margin deposits for NYMEX transactions and are unconditionally guaranteed by us.

Under the terms of our Credit Facilities, which expires in August 2011, the aggregate principal amount available is $1 billion and we can request an option to increase the aggregate principal amount available for borrowing to $1.25 billion on not more than three occasions during each calendar year.

In September 2008, we completed a $140 million supplemental credit facility that expires in September 2009, which will provide additional liquidity for working capital and capital expenditure needs. This $140 million credit facility allows for the option to request an increase in the borrowing capacity to $150 million and supplements our existing $1 billion Credit Facility which expires in August 2011.

More information on our short-term debt as of December 31, 2008, which we consider one of our primary sources of liquidity, is presented in the following table:

In millions	Capacity	Outstanding
Credit Facilities	$1,140	$773
SouthStar line of credit	75	75
Sequent lines of credit	30	17
Total	$1,245	$865

We normally access the commercial paper markets to finance our working capital needs. However, during the third and fourth quarters of 2008, adverse developments in the global financial and credit markets, including the failure or merger between several large financial institutions, have made it more difficult for us to access the commercial paper market at reasonable rates. As a result, at times we relied upon our Credit Facilities for our liquidity and capital resource needs. At December 31, 2007, we had no outstanding credit line borrowings under the Credit Facilities and $566 million of commercial paper issuances.

Long-term Debt Our long-term debt matures more than one year from the balance sheet date and consists of medium-term notes, senior notes, gas facility revenue bonds, and capital leases. The following represents our long-term debt activity over the last three years.

Gas Facility Revenue Bonds

- In June 2008, we refinanced $122 million of our gas facility revenue bonds, $47 million due October 2022, $20 million due October 2024 and $55 million due June 2032. There was no change to the maturity dates of these bonds. The $55 million bond had an interest rate that resets daily and the $47 million and $20 million bonds had a 35-day auction period where the interest rate adjusted every 35 days. Both the bonds with principal amounts of $47 million and $55 million now have interest rates that reset daily and the bond with a principal amount of $20 million has an interest rate that resets weekly. The interest rates at December 31, 2008, ranged from 0.7% to 1.10%.
- In September 2008, we refinanced $39 million of our gas facility revenue bonds due June 2026.The bonds had a 35-day auction period where the interest rate adjusted every 35 days now they have interest rates that reset daily. The maturity date of these bonds remains June 2026. The interest rate at December 31, 2008, was 1.1%.

Senior notes

- In December 2007 and June 2006, AGL Capital issued $125 million and $175 million of 6.375% senior notes. The proceeds of the note issuances, equal to approximately $296 million, were used to pay down short-term indebtedness incurred under our commercial paper program.

Notes payable to Trusts

- In July 2007, we used the proceeds from the sale of commercial paper to pay AGL Capital Trust I the $75 million principal amount of 8.17% junior subordinated debentures plus a $3 million premium for early redemption of the junior subordinated debentures, and to pay a $2 million note representing our common securities interest in AGL Capital Trust I.
- In May 2006, we used the proceeds from the sale of commercial paper to pay AGL Capital

Trust II the $150 million of junior subordinated debentures and to pay a $5 million note representing our common securities interest in AGL Capital Trust II.

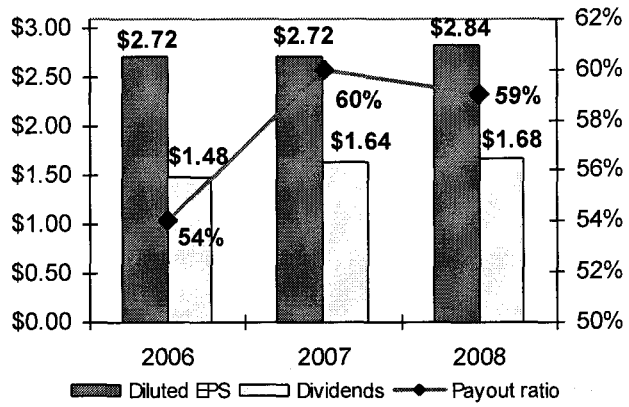
Medium-term notes

- In January 2007, we used proceeds from the sale of commercial paper to redeem $11 million of 7% medium-term notes previously scheduled to mature in January 2015.

Minority Interest A cash distribution of $30 million in 2008, $23 million in 2007 and $22 million in 2006 for SouthStar's dividend distributions to Piedmont were recorded in our consolidated statement of cash flows as a financing activity.

Dividends on Common Stock Our common stock dividend payments were $124 million in 2008, a $1 million increase from 2007. While our dividends per common share increased 2% in 2008 from $1.64 to $1.68 per common share; this was offset by fewer outstanding shares as a result of our share repurchase plans. The $12 million or 11% increase in common stock dividend payments in 2007 compared to 2006, resulted from our 11% increase in our common stock dividends per share from $1.48 to $1.64 per common share.

In 2008, our dividend payout ratio was 59%, which is consistent with our payout ratio of 60% in 2007. We expect that our dividend payout ratio will remain consistent with the dividend payout ratios of our peer companies, which is currently an average of 58% with an average dividend yield of 4.3%. Our diluted earnings per share and declared common stock dividends per share along with our dividend payout ratio for the last three years are presented in the following chart.



For information about restrictions on our ability to pay dividends on our common stock, see Note 5 "Common Shareholders' Equity."

Treasury Shares In March 2001 our Board of Directors approved the purchase of up to 600,000 shares of our common stock to be used for issuances under the Officer Incentive Plan. During 2008, we purchased 15,133 shares. As of December 31, 2008, we had purchased a total 312,367 shares, leaving 287,633 shares available for purchase.

In February 2006, our Board of Directors authorized a plan to purchase up to 8 million shares of our outstanding common stock over a five-year period. These purchases are intended principally to offset share issuances under our employee and non-employee director incentive compensation plans and our dividend reinvestment and stock purchase plans. Stock purchases under this program may be made in the open market or in private transactions at times and in amounts that we deem appropriate. There is no guarantee as to the exact number of shares that we will purchase, and we can terminate or limit the program at any time.

For the year ended December 31, 2008, we did not purchase shares of our common stock. During the same period in 2007, we purchased approximately 2 million shares of our common stock at a weighted average cost of $39.56 per share and an aggregate cost of $80 million. We hold the purchased shares as treasury shares. For more information on our share repurchases see Item 5 "Market for the Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities."

Shelf Registration In August 2007, we filed a new shelf registration with the SEC. The debt securities and related guarantees will be issued by AGL Capital under an indenture dated as of February 20, 2001, as supplemented and modified, as necessary, among AGL Capital, AGL Resources and The Bank of New York Trust Company, N.A., as trustee. The indenture provides for the issuance from time to time of debt securities in an unlimited dollar amount and an unlimited number of series subject to our Credit Facilities' financial covenants related to total debt to total capitalization. The debt securities will be guaranteed by AGL Resources.

Contractual Obligations and Commitments We have incurred various contractual obligations and financial commitments in the normal course of our operating and financing activities that are reasonably likely to have a material effect on liquidity or the availability of requirements for capital resources. Contractual obligations include future cash payments required under existing contractual arrangements, such as debt and lease agreements.

These obligations may result from both general financing activities and from commercial arrangements that are directly supported by related revenue-producing activities. Contingent financial commitments represent obligations that become payable only if certain predefined events occur, such as financial guarantees, and include the nature of the guarantee and the maximum potential amount of future payments that could be required of us as the guarantor. As we do for other subsidiaries, AGL Resources provides guarantees to certain gas suppliers for SouthStar in support of payment obligations. The following table illustrates our expected future contractual obligation payments such as debt and lease agreements, and commitments and contingencies as of December 31, 2008.

In millions	Total	2009	2010 & 2011	2012 & 2013	2014 & thereafter
Recorded contractual obligations:					
Long-term debt	$1,675	$-	$302	$242	$1,131
Short-term debt	866	866	-	-	-
PRP costs (1)	189	49	91	49	-
Environmental remediation liabilities (1)	106	17	41	38	10
Total	$2,836	$932	$434	$329	$1,141
Unrecorded contractual obligations and commitments (2)**:**					
Pipeline charges, storage capacity and gas supply (3)	$1,713	$491	$573	$299	$350
Interest charges (4)	975	94	168	137	576
Operating leases	137	30	45	25	37
Standby letters of credit, performance / surety bonds	52	48	3	1	-
Asset management agreements (5)	32	12	19	1	-
Pension contributions	7	7	-	-	-
Total	$2,916	$682	$808	$463	$963

(1) Includes charges recoverable through rate rider mechanisms.
(2) In accordance with GAAP, these items are not reflected in our consolidated balance sheets.
(3) Charges recoverable through a natural gas cost recovery mechanism or alternatively billed to Marketers, and includes demand charges associated with Sequent.
(4) Floating rate debt is based on the interest rate as of December 31, 2008, and the maturity of the underlying debt instrument. As of December 31, 2008, we have $35 million of accrued interest on our consolidated balance sheet that will be paid in 2009.
(5) Represent fixed-fee minimum payments for Sequent's affiliated asset management.

Pipeline Charges, Storage Capacity and Gas Supply Contracts. A subsidiary of NUI entered into two 20-year agreements for the firm transportation and storage of natural gas during 2003 with annual aggregate demand charges of approximately $5 million. As a result of our acquisition of NUI and in accordance with SFAS 141, we valued the contracts at fair value and established a long-term liability of $38 million for the excess liability that will be amortized to our consolidated statements of income over the remaining lives of the contracts of $2 million annually through November 2023 and $1 million annually from November 2023 to November 2028. The gas supply amount includes SouthStar gas commodity purchase commitments of 15 Bcf at floating gas prices calculated using forward natural gas prices as of December 31, 2008, and is valued at $85 million.

Operating leases. We have certain operating leases with provisions for step rent or escalation payments and certain lease concessions. We account for these leases by recognizing the future minimum lease payments on a straight-line basis over the respective minimum lease terms, in accordance with SFAS 13. However, this accounting treatment does not affect the future annual operating lease cash obligations as shown herein. We expect to fund these obligations with cash flow from operating and financing activities.

Standby letters of credit and performance / surety bonds. We also have incurred various financial commitments in the normal course of business. Contingent financial commitments represent obligations that become payable only if certain predefined events occur, such as financial guarantees, and include the nature of the guarantee and the maximum potential amount of future payments that could be required of us as the guarantor. We would expect to fund these contingent financial commitments with operating and financing cash flows.

Pension and Postretirement Obligations. Generally, our funding policy is to contribute annually an amount that will at least equal the minimum amount required to comply with the Employee Retirement Income Security Act of 1974. Additionally, we calculate any required pension contributions using the projected unit credit cost method. However, additional voluntary contributions are made from time to time as considered necessary. Contributions are

intended to provide not only for benefits attributed to service to date but also for those expected to be earned in the future. The contributions represent the portion of the postretirement costs we are responsible for under the terms of our plan and minimum funding required by state regulatory commissions.

The state regulatory commissions have phase-ins that defer a portion of the postretirement benefit expense for future recovery. We recorded a regulatory asset for these future recoveries of $11 million as of December 31, 2008 and $12 million as of December 31, 2007. In addition, we recorded a regulatory liability of $5 million as of December 31, 2008 and $4 million as of December 31, 2007 for our expected expenses under the AGL Postretirement Plan. See Note 3 "Employee Benefit Plans," for additional information about our pension and postretirement plans.

We were not required to make a minimum funding contribution to our pension plans during 2008. Based on the current funding status of the plans, we would be required to make a minimum contribution to the plans of approximately $7 million in 2009. We are planning to make additional contributions in 2009 up to $61 million, for a total of up to $68 million, in order to preserve the current level of benefits under the plans and in accordance with the funding requirements of the Pension Protection Act.

Critical Accounting Policies

The preparation of our financial statements requires us to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses and the related disclosures of contingent assets and liabilities. We base our estimates on historical experience and various other assumptions that we believe to be reasonable under the circumstances, and we evaluate our estimates on an ongoing basis. Our actual results may differ from our estimates. Each of the following critical accounting policies involves complex situations requiring a high degree of judgment either in the application and interpretation of existing literature or in the development of estimates that impact our financial statements.

Pipeline Replacement Program Liabilities Atlanta Gas Light was ordered by the Georgia Commission (through a joint stipulation and a subsequent settlement agreement between Atlanta Gas Light and the Georgia Commission staff) to undertake a PRP that would replace all bare steel and cast iron pipe in its system. Approximately 68 miles of cast iron and 420 miles of bare steel pipe still require replacement. If Atlanta Gas Light does not perform in accordance with the initial and amended PRP stipulation, it can be assessed certain nonperformance penalties. However to date, Atlanta Gas Light is in full compliance.

The stipulation also provides for recovery of all prudent costs incurred under the program, which Atlanta Gas Light has recorded as a regulatory asset. The regulatory asset has two components:

- the costs incurred to date that have not yet been recovered through rate riders
- the future expected costs to be recovered through rate riders

The determination of future expected costs associated with our PRP involves judgment. Factors that must be considered in estimating the future expected costs are projected capital expenditure spending, including labor and material costs, and the remaining infrastructure footage to be replaced for the remaining years of the program. We recorded a long-term liability of $140 million as of December 31, 2008 and $190 million as of December 31, 2007, which represented engineering estimates for remaining capital expenditure costs in the PRP. As of December 31, 2008, we had recorded a current liability of $49 million, representing expected PRP expenditures for the next 12 months. We report these estimates on an undiscounted basis. If Atlanta Gas Light's PRP expenditures, subject to future recovery, were $10 million higher or lower its incremental expected annual revenues would have changed by approximately $1 million.

Environmental Remediation Liabilities We historically reported estimates of future remediation costs based on probabilistic models of potential costs. We report these estimates on an undiscounted basis. As we continue to conduct the actual remediation and enter into cleanup contracts, we are increasingly able to provide conventional engineering estimates of the likely costs of many elements of the remediation program. These estimates contain various engineering uncertainties, and we continuously attempt to refine and update these engineering estimates.

Our latest available estimate as of December 31, 2008 for those elements of the remediation program with in-place contracts or engineering cost estimates is $12 million for Atlanta Gas Light's Georgia and Florida sites. This is a decrease of $3 million from the December 31, 2007 estimate of projected engineering and in-place contracts. For elements of the remediation program where Atlanta Gas Light still cannot perform engineering cost estimates, considerable variability remains in available estimates. The estimated remaining cost of future actions at these sites is $26 million, which includes less than $1 million in estimates of certain other

costs it pays related to administering the remediation program and remediation of sites currently in the investigation phase. Beyond 2010, these costs cannot be estimated. As of December 31, 2008, we have recorded a liability of $38 million.

Atlanta Gas Light's environmental remediation liability is included in its corresponding regulatory asset. Atlanta Gas Light's estimate does not include other potential expenses, such as unasserted property damage, personal injury or natural resource damage claims, unbudgeted legal expenses, or other costs for which it may be held liable but with respect to which the amount cannot be reasonably forecast. Atlanta Gas Light's recovery of environmental remediation costs is subject to review by the Georgia Commission, which may seek to disallow the recovery of some expenses.

In New Jersey, Elizabethtown Gas is currently conducting remediation activities with oversight from the New Jersey Department of Environmental Protection. Although the actual total cost of future environmental investigation and remediation efforts cannot be estimated with precision, the range of reasonably probable costs is $58 million to $116 million. As of December 31, 2008, we have recorded a liability of $58 million.

The New Jersey Commission has authorized Elizabethtown Gas to recover prudently incurred remediation costs for the New Jersey properties through its remediation adjustment clause. As a result, Elizabethtown Gas has recorded a regulatory asset of approximately $66 million, inclusive of interest, as of December 31, 2008, reflecting the future recovery of both incurred costs and future remediation liabilities in the state of New Jersey. Elizabethtown Gas has also been successful in recovering a portion of remediation costs incurred in New Jersey from its insurance carriers and continues to pursue additional recovery. As of December 31, 2008, the variation between the amounts of the environmental remediation cost liability recorded in the consolidated balance sheet and the associated regulatory asset is due to expenditures for environmental investigation and remediation exceeding recoveries from ratepayers and insurance carriers.

We also own remediation sites located outside of New Jersey. One site, in Elizabeth City, North Carolina, is subject to an order by the North Carolina Department of Environment and Natural Resources. Preliminary estimates for investigation and remediation costs range from $10 million to $20 million. As of December 31, 2008, we had recorded a liability of $10 million related to this site. There is one other site in North Carolina where investigation and remediation is probable, although no regulatory order exists and we do not believe costs associated with this site can be reasonably estimated. In addition, there are as many as six other sites with which we had some association, although no basis for liability has been asserted. We do not believe that costs to investigate and remediate these sites, if any, can be reasonably estimated at this time.

With respect to these costs, we currently pursue or intend to pursue recovery from ratepayers, former owners and operators and insurance carriers. While we have been successful in recovering a portion of these remediation costs from our insurance carriers, we are not able to express a belief as to the success of additional recovery efforts. We are working with the regulatory agencies to manage our remediation costs so as to mitigate the impact of such costs on both ratepayers and shareholders.

Derivatives and Hedging Activities SFAS 133, as updated by SFAS 149, established accounting and reporting standards which require that every derivative financial instrument (including certain derivative instruments embedded in other contracts) be recorded in the balance sheet as either an asset or liability measured at its fair value. However, if the derivative transaction qualifies for and is designated as a normal purchase and sale, it is exempted from the fair value accounting treatment of SFAS 133, as updated by SFAS 149, and is accounted for using traditional accrual accounting.

SFAS 133 requires that changes in the derivative's fair value be recognized currently in earnings unless specific hedge accounting criteria are met. If the derivatives meet those criteria, SFAS 133 allows a derivative's gains and losses to offset related results on the hedged item in the income statement in the case of a fair value hedge, or to record the gains and losses in OCI until the hedged transaction occurs in the case of a cash flow hedge. Additionally, SFAS 133 requires that a company formally designate a derivative as a hedge as well as document and assess the effectiveness of derivatives associated with transactions that receive hedge accounting treatment. SFAS 133 applies to treasury locks and interest rate swaps executed by AGL Capital and gas commodity contracts executed by Sequent and SouthStar. SFAS 133 also applies to gas commodity contracts executed by Elizabethtown Gas under a New Jersey Commission authorized hedging program that requires gains and losses on these derivatives are reflected in purchased gas costs and ultimately billed to customers. Our derivative and hedging activities are described in further detail in Note 2 "Financial Instruments and Risk Management" and Item 1 "Business."

Commodity-related Derivative Instruments We are exposed to risks associated with changes in the

market price of natural gas. Through Sequent and SouthStar, we use derivative instruments to reduce our exposure impact to our results of operations due to the risk of changes in the price of natural gas.

Sequent recognizes the change in value of a derivative instrument as an unrealized gain or loss in revenues in the period when the market value of the instrument changes. Sequent recognizes cash inflows and outflows associated with the settlement of its risk management activities in operating cash flows, and reports these settlements as receivables and payables in the balance sheet separately from the risk management activities reported as energy marketing receivables and trade payables.

We attempt to mitigate substantially all our commodity price risk associated with Sequent's natural gas storage portfolio and lock in the economic margin at the time we enter into purchase transactions for our stored natural gas. We purchase natural gas for storage when the current market price we pay plus storage costs is less than the market price we could receive in the future. We lock in the economic margin by selling NYMEX futures contracts or other OTC derivatives in the forward months corresponding with our withdrawal periods. We use contracts to sell natural gas at that future price to lock in the operating revenues we will ultimately realize when the stored natural gas is actually sold. These contracts meet the definition of a derivative under SFAS 133.

The purchase, storage and sale of natural gas are accounted for differently from the derivatives we use to mitigate the commodity price risk associated with our storage portfolio. That difference in accounting can result in volatility in our reported operating margin, even though the economic margin is essentially unchanged from the date we entered into the transactions. We do not currently use hedge accounting under SFAS 133 to account for this activity.

Natural gas that we purchase and inject into storage is accounted for at the lower of weighted average cost or market value. Under current accounting guidance, we recognize a loss in any period when the market price for natural gas is lower than the carrying amount of our purchased natural gas inventory. Costs to store the natural gas are recognized in the period the costs are incurred. We recognize revenues and cost of natural gas sold in our statement of consolidated income in the period we sell gas and it is delivered out of the storage facility.

The derivatives we use to mitigate commodity price risk and substantially lock in the operating margin upon the sale of stored natural gas are accounted for at fair value and marked to market each period, with changes in fair value recognized as unrealized gains or losses in the period of change. This difference in accounting - the lower of weighted average cost or market basis for our storage inventory versus the fair value accounting for the derivatives used to mitigate commodity price risk - can and does result in volatility in our reported earnings.

Over time, gains or losses on the sale of storage inventory will be substantially offset by losses or gains on the derivatives, resulting in realization of the economic profit margin we expected when we entered into the transactions. This accounting difference causes Sequent's earnings on its storage positions to be affected by natural gas price changes, even though the economic profits remain essentially unchanged.

SouthStar also uses derivative instruments to manage exposures arising from changing commodity prices. SouthStar's objective for holding these derivatives is to minimize volatility in wholesale commodity natural gas prices. A portion of SouthStar's derivative transactions are designated as cash flow hedges under SFAS 133. Derivative gains or losses arising from cash flow hedges are recorded in OCI and are reclassified into earnings in the same period the underlying hedged item is reflected in the income statement. As of December 31, 2008, the ending balance in OCI for derivative transactions designated as cash flow hedges under SFAS 133 was a loss of $6 million, net of minority interest and taxes. Any hedge ineffectiveness, defined as when the gains or losses on the hedging instrument do not offset the losses or gains on the hedged item, is recorded into earnings in the period in which it occurs. SouthStar currently has minimal hedge ineffectiveness. SouthStar's remaining derivative instruments are not designated as hedges under SFAS 133. Therefore, changes in their fair value are recorded in earnings in the period of change.

SouthStar also enters into weather derivative instruments in order to stabilize operating margins in the event of warmer-than-normal and colder-than-normal weather in the winter months. These contracts are accounted for using the intrinsic value method under the guidance of EITF 99-02. Changes in the intrinsic value of these derivatives are recorded in earnings in the period of change. The weather derivative contracts contain strike amount provisions based on cumulative heating degree days for the covered periods. In 2008 and 2007, SouthStar entered into weather derivatives (swaps and options) for the respective winter heating seasons, primarily from November through March. As of December 31, 2008, SouthStar recorded a current asset of $4 million for this hedging activity.

Contingencies Our accounting policies for contingencies cover a variety of business activities, including contingencies for potentially uncollectible receivables, rate matters, and legal and environmental exposures. We accrue for these contingencies when our assessments indicate that it is probable that a liability has been incurred or an asset will not be recovered, and an amount can be reasonably estimated in accordance with SFAS 5. We base our estimates for these liabilities on currently available facts and our estimates of the ultimate outcome or resolution of the liability in the future. Actual results may differ from estimates, and estimates can be, and often are, revised either negatively or positively, depending on actual outcomes or changes in the facts or expectations surrounding each potential exposure.

Pension and Other Postretirement Plans Our pension and other postretirement plan costs and liabilities are determined on an actuarial basis and are affected by numerous assumptions and estimates including the market value of plan assets, estimates of the expected return on plan assets, assumed discount rates and current demographic and actuarial mortality data. We annually review the estimates and assumptions underlying our pension and other postretirement plan costs and liabilities. The assumed discount rate and the expected return on plan assets are the assumptions that generally have the most significant impact on our pension costs and liabilities. The assumed discount rate, the assumed health care cost trend rate and the assumed rates of retirement generally have the most significant impact on our postretirement plan costs and liabilities.

Our total pension and other benefit costs remained relatively unchanged during the current-year period when compared with the prior-year period as the assumptions we made during our annual pension plan valuation were consistent with the prior year. The discount rate used to compute the present value of a plan's liabilities generally is based on rates of high-grade corporate bonds with maturities similar to the average period over which the benefits will be paid. Our expected return on our pension plan assets remained constant at 9%.

The discount rate is used principally to calculate the actuarial present value of our pension and postretirement obligations and net pension and postretirement cost. When establishing our discount rate which we have determined to be 6.2% at December 31, 2008, we consider high quality corporate bond rates based on Moody's Corporate AA long-term bond rate of 5.62% and the Citigroup Pension Liability rate of 5.87% at December 31, 2008. We further use these market indices as a comparison to a single equivalent discount rate derived with the assistance of our actuarial advisors. This analysis as of December 31, 2008 produced a single equivalent discount rate of 6.2%.

The actuarial assumptions used may differ materially from actual results due to changing market and economic conditions, higher or lower withdrawal rates, or longer or shorter life spans of participants. These differences may result in a significant impact on the amount of pension expense recorded in future periods.

The expected long-term rate of return on assets is used to calculate the expected return on plan assets component of our annual pension and postretirement plan cost. We estimate the expected return on plan assets by evaluating expected bond returns, equity risk premiums, asset allocations, the effects of active plan management, the impact of periodic plan asset rebalancing and historical performance. We also consider guidance from our investment advisors in making a final determination of our expected rate of return on assets. To the extent the actual rate of return on assets realized over the course of a year is greater than or less than the assumed rate, that year's annual pension or postretirement plan cost is not affected. Rather, this gain or loss reduces or increases future pension or postretirement plan costs.

Our postretirement plans have been capped at 2.5% for increases in health care costs. Consequently, a one-percentage-point increase or decrease in the assumed health care trend rate does not materially affect the periodic benefit cost for our postretirement plans. A one percentage-point increase in the assumed health care cost trend rate would increase our accumulated projected benefit obligation by $4 million. A one percentage-point decrease in the assumed health care cost trend rate would decrease our accumulated projected benefit obligation by $3 million. Our assumed rate of retirement is estimated based upon an annual review of participant census information as of the measurement date.

At December 31, 2008, our pension and postretirement liability increased by approximately $178 million, primarily resulting from an after-tax loss to OCI of $111 million ($184 million before tax) offset by $5 million in benefit payments that we funded and $1 million in net pension and postretirement benefit credits we recorded in 2008. These changes reflect our funding contributions to the plan, benefit payments out of the plans, and updated valuations for the projected benefit obligation (PBO) and plan assets.

Equity market performance and corporate bond rates have a significant effect on our reported unfunded

accumulated benefit obligation (ABO), as the primary factors that drive the value of our unfunded ABO are the assumed discount rate and the actual return on plan assets. Additionally, equity market performance has a significant effect on our market-related value of plan assets (MRVPA), which is a calculated value and differs from the actual market value of plan assets. The MRVPA recognizes differences between the actual market value and expected market value of our plan assets and is determined by our actuaries using a five-year moving weighted average methodology. Gains and losses on plan assets are spread through the MRVPA based on the five-year moving weighted average methodology, which affects the expected return on plan assets component of pension expense.

See "Note 3, Employee Benefit Plans," for additional information on our pension and postretirement plans, which includes our investment policies and strategies, target allocation ranges and weighted average asset allocations for 2008 and 2007.

The actual return on our pension plan assets compared to the expected return on plan assets of 8.75% will have an impact on our ABO as of December 31, 2009 and our pension expense for 2009. We are unable to determine how this actual return on plan assets will affect future ABO and pension expense, as actuarial assumptions and differences between actual and expected returns on plan assets are determined at the time we complete our actuarial evaluation as of December 31, 2009. Our actual returns may also be positively or negatively impacted as a result of future performance in the equity and bond markets. The following tables illustrate the effect of changing the critical actuarial assumptions, as discussed previously, while holding all other assumptions constant.

AGL Resources Inc. Retirement and Postretirement Plans

In millions

Actuarial assumptions	Percentage-point change in assumption	Increase (decrease) in ABO	Increase (decrease) in cost
Expected long-term return on plan assets	+/- 1%	$- / -	$(3) / 3
Discount rate	+/- 1%	(41) / 46	(4) / 4

NUI Corporation Retirement Plan

In millions

Actuarial assumptions	Percentage-point change in assumption	Increase (decrease) in ABO	Increase (decrease) in cost
Expected long-term return on plan assets	+/- 1%	$- / -	$(1) / 1
Discount rate	+/- 1%	(6) / 7	- / (-)

Differences between actuarial assumptions and actual plan results are deferred and amortized into cost when the accumulated differences exceed 10% of the greater of the PBO or the MRVPA. If necessary, the excess is amortized over the average remaining service period of active employees.

In addition to the assumptions listed above, the measurement of the plans' obligations and costs depend on other factors such as employee demographics, the level of contributions made to the plans, earnings on the plans' assets and mortality rates. Consequently, based on these factors as well as a discount rate of 6.2%, an expected return on plan assets of 8.75% and our expectations with respect to plan contributions, we expect net periodic pension and other postretirement benefit costs to be in the range of $10 million to $12 million in 2009, an $11 million to $13 million increase relative to 2008.

Income Taxes We account for income taxes in accordance with SFAS 109 and FIN 48 which require that deferred tax assets and liabilities be recognized using enacted tax rates for the effect of temporary differences between the book and tax basis of recorded assets and liabilities. SFAS 109 and FIN 48 also requires that deferred tax assets be reduced by a valuation if it is more likely than not that some portion or all of the deferred tax asset will not be realized. We adopted the provisions of FIN 48 on January 1, 2007. At the date of adoption, as of December 31, 2007 and as of December 31, 2008, we did not have a liability for unrecognized tax benefits.

Our net long-term deferred tax liability totaled $646 million at December 31, 2008 (see Note 8 "Income Taxes"). This liability is estimated based on the expected future tax consequences of items recognized in the financial statements. After application of the federal statutory tax rate to book income, judgment is required with respect to the timing and deductibility of expense in our income tax returns. For state income tax and other taxes, judgment is also required with respect to the apportionment among the various jurisdictions. A valuation allowance is recorded if we expect that it is more likely than not that our deferred tax assets will not be realized. We had a $3 million valuation allowance on $104 million of deferred tax assets as of December 31, 2008, reflecting the expectation that most of these assets will be realized. In addition, we operate within multiple taxing jurisdictions and we are subject to audit in these jurisdictions. These audits can involve complex issues, which may require an extended period of time to resolve. We maintain a liability for the estimate of potential income tax exposure and in our opinion adequate provisions for income taxes have been made for all years.

Accounting Developments

Previously discussed

SFAS 160 In December 2007, the FASB issued SFAS 160, which is effective for fiscal years beginning after December 15, 2008. SFAS 160 will require us to present our minority interest, to be referred to as a noncontrolling interest, separately within the capitalization section of our consolidated balance sheet. We will adopt SFAS 160 as of January 1, 2009.

Recently issued

SFAS 161 In March 2008, the FASB issued SFAS 161, which is effective for fiscal years beginning after November 15, 2008. SFAS 161 amends the disclosure requirements of SFAS 133 to provide an enhanced understanding of how and why derivative instruments are used, how they are accounted for and their effect on an entity's financial condition, performance and cash flows. We will adopt SFAS 161 on January 1, 2009 which will require additional disclosures, but will not have a financial impact to our consolidated results of operations, cash flows or financial condition.

FSP EITF 03-6-1 The FASB issued this FSP in June 2008 and it is effective for fiscal years beginning after December 15, 2008. This FSP classifies unvested share-based payment grants containing nonforfeitable rights to dividends as participating securities that will be included in the computation of earnings per share. As of December 31, 2008, we had approximately 145,000 restricted shares with nonforfeitable dividend rights. We will adopt FSP EITF 03-6-1 effective on January 1, 2009.

FSP FAS 133-1 The FASB issued this FSP in September 2008 and it is effective for fiscal years beginning after November 15, 2008. This FSP requires more detailed disclosures about credit derivatives, including the potential adverse effects of changes in credit risk on the financial position, financial performance and cash flows of the sellers of the instruments. This FSP will have no financial impact to our consolidated results of operations, cash flows or financial condition. We will adopt FSP FAS 133-1 effective on January 1, 2009.

FSP FAS 157-3 The FASB issued this FSP in October 2008 and it is effective upon issuance including prior periods for which financial statements have not been issued. This FSP clarifies the application of SFAS 157 in an inactive market, including; how internal assumptions should be considered when measuring fair value, how observable market information in a market that is not active should be considered and how the use of market quotes should be used when assessing observable and unobservable data. We adopted this FSP as of September 30, 2008, which had no financial impact to our consolidated results of operations, cash flows or financial condition.

FSP FAS 140-4 and FIN 46R-8 The FASB issued this FSP in December 2008 and it is effective for the first reporting period ending after December 15, 2008. This FSP requires additional disclosures related to variable interest entities in accordance with SFAS 140 and FIN 46R. These disclosures include significant judgments and assumptions, restrictions on assets, risks and the affects on financial position, financial performance and cash flows. We adopted this FSP as of December 31, 2008, which had no financial impact to our consolidated results of operations, cash flows or financial condition.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

We are exposed to risks associated with commodity prices, interest rates and credit. Commodity price risk is defined as the potential loss that we may incur as a result of changes in the fair value of natural gas. Interest rate risk results from our portfolio of debt and equity instruments that we issue to provide financing and liquidity for our business. Credit risk results from the extension of credit throughout all aspects of our business but is particularly concentrated at Atlanta Gas Light in distribution operations and in wholesale services.

Our Risk Management Committee (RMC) is responsible for establishing the overall risk management policies and monitoring compliance with, and adherence to, the terms within these policies, including approval and authorization levels and delegation of these levels. Our RMC consists of members of senior management who monitor open commodity price risk positions and other types of risk, corporate exposures, credit exposures and overall results of our risk management activities. It is chaired by our chief risk officer, who is responsible for ensuring that appropriate reporting mechanisms exist for the RMC to perform its monitoring functions. Our risk management activities and related accounting treatments are described in further detail in Note 2, Financial Instruments and Risk Management.

Commodity Price Risk

Retail Energy Operations SouthStar's use of derivatives is governed by a risk management policy, approved and monitored by its Risk and Asset Management Committee, which prohibits the use of derivatives for speculative purposes.

Energy Marketing and Risk Management Activities
SouthStar generates operating margin from the active management of storage positions through a variety of hedging transactions and derivative instruments aimed at managing exposures arising from changing commodity prices. SouthStar uses these hedging instruments to lock in economic margins (as spreads between wholesale and retail commodity prices widen between periods) and thereby minimize its exposure to declining operating margins.

We have designated a portion of SouthStar's derivative transactions as cash flow hedges in accordance with SFAS 133. We record derivative gains or losses arising from cash flow hedges in OCI and reclassify them into earnings as cost of gas in our consolidated statement of income in the same period as the underlying hedged transaction occurs and is recorded in earnings. We record any hedge ineffectiveness, defined as when the gains or losses on the hedging instrument do not offset and are greater than the losses or gains on the hedged item, in cost of gas in our consolidated statement of income in the period in which the ineffectiveness occurs. SouthStar currently has minimal hedge ineffectiveness. We have not designated the remainder of SouthStar's derivative instruments as hedges under SFAS 133 and, accordingly, we record changes in their fair value in earnings as cost of gas in our consolidated statements of income in the period of change.

SouthStar recorded a net unrealized loss related to changes in the fair value of derivative instruments utilized in its energy marketing and risk management activities of $27 million during 2008 and $7 million during 2007, and net unrealized gains of $14 million during 2006. The following tables illustrate the change in the net fair value of the derivative instruments and energy-trading contracts during 2008, 2007 and 2006 and provide details of the net fair value of contracts outstanding as of December 31, 2008, 2007 and 2006.

In millions	**2008**	**2007**	**2006**
Net fair value of contracts outstanding at beginning of period	$10	$17	$3
Contracts realized or otherwise settled during period	(10)	(16)	(3)
Change in net fair value of contracts	(17)	9	17
Net fair value of contracts outstanding at end of period	(17)	10	17
Netting of cash collateral	31	3	(5)
Cash collateral and net fair value of contracts outstanding at end of period	$14	$13	$12

The sources of SouthStar's net fair value at December 31, 2008, are as follows.

In millions	**Prices actively quoted** (1)	**Prices provided by other external sources** (2)
Mature through 2009	$(24)	$2
Mature through 2010	5	-
Total net fair value	$(19)	$2

(1) Valued using NYMEX futures prices.
(2) Values primarily related to weather derivative transactions that are valued on an intrinsic basis in accordance with EITF 99-02 as based on heating degree days. Additionally, includes values associated with basis transactions that represent the commodity from a NYMEX delivery point to the contract delivery point. These transactions are based on quotes obtained either through electronic trading platforms or directly from brokers.

SouthStar routinely utilizes various types of financial and other instruments to mitigate certain commodity price and weather risks inherent in the natural gas industry. These instruments include a variety of exchange-traded and OTC energy contracts, such as forward contracts, futures contracts, options contracts and swap agreements. The following table includes the cash collateral fair values and average values of SouthStar's energy marketing and risk management assets and liabilities as of December 31, 2008 and 2007. SouthStar bases the average values on monthly averages for the 12 months ended December 31, 2008 and 2007.

	Average values at December 31,	
In millions	**2008**	**2007**
Asset	$17	$11
Liability	12	4

	Cash collateral and fair values at December 31,	
In millions	**2008**	**2007**
Asset	$16	$13
Liability	2	-

Value-at-risk A 95% confidence interval is used to evaluate VaR exposure. A 95% confidence interval means there is a 5% confidence that the actual loss in portfolio value will be greater than the calculated VaR value over the holding period. We calculate VaR based on the variance-covariance technique. This technique requires several assumptions for the basis of the calculation, such as price distribution, price volatility, confidence interval and holding period. Our VaR may not be comparable to a similarly titled measure of another company because, although VaR is a common metric in the energy industry, there is no established industry standard for calculating VaR or for the assumptions underlying such calculations. SouthStar's portfolio of positions for 2008 and 2007, had annual average 1-day holding period VaRs of less than $100,000, and its high, low

and period end 1-day holding period VaR were immaterial.

Wholesale Services Sequent routinely uses various types of financial and other instruments to mitigate certain commodity price risks inherent in the natural gas industry. These instruments include a variety of exchange-traded and OTC energy contracts, such as forward contracts, futures contracts, options contracts and financial swap agreements.

Energy Marketing and Risk Management Activities We account for derivative transactions in connection with Sequent's energy marketing activities on a fair value basis in accordance with SFAS 133. We record derivative energy commodity contracts (including both physical transactions and financial instruments) at fair value, with unrealized gains or losses from changes in fair value reflected in our earnings in the period of change.

Sequent's energy-trading contracts are recorded on an accrual basis as required under the EITF 02-03 rescission of EITF 98-10, unless they are derivatives that must be recorded at fair value under SFAS 133.

The changes in fair value of Sequent's derivative instruments utilized in its energy marketing and risk management activities and contract settlements increased the net fair value of its contracts outstanding by $25 million during 2008, reduced net fair value by $62 million during 2007 and increased net fair value by $132 million during 2006. The following tables illustrate the change in the net fair value of Sequent's derivative instruments during 2008, 2007 and 2006 and provide details of the net fair value of contracts outstanding as of December 31, 2008, 2007 and 2006.

In millions	**2008**	**2007**	**2006**
Net fair value of contracts outstanding at beginning of period	$57	$119	$(13)
Contracts realized or otherwise settled during period	(49)	(102)	17
Change in net fair value of contracts	74	40	115
Net fair value of contracts outstanding at end of period	82	57	119
Netting of cash collateral	97	(9)	(19)
Cash collateral and net fair value of contracts outstanding at end of period	$179	$48	$100

The sources of Sequent's net fair value at December 31, 2008, are as follows.

In millions	**Prices actively quoted** (1)	**Prices provided by other external sources** (2)
Mature through 2009	$(26)	$100
Mature 2010 – 2011	(19)	21
Mature 2012 - 2014	-	6
Total net fair value	$(45)	$127

(1) Valued using NYMEX futures prices.
(2) Valued using basis transactions that represent the cost to transport the commodity from a NYMEX delivery point to the contract delivery point. These transactions are based on quotes obtained either through electronic trading platforms or directly from brokers.

The following tables include the cash collateral fair values and average values of Sequent's energy marketing and risk management assets and liabilities as of December 31, 2008 and 2007. Sequent bases the average values on monthly averages for the 12 months ended December 31, 2008 and 2007.

	Average values at December 31,	
In millions	**2008**	**2007**
Asset	$96	$63
Liability	45	16

	Cash collateral and fair values at December 31,	
In millions	**2008**	**2007**
Asset	$206	$61
Liability	27	13

Value-at-risk Sequent employs a systematic approach to evaluating and managing the risks associated with contracts related to wholesale marketing and risk management, including VaR. Similar to SouthStar, Sequent uses a 1-day holding period and a 95% confidence interval to evaluate its VaR exposure.

Sequent's open exposure is managed in accordance with established policies that limit market risk and require daily reporting of potential financial exposure to senior management, including the chief risk officer. Because Sequent generally manages physical gas assets and economically protects its positions by hedging in the futures and OTC markets, its open exposure is generally minimal, permitting Sequent to operate within relatively low VaR limits. Sequent employs daily risk testing, using both VaR and stress testing, to evaluate the risks of its open positions.

Sequent's management actively monitors open commodity positions and the resulting VaR. Sequent continues to maintain a relatively matched book, where its total buy volume is close to its sell volume, with minimal open commodity risk. Based on a 95% confidence interval and employing a 1-day holding period for all positions, Sequent's portfolio of positions for the 12 months ended December 31,

2008, 2007 and 2006 had the following 1-day holding period VaRs.

In millions	**2008**	**2007**	**2006**
Period end	$2.5	$1.2	$1.3
12-month average	1.8	1.3	1.2
High	3.1	2.3	2.5
Low	0.8	0.7	0.7

Interest Rate Risk

Interest rate fluctuations expose our variable-rate debt to changes in interest expense and cash flows. We manage interest expense using a combination of fixed-rate and variable-rate debt. Based on $1,026 million of variable-rate debt, which includes $865 million of our variable-rate short-term debt and $161 million of variable-rate gas facility revenue bonds outstanding at December 31, 2008, a 100 basis point change in market interest rates from 1.2% to 2.2% would have resulted in an increase in pretax interest expense of $10 million on an annualized basis.

At the beginning of 2008, we had a notional principal amount of $100 million of interest rate swap agreements associated with our senior notes. In March 2008, we terminated these interest rate swap agreements. We received a payment of $2 million, which included accrued interest and the fair value of the interest rate swap agreements at the termination date which was recorded as a liability in our condensed consolidated balance sheets and will be amortized through January 2011, which is the remaining life of the associated senior notes.

Credit Risk

Distribution Operations Atlanta Gas Light has a concentration of credit risk as it bills only 11 Marketers in Georgia for its services. The credit risk exposure to Marketers varies with the time of the year, with exposure at its lowest in the nonpeak summer months and highest in the peak winter months. Marketers are responsible for the retail sale of natural gas to end-use customers in Georgia. These retail functions include customer service, billing, collections, and the purchase and sale of the natural gas commodity. The provisions of Atlanta Gas Light's tariff allow Atlanta Gas Light to obtain security support in an amount equal to a minimum of two times a Marketer's highest month's estimated bill from Atlanta Gas Light. For 2008, the four largest Marketers based on customer count, one of which was SouthStar, accounted for approximately 31% of our consolidated operating margin and 43% of distribution operations' operating margin.

Several factors are designed to mitigate our risks from the increased concentration of credit that has resulted from deregulation. In addition to the security support described above, Atlanta Gas Light bills intrastate delivery service to Marketers in advance rather than in arrears. We accept credit support in the form of cash deposits, letters of credit/surety bonds from acceptable issuers and corporate guarantees from investment-grade entities. The RMC reviews on a monthly basis the adequacy of credit support coverage, credit rating profiles of credit support providers and payment status of each Marketer. We believe that adequate policies and procedures have been put in place to properly quantify, manage and report on Atlanta Gas Light's credit risk exposure to Marketers.

Atlanta Gas Light also faces potential credit risk in connection with assignments of interstate pipeline transportation and storage capacity to Marketers. Although Atlanta Gas Light assigns this capacity to Marketers, in the event that a Marketer fails to pay the interstate pipelines for the capacity, the interstate pipelines would in all likelihood seek repayment from Atlanta Gas Light.

Retail Energy Operations SouthStar obtains credit scores for its firm residential and small commercial customers using a national credit reporting agency, enrolling only those customers that meet or exceed SouthStar's credit threshold.

SouthStar considers potential interruptible and large commercial customers based on a review of publicly available financial statements and review of commercially available credit reports. Prior to entering into a physical transaction, SouthStar also assigns physical wholesale counterparties an internal credit rating and credit limit based on the counterparties' Moody's, S&P and Fitch ratings, commercially available credit reports and audited financial statements.

Wholesale Services Sequent has established credit policies to determine and monitor the creditworthiness of counterparties, as well as the quality of pledged collateral. Sequent also utilizes master netting agreements whenever possible to mitigate exposure to counterparty credit risk. When Sequent is engaged in more than one outstanding derivative transaction with the same counterparty and it also has a legally enforceable netting agreement with that counterparty, the "net" mark-to-market exposure represents the netting of the positive and negative exposures with that counterparty and a reasonable measure of Sequent's credit risk. Sequent also uses other netting agreements with certain counterparties with whom it conducts significant transactions.

Master netting agreements enable Sequent to net certain assets and liabilities by counterparty. Sequent also nets across product lines and against cash collateral provided the master netting and cash

collateral agreements include such provisions. Additionally, Sequent may require counterparties to pledge additional collateral when deemed necessary.

Sequent conducts credit evaluations and obtains appropriate internal approvals for its counterparty's line of credit before any transaction with the counterparty is executed. In most cases, the counterparty must have a minimum long-term debt rating of Baa3 from Moody's and BBB- from S&P. Generally, Sequent requires credit enhancements by way of guaranty, cash deposit or letter of credit for transaction counterparties that do not meet the minimum ratings threshold.

Sequent, which provides services to retail marketers and utility and industrial customers, also has a concentration of credit risk as measured by its 30-day receivable exposure plus forward exposure. As of December 31, 2008, Sequent's top 20 counterparties represented approximately 63% of the total counterparty exposure of $505 million.

As of December 31, 2008, Sequent's counterparties, or the counterparties' guarantors, had a weighted average S&P equivalent credit rating of A-, which is consistent with the prior year. The S&P equivalent credit rating is determined by a process of converting the lower of the S&P or Moody's ratings to an internal rating ranging from 9 to 1, with 9 being equivalent to AAA/Aaa by S&P and Moody's and 1 being D or Default by S&P and Moody's. A counterparty that does not have an external rating is assigned an internal rating based on the strength of the financial ratios of that counterparty. To arrive at the weighted average credit rating, each counterparty's assigned internal rating is multiplied by the counterparty's credit exposure and summed for all counterparties. That sum is divided by the aggregate total counterparties' exposures, and this numeric value is then converted to an S&P equivalent. The following table shows Sequent's commodity receivable and payable positions.

	As of Dec. 31, Gross receivables	
In millions	**2008**	**2007**
Netting agreements in place:		
Counterparty is investment grade	$398	$437
Counterparty is non-investment grade	15	24
Counterparty has no external rating	129	134
No netting agreements in place:		
Counterparty is investment grade	7	3
Amount recorded on balance sheet	$549	$598

	As of Dec. 31, Gross payables	
In millions	**2008**	**2007**
Netting agreements in place:		
Counterparty is investment grade	$266	$356
Counterparty is non-investment grade	41	18
Counterparty has no external rating	228	204
No netting agreements in place:		
Counterparty is investment grade	4	-
Amount recorded on balance sheet	$539	$578

Sequent has certain trade and credit contracts that have explicit minimum credit rating requirements. These credit rating requirements typically give counterparties the right to suspend or terminate credit if our credit ratings are downgraded to non-investment grade status. Under such circumstances, Sequent would need to post collateral to continue transacting business with some of its counterparties. Posting collateral would have a negative effect on our liquidity. If such collateral were not posted, Sequent's ability to continue transacting business with these counterparties would be impaired. If at December 31, 2008, Sequent's credit ratings had been downgraded to non-investment grade status, the required amounts to satisfy potential collateral demands under such agreements between Sequent and its counterparties would have totaled $12 million.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders of AGL Resources Inc.:

In our opinion, the consolidated financial statements listed in the index appearing under item 15(a)(1) present fairly, in all material respects, the financial position of AGL Resources Inc. and its subsidiaries at December 31, 2008 and 2007, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2008 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statements schedule listed in the accompanying index appearing under Item 15(a)(2) presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2008, based on criteria established in *Internal Control - Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements and financial statement schedule, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in Management's Report on Internal Control Over Financial Reporting appearing under Item 9A. Our responsibility is to express opinions on these financial statements, on the financial statements schedule, and on the Company's internal control over financial reporting bases on our integrated audits. We conducted our audits in accordance with the standards of Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included 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. Our audit of internal control over financial reporting included obtaining and understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

As discussed in Notes 4 and 3, respectively, to the consolidated financial statements, AGL Resources Inc. and subsidiaries changed its method of accounting for stock based compensation plans as of January 1, 2006 and its method of accounting for defined benefit pension and other postretirement plans as of December 31, 2006.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ PricewaterhouseCoopers LLP

PricewaterhouseCoopers LLP
Atlanta, Georgia
February 5, 2009

Management's Report on Internal Control Over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, we conducted an evaluation of the effectiveness of our internal control over financial reporting based on the framework in *Internal Control - Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Based on our evaluation under the framework in Internal Control – Integrated Framework issued by COSO, our management concluded that our internal control over financial reporting was effective as of December 31, 2008, in providing reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

February 5, 2009

/s/ John W Somerhalder II
John W. Somerhalder II
Chairman, President and Chief Executive Officer

/s/ Andrew W. Evans
Andrew W. Evans
Executive Vice President and Chief Financial Officer

AGL Resources Inc.
Consolidated Balance Sheets - Assets

In millions	As of December 31, 2008	December 31, 2007
Current assets		
Cash and cash equivalents	$16	$19
Receivables		
Energy marketing	549	598
Gas	264	213
Unbilled revenues	181	179
Other	27	13
Less allowance for uncollectible accounts	(16)	(14)
Total receivables	1,005	989
Inventories		
Natural gas stored underground	629	521
Other	34	30
Total inventories	663	551
Energy marketing and risk management assets	207	69
Unrecovered PRP costs – current portion	41	31
Unrecovered ERC – current portion	18	23
Other current assets	92	115
Total current assets	2,042	1,797
Property, plant and equipment		
Property, plant and equipment	5,500	5,177
Less accumulated depreciation	1,684	1,611
Property, plant and equipment – net	3,816	3,566
Deferred debits and other assets		
Goodwill	418	420
Unrecovered PRP costs	196	254
Unrecovered ERC	125	135
Other	113	86
Total deferred debits and other assets	852	895
Total assets	$6,710	$6,258

See Notes to Consolidated Financial Statements.

AGL Resources Inc.
Consolidated Balance Sheets - Liabilities and Capitalization

In millions, except share amounts	As of December 31, 2008	As of December 31, 2007
Current liabilities		
Short-term debt	$866	$580
Energy marketing trade payable	539	578
Accounts payable – trade	202	172
Customer deposits	50	35
Accrued PRP costs – current portion	49	55
Energy marketing and risk management liabilities – current portion	50	16
Accrued wages and salaries	42	24
Accrued taxes	36	23
Accrued interest	35	39
Deferred natural gas costs	25	28
Accrued environmental remediation liabilities – current portion	17	10
Other current liabilities	72	74
Total current liabilities	1,983	1,634
Accumulated deferred income taxes	571	566
Long-term liabilities and other deferred credits (excluding long-term debt)		
Accrued pension obligations	199	43
Accumulated removal costs	178	169
Accrued PRP costs	140	190
Accrued environmental remediation liabilities	89	97
Accrued postretirement benefit costs	46	24
Other long-term liabilities and other deferred credits	145	152
Total long-term liabilities and other deferred credits (excluding long-term debt)	797	675
Commitments and contingencies (see Note 7)		
Minority interest	32	47
Capitalization		
Long-term debt	1,675	1,675
Common shareholders' equity, $5 par value; 750 million shares authorized; 76.9 million and 76.4 million shares outstanding at December 31, 2008 and 2007	1,652	1,661
Total capitalization	3,327	3,336
Total liabilities and capitalization	$6,710	$6,258

See Notes to Consolidated Financial Statements.

AGL Resources Inc.
Statements of Consolidated Income

In millions, except per share amounts	Years ended December 31, 2008	2007	2006
Operating revenues	$2,800	$2,494	$2,621
Operating expenses			
Cost of gas	1,654	1,369	1,482
Operation and maintenance	472	451	473
Depreciation and amortization	152	144	138
Taxes other than income taxes	44	41	40
Total operating expenses	2,322	2,005	2,133
Operating income	478	489	488
Other income (expenses)	6	4	(1)
Minority interest	(20)	(30)	(23)
Interest expense, net	(115)	(125)	(123)
Earnings before income taxes	349	338	341
Income taxes	132	127	129
Net income	$217	$211	$212
Per common share data			
Basic earnings per common share	$2.85	$2.74	$2.73
Diluted earnings per common share	$2.84	$2.72	$2.72
Cash dividends declared per common share	$1.68	$1.64	$1.48
Weighted average number of common shares outstanding			
Basic	76.3	77.1	77.6
Diluted	76.6	77.4	78.0

See Notes to Consolidated Financial Statements.

AGL Resources Inc.
Statements of Consolidated Common Shareholders' Equity

In millions, except per share amounts	Common stock Shares	Common stock Amount	Premium on common stock	Earnings reinvested	Other comprehensive loss	Shares held in treasury and trust	Total
Balance as of December 31, 2005	77.8	$389	$655	$508	$(53)	$-	$1,499
Comprehensive income:							
Net income	-	-	-	212	-	-	212
OCI - gain resulting from unfunded pension and postretirement obligation (net of tax of $7)	-	-	-	-	11	-	11
Unrealized gain from hedging activities (net of tax of $7)	-	-	-	-	10	-	10
Total comprehensive income							233
Dividends on common stock ($1.48 per share)	-	-	1	(115)	-	3	(111)
Benefit, stock compensation, dividend reinvestment and stock purchase plans	0.3	1	2	-	-	-	3
Issuance of treasury shares	0.6	-	(3)	(4)	-	21	14
Purchase of treasury shares	(1.0)	-	-	-	-	(38)	(38)
Stock-based compensation expense (net of tax of $5)	-	-	9	-	-	-	9
Balance as of December 31, 2006	77.7	390	664	601	(32)	(14)	1,609
Comprehensive income:							
Net income	-	-	-	211	-	-	211
OCI - gain resulting from unfunded pension and postretirement obligation (net of tax of $16)	-	-	-	-	24	-	24
Unrealized loss from hedging activities (net of tax of $3)	-	-	-	-	(5)	-	(5)
Total comprehensive income							230
Dividends on common stock ($1.64 per share)	-	-	-	(127)	-	4	(123)
Issuance of treasury shares	0.7	-	(6)	(5)	-	27	16
Purchase of treasury shares	(2.0)	-	-	-	-	(80)	(80)
Stock-based compensation expense (net of tax of $3)	-	-	9	-	-	-	9
Balance as of December 31, 2007	76.4	390	667	680	(13)	(63)	1,661
Comprehensive income:							
Net income	-	-	-	217	-	-	217
OCI - loss resulting from unfunded pension and postretirement obligation (net of tax of $73)	-	-	-	-	(111)	-	(111)
Unrealized loss from hedging activities (net of tax of $6)	-	-	-	-	(10)	-	(10)
Total comprehensive income							96
Dividends on common stock ($1.68 per share)	-	-	-	(128)	-	4	(124)
Issuance of treasury shares	0.5	-	(1)	(6)	-	16	9
Stock-based compensation expense (net of tax of $1)	-	-	10	-	-	-	10
Balance as of December 31, 2008	76.9	$390	$676	$763	$(134)	$(43)	$1,652

See Notes to Consolidated Financial Statements.

AGL Resources Inc.
Statements of Consolidated Cash Flows

In millions	Years ended December 31, 2008	2007	2006
Cash flows from operating activities			
Net income	$217	$211	$212
Adjustments to reconcile net income to net cash flow provided by operating activities			
Depreciation and amortization	152	144	138
Deferred income taxes	89	30	133
Minority interest	20	30	23
Change in energy marketing and risk management assets and liabilities	(129)	74	(112)
Changes in certain assets and liabilities			
Trade payables	30	(35)	(53)
Accrued expenses	26	(34)	15
Energy marketing receivables and energy marketing trade payables, net	10	(26)	(95)
Gas, unbilled and other receivables	(65)	(15)	170
Inventories	(112)	46	(54)
Other – net	(11)	(48)	(26)
Net cash flow provided by operating activities	227	377	351
Cash flows from investing activities			
Expenditures for property, plant and equipment	(372)	(259)	(253)
Other	-	6	5
Net cash flow used in investing activities	(372)	(253)	(248)
Cash flows from financing activities			
Net payments and borrowings of short-term debt	286	52	6
Issuances of variable rate gas facility revenue bonds	161	-	-
Issuance of treasury shares	9	16	14
Distribution to minority interest	(30)	(23)	(22)
Dividends paid on common shares	(124)	(123)	(111)
Payments of gas facility revenue bonds	(161)	-	-
Issuances of senior notes	-	125	175
Payments of medium-term notes	-	(11)	-
Payments of trust preferred securities	-	(75)	(150)
Purchase of treasury shares	-	(80)	(38)
Other	1	(3)	8
Net cash flow provided by (used in) financing activities	142	(122)	(118)
Net (decrease) increase in cash and cash equivalents	(3)	2	(15)
Cash and cash equivalents at beginning of period	19	17	32
Cash and cash equivalents at end of period	$16	$19	$17
Cash paid during the period for			
Interest	$115	$127	$109
Income taxes	27	118	37

See Notes to Consolidated Financial Statements.

Notes to Consolidated Financial Statements

Note 1 - Accounting Policies and Methods of Application

General

AGL Resources Inc. is an energy services holding company that conducts substantially all its operations through its subsidiaries. Unless the context requires otherwise, references to "we," "us," "our," the "company", or "AGL Resources" mean consolidated AGL Resources Inc. and its subsidiaries. We have prepared the accompanying consolidated financial statements under the rules of the SEC. For a glossary of key terms and referenced accounting standards, see pages 4 and 5.

Basis of Presentation

Our consolidated financial statements as of and for the period ended December 31, 2008, include our accounts, the accounts of our majority-owned and controlled subsidiaries and the accounts of variable interest entities for which we are the primary beneficiary. This means that our accounts are combined with the subsidiaries' accounts. We have eliminated any intercompany profits and transactions in consolidation; however, we have not eliminated intercompany profits when such amounts are probable of recovery under the affiliates' rate regulation process. Certain amounts from prior periods have been reclassified and revised to conform to the current period presentation.

We currently own a noncontrolling 70% financial interest in SouthStar and Piedmont owns the remaining 30%. Our 70% interest is noncontrolling because all significant management decisions require approval by both owners. We record the earnings allocated to Piedmont as a minority interest in our consolidated statements of income and we record Piedmont's portion of SouthStar's capital as a minority interest in our consolidated balance sheets.

We are the primary beneficiary of SouthStar's activities and have determined that SouthStar is a variable interest entity as defined by FIN 46 revised in December 2003, FIN 46R. We determined that SouthStar was a variable interest entity because our equal voting rights with Piedmont are not proportional to our economic obligation to absorb 75% of any losses or residual returns from SouthStar, except those losses and returns related to customers in Ohio and Florida. Earnings related to SouthStar's customers in Ohio and Florida are allocated 70% to us and 30% to Piedmont. The nature of restrictions on SouthStar's assets are immaterial. The primary risks associated with SouthStar include weather, government regulation, competition, market risk, natural gas prices, economic conditions, inflation and bad debt. See Note 9 for income statement, balance sheet and capital expenditure information related to the retail energy operations segment. In addition, SouthStar obtains substantially all its transportation capacity for delivery of natural gas through our wholly-owned subsidiary, Atlanta Gas Light.

Cash and Cash Equivalents

Our cash and cash equivalents consist primarily of cash on deposit, money market accounts and certificates of deposit with original maturities of three months or less.

Receivables and Allowance for Uncollectible Accounts

Our receivables consist of natural gas sales and transportation services billed to residential, commercial, industrial and other customers. We bill customers monthly, and accounts receivable are due within 30 days. For the majority of our receivables, we establish an allowance for doubtful accounts based on our collection experience and other factors. On certain other receivables where we are aware of a specific customer's inability or reluctance to pay, we record an allowance for doubtful accounts against amounts due to reduce the net receivable balance to the amount we reasonably expect to collect. However, if circumstances change, our estimate of the recoverability of accounts receivable could be different. Circumstances that could affect our estimates include, but are not limited to, customer credit issues, the level of natural gas prices, customer deposits and general economic conditions. We write-off our customer's accounts once we deem them to be uncollectible.

Inventories

For our distribution operations subsidiaries, we record natural gas stored underground at WACOG. For Sequent and SouthStar, we account for natural gas inventory at the lower of WACOG or market price.

Sequent and SouthStar evaluate the average cost of their natural gas inventories against market prices to determine whether any declines in market prices below the WACOG are other than temporary. For any declines considered to be other than temporary, adjustments are recorded to reduce the weighted average cost of the natural gas inventory to market price. Consequently, as a result of declining natural gas prices, Sequent recorded LOCOM adjustments against cost of gas to reduce the value of its inventories to market value of $40 million in 2008, $4 million in 2007 and $43 million in 2006. SouthStar recorded LOCOM adjustments of $24 million in 2008

and $6 million in 2006, but was not required to make LOCOM adjustments in 2007.

In Georgia's competitive environment, Marketers including SouthStar, our marketing subsidiary, began selling natural gas in 1998 to firm end-use customers at market-based prices. Part of the unbundling process, which resulted from deregulation that provides for this competitive environment, is the assignment to Marketers of certain pipeline services that Atlanta Gas Light has under contract. Atlanta Gas Light assigns, on a monthly basis, the majority of the pipeline storage services that it has under contract to Marketers, along with a corresponding amount of inventory.

Property, Plant and Equipment

A summary of our PP&E by classification as of December 31, 2008 and 2007 is provided in the following table.

In millions	2008	2007
Transmission and distribution	$4,344	$4,193
Storage	290	285
Other	543	509
Construction work in progress	323	190
Total gross PP&E	5,500	5,177
Accumulated depreciation	(1,684)	(1,611)
Total net PP&E	$3,816	$3,566

Distribution Operations PP&E expenditures consist of property and equipment that is in use, being held for future use and under construction. We report PP&E at its original cost, which includes:

- material and labor
- contractor costs
- construction overhead costs
- an allowance for funds used during construction (AFUDC) which represents the estimated cost of funds, from both debt and equity sources, used to finance the construction of major projects and is capitalized in rate base for ratemaking purposes when the completed projects are placed in service

We charge property retired or otherwise disposed of to accumulated depreciation since such costs are recovered in rates.

Retail Energy Operations, Wholesale Services, Energy Investments and Corporate PP&E expenditures include property that is in use and under construction, and we report it at cost. We record a gain or loss for retired or otherwise disposed-of property. Natural gas in storage at Jefferson Island that is retained as pad gas (volumes of non-working natural gas used to maintain the operational integrity of the cavern facility) is classified as non-depreciable property, plant and equipment and is valued at cost.

Depreciation Expense

We compute depreciation expense for distribution operations by applying composite, straight-line rates (approved by the state regulatory agencies) to the investment in depreciable property. The composite straight-line depreciation rate for depreciable property -- excluding transportation equipment for Atlanta Gas Light, Virginia Natural Gas and Chattanooga Gas -- was approximately 2.5% during 2008, 2007 and 2006. The composite, straight-line rate for Elizabethtown Gas, Florida City Gas and Elkton Gas was approximately 3.3 % for 2008, 3.2% during 2007 and 3.0% during 2006. We depreciate transportation equipment on a straight-line basis over a period of 5 to 10 years. We compute depreciation expense for other segments on a straight-line basis up to 35 years based on the useful life of the asset.

AFUDC

Four of our utilities are authorized by applicable state regulatory agencies or legislatures to record the cost of debt and equity funds as part of the cost of construction projects in our consolidated balance sheets and as AFUDC of $8 million in 2008, $4 million in 2007 and $5 million in 2006 within in the statements of consolidated income. The capital expenditures of our two other utilities do not qualify for AFUDC treatment. More information on our authorized AFUDC rates is provided in the following table.

	Authorized AFUDC rate
Atlanta Gas Light	8.53%
Chattanooga Gas (1)	7.89%
Elizabethtown Gas (2)	2.84%
Virginia Natural Gas (3)	8.91%

(1) Prior to 2007, the authorized rate was 7.43%.
(2) Variable rate as of December 31, 2008, and is determined by FERC method of AFUDC accounting.
(3) Approved only for Hampton Roads construction project.

Goodwill

We have included $418 million of goodwill in our consolidated balance sheets as of December 31, 2008, which consists of:

Date	Acquisition	Goodwill amount
2004	NUI	$227
2004	Jefferson Island	14
2000	Virginia Natural Gas	170
1998	Chattanooga Gas	7

SFAS 142 requires us to perform an annual goodwill impairment test at a reporting unit level which generally equates to our operating segments as discussed in Note 9 "Segment Information." We

performed this annual test as of our fiscal year-end or December 31, 2008, 2007 and 2006 and did not recognize any impairment charges. We also assess goodwill for impairment if events or changes in circumstances may indicate an impairment of goodwill exists. When such events or circumstances are present, we assess the recoverability of long-lived assets by determining whether the carrying value will be recovered through the expected future cash flows. In the event the sum of the expected future cash flows resulting from the use of the asset is less than the carrying value of the asset, we record an impairment loss equal to the excess of the asset's carrying value over its fair value. We conduct this assessment principally through a review of our market capitalization relative to our net book value, financial results, changes in state and federal legislation and regulation, regulatory and legal proceedings and the periodic regulatory filings for our regulated utilities.

Taxes

The reporting of our assets and liabilities for financial accounting purposes differs from the reporting for income tax purposes. The principal differences between net income and taxable income relate to the timing of deductions, primarily due to the benefits of tax depreciation since we generally depreciate assets for tax purposes over a shorter period of time than for book purposes. The determination of our provision for income taxes requires significant judgment, the use of estimates, and the interpretation and application of complex tax laws. Significant judgment is required in assessing the timing and amounts of deductible and taxable items. We report the tax effects of depreciation and other differences in those items as deferred income tax assets or liabilities in our consolidated balance sheets in accordance with SFAS 109 and FIN 48. Investment tax credits of approximately $14 million previously deducted for income tax purposes for Atlanta Gas Light, Elizabethtown Gas, Florida City Gas and Elkton Gas have been deferred for financial accounting purposes and are being amortized as credits to income over the estimated lives of the related properties in accordance with regulatory requirements.

We do not collect income taxes from our customers on behalf of governmental authorities. We collect and remit various taxes on behalf of various governmental authorities. We record these amounts in our consolidated balance sheets except taxes in the state of Florida which we are required to include in revenues and operating expenses. These Florida related taxes are not material for any periods presented.

Revenues

Distribution operations We record revenues when services are provided to customers. Those revenues are based on rates approved by the state regulatory commissions of our utilities.

As required by the Georgia Commission, in July 1998, Atlanta Gas Light began billing Marketers in equal monthly installments for each residential, commercial and industrial customer's distribution costs. As required by the Georgia Commission, effective February 1, 2001, Atlanta Gas Light implemented a seasonal rate design for the calculation of each residential customer's annual straight-fixed-variable (SFV) capacity charge, which is billed to Marketers and reflects the historic volumetric usage pattern for the entire residential class. Generally, this change results in residential customers being billed by Marketers for a higher capacity charge in the winter months and a lower charge in the summer months. This requirement has an operating cash flow impact but does not change revenue recognition. As a result, Atlanta Gas Light continues to recognize its residential SFV capacity revenues for financial reporting purposes in equal monthly installments.

Any difference between the billings under the seasonal rate design and the SFV revenue recognized is deferred and reconciled to actual billings on an annual basis. Atlanta Gas Light had unrecovered seasonal rates of approximately $11 million as of December 31, 2008 and 2007 (included as current assets in the consolidated balance sheets) related to the difference between the billings under the seasonal rate design and the SFV revenue recognized.

The Elizabethtown Gas, Virginia Natural Gas, Florida City Gas, Chattanooga Gas and Elkton Gas rate structures include volumetric rate designs that allow recovery of costs through gas usage. Revenues from sales and transportation services are recognized in the same period in which the related volumes are delivered to customers. Revenues from residential and certain commercial and industrial customers are recognized on the basis of scheduled meter readings. In addition, revenues are recorded for estimated deliveries of gas not yet billed to these customers, from the last meter reading date to the end of the accounting period. These are included in the consolidated balance sheets as unbilled revenue. For other commercial and industrial customers and all wholesale customers, revenues are based on actual deliveries to the end of the period.

The tariffs for Elizabethtown Gas, Virginia Natural Gas and Chattanooga Gas contain WNA's that

partially mitigate the impact of unusually cold or warm weather on customer billings and operating margin. The WNA's purpose is to reduce the effect of weather on customer bills by reducing bills when winter weather is colder than normal and increasing bills when weather is warmer than normal.

Retail energy operations We record retail energy operations' revenues when services are provided to customers. Revenues from sales and transportation services are recognized in the same period in which the related volumes are delivered to customers. Sales revenues from residential and certain commercial and industrial customers are recognized on the basis of scheduled meter readings. In addition, revenues are recorded for estimated deliveries of gas not yet billed to these customers, from the most recent meter reading date to the end of the accounting period. These are included in the consolidated balance sheets as unbilled revenue. For other commercial and industrial customers and all wholesale customers, revenues are based on actual deliveries to the end of the period.

Wholesale services We record wholesale services' revenues when services are provided to customers. Profits from sales between segments are eliminated in the corporate segment and are recognized as goods or services sold to end-use customers. Transactions that qualify as derivatives under SFAS 133 are recorded at fair value with changes in fair value recognized in earnings in the period of change and characterized as unrealized gains or losses.

Energy investments We record operating revenues at Jefferson Island in the period in which actual volumes are transported and storage services are provided. The majority of our storage services are covered under medium to long-term contracts at fixed market rates.

We record operating revenues at AGL Networks from leases of dark fiber pursuant to indefeasible rights-of-use (IRU) agreements as services are provided. Dark fiber IRU agreements generally require the customer to make a down payment upon execution of the agreement; however in some cases AGL Networks receives up to the entire lease payment at the inception of the lease and recognizes ratably over the lease term. AGL Networks had deferred revenue in our consolidated balance sheet of $33 million at December 31, 2008 and $38 million at December 31, 2007. In addition, AGL Networks recognizes sales revenues upon the execution of certain sales-type agreements for dark fiber when the agreements provide for the transfer of legal title to the dark fiber to the customer at the end of the agreement's term. This sales-type accounting treatment is in accordance with EITF 00-11 and SFAS 66, which provides that such transactions meet the criteria for sales-type lease accounting if the agreement obligates the lessor to convey ownership of the underlying asset to the lessee by the end of the lease term.

Cost of gas

Excluding Atlanta Gas Light, we charge our utility customers for natural gas consumed using natural gas cost recovery mechanisms set by the state regulatory agencies. Under the these mechanisms, we defer (that is, include as a current asset or liability in the consolidated balance sheets and exclude from the statements of consolidated income) the difference between the actual cost of gas and what is collected from or billed to customers in a given period. The deferred amount is either billed or refunded to our customers prospectively through adjustments to the commodity rate.

Our retail energy operations customers are charged for natural gas consumed. We also include within our cost of gas amounts for fuel and lost and unaccounted for gas, adjustments to reduce the value of our inventories to market value and for gains and losses associated with derivatives.

Comprehensive Income

Our comprehensive income includes net income plus OCI, which includes other gains and losses affecting shareholders' equity that GAAP excludes from net income. Such items consist primarily of unrealized gains and losses on certain derivatives designated as cash flow hedges and overfunded or unfunded pension obligation adjustments. The following table illustrates our OCI activity during the last three years.

In millions	2008	2007	2006
Cash flow hedges:			
Net derivative unrealized (losses) gains arising during the period (net of $2 , $2 and $7 in taxes)	$(4)	$3	$11
Less reclassification of realized gains included in net income (net of $4, $5 and $1 in taxes)	(6)	(8)	(1)
(Unfunded) over funded pension obligation (net of $73, $16 and $7 in taxes)	(111)	24	11
Total	$(121)	$19	$21

Earnings Per Common Share

We compute basic earnings per common share by dividing our income available to common shareholders by the daily weighted average number of common shares outstanding daily. Diluted earnings per common share reflect the potential reduction in earnings per common share that could

occur when potentially dilutive common shares are added to common shares outstanding.

We derive our potentially dilutive common shares by calculating the number of shares issuable under restricted stock, restricted stock units and stock options. The future issuance of shares underlying the restricted stock and restricted share units depends on the satisfaction of certain performance criteria. The future issuance of shares underlying the outstanding stock options depends on whether the exercise prices of the stock options are less than the average market price of the common shares for the respective periods. The following table shows the calculation of our diluted earnings per share for the periods presented if performance units currently earned under the plan ultimately vest and if stock options currently exercisable at prices below the average market prices are exercised.

In millions	2008	2007	2006
Denominator for basic earnings per share (1)	76.3	77.1	77.6
Assumed exercise of potential common shares	0.3	0.3	0.4
Denominator for diluted earnings per share	76.6	77.4	78.0

(1) Daily weighted average shares outstanding.

The following table contains the weighted average shares attributable to outstanding stock options that were excluded from the computation of diluted earnings per share because their effect would have been anti-dilutive, as the exercise prices were greater than the average market price:

	December 31,		
In millions	2008	2007	2006
Twelve months ended (1)	1.6	0.0	0.0

(1) 0.0 values represent amounts less than 0.1 million.

The increase in the number of shares that were excluded from the computation is the result of a significant decline in the market value of our common shares at December 31, 2008 as compared to December 31, 2007 and 2006.

Regulatory Assets and Liabilities

We have recorded regulatory assets and liabilities in our consolidated balance sheets in accordance with SFAS 71. Our regulatory assets and liabilities, and associated liabilities for our unrecovered PRP costs, unrecovered ERC and the associated assets and liabilities for our Elizabethtown Gas hedging program, are summarized in the following table.

	December 31,	
In millions	2008	2007
Regulatory assets		
Unrecovered PRP costs	$237	$285
Unrecovered ERC (1)	143	158
Unrecovered postretirement benefit costs	11	12
Unrecovered seasonal rates	11	11
Unrecovered natural gas costs	19	23
Other	30	24
Total regulatory assets	451	513
Associated assets		
Elizabethtown Gas hedging program	23	4
Total regulatory and associated assets	$474	$517
Regulatory liabilities		
Accumulated removal costs	$178	$169
Elizabethtown Gas hedging program	23	4
Unamortized investment tax credit	14	16
Deferred natural gas costs	25	28
Regulatory tax liability	19	20
Other	22	19
Total regulatory liabilities	281	256
Associated liabilities		
PRP costs	189	245
ERC (1)	96	96
Total associated liabilities	285	341
Total regulatory and associated liabilities	$566	$597

(1) For a discussion of ERC, see Note 7.

Our regulatory assets are recoverable through either rate riders or base rates specifically authorized by a state regulatory commission. Base rates are designed to provide both a recovery of cost and a return on investment during the period rates are in effect. As such, all our regulatory assets are subject to review by the respective state regulatory commission during any future rate proceedings. In the event that the provisions of SFAS 71 were no longer applicable, we would recognize a write-off of regulatory assets that would result in a charge to net income, and be classified as an extraordinary item. Additionally, the regulatory liabilities would not be written-off but would continue to be recorded as liabilities but not as regulatory liabilities. Although the natural gas distribution industry is becoming increasingly competitive, our utility operations continue to recover their costs through cost-based rates established by the state regulatory commissions. As a result, we believe that the accounting prescribed under SFAS 71 remains appropriate. It is also our opinion that all regulatory assets are recoverable in future rate proceedings, and therefore we have not recorded any regulatory assets that are recoverable but are not yet included in base rates or contemplated in a rate rider.

All the regulatory assets included in the preceding table are included in base rates except for the unrecovered PRP costs, unrecovered ERC and deferred natural gas costs, which are recovered

through specific rate riders on a dollar for dollar basis. The rate riders that authorize recovery of unrecovered PRP costs and the deferred natural gas costs include both a recovery of costs and a return on investment during the recovery period. We have two rate riders that authorize the recovery of unrecovered ERC. The ERC rate rider for Atlanta Gas Light only allows for recovery of the costs incurred and the recovery period occurs over the five years after the expense is incurred. ERC associated with the investigation and remediation of Elizabethtown Gas remediation sites located in the state of New Jersey are recovered under a remediation adjustment clause and include the carrying cost on unrecovered amounts not currently in rates. Elizabethtown Gas' hedging program asset and liability reflect unrealized losses or gains that will be recovered from or passed to rate payers through the recovery of its natural gas costs on a dollar for dollar basis, once the losses or gains are realized. Unrecovered postretirement benefit costs are recoverable through base rates over the next 5 to 24 years based on the remaining recovery period as designated by the applicable state regulatory commissions. Unrecovered seasonal rates reflect the difference between the recognition of a portion of Atlanta Gas Light's residential base rates revenues on a straight-line basis as compared to the collection of the revenues over a seasonal pattern. The unrecovered amounts are fully recoverable through base rates within one year.

The regulatory liabilities are refunded to ratepayers through a rate rider or base rates. If the regulatory liability is included in base rates, the amount is reflected as a reduction to the rate base in setting rates.

Pipeline Replacement Program

Atlanta Gas Light The PRP, ordered by the Georgia Commission to be administered by Atlanta Gas Light, requires, among other things, that Atlanta Gas Light replace all bare steel and cast iron pipe in its system in the state of Georgia within a 10-year period beginning October 1, 1998. Atlanta Gas Light identified, and provided notice to the Georgia Commission of 2,312 miles of pipe to be replaced. Atlanta Gas Light subsequently identified an additional 320 miles of pipe subject to replacement under this program. If Atlanta Gas Light does not perform in accordance with this order, it will be assessed certain nonperformance penalties.

The order also provides for recovery of all prudent costs incurred in the performance of the program, which Atlanta Gas Light has recorded as a regulatory asset. Atlanta Gas Light will recover from end-use customers, through billings to Marketers, the costs related to the program net of any cost savings from the program. All such amounts will be recovered through a combination of straight-fixed-variable rates and a pipeline replacement revenue rider. The regulatory asset has two components:

- the costs incurred to date that have not yet been recovered through the rate rider
- the future expected costs to be recovered through the rate rider

On June 10, 2005, Atlanta Gas Light and the Georgia Commission entered into a Settlement Agreement that, among other things, extends Atlanta Gas Light's PRP by five years to require that all replacements be completed by December 2013. The timing of replacements was subsequently specified in an amendment to the PRP stipulation. This amendment, which was approved by the Georgia Commission on December 20, 2005, requires Atlanta Gas Light to replace all cast iron pipe and 70% of all bare steel pipe by December 2010. The remaining 30% of bare steel pipe is required to be replaced by December 2013. These replacements are on schedule.

Under the Settlement Agreement, base rates charged to customers will remain unchanged through April 30, 2010, but Atlanta Gas Light will recognize reduced base rate revenues of $5 million on an annual basis through April 30, 2010. The five-year total reduction in recognized base rate revenues of $25 million will be applied to the allowed amount of costs incurred to replace pipe, which will reduce the amounts recovered from customers under the PRP rider. The Settlement Agreement also set the per customer fixed PRP rate that Atlanta Gas Light will charge at $1.29 per customer per month from May 2005 through September 2008 and at $1.95 from October 2008 through December 2013 and includes a provision that allows for a true-up of any over- or under-recovery of PRP revenues that may result from a difference between PRP charges collected through fixed rates and actual PRP revenues recognized through the remainder of the program.

The Settlement Agreement also allows Atlanta Gas Light to recover through the PRP $4 million of the $32 million capital costs associated with its March 2005 purchase of 250 miles of pipeline in central Georgia from Southern Natural Gas Company, a subsidiary of El Paso Corporation. The remaining capital costs are included in Atlanta Gas Light's rate base and collected through base rates.

Atlanta Gas Light has recorded a long-term regulatory asset of $196 million, which represents the expected future collection of both expenditures already incurred and expected future capital expenditures to be incurred through the remainder of the program. Atlanta Gas Light has also recorded a current asset of $41 million, which represents the

expected amount to be collected from customers over the next 12 months. The amounts recovered from the pipeline replacement revenue rider during the last three years were:

- $30 million in 2008
- $27 million in 2007
- $27 million in 2006

As of December 31, 2008, Atlanta Gas Light had recorded a current liability of $49 million representing expected program expenditures for the next 12 months and a long-term liability of $140 million, representing expected program expenditures starting in 2009 through the end of the program in 2013.

Atlanta Gas Light capitalizes and depreciates the capital expenditure costs incurred from the PRP over the life of the assets. Operation and maintenance costs are expensed as incurred. Recoveries, which are recorded as revenue, are based on a formula that allows Atlanta Gas Light to recover operation and maintenance costs in excess of those included in its current base rates, depreciation expense and an allowed rate of return on capital expenditures. In the near term, the primary financial impact to Atlanta Gas Light from the PRP is reduced cash flow from operating and investing activities, as the timing related to cost recovery does not match the timing of when costs are incurred. However, Atlanta Gas Light is allowed the recovery of carrying costs on the under-recovered balance resulting from the timing difference.

Elizabethtown Gas In August 2006, the New Jersey Commission issued an order adopting a pipeline replacement cost recovery rider program for the replacement of certain 8" cast iron main pipes and any unanticipated 10"-12" cast iron main pipes integral to the replacement of the 8" main pipes. The order allows Elizabethtown Gas to recognize revenues under a deferred recovery mechanism for costs to replace the pipe that exceeds a baseline amount of $3 million. Elizabethtown Gas' recognition of these revenues could be disallowed by the New Jersey Commission if its return on equity exceeds the authorized rate of 10%. The term of the stipulation was from the date of the order through December 31, 2008. Total replacement costs through December 31, 2008 were $21 million, of which $16 million will be eligible for the deferred recovery mechanism. Revenues recognized and deferred for recovery under the stipulation are estimated to be approximately $2 million. All costs incurred under the program will be included in Elizabethtown Gas' next rate case to be filed in 2009.

Use of Accounting Estimates

The preparation of our financial statements in conformity with GAAP requires us to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses and the related disclosures of contingent assets and liabilities. We based our estimates on historical experience and various other assumptions that we believe to be reasonable under the circumstances, and we evaluate our estimates on an ongoing basis. Each of our estimates involve complex situations requiring a high degree of judgment either in the application and interpretation of existing literature or in the development of estimates that impact our financial statements. The most significant estimates include our PRP accruals, environmental liability accruals, uncollectible accounts and other allowance for contingencies, pension and postretirement obligations, derivative and hedging activities and provision for income taxes. Our actual results could differ from our estimates.

Accounting Developments

Previously discussed

SFAS 160 In December 2007, the FASB issued SFAS 160, which is effective for fiscal years beginning after December 15, 2008. Early adoption is prohibited. SFAS 160 will require us to present our minority interest, now to be referred to as a noncontrolling interest, separately within the capitalization section of our consolidated balance sheet. We will adopt SFAS 160 as of January 1, 2009.

Recently issued

SFAS 161 In March 2008, the FASB issued SFAS 161, which is effective for fiscal years beginning after November 15, 2008. SFAS 161 amends the disclosure requirements of SFAS 133 to provide an enhanced understanding of how and why derivative instruments are used, how they are accounted for and their effect on an entity's financial condition, performance and cash flows. We will adopt SFAS 161 effective on January 1, 2009, which will require additional disclosures, but will not have a financial impact to our consolidated results of operations, cash flows or financial condition.

FSP EITF 03-6-1 The FASB issued this FSP in June 2008 and it is effective for fiscal years beginning after December 15, 2008. This FSP classifies unvested share-based payment grants containing nonforfeitable rights to dividends as participating securities that will be included in the computation of earnings per share. As of December 31, 2008, we had approximately 145,000 restricted shares with

nonforfeitable dividend rights. We will adopt FSP EITF 03-6-1 effective on January 1, 2009.

FSP FAS 133-1 The FASB issued this FSP in September 2008 and it is effective for fiscal years beginning after November 15, 2008. This FSP requires more detailed disclosures about credit derivatives, including the potential adverse effects of changes in credit risk on the financial position, financial performance and cash flows of the sellers of the instruments. This FSP will have no financial impact to our consolidated results of operations, cash flows or financial condition. We will adopt FSP FAS 133-1 effective on January 1, 2009.

FSP FAS 157-3 The FASB issued this FSP in October 2008 and it is effective upon issuance including prior periods for which financial statements have not been issued. This FSP clarifies the application of SFAS 157 in an inactive market, including; how internal assumptions should be considered when measuring fair value, how observable market information in a market that is not active should be considered and how the use of market quotes should be used when assessing observable and unobservable data. We adopted this FSP as of September 30, 2008, it had no financial impact to our consolidated results of operations, cash flows or financial condition.

FSP FAS 140-4 and FIN 46R-8 The FASB issued this FSP in December 2008 and it is effective for the first reporting period ending after December 15, 2008. This FSP requires additional disclosures related to variable interest entities in accordance with SFAS 140 and FIN 46R. These disclosures include significant judgments and assumptions, restrictions on assets, risks and the affects on financial position, financial performance and cash flows. We adopted this FSP as of December 31, 2008, it had no financial impact to our consolidated results of operations, cash flows or financial condition.

Note 2 – Financial Instruments and Risk Management

Netting of Cash Collateral and Derivative Assets and Liabilities under Master Netting Arrangements

We maintain accounts with brokers to facilitate financial derivative transactions in support of our energy marketing and risk management activities. Based on the value of our positions in these accounts and the associated margin requirements, we may be required to deposit cash into these broker accounts.

On January 1, 2008, we adopted FIN 39-1, which required that we offset cash collateral held in these broker accounts on our condensed consolidated balance sheets with the associated fair value of the instruments in the accounts. Prior to the adoption of FIN 39-1, we presented such cash collateral on a gross basis within other current assets and liabilities on our condensed consolidated balance sheets. Our cash collateral amounts are provided in the following table.

In millions	As of December 31, 2008	2007
Right to reclaim cash collateral	$128	$3
Obligations to return cash collateral	(4)	(10)
Total cash collateral	$124	$(7)

Fair value measurements

In September 2006, the FASB issued SFAS 157, which establishes a framework for measuring fair value and requires expanded disclosures regarding fair value measurements. SFAS 157 does not require any new fair value measurements; however, it eliminates inconsistencies in the guidance provided in previous accounting pronouncements. The carrying value of cash and cash equivalents, receivables, accounts payable, other current liabilities and accrued interest approximate fair value. The following table shows the carrying amounts and fair values of our long-term debt including any current portions included in our condensed consolidated balance sheets.

In millions	Carrying amount	Estimated fair value
As of December 31, 2008	$1,675	$1,647
As of December 31, 2007	1,675	1,710

We estimate the fair value of our long-term debt using a discounted cash flow technique that incorporates a market interest yield curve with adjustments for duration, optionality and risk profile. In determining the market interest yield curve, we considered our currently assigned ratings for unsecured debt of BBB+ by S&P, Baa1 by Moody's and A- by Fitch.

SFAS 157 was effective for financial statements issued for fiscal years beginning after November 15, 2007, and interim periods within those fiscal years. In December 2007, the FASB provided a one-year deferral of SFAS 157 for nonfinancial assets and nonfinancial liabilities, except those that are recognized or disclosed at fair value on a recurring basis, at least annually. We adopted SFAS 157 on January 1, 2008, for our financial assets and liabilities, which primarily consist of derivatives we record in accordance with SFAS 133. The adoption of SFAS 157 primarily impacts our disclosures and did not have a material impact on our condensed consolidated results of operations, cash flows and financial condition. We will adopt SFAS 157 for our

nonfinancial assets and liabilities on January 1, 2009, and are currently evaluating the impact to our condensed consolidated results of operations, cash flows and financial condition.

As defined in SFAS 157, fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). We utilize market data or assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, market corroborated, or generally unobservable. We primarily apply the market approach for recurring fair value measurements and endeavor to utilize the best available information. Accordingly, we use valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs. We are able to classify fair value balances based on the observance of those inputs. SFAS 157 establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (level 1) and the lowest priority to unobservable inputs (level 3). The three levels of the fair value hierarchy defined by SFAS 157 are as follows:

Level 1

Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis. Our Level 1 items consist of financial instruments with exchange-traded derivatives.

Level 2

Pricing inputs are other than quoted prices in active markets included in level 1, which are either directly or indirectly observable as of the reporting date. Level 2 includes those financial and commodity instruments that are valued using valuation methodologies. These methodologies are primarily industry-standard methodologies that consider various assumptions, including quoted forward prices for commodities, time value, volatility factors, and current market and contractual prices for the underlying instruments, as well as other relevant economic measures. Substantially all of these assumptions are observable in the marketplace throughout the full term of the instrument, can be derived from observable data or are supported by observable levels at which transactions are executed in the marketplace. We obtain market price data from multiple sources in order to value some of our Level 2 transactions and this data is representative of transactions that occurred in the market place. As we aggregate our disclosures by counterparty, the underlying transactions for a given counterparty may be a combination of exchange-traded derivatives and values based on other sources. Instruments in this category include shorter tenor exchange-traded and non-exchange-traded derivatives such as OTC forwards and options.

Level 3

Pricing inputs include significant inputs that are generally less observable from objective sources. These inputs may be used with internally developed methodologies that result in management's best estimate of fair value. Level 3 instruments include those that may be more structured or otherwise tailored to customers' needs. We do not have any material assets or liabilities classified as level 3.

The following table sets forth, by level within the fair value hierarchy, our financial assets and liabilities that were accounted for at fair value on a recurring basis as of December 31, 2008. As required by SFAS 157, financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels.

In millions	Recurring fair value measurements as of December 31, 2008				
	Quoted prices in active markets (Level 1)	Significant other observable inputs (Level 2)	Significant unobservable inputs (Level 3)	Netting of cash collateral	Total carrying value
Assets: (1)					
Derivatives at wholesale services	$17	$154	$-	$35	$206
Derivatives at distribution operations	23	-	-	-	23
Derivatives at retail energy operations (3)	12	-	-	-	12
Total assets	**$52**	**$154**	**$-**	**$35**	**$241**
Liabilities: (2)					
Derivatives at wholesale services	$62	$27	$-	$(62)	$27
Derivatives at distribution operations	23	-	-	4	27
Derivatives at retail energy operations	32	1	-	(31)	2
Total liabilities	**$117**	**$28**	**$-**	**$(89)**	**$56**

(1) Includes $203 million of current assets and $38 million of long-term assets reflected within our consolidated balance sheet.
(2) Includes $50 million of current liabilities and $6 million of long-term liabilities reflected within our consolidated balance sheet.
(3) $4 million premium associated with weather derivatives has been excluded as they are based on intrinsic value, not fair value.

The determination of the fair values above incorporates various factors required under SFAS 157. These factors include not only the credit standing of the counterparties involved and the impact of credit enhancements (such as cash deposits, letters of credit and priority interests), but also the impact of our nonperformance risk on our liabilities.

Derivatives at distribution operations relate to Elizabethtown Gas and are utilized in accordance with a directive from the New Jersey Commission to create a program to hedge the impact of market fluctuations in natural gas prices. These derivative products are accounted for at fair value each reporting period. In accordance with regulatory requirements, realized gains and losses related to these derivatives are reflected in purchased gas costs and ultimately included in billings to customers. Unrealized gains and losses are reflected as a regulatory asset or liability, as appropriate, in our condensed consolidated balance sheets.

Sequent's and SouthStar's derivatives include exchange-traded and OTC derivative contracts. Exchange-traded derivative contracts, which include futures and exchange-traded options, are generally based on unadjusted quoted prices in active markets and are classified within level 1. Some exchange-traded derivatives are valued using broker or dealer quotation services, or market transactions in either the listed or OTC markets, which are classified within level 2.

At the beginning of 2008, we had a notional principal amount of $100 million of interest rate swap agreements associated with our senior notes. In March 2008, we terminated these interest rate swap agreements. We received a payment of $2 million, which included accrued interest and the fair value of the interest rate swap agreements at the termination date. The payment was recorded as deferred income and classified as a liability in our consolidated balance sheets. The amount will be amortized through January 2011, the remaining life of the associated senior notes. The following table sets forth a reconciliation of the termination of our interest rate swaps, classified as level 3 in the fair value hierarchy.

In millions	Year ended December 31, 2008
Balance as of January 1, 2008	$(2)
Realized and unrealized gains	-
Settlements	2
Transfers in or out of level 3	-
Balance as of December 31, 2008	$-
Change in unrealized gains (losses) relating to instruments held as of December 31, 2008	$-

Transfers in or out of level 3 represent existing assets or liabilities that were either previously categorized as a higher level for which the methodology inputs became unobservable or assets and liabilities that were previously classified as level 3 for which the lowest significant input became observable during the period.

Risk Management

Our risk management activities are monitored by our Risk Management Committee (RMC), which consists of members of senior management. The RMC and is charged with reviewing and enforcing our risk management activities. Our risk management policies limit the use of derivative financial instruments and physical transactions within predefined risk tolerances associated with pre-existing or anticipated physical natural gas sales and purchases and system use and storage. We use the following derivative financial instruments and physical transactions to manage commodity price, interest rate, weather, fuel price and foreign currency risks:

- forward contracts
- futures contracts
- options contracts
- financial swaps
- treasury locks
- weather derivative contracts
- storage and transportation capacity transactions
- foreign currency forward contracts

Interest Rate Swaps

To maintain an effective capital structure, our policy is to borrow funds using a mix of fixed-rate and variable-rate debt. We entered into interest rate swap agreements for the purpose of managing the appropriate mix of risk associated with our fixed-rate and variable-rate debt obligations. We designated these interest rate swaps as fair value hedges in accordance with SFAS 133. We record the gain or loss on fair value hedges in earnings in the period of change, together with the offsetting loss or gain on the hedged item attributable to the interest rate risk being hedged.

Commodity-related Derivative Instruments

All activities associated with price risk management activities and derivative instruments are included as a component of cash flows from operating activities in our consolidated statements of cash flows. Our derivatives not designated as hedges under SFAS 133, included within operating cash flows as a source (use) of cash was $(129) million in 2008, $74 million in 2007, and $(112) million in 2006.

Elizabethtown Gas In accordance with a directive from the New Jersey Commission, Elizabethtown Gas enters into derivative transactions to hedge the impact of market fluctuations in natural gas prices. Pursuant to SFAS 133, such derivative transactions are marked to market each reporting period. In accordance with regulatory requirements, realized gains and losses related to these derivatives are reflected in purchased gas costs and ultimately included in billings to customers. As of December 31, 2008, Elizabethtown Gas had entered into OTC swap contracts to purchase approximately 11 Bcf of natural gas. Approximately 57% of these contracts have durations of one year or less, and none of these contracts extends beyond January 2011. The fair values of these derivative instruments were reflected as a current asset and liability of $23 million at December 31, 2008 and $4 million at December 31, 2007. For more information on our regulatory assets and liabilities see Note 1.

SouthStar Commodity-related derivative financial instruments (futures, options and swaps) are used by SouthStar to manage exposures arising from changing commodity prices. SouthStar's objective for holding these derivatives is to utilize the most effective method to reduce or eliminate the impact of this exposure. We have designated a portion of SouthStar's derivative transactions as cash flow hedges under SFAS 133. We record derivative gains or losses arising from cash flow hedges in OCI and reclassify them into earnings in the same period as the settlement of the underlying hedged item. We record any hedge ineffectiveness, defined as when the gains or losses on the hedging instrument do not offset and are greater than the losses or gains on the hedged item, in cost of gas in our statement of consolidated income in the period in which it occurs. SouthStar currently has minimal hedge ineffectiveness. We have not designated the remainder of SouthStar's derivative instruments as hedges under SFAS 133 and, accordingly, we record changes in their fair value as cost of gas in our statements of consolidated income in the period of change.

At December 31, 2008, the fair values of these derivatives were reflected in our consolidated financial statements as a current asset of $11 million, a long-term asset of $5 million and a current liability of $2 million representing a net position of 28 Bcf. This includes a $4 million current asset associated with a premium for weather derivatives.

SouthStar also enters into both exchange and OTC derivative transactions to hedge commodity price risk. Credit risk is mitigated for exchange transactions through the backing of the NYMEX member firms. For OTC transactions, SouthStar utilizes master netting arrangements to reduce overall credit risk. As of December 31, 2008, SouthStar's maximum exposure to any single OTC counterparty was $8 million.

Sequent We are exposed to risks associated with changes in the market price of natural gas. Sequent uses derivative financial instruments to reduce our exposure to the risk of changes in the prices of natural gas. The fair value of these derivative financial instruments reflects the estimated amounts that we would receive or pay to terminate or close the contracts at the reporting date, taking into account the current unrealized gains or losses on open contracts. We use external market quotes and indices to value substantially all the financial instruments we use.

We mitigate substantially all the commodity price risk associated with Sequent's natural gas portfolio by locking in the economic margin at the time we enter into natural gas purchase transactions for our stored natural gas. We purchase natural gas for storage when the difference in the current market price we pay to buy and transport natural gas plus the cost to store the natural gas is less than the market price we

can receive in the future, resulting in a positive net operating margin. We use NYMEX futures contracts and other OTC derivatives to sell natural gas at that future price to substantially lock in the operating margin we will ultimately realize when the stored natural gas is actually sold. These futures contracts meet the definition of derivatives under SFAS 133 and are recorded at fair value and marked to market in our consolidated balance sheets, with changes in fair value recorded in earnings in the period of change. The purchase, transportation, storage and sale of natural gas are accounted for on a weighted average cost or accrual basis, as appropriate rather than on the mark-to-market basis we utilize for the derivatives used to mitigate the commodity price risk associated with our storage portfolio. This difference in accounting can result in volatility in our reported earnings, even though the economic margin is essentially unchanged from the date the transactions were consummated.

At December 31, 2008, Sequent's commodity-related derivative financial instruments represented purchases (long) of 819 Bcf and sales (short) of 688 Bcf with approximately 92% of purchase instruments and 94% of the sales instruments are scheduled to mature in less than 2 years and the remaining 8% and 6%, respectively, in 3 to 9 years. At December 31, 2008, the fair values of these derivatives were reflected in our consolidated financial statements as an asset of $206 million and a liability of $27 million.

The changes in fair value of Sequent's derivative instruments utilized in its energy marketing and risk management activities and contract settlements increased the net fair value of its contracts outstanding by $25 million during 2008, reduced net fair value by $62 million during 2007 and increased net fair value by $132 million during 2006.

Weather Derivatives

In 2008 and 2007, SouthStar entered into weather derivative contracts as economic hedges of operating margins in the event of warmer-than-normal and colder-than-normal weather in the heating season, primarily from November through March. SouthStar accounts for these contracts using the intrinsic value method under the guidelines of EITF 99-02. SouthStar recorded current assets for this hedging activity of $4 million at December 31, 2008 and $5 million at December 31, 2007.

Concentration of Credit Risk

Atlanta Gas Light Concentration of credit risk occurs at Atlanta Gas Light for amounts billed for services and other costs to its customers, which consist of 11 Marketers in Georgia. The credit risk exposure to Marketers varies seasonally, with the lowest exposure in the nonpeak summer months and the highest exposure in the peak winter months. Marketers are responsible for the retail sale of natural gas to end-use customers in Georgia. These retail functions include customer service, billing, collections, and the purchase and sale of natural gas. Atlanta Gas Light's tariff allows it to obtain security support in an amount equal to no less than two times a Marketer's highest month's estimated bill from Atlanta Gas Light.

Wholesale Services Sequent has a concentration of credit risk for services it provides to marketers and to utility and industrial counterparties. This credit risk is measured by 30-day receivable exposure plus forward exposure, which is generally concentrated in 20 of its counterparties. Sequent evaluates the credit risk of its counterparties using a S&P equivalent credit rating, which is determined by a process of converting the lower of the S&P or Moody's rating to an internal rating ranging from 9.00 to 1.00, with 9.00 being equivalent to AAA/Aaa by S&P and Moody's and 1.00 being equivalent to D or Default by S&P and Moody's. For a customer without an external rating, Sequent assigns an internal rating based on Sequent's analysis of the strength of its financial ratios. At December 31, 2008, Sequent's top 20 counterparties represented approximately 63% of the total credit exposure of $505 million, derived by adding together the top 20 counterparties' exposures and dividing by the total of Sequent's counterparties' exposures. Sequent's counterparties or the counterparties' guarantors had a weighted average S&P equivalent rating of A- at December 31, 2008.

The weighted average credit rating is obtained by multiplying each customer's assigned internal rating by its credit exposure and then adding the individual results for all counterparties. That total is divided by the aggregate total exposure. This numeric value is converted to an S&P equivalent.

Sequent has established credit policies to determine and monitor the creditworthiness of counterparties, including requirements for posting of collateral or other credit security, as well as the quality of pledged collateral. Collateral or credit security is most often in the form of cash or letters of credit from an investment-grade financial institution, but may also include cash or U.S. Government Securities held by a trustee. When Sequent is engaged in more than one outstanding derivative transaction with the same counterparty and it also has a legally enforceable netting agreement with that counterparty, the "net" mark-to-market exposure represents the netting of the positive and negative exposures with that counterparty and a reasonable measure of Sequent's credit risk. Sequent also uses other netting agreements with certain counterparties with which it conducts significant transactions.

Note 3 - Employee Benefit Plans

Oversight of Plans

The Retirement Plan Investment Committee (the Committee) appointed by our Board of Directors is responsible for overseeing the investments of the retirement plans. Further, we have an Investment Policy (the Policy) for the retirement and postretirement benefit plans that aims to preserve these plans' capital and maximize investment earnings in excess of inflation within acceptable levels of capital market volatility. To accomplish this goal, the retirement and postretirement benefit plans' assets are actively managed to optimize long-term return while maintaining a high standard of portfolio quality and proper diversification.

The Policy's risk management strategy establishes a maximum tolerance for risk in terms of volatility to be measured at 75% of the volatility experienced by the S&P 500. We will continue to diversify retirement plan investments to minimize the risk of large losses in a single asset class. The Policy's permissible investments include domestic and international equities (including convertible securities and mutual funds), domestic and international fixed income (corporate and U.S. government obligations), cash and cash equivalents and other suitable investments. The asset mix of these permissible investments is maintained within the Policy's target allocations as included in the preceding tables, but the Committee can vary allocations between various classes or investment managers in order to improve investment results.

Equity market performance and corporate bond rates have a significant effect on our reported unfunded ABO, as the primary factors that drive the value of our unfunded ABO are the assumed discount rate and the actual return on plan assets. Additionally, equity market performance has a significant effect on our market-related value of plan assets (MRVPA), which is a calculated value and differs from the actual market value of plan assets. The MRVPA recognizes the difference between the actual market value and expected market value of our plan assets and is determined by our actuaries using a five-year moving weighted average methodology. Gains and losses on plan assets are spread through the MRVPA based on the five-year moving weighted average methodology, which affects the expected return on plan assets component of pension expense.

Pension Benefits

We sponsor two tax-qualified defined benefit retirement plans for our eligible employees, the AGL Resources Inc. Retirement Plan (AGL Retirement Plan) and the Employees' Retirement Plan of NUI Corporation (NUI Retirement Plan). A defined benefit plan specifies the amount of benefits an eligible participant eventually will receive using information about the participant.

We generally calculate the benefits under the AGL Retirement Plan based on age, years of service and pay. The benefit formula for the AGL Retirement Plan is a career average earnings formula, except for participants who were employees as of July 1, 2000, and who were at least 50 years of age as of that date. For those participants, we use a final average earnings benefit formula, and will continue to use this benefit formula for such participants until June 2010, at which time any of those participants who are still active will accrue future benefits under the career average earnings formula.

The NUI Retirement Plan covers substantially all of NUI's employees who were employed on or before December 31, 2006, except Florida City Gas union employees, who until February 2008 participated in a union-sponsored multiemployer plan. Pension benefits are based on years of credited service and final average compensation.

Postretirement Benefits

We sponsor a defined benefit postretirement health care plan for our eligible employees, the Health and Welfare Plan for Retirees and Inactive Employees of AGL Resources Inc. (AGL Postretirement Plan). Eligibility for these benefits is based on age and years of service.

The AGL Postretirement Plan covers all eligible AGL Resources employees who were employed as of June 30, 2002, if they reach retirement age while working for us. The state regulatory commissions have approved phase-ins that defer a portion of other postretirement benefits expense for future recovery. We recorded a regulatory asset for these future recoveries of $11 million as of December 31, 2008 and $12 million as of December 31, 2007. In addition, we recorded a regulatory liability of $5 million as of December 31, 2008 and $4 million as of December 31, 2007 for our expected expenses under the AGL Postretirement Plan. We expect to pay $7 million of insurance claims for the postretirement plan in 2009, but we do not anticipate making any additional contributions.

Effective December 8, 2003, the Medicare Prescription Drug, Improvement and Modernization Act of 2003 was signed into law. This act provides for a prescription drug benefit under Medicare (Part D) as well as a federal subsidy to sponsors of retiree health care benefit plans that provide a benefit that is at least actuarially equivalent to Medicare Part D.

Medicare-eligible participants receive prescription drug benefits through a Medicare Part D plan offered by a third party and to which we subsidize participant premiums. Medicare-eligible retirees who opt out of the AGL Postretirement Plan are eligible to receive a cash subsidy which may be used towards eligible prescription drug expenses.

SFAS 158 In September 2006, the FASB issued SFAS 158, which we adopted prospectively on December 31, 2007. SFAS 158 requires that we recognize all obligations related to defined benefit pensions and other postretirement benefits. This statement requires that we quantify the plans' funding status as an asset or a liability on our consolidated balance sheets. SFAS 158 further requires that we measure the plans' assets and obligations that determine our funded status as of the end of the fiscal year. We are also required to recognize as a component of OCI the changes in funded status that occurred during the year that are not recognized as part of net periodic benefit cost as explained in SFAS 87, or SFAS 106.

Based on the funded status of our defined benefit pension and postretirement benefit plans as of December 31, 2008, we reported an after-tax loss to our OCI of $111 million, a net increase of $184 million to accrued pension and postretirement obligations and a decrease of $73 million to accumulated deferred income taxes. Our adoption of SFAS 158 on December 31, 2007, had no impact on our earnings.

Contributions

Our employees do not contribute to the retirement plans. Additionally, we annually fund our postretirement plan; however, our retirees contribute 20% of medical premiums, 50% of the medical premium for spousal coverage and 100% of the dental premium to the AGL Postretirement Plan. We fund the plans by contributing at least the minimum amount required by applicable regulations and as recommended by our actuary. However, we may also contribute in excess of the minimum required amount. We calculate the minimum amount of funding using the projected unit credit cost method.

The Pension Protection Act (the Act) of 2006 contained new funding requirements for single employer defined benefit pension plans. The Act establishes a 100% funding target for plan years beginning after December 31, 2008. However, a delayed effective date of 2011 may apply if the pension plan meets the following targets; 92% funded in 2008; 94% funded in 2009; and 96% funded in 2010. In December 2008, the Worker, Retiree and Employer Recovery Act of 2008 allowed us to measure our 2008 and 2009 funding target at 92%. In 2008 and 2007, we did not make contributions as one was not required for our pension plans. For more information on our 2009 contributions to our pension plans, see Note 7.

The following tables present details about our pension and postretirement plans.

Dollars in millions	AGL Retirement Plan 2008	AGL Retirement Plan 2007	NUI Retirement Plan 2008	NUI Retirement Plan 2007	AGL Postretirement Plan 2008	AGL Postretirement Plan 2007
Change in benefit obligation						
Benefit obligation, January 1,	$353	$368	$74	$86	$94	$95
Service cost	7	7	-	-	-	1
Interest cost	22	21	4	5	6	6
Actuarial loss (gain)	9	(23)	-	(9)	(1)	-
Benefits paid	(21)	(20)	(6)	(8)	(4)	(8)
Benefit obligation, December 31,	$370	$353	$72	$74	$95	$94
Change in plan assets						
Fair value of plan assets, January 1,	$313	$303	$70	$72	$70	$63
Actual (loss) gain on plan assets	(93)	30	(22)	6	(21)	7
Employer contribution	1	-	-	-	4	8
Benefits paid	(21)	(20)	(6)	(8)	(4)	(8)
Fair value of plan assets, December 31,	$200	$313	$42	$70	$49	$70
Amounts recognized in the consolidated balance sheets consist of						
Current liability	$(1)	$(1)	$-	$-	$-	$-
Long-term liability	(169)	(39)	(30)	(4)	(46)	(24)
Total liability at December 31,	$(170)	$(40)	$(30)	$(4)	$(46)	$(24)
Assumptions used to determine benefit obligations						
Discount rate	6.2%	6.4%	6.2%	6.4%	6.2%	6.4%
Rate of compensation increase	3.7%	3.7%	-	3.7%	3.7%	3.7%
Accumulated benefit obligation	$352	$337	$73	$74	N/A	N/A

The components of our pension and postretirement benefit costs are set forth in the following table.

Dollars in millions	AGL Retirement Plan 2008	AGL Retirement Plan 2007	AGL Retirement Plan 2006	NUI Retirement Plan 2008	NUI Retirement Plan 2007	NUI Retirement Plan 2006	AGL Postretirement Plan 2008	AGL Postretirement Plan 2007	AGL Postretirement Plan 2006
Net benefit cost									
Service cost	$7	$7	$7	$-	$-	$-	$-	$1	$1
Interest cost	22	21	20	4	5	5	6	6	5
Expected return on plan assets	(26)	(25)	(24)	(6)	(6)	(7)	(6)	(5)	(4)
Net amortization	(1)	(1)	(1)	(1)	(1)	(1)	(4)	(4)	(4)
Recognized actuarial loss	3	7	9	-	-	-	1	1	1
Net annual pension cost	$5	$9	$11	$(3)	$(2)	$(3)	$(3)	$(1)	$(1)
Assumptions used to determine benefit costs									
Discount rate	6.4%	5.8%	5.5%	6.4%	5.8%	5.5%	6.4%	5.8%	5.5%
Expected return on plan assets	9.0%	9.0%	8.8%	9.0%	9.0%	8.8%	9.0%	9.0%	8.5%
Rate of compensation increase	3.7%	3.7%	4.0%	-	-	-	3.7%	3.7%	4.0%

There were no other changes in plan assets and benefit obligations recognized for our retirement and postretirement plans for the year ended December 31, 2008.The 2009 estimated OCI amortization and expected refunds for these plans are set forth in the following table.

In millions	AGL Retirement Plan	NUI Retirement Plan	AGL Postretirement Plan
Amortization of prior service cost	$(1)	$(1)	$(4)
Amortization of net loss	14	1	2
Refunds expected	-	-	-

We consider a number of factors in determining and selecting assumptions for the overall expected long-term rate of return on plan assets. We consider the historical long-term return experience of our assets, the current and expected allocation of our plan assets, and expected long-term rates of return. We derive these expected long-term rates of return with the assistance of our investment advisors and generally base these rates on a 10-year horizon for various asset classes, our expected investments of plan assets and active asset management as opposed to investment in a passive index fund. We base our expected allocation of plan assets on a diversified

portfolio consisting of domestic and international equity securities, fixed income, real estate, private equity securities and alternative asset classes.

We consider a variety of factors in determining and selecting our assumptions for the discount rate at December 31. We consider certain market indices, including Moody's Corporate AA long-term bond rate, the Citigroup Pension Liability rate, a single equivalent discount rate derived with the assistance of our actuaries and our own payment stream based on these indices to develop our rate. Consequently, we selected a discount rate of 6.2% as of December 31, 2008, following our review of these various factors. Our actual retirement and postretirement plans' weighted average asset allocations at December 31, 2008 and 2007 and our target asset allocation ranges are as follows:

	Target Range Asset Allocation	AGL Retirement Plan		NUI Retirement Plan		AGL Postretirement Plan	
		2008	2007	2008	2007	2008	2007
Equity	30%-95%	63%	68%	63%	71%	70%	73%
Fixed income	10%-40%	30%	25%	32%	27%	28%	26%
Real estate and other	10%-35%	6%	3%	-	2%	-	-
Cash	0%-10%	1%	4%	5%	-	2%	1%

Our health care trend rate for the AGL Postretirement Plan is capped at 2.5%. This cap limits the increase in our contributions to the annual change in the consumer price index (CPI). An annual CPI rate of 2.5% was assumed for future years. Assumed health care cost trend rates impact the amounts reported for our health care plans. A one-percentage-point change in the assumed health care cost trend rates would have the following effects for the AGL Postretirement Plan.

	AGL Postretirement Plan One-Percentage-Point	
In millions	Increase	Decrease
Effect on total of service and interest cost	$-	$-
Effect on accumulated postretirement benefit obligation	4	(3)

The following table presents expected benefit payments for the years ended December 31, 2009 through 2018 for our retirement and postretirement plans. There will be benefit payments under these plans beyond 2018.

In millions	AGL Retirement Plan	NUI Retirement Plan	AGL Postretirement Plan
2009	$20	$6	$7
2010	20	6	7
2011	21	6	7
2012	21	6	7
2013	21	6	7
2014-2018	116	28	35
Total	$219	$58	$70

The following table presents the amounts not yet reflected in net periodic benefit cost and included in accumulated OCI as of December 31, 2008.

In millions	AGL Retirement Plan	NUI Retirement Plan	AGL Postretirement Plan
Prior service credit	$(7)	$(12)	$(17)
Net loss	195	21	39
Accumulated OCI	188	9	22
Net amount recognized in consolidated balance sheet	(170)	(30)	(46)
Prepaid (accrued) cumulative employer contributions in excess of net periodic benefit cost	$18	$(21)	$(24)

There were no other changes in plan assets and benefit obligations recognized in our retirement and postretirement plans for the year ended December 31, 2008.

Employee Savings Plan Benefits

We sponsor the Retirement Savings Plus Plan (RSP), a defined contribution benefit plan that allows eligible participants to make contributions to their accounts up to specified limits. Under the RSP, we made matching contributions to participant accounts of $6 million in 2008, 2007 and 2006.

Note 4 - Stock-based and Other Incentive Compensation Plans and Agreements

General

We currently sponsor the following stock-based and other incentive compensation plans and agreements:

	Shares issuable upon exercise of outstanding stock options and / or SARs (1)	Shares issuable and / or SARs available for issuance (1)	Details
2007 Omnibus Performance Incentive Plan	280,200	4,561,386	Grants of incentive and nonqualified stock options, stock appreciation rights (SARs), shares of restricted stock, restricted stock units and performance cash awards to key employees.
Long-Term Incentive Plan (1999) (2)	2,221,407	-	Grants of incentive and nonqualified stock options, shares of restricted stock and performance units to key employees.
Officer Incentive Plan	76,224	211,409	Grants of nonqualified stock options and shares of restricted stock to new-hire officers.
2006 Non-Employee Directors Equity Compensation Plan	not applicable	173,433	Grants of stock to non-employee directors in connection with non-employee director compensation (for annual retainer, chair retainer and for initial election or appointment).
1996 Non-Employee Directors Equity Compensation Plan	42,924	13,304	Grants of nonqualified stock options and stock to non-employee directors in connection with non-employee director compensation (for annual retainer and for initial election or appointment). The plan was amended in 2002 to eliminate the granting of stock options.
Employee Stock Purchase Plan	not applicable	321,912	Nonqualified, broad-based employee stock purchase plan for eligible employees

(1) As of December 31, 2008
(2) Following shareholder approval of the Omnibus Performance Incentive Plan, no further grants will be made except for reload options that may be granted under the plan's outstanding options.

Accounting Treatment and Compensation Expense

Effective January 1, 2006, we adopted SFAS 123R, using the modified prospective application transition method. Prior to January 1, 2006, we accounted for our share-based payment transactions in accordance with SFAS 123, as amended by SFAS 148. This allowed us to rely on APB 25 and related interpretations in accounting for our stock-based compensation plans under the intrinsic value method. SFAS 123R requires us to measure and recognize stock-based compensation expense in our financial statements based on the estimated fair value at the date of grant for our stock-based awards, which include:

- stock options
- stock awards, and
- performance units (restricted stock units and performance cash units)

Performance-based stock awards and performance units contain market conditions. Stock options, restricted stock awards and performance units also contain a service condition. In accordance with SFAS 123R, we recognize compensation expense over the requisite service period for:

- awards granted on or after January 1, 2006 and
- unvested awards previously granted and outstanding as of January 1, 2006

In addition, we estimate forfeitures over the requisite service period when recognizing compensation expense. These estimates are adjusted to the extent that actual forfeitures differ, or are expected to materially differ, from such estimates.

The following table provides additional information on compensation costs and income tax benefits related to our stock-based compensation awards. We recorded these amounts in our consolidated statements of income for the years ended December 31, 2008, 2007 and 2006.

In millions	2008	2007	2006
Compensation costs	$10	$9	$9
Income tax benefits	1	3	3

Prior to our adoption of SFAS 123R, benefits of tax deductions in excess of recognized compensation costs were reported as operating cash flows. SFAS 123R requires excess tax benefits to be reported as a financing cash inflow rather than as a reduction of taxes paid. In 2007 and 2006, our cash flows from financing activities included an immaterial amount for recognized compensation costs in excess of the benefits of tax deductions. In 2008, we included $2 million of such benefits in cash flow provided by operating activities.

Incentive and Nonqualified Stock Options

We grant incentive and nonqualified stock options with a strike price equal to the fair market value on the date of the grant. "Fair market value" is defined under the terms of the applicable plans as the most recent closing price per share of AGL Resources common stock as reported in *The Wall Street Journal*. Stock options generally have a three-year vesting period. Nonqualified options generally expire 10 years after the date of grant. Participants realize value from option grants only to the extent that the fair market value of our common stock on the date of exercise of the option exceeds the fair market value of the common stock on the date of the grant. Compensation expense associated with stock options is generally recorded over the option vesting period; however, for unvested options that are granted to employees who are retirement-eligible, the remaining compensation expense is recorded in the current period rather than over the remaining vesting period.

As of December 31, 2008, we had $2 million of total unrecognized compensation costs related to stock options. These costs are expected to be recognized over the remaining average requisite service period of approximately 2 years. Cash received from stock option exercises for 2008 was $5 million, and the income tax benefit from stock option exercises was $1 million. The following tables summarize activity related to stock options for key employees and non-employee directors.

Stock Options

	Number of options	Weighted average exercise price	Weighted average remaining life (in years)	Aggregate intrinsic value (in millions)
Outstanding – December 31, 2005	2,221,245	$27.79		
Granted	914,216	35.81		
Exercised	(543,557)	24.69		
Forfeited (1)	(266,418)	34.93		
Outstanding – December 31, 2006	2,325,486	$30.85		
Granted	735,196	39.11		
Exercised	(361,385)	27.78		
Forfeited (1)	(181,799)	36.75		
Outstanding – December 31, 2007	2,517,498	$33.28	7.1	
Granted	258,017	38.70	8.5	
Exercised	(212,600)	23.53	2.1	
Forfeited (1)	(86,926)	38.01	8.5	
Outstanding – December 31, 2008	2,475,989	$34.52	6.7	$3
Exercisable – December 31, 2008	1,447,508	$32.18	5.9	$3

(1) Includes 4,226 shares which expired in 2008, none in 2007 and 452 in 2006.

Unvested Stock Options

	Number of unvested options	Weighted average exercise price	Weighted average remaining vesting period (in years)	Weighted average fair value
Outstanding – December 31, 2007	1,414,962	$37.02	1.6	$4.82
Granted	258,017	38.70	2.0	2.64
Forfeited	(51,497)	38.68	2.2	4.39
Vested	(593,001)	36.26	-	4.77
Outstanding – December 31, 2008	1,028,481	$37.80	1.1	$4.33

Information about outstanding and exercisable options as of December 31, 2008, is as follows.

	Options outstanding			Options Exercisable	
Range of Exercise Prices	Number of options	Weighted average remaining contractual life (in years)	Weighted average exercise price	Number of options	Weighted average exercise price
$16.25 to $20.79	27,274	1.5	$19.53	27,274	$19.53
$20.80 to $25.34	173,326	3.1	21.82	173,326	21.82
$25.35 to $29.89	233,157	4.4	27.07	233,157	27.07
$29.90 to $34.44	406,701	6.0	33.21	406,701	33.21
$34.45 to $38.99	1,388,835	7.5	37.15	587,250	36.83
$39.00 to $43.54	246,696	8.8	39.43	19,800	41.20
Outstanding - Dec. 31, 2008	2,475,989	6.7	$34.52	1,447,508	$32.18

Summarized below are outstanding options that are fully exercisable.

Exercisable at:	Number of options	Weighted average exercise price
December 31, 2006	1,013,672	$25.45
December 31, 2007	1,102,536	$28.48
December 31, 2008	1,447,508	$32.18

In accordance with the fair value method of determining compensation expense, we use the Black-Scholes pricing model. Below are the ranges for per share value and information about the underlying assumptions used in developing the grant date value for each of the grants made during 2008, 2007 and 2006.

	2008	2007	2006
Expected life (years)	7	7	7
Risk-free interest rate % (1)	2.93 - 3.31	3.87 – 5.05	4.5 – 5.1
Expected volatility % (2)	12.8 - 13.0	13.2 – 14.3	14.2 – 15.9
Dividend yield % (3)	4.3 – 4.84	3.8 – 4.2	3.7 – 4.2
Fair value of options granted (4)	$0.19 – $2.69	$3.55 – $5.98	$4.55– $6.18

(1) US Treasury constant maturity - 7 years
(2) Volatility is measured over 7 years, the expected life of the options; weighted average volatility % for 2008 was 13.0%, 2007 was 14.2% and 2006 was 15.8%.
(3) Weighted average dividend yields for 2008 was 4.3%, 2007 was 4.2% and 2006 was 4.1%
(4) Represents per share value.

Intrinsic value for options is defined as the difference between the current market value and the grant price. Total intrinsic value of options exercised during 2008 was $2 million. With the implementation of our share repurchase program in 2006, we use shares purchased under this program to satisfy share-based exercises to the extent that repurchased shares are available. Otherwise, we issue new shares from our authorized common stock.

Performance Units

In general, a performance unit is an award of the right to receive (i) an equal number of shares of our common stock, which we refer to as a restricted stock unit or (ii) cash, subject to the achievement of certain pre-established performance criteria, which we refer to as a performance cash unit. Performance units are subject to certain transfer restrictions and forfeiture upon termination of employment. The dollar value of restricted stock unit awards is equal to the grant date fair value of the awards, over the requisite service period, determined pursuant to FAS 123R. The dollar value of performance cash unit awards is equal to the grant date fair value of the awards measured against progress towards the performance measure, over the requisite service period, determined pursuant to FAS 123R. No other assumptions are used to value these awards.

Restricted Stock Units In general, a restricted stock unit is an award that represents the opportunity to receive a specified number of shares of our common stock, subject to the achievement of certain pre-established performance criteria. In 2008, we granted to a select group a total of 206,700 restricted stock units (the 2008 restricted stock units), of which 196,100 of these units were outstanding as of December 31, 2008. These restricted stock units had a performance measurement period that ended December 31, 2008, and a performance measure related to a basic earnings per share goal that was met.

Performance Cash Units In general, a performance cash unit is an award that represents the opportunity to receive a cash award, subject to the achievement of certain pre-established performance criteria. In 2008, we granted performance cash awards to a select group of officers. These awards have a performance measure that is related to annual growth in basic earnings per share, plus the average dividend yield, as adjusted to reflect the effect of economic value created during the performance measurement period by our wholesale services segment. In 2008, the basic earnings per share growth target was not achieved with respect to the 2007 awards. Accruals in connection with these grants are as follows:

Dollars in millions	Units	Measurement period end date	Accrued at Dec. 31, 2008	Maximum aggregate payout
Year of grant				
2006 (1)	15	Dec. 31, 2008	$1	$2
2007	23	Dec. 31, 2009	-	3
2008	3	Dec. 31, 2010	1	2

(1) In February 2009, the 2006 performance cash units vested and resulted in an aggregate payout of $1 million.

Stock and Restricted Stock Awards

In general, we refer to a stock award as an award of our common stock that is 100% vested and not forfeitable as of the date of grant. We refer to restricted stock as an award of our common stock that is subject to time-based vesting or achievement of performance measures. Restricted stock awards are subject to certain transfer restrictions and forfeiture upon termination of employment. The dollar value of both stock awards and restricted stock awards are equal to the grant date fair value of the awards, over the requisite service period, determined pursuant to FAS 123R. No other assumptions are used to value the awards.

Stock Awards – Non-Employee Directors Non-employee director compensation may be paid in shares of our common stock in connection with initial election, the annual retainer, and chair retainers, as applicable. Stock awards for non-employee directors are 100% vested and nonforfeitable as of the date of grant. The following table summarizes activity during 2008, related to stock awards for our non-employee directors.

Restricted Stock Awards	Shares of restricted stock	Weighted average fair value
Issued	15,674	$35.05
Forfeited	-	-
Vested	15,674	$35.05
Outstanding	-	-

Restricted Stock Awards – Employees From time to time, we may give restricted stock awards to our key employees. The following table summarizes activity during the year ended December 31, 2008, related to restricted stock awards for our key employees.

Restricted Stock Awards	Shares of restricted stock	Weighted average remaining vesting period (in years)	Weighted average fair value
Outstanding – December 31, 2007 (1)	349,036	2.1	$38.15
Issued	28,024	0.6	35.63
Forfeited	(6,483)	1.2	38.43
Vested	(70,199)	-	36.75
Outstanding – December 31, 2008 (1)	300,378	1.3	$37.87

(1) Subject to restriction

Employee Stock Purchase Plan (ESPP)

Under the ESPP, employees may purchase shares of our common stock in quarterly intervals at 85% of fair market value. Employee contributions under the ESPP may not exceed $25,000 per employee during any calendar year.

	2008	2007	2006
Shares purchased on the open market	66,247	52,299	45,361
Average per-share purchase price	$33.22	$34.69	$31.40
Purchase price discount	$326,615	$313,584	$252,752

Note 5 - Common Shareholders' Equity

Treasury Shares

Our Board of Directors has authorized us to purchase up to 8 million treasury shares through our repurchase plans. These plans are used to offset shares issued under our employee and non-employee director incentive compensation plans and our dividend reinvestment and stock purchase plans. Stock purchases under these plans may be made in the open market or in private transactions at times and in amounts that we deem appropriate. There is no guarantee as to the exact number of shares that we will purchase, and we can terminate or limit the program at any time. We will hold the purchased shares as treasury shares and account for them using the cost method. As of December 31, 2008 we had 5 million remaining authorized shares available for purchase. The following table provides more information on our treasury share activity.

In millions, except per share amounts	Total amount purchased	Shares purchased	Weighted average price per share
2006	$38	1	$36.67
2007	80	2	39.56
2008	-	-	-

Dividends

Our common shareholders may receive dividends when declared at the discretion of our Board of Directors. Dividends may be paid in cash, stock or other form of payment, and payment of future dividends will depend on our future earnings, cash flow, financial requirements and other factors. Additionally, we derive a substantial portion of our consolidated assets, earnings and cash flow from the operation of regulated utility subsidiaries, whose legal authority to pay dividends or make other distributions to us is subject to regulation. As with most other companies, the payment of dividends are restricted by laws in the states where we do business. In certain cases, our ability to pay dividends to our common shareholders is limited by the following:

- our ability to pay our debts as they become due in the usual course of business, satisfy our obligations under certain financing agreements, including debt-to-capitalization covenants
- our total assets are less than our total liabilities, and
- our ability to satisfy our obligations to any preferred shareholders

Note 6 - Debt

Our issuance of various securities, including long-term and short-term debt, is subject to customary approval or authorization by state and federal regulatory bodies, including state public service commissions, the SEC and the FERC as granted by the Energy Policy Act of 2005. The following table provides more information on our various securities.

In millions	Year(s) due	Interest rate (1)	Weighted average interest rate (2)	Outstanding as of December 31, 2008	2007
Short-term debt					
Credit Facilities	2009	0.8%	2.9%	$500	$-
Commercial paper	2009	2.2	3.6	273	566
SouthStar line of credit	2009	1.1	2.9	75	-
Sequent lines of credit	2009	0.9	2.3	17	1
Capital leases	2009	4.9	4.9	1	1
Pivotal Utility line of credit	-	-	-	-	12
Total short-term debt		**1.3%**	**3.3%**	**$866**	**$580**
Long-term debt - net of current portion					
Senior notes	2011-2034	4.5-7.1%	5.9%	$1,275	$1,275
Gas facility revenue bonds	2022-2033	0.7-5.3	3.2	200	200
Medium-term notes	2012-2027	6.6-9.1	7.8	196	196
Capital leases	2013	4.9	4.9	4	6
AGL Capital interest rate swaps		-	-	-	(2)
Total long-term debt		**5.6%**	**5.7%**	**$1,675**	**$1,675**
Total debt		**4.1%**	**5.2%**	**$2,541**	**$2,255**

(1) As of December 31, 2008.
(2) For the year ended December 31, 2008.

Short-term Debt

Our short-term debt at December 31, 2008 and 2007 was composed of borrowings under our commercial paper program; Credit Facilities; current portions of our capital lease obligations; and lines of credit for Sequent, SouthStar and Pivotal Utility.

Commercial Paper and Credit Facilities Our commercial paper consists of short-term, unsecured promissory notes with maturities ranging from 2 to 16 days. These unsecured promissory notes are supported by our $1 billion Credit Facility which expires in August 2011 and a supplemental $140 million Credit Facility that expires in September 2009. We have the option to request an increase in the aggregate principal amount available for borrowing under the $1 billion Credit Facility to $1.25 billion on not more than three occasions during each calendar year. The $140 million Credit Facility allows for the option to request an increase in the borrowing capacity to $150 million.

Several of our subsidiaries, including SouthStar participate in our commercial paper program. As of December 31, 2008, we had $273 million of commercial paper borrowings and $500 million outstanding under the Credit Facilities. As of December 31, 2007, we did not have any amounts outstanding under the Credit Facilities.

SouthStar Credit Facility SouthStar's five-year $75 million unsecured credit facility expires in November 2011. SouthStar will use this line of credit for working capital and its general corporate needs. We had $75 million of outstanding borrowings on this line of credit at December 31, 2008. At December 31, 2007, there were no outstanding borrowings on this line of credit. We do not guarantee or provide any other form of security for the repayment of this credit facility.

Sequent Lines of Credit In June 2008, we extended Sequent's $25 million unsecured line of credit to June 2009, which bears interest at the federal funds effective rate plus 0.75%. In September 2008, Sequent extended its second $20 million line of credit that bears interest at the LIBOR rate plus 1.0% to September 2009. In December 2008 the terms of this line of credit were amended to $5 million bearing interest at the LIBOR Rate plus 3.0%. Both lines of credit are used solely for the posting of margin deposits for NYMEX transactions and are unconditionally guaranteed by us.

Pivotal Utility Line of Credit This $20 million line of credit, which had been established to support Elizabethtown Gas' hedging program, was terminated in October 2008. For more information on this hedging program, see Note 2.

Long-term Debt

Our long-term debt at December 31, 2008 and 2007 matures more than one year from the balance sheet date and consists of medium-term notes: Series A, Series B and Series C, which we issued under an indenture dated December 1, 1989; senior notes; gas facility revenue bonds; and capital leases. Our annual maturities of long-term debt, excluding capital leases of $4 million, are as follows:

Year	Amount (in millions)
2011	$300
2012	15
2013	225
2015	200
2016	300
2017	22
2021	30
2022	93
2024	20
2026	69
2027	53
2032	55
2033	39
2034	250
Total	$1,671

Medium-term notes The following table provides more information on our medium-term notes, which were issued to refinance portions of our existing short-term debt and for general corporate purposes. Our annual maturities of our medium-term notes are as follows:

Issue Date	Amount (in millions)	Interest rate	Maturity
June 1992	$5	8.4%	June 2012
June 1992	5	8.3	June 2012
June 1992	5	8.3	July 2012
July 1997	22	7.2	July 2017
Feb. 1991	30	9.1	Feb. 2021
April 1992	5	8.55	April 2022
April 1992	25	8.7	April 2022
April 1992	6	8.55	April 2022
May 1992	10	8.55	May 2022
Nov. 1996	30	6.55	Nov. 2026
July 1997	53	7.3	July 2027
Total	$196		

Senior Notes The following table provides more information on our senior notes, which were issued to refinance portions of our existing short-term and long-term debt, to finance acquisitions and for general corporate purposes.

Issue date	Amount (in millions)	Interest rate	Maturity
Feb. 2001	$300	7.125%	Jan 2011
July 2003	225	4.45	Apr 2013
Dec. 2004	200	4.95	Jan 2015
June 2006	175	6.375	Jul 2016
Dec. 2007	125	6.375	Jul 2016
Sep. 2004	250	6.0	Oct 2034
Total	$1,275		

The trustee with respect to all of the above-referenced senior notes is The Bank of New York Trust Company, N.A., pursuant to an indenture dated February 20, 2001. We fully and unconditionally guarantee all of our senior notes.

Gas Facility Revenue Bonds Pivotal Utility is party to a series of loan agreements with the New Jersey Economic Development Authority (NJEDA) pursuant to which the NJEDA has issued a series of gas facility revenue bonds as shown in the following table.

Issue Date	Amount (in millions)	Interest rate	Maturity
July 1994 (1)	$47	0.70%	Oct. 2022
July 1994 (1)	20	1.10	Oct. 2024
June 1992 (1)	39	1.10	June 2026
June 1992 (1)	55	0.85	June 2032
July 1997	39	5.25	Nov. 2033
Total	$200		

(1) Interest rate is adjusted daily or weekly. Rates indicated are as of December 31, 2008.

In 2008, a portion of our gas facility revenue bonds failed to draw enough potential buyers due to the dislocation or disruption in the auction markets as a result of the downgrades to the bond insurers that provide credit protections for these instruments which reduced investor demand and liquidity for these types of investments. In March and April 2008, we tendered these bonds with a cumulative principal amount of $161 million through commercial paper borrowings.

In June and September 2008, we completed a Letter of Credit Agreement for these bonds which provided additional credit support which increased investor demand for the bonds. As a result, these bonds with a cumulative principal amount of $161 million were successfully auctioned and issued as variable rate gas facility bonds and reduced our commercial paper borrowings. The bonds with principal amounts of $55 million, $47 million and $39 million now have interest rates that reset daily and the bond with a principal amount of $20 million has an interest rate that resets weekly. There was no change to the maturity dates on these bonds.

Preferred Securities As of December 31, 2008, we had 10 million shares of authorized, unissued Class A junior participating preferred stock, no par value, and 10 million shares of authorized, unissued preferred stock, no par value.

Capital Leases Our capital leases consist primarily of a sale/leaseback transaction completed in 2002 by Florida City Gas related to its gas meters and other equipment and will be repaid at approximately $1 million per year until 2013. Pursuant to the terms of the lease agreement, Florida City Gas is required to insure the leased equipment during the lease term. In addition, at the expiration of the lease term, Florida City Gas has the option to purchase the leased meters from the lessor at their fair market value. The fair market value of the equipment will be determined on the basis of an arm's-length transaction between an informed and willing buyer.

Default Events

Our Credit Facilities' financial covenants requires us to maintain a ratio of total debt to total capitalization of no greater than 70%; however, our goal is to maintain this ratio at levels between 50% and 60%. Our ratio of total debt to total capitalization calculation contained in our debt covenant includes minority interest, standby letters of credit, surety bonds and the exclusion of other comprehensive income pension adjustments. Adjusting for these items, our debt-to-equity calculation, as defined by our Credit Facilities, was 59% at December 31, 2008 and 58% at December 31, 2007. These amounts are within our required and targeted ranges. Our debt-to-equity calculation, as calculated from our consolidated balance sheets, was 61% at December 31, 2008 and 58% at December 31, 2007.

Our debt instruments and other financial obligations include provisions that, if not complied with, could require early payment, additional collateral support or similar actions. Our most important default events include:

- a maximum leverage ratio
- insolvency events and nonpayment of scheduled principal or interest payments
- acceleration of other financial obligations
- change of control provisions

We have no trigger events in our debt instruments that are tied to changes in our specified credit ratings or our stock price and have not entered into any transaction that requires us to issue equity based on credit ratings or other trigger events. We are currently in compliance with all existing debt provisions and covenants.

Note 7 - Commitments and Contingencies

We have incurred various contractual obligations and financial commitments in the normal course of our operating and financing activities that are reasonably likely to have a material affect on liquidity or the availability of requirements for capital resources. Contractual obligations include future cash payments required under existing contractual arrangements, such as debt and lease agreements. These obligations may result from both general financing activities and from commercial arrangements that are directly supported by related revenue-producing activities. As we do for other subsidiaries, we provide guarantees to certain gas suppliers for SouthStar in support of payment obligations. The following table illustrates our expected future contractual payments such as debt and lease agreements, and commitment and contingencies as of December 31, 2008.

In millions	Total	2009	2010 & 2011	2012 & 2013	2014 & thereafter
Recorded contractual obligations:					
Long-term debt	$1,675	$-	$302	$242	$1,131
Short-term debt	866	866	-	-	-
PRP costs (1)	189	49	91	49	-
Environmental remediation liabilities (1)	106	17	41	38	10
Total	$2,836	$932	$434	$329	$1,141
Unrecorded contractual obligations and commitments (2):					
Pipeline charges, storage capacity and gas supply (3)	$1,713	$491	$573	$299	$350
Interest charges (4)	975	94	168	137	576
Operating leases (5)	137	30	45	25	37
Standby letters of credit, performance / surety bonds	52	48	3	1	-
Asset management agreements (6)	32	12	19	1	-
Pension contributions (7)	7	7	-	-	-
Total	$2,916	$682	$808	$463	$963

(1) Includes charges recoverable through rate rider mechanisms.
(2) In accordance with GAAP, these items are not reflected in our consolidated balance sheets.
(3) Charges recoverable through a natural gas cost recovery mechanism or alternatively billed to Marketers. Also includes demand charges associated with Sequent. A subsidiary of NUI entered into two 20-year agreements for the firm transportation and storage of natural gas during 2003 with annual aggregate demand charges of approximately $5 million. As a result of our acquisition of NUI and in accordance with SFAS 141, we valued the contracts at fair value and established a long-term liability of $38 million for the excess liability that will be amortized to our consolidated statements of income over the remaining lives of the contracts of $2 million annually through November 2023 and $1 million annually from November 2023 to November 2028. The gas supply amount includes SouthStar gas commodity purchase commitments of 15 Bcf at floating gas prices calculated using forward natural gas prices as of December 31, 2008, and is valued at $85 million.
(4) Floating rate debt is based on the interest rate as of December 31, 2008 and the maturity of the underlying debt instrument. As of December 31, 2008, we have $35 million of accrued interest on our consolidated balance sheet that will be paid in 2009.
(5) We have certain operating leases with provisions for step rent or escalation payments and certain lease concessions. We account for these leases by recognizing the future minimum lease payments on a straight-line basis over the respective minimum lease terms, in accordance with SFAS 13. However, this lease accounting treatment does not affect the future annual operating lease cash obligations as shown herein.
(6) Represent fixed-fee minimum payments for Sequent's affiliated asset management agreements.
(7) Based on the current funding status of the plans, we would be required to make a minimum contribution to our pension plans of approximately $7 million in 2009. We may make additional contributions in 2009.

Environmental Remediation Costs

We are subject to federal, state and local laws and regulations governing environmental quality and pollution control. These laws and regulations require us to remove or remedy the effect on the environment of the disposal or release of specified substances at current and former operating sites.

Atlanta Gas Light The presence of coal tar and certain other byproducts of a natural gas manufacturing process used to produce natural gas prior to the 1950s has been identified at or near 10 former Atlanta Gas Light operating sites in Georgia and at 3 sites of predecessor companies in Florida. Atlanta Gas Light has active environmental remediation or monitoring programs in effect at 10 of these sites. Two sites in Florida are currently in the investigation or preliminary engineering design phase, and one Georgia site has been deemed compliant with state standards.

Atlanta Gas Light has customarily reported estimates of future remediation costs for these former sites based on probabilistic models of potential costs. These estimates are reported on an undiscounted

basis. As cleanup options and plans mature and cleanup contracts are entered into, Atlanta Gas Light is better able to provide conventional engineering estimates of the likely costs of remediation at its former sites. These estimates contain various engineering uncertainties, but Atlanta Gas Light continuously attempts to refine and update these engineering estimates.

Atlanta Gas Light's current estimate for the remaining cost of future actions at its former operating sites is $38 million, which may change depending on whether future measures for groundwater will be required. As of December 31, 2008, we have recorded a liability equal to the low end of the range of $38 million, of which $10 million is expected to be incurred over the next 12 months.

These liabilities do not include other potential expenses, such as unasserted property damage claims, personal injury or natural resource damage claims, unbudgeted legal expenses or other costs for which Atlanta Gas Light may be held liable but for which it cannot reasonably estimate an amount.

The ERC liability is included as a corresponding regulatory asset, which is a combination of accrued ERC and unrecovered cash expenditures for investigation and cleanup costs. Atlanta Gas Light has three ways of recovering investigation and cleanup costs. First, the Georgia Commission has approved an ERC recovery rider. The ERC recovery mechanism allows for recovery of expenditures over a five-year period subsequent to the period in which the expenditures are incurred. Atlanta Gas Light expects to collect $17 million in revenues over the next 12 months under the ERC recovery rider, which is reflected as a current asset. The amounts recovered from the ERC recovery rider during the last three years were:

- $22 million in 2008
- $26 million in 2007
- $29 million in 2006

The second way to recover costs is by exercising the legal rights Atlanta Gas Light believes it has to recover a share of its costs from other potentially responsible parties, typically former owners or operators of these sites. There were no material recoveries from potentially responsible parties during 2008, 2007 or 2006.

The third way to recover costs is from the receipt of net profits from the sale of remediated property.

Elizabethtown Gas In New Jersey, Elizabethtown Gas is currently conducting remediation activities with oversight from the New Jersey Department of Environmental Protection. Although we cannot estimate the actual total cost of future environmental investigation and remediation efforts with precision, based on probabilistic models similar to those used at Atlanta Gas Light's former operating sites, the range of reasonably possible costs is $58 million to $116 million. As of December 31, 2008, we have recorded a liability equal to the low end of that range, or $58 million, of which $7 million in expenditures are expected to be incurred over the next 12 months.

Prudently incurred remediation costs for the New Jersey properties have been authorized by the New Jersey Commission to be recoverable in rates through a remediation adjustment clause. As a result, Elizabethtown Gas has recorded a regulatory asset of approximately $66 million, inclusive of interest, as of December 31, 2008, reflecting the future recovery of both incurred costs and accrued carrying charges. Elizabethtown Gas expects to collect approximately $1 million in revenues over the next 12 months. Elizabethtown Gas has also been successful in recovering a portion of remediation costs incurred in New Jersey from its insurance carriers and continues to pursue additional recovery.

We own a site in Elizabeth City, North Carolina that is subject to a remediation order by the North Carolina Department of Energy and Natural Resources. We had recorded liabilities of $10 million as of December 31, 2008 and $11 million as of December 31, 2007 related to this site.

There is one other site in North Carolina where investigation and remediation is likely, although no remediation order exists and we do not believe costs associated with this site can be reasonably estimated. In addition, there are as many as six other sites with which we had some association, although no basis for liability has been asserted, and accordingly we have not accrued any remediation liability. There are currently no cost recovery mechanisms for the environmental remediation sites in North Carolina.

Rental Expense

We incurred rental expense in the amounts of $21 million in 2008, $21 million in 2007 and $19 million in 2006.

Litigation

We are involved in litigation arising in the normal course of business. We believe the ultimate resolution of such litigation will not have a material adverse effect on our consolidated financial position, results of operations or cash flows.

In August 2006, the Office of Mineral Resources of the Louisiana DNR informed Jefferson Island that its mineral lease – which authorizes salt extraction to

create two new storage caverns – at Lake Peigneur had been terminated. The Louisiana DNR identified two bases for the termination: (1) failure to make certain mining leasehold payments in a timely manner, and (2) the absence of salt mining operations for six months.

In September 2006, Jefferson Island filed suit against the State of Louisiana, in the 19th Judicial District Court in Baton Rouge, to maintain its lease to complete an ongoing natural gas storage expansion project in Louisiana. The project would add two salt dome storage caverns under Lake Peigneur to the two caverns currently owned and operated by Jefferson Island. In its suit, Jefferson Island alleges that the Louisiana DNR accepted all leasehold payments without reservation and never provided Jefferson Island with notice and opportunity to cure, as required by state law. In its answer to the suit, the State denied that anyone with proper authority approved the late payments. As to the second basis for termination, the suit contends that Jefferson Island's lease with the State of Louisiana was amended in 2004 so that mining operations are no longer required to maintain the lease. The State's answer denies that the 2004 amendment was properly authorized. In March 2008, Jefferson Island served discovery requests on the State of Louisiana and sought a trial date in its pending lawsuit over its natural gas storage expansion project at Lake Peigneur. Jefferson Island also asserted additional claims against the State seeking to obtain a declaratory ruling that Jefferson Island's surface lease, under which it operates its existing two storage caverns, authorizes the creation of the two new expansion caverns separate and apart from the mineral lease challenged by the State.

In addition, in June 2008, the State of Louisiana passed legislation restricting water usage from the Chicot aquifer, which is a main source of fresh water required for the expansion of our Jefferson Island capacity. We contend that this legislation is unconstitutional and have sought to amend the pending litigation to seek a declaration that the legislation is invalid and cannot be enforced. Even if we are not successful on those grounds, we believe the legislation does not materially impact the feasibility of the expansion project. If we are unable to reach a settlement, we are not able to predict the outcome of the litigation. As of January 2009, our current estimate of costs incurred that would be considered unusable if the Louisiana DNR was successful in terminating our lease and causing us to cease the expansion project is approximately $6 million.

In February 2008, the consumer affairs staff of the Georgia Commission alleged that GNG charged its customers on variable rate plans prices for natural gas that were in excess of the published price, that it failed to give proper notice regarding the availability of potentially lower price plans and that it changed its methodology for computing variable rates. GNG asserted that it fully complied with all applicable rules and regulations, that it properly charged its customers on variable rate plans the rates on file with the Georgia Commission, and that, consistent with its terms and conditions of service, it routinely switched customers who requested to move to another price plan for which they qualified. In order to resolve this matter GNG agreed to pay $2.5 million in the form of credits to customers, or as directed by the Georgia Commission, which was recorded in our statements of consolidated income for the year ended December 31, 2008.

In February 2008, a class action lawsuit was filed in the Superior Court of Fulton County in the State of Georgia against GNG containing similar allegations to those asserted by the Georgia Commission staff and seeking damages on behalf of a class of GNG customers. This lawsuit was dismissed in September 2008. In October 2008, the plaintiffs appealed the dismissal of the lawsuit and the parties are in the process of filing briefs on that appeal.

In March 2008, a second class action suit was filed against GNG in the State Court of Fulton County in the State of Georgia, regarding monthly service charges. This lawsuit alleges that GNG arbitrarily assigned customer service charges rather than basing each customer service charge on a specific credit score. GNG asserts that no violation of law or Georgia Commission rules has occurred, that this lawsuit is without merit and has filed motions to dismiss this class action suit on various grounds. The ultimate resolution of this lawsuit cannot be determined, but is not expected to have a material adverse effect on our condensed consolidated results of operations, cash flows or financial condition.

Review of Compliance with FERC Regulations

In 2008, we conducted an internal review of our compliance with FERC interstate natural gas pipeline capacity release rules and regulations. Independent of our internal review, we also received data requests from FERC's Office of Enforcement relating specifically to compliance with FERC's capacity release posting and bidding requirements. We have responded to FERC's data requests and are fully cooperating with FERC in its investigation. As a result of this process, we have identified certain instances of possible non-compliance. We are committed to full regulatory compliance and we have met with the FERC Enforcement staff to discuss with them these instances of possible non-compliance. Accordingly we have accrued an appropriate

estimate of possible penalties assessed by the FERC. This estimate does not have, and management does not believe the ultimate resolution will have, a material financial impact to our consolidated results of operations, cash flows or financial condition.

Note 8 - Income Taxes

We have two categories of income taxes in our statements of consolidated income: current and deferred. Current income tax expense consists of federal and state income tax less applicable tax credits related to the current year. Deferred income tax expense generally is equal to the changes in the deferred income tax liability and regulatory tax liability during the year.

Investment and Other Tax Credits

Deferred investment tax credits associated with distribution operations are included as a regulatory liability in our consolidated balance sheets (see Note 1, "Accounting Policies and Methods of Application"). These investment tax credits are being amortized over the estimated life of the related properties as credits to income in accordance with regulatory requirements. In 2007, we invested in a guaranteed affordable housing tax credit fund. We reduce income tax expense in our statements of consolidated income for the investment tax credits and other tax credits associated with our nonregulated subsidiaries, including the affordable housing credits. Components of income tax expense shown in the statements of consolidated income are shown in the following table.

Income Tax Expense

The relative split between current and deferred taxes is due to a variety of factors including true ups of prior year tax returns, and most importantly, the timing of our property-related deductions.

In millions	2008	2007	2006
Current income taxes			
Federal	$37	$86	$(4)
State	7	12	2
Deferred income taxes			
Federal	77	23	115
State	12	7	18
Amortization of investment tax credits	(1)	(1)	(2)
Total	$132	$127	$129

The reconciliations between the statutory federal income tax rate, the effective rate and the related amount of tax for the years ended December 31, 2008, 2007 and 2006 are presented in the following table.

	2008		2007		2006	
In millions	Amount	% of pretax income	Amount	% of pretax income	Amount	% of pretax income
Computed tax expense at statutory rate	$122	35.0%	$118	35.0%	$119	35.0%
State income tax, net of federal income tax benefit	14	4.0	13	3.8	12	3.6
Amortization of investment tax credits	(1)	(0.4)	(1)	(0.3)	(2)	(0.5)
Affordable housing credits	(2)	(0.5)	(1)	(0.3)	-	-
Flexible dividend deduction	(2)	(0.5)	(2)	(0.6)	(2)	(0.5)
Other – net	1	0.2	-	-	2	0.2
Total income tax expense at effective rate	$132	37.8%	$127	37.6%	$129	37.8%

Accumulated Deferred Income Tax Assets and Liabilities

We report some of our assets and liabilities differently for financial accounting purposes than we do for income tax purposes. We report the tax effects of the differences in those items as deferred income tax assets or liabilities in our consolidated balance sheets. We measure the assets and liabilities using income tax rates that are currently in effect. Because of the regulated nature of the utilities' business, we recorded a regulatory tax liability in accordance with SFAS 109, which we are amortizing over approximately 30 years (see Note 1 "Accounting Policies and Methods of Application"). Our deferred tax assets include $86 million related to an unfunded pension and postretirement benefit obligation an increase of $51 million from 2007.

As indicated in the following table, our deferred tax assets and liabilities include certain items we acquired from NUI. We have provided a valuation allowance for some of these items that reduce our net deferred tax assets to amounts we believe are more likely than not to be realized in future periods. With respect to our continuing operations, we have net operating losses in various jurisdictions. Components that give rise to the net accumulated deferred income tax liability are as follows.

In millions	As of December 31, 2008	2007
Accumulated deferred income tax liabilities		
Property – accelerated depreciation and other property-related items	$635	$568
Mark to market	5	4
Other	32	44
Total accumulated deferred income tax liabilities	672	616
Accumulated deferred income tax assets		
Deferred investment tax credits	5	6
Unfunded pension and postretirement benefit obligation	86	35
Net operating loss – NUI (1)	2	5
Other	11	7
Total accumulated deferred income tax assets	104	53
Valuation allowances (2)	(3)	(3)
Total accumulated deferred income tax assets, net of valuation allowance	101	50
Net accumulated deferred tax liability	$571	$566

(1) Expire in 2021.
(2) Valuation allowance is due to the net operating losses on NUI headquarters that are not usable in New Jersey.

Tax Benefits

In June 2006, the FASB issued FIN 48, which addressed the determination of whether tax benefits claimed or expected to be claimed on a tax return should be recorded in the financial statements. Under FIN 48, we may recognize the tax benefit from an uncertain tax position only if it is more likely than not that the tax position will be sustained on examination by the taxing authorities, based on the technical merits of the position. The tax benefits recognized in the financial statements from such a position should be measured based on the largest benefit that has a greater than fifty percent likelihood of being realized upon ultimate settlement. FIN 48 also provides guidance on derecognition, classification, interest and penalties on income taxes, accounting in interim periods and requires increased disclosures. We adopted the provisions of FIN 48 on January 1, 2007. At the date of adoption, as of December 31, 2007 and as of December 31, 2008, we did not have a liability for unrecognized tax benefits. Based on current information, we do not anticipate that this will change materially in 2009.

We recognize accrued interest and penalties related to uncertain tax positions in operating expenses in the consolidated statements of income, which is consistent with the recognition of these items in prior reporting periods. As of December 31, 2008, we did not have a liability recorded for payment of interest and penalties associated with uncertain tax positions.

We file a U.S. federal consolidated income tax return and various state income tax returns. We are no longer subject to income tax examinations by the Internal Revenue Service or any state for years before 2002, but we are currently under audit by the Internal Revenue Service for tax years 2006 and 2007.

Note 9 - Segment Information

We are an energy services holding company whose principal business is the distribution of natural gas in six states - Florida, Georgia, Maryland, New Jersey, Tennessee and Virginia. We generate nearly all our operating revenues through the sale, distribution, transportation and storage of natural gas. We are involved in several related and complementary businesses, including retail natural gas marketing to end-use customers primarily in Georgia; natural gas asset management and related logistics activities for each of our utilities as well as for nonaffiliated companies; natural gas storage arbitrage and related activities; and the development and operation of high-deliverability natural gas storage assets. We manage these businesses through four operating segments – distribution operations, retail energy operations, wholesale services and energy investments and a nonoperating corporate segment which includes intercompany eliminations.

We evaluate segment performance based primarily on the non-GAAP measure of EBIT, which includes the effects of corporate expense allocations. EBIT is a non-GAAP measure that includes operating income, other income and expenses and minority interest. Items we do not include in EBIT are financing costs, including interest and debt expense and income taxes, each of which we evaluate on a consolidated level. We believe EBIT is a useful measurement of our performance because it provides information that can be used to evaluate the effectiveness of our businesses from an operational perspective, exclusive of the costs to finance those activities and exclusive of income taxes, neither of which is directly relevant to the efficiency of those operations.

You should not consider EBIT an alternative to, or a more meaningful indicator of, our operating performance than operating income or net income as determined in accordance with GAAP. In addition, our EBIT may not be comparable to a similarly titled measure of another company. The reconciliations of EBIT to operating income, earnings before income taxes and net income for 2008, 2007 and 2006 are presented below.

In millions	2008	2007	2006
Operating revenues	$2,800	$2,494	$2,621
Operating expenses	2,322	2,005	2,133
Operating income	478	489	488
Minority interest	(20)	(30)	(23)
Other income (expense)	6	4	(1)
EBIT	464	463	464
Interest expense	115	125	123
Earnings before income taxes	349	338	341
Income taxes	132	127	129
Net income	$217	$211	$212

Summarized income statement, balance sheet and capital expenditure information by segment as of and for the years ended December 31, 2008, 2007 and 2006 is shown in the following tables.

2008

In millions	Distribution operations	Retail energy operations	Wholesale services	Energy investments	Corporate and intercompany eliminations	Consolidated AGL Resources
Operating revenues from external parties	$1,581	$987	$170	$55	$7	$2,800
Intercompany revenues (1)	187	-	-	-	(187)	-
Total operating revenues	1,768	987	170	55	(180)	2,800
Operating expenses						
Cost of gas	950	838	48	5	(187)	1,654
Operation and maintenance	330	67	55	24	(4)	472
Depreciation and amortization	128	4	5	6	9	152
Taxes other than income taxes	35	2	2	1	4	44
Total operating expenses	1,443	911	110	36	(178)	2,322
Operating income (loss)	325	76	60	19	(2)	478
Minority interest	-	(20)	-	-	-	(20)
Other income	4	1	-	-	1	6
EBIT	$329	$57	$60	$19	$(1)	$464
Identifiable and total assets	$5,138	$315	$970	$353	$(66)	$6,710
Goodwill	$404	$-	$-	$14	$-	$418
Capital expenditures	$278	$6	$1	$75	$12	$372

2007

In millions	Distribution operations	Retail energy operations	Wholesale services	Energy investments	Corporate and intercompany eliminations	Consolidated AGL Resources
Operating revenues from external parties	$1,477	$892	$83	$42	$-	$2,494
Intercompany revenues (1)	188	-	-	-	(188)	-
Total operating revenues	1,665	892	83	42	(188)	2,494
Operating expenses						
Cost of gas	845	704	6	2	(188)	1,369
Operation and maintenance	330	69	38	19	(5)	451
Depreciation and amortization	122	5	4	5	8	144
Taxes other than income taxes	33	1	1	1	5	41
Total operating expenses	1,330	779	49	27	(180)	2,005
Operating income (loss)	335	113	34	15	(8)	489
Minority interest	-	(30)	-	-	-	(30)
Other income	3	-	-	-	1	4
EBIT	$338	$83	$34	$15	$(7)	$463
Identifiable and total assets	$4,847	$282	$890	$287	$(48)	$6,258
Goodwill	$406	$-	$-	$14	$-	$420
Capital expenditures	$201	$2	$2	$26	$28	$259

2006						
In millions	Distribution operations	Retail energy operations	Wholesale services	Energy investments	Corporate and intercompany eliminations	Consolidated AGL Resources
Operating revenues from external parties	$1,467	$930	$182	$41	$1	$2,621
Intercompany revenues (1)	157	-	-	-	(157)	-
Total operating revenues	1,624	930	182	41	(156)	2,621
Operating expenses						
Cost of gas	817	774	43	5	(157)	1,482
Operation and maintenance	350	64	46	20	(7)	473
Depreciation and amortization	116	3	2	5	12	138
Taxes other than income taxes	33	1	1	1	4	40
Total operating expenses	1,316	842	92	31	(148)	2,133
Operating income (loss)	308	88	90	10	(8)	488
Minority interest	-	(23)	-	-	-	(23)
Other income (expense)	2	(2)	-	-	(1)	(1)
EBIT	$310	$63	$90	$10	$(9)	$464
Identifiable and total assets	$4,565	$293	$830	$373	$62	$6,123
Goodwill	$406	$-	$-	$14	$-	$420
Capital expenditures	$174	$9	$2	$23	$45	$253

(1) Intercompany revenues – Wholesale services records its energy marketing and risk management revenue on a net basis. Wholesale services total operating revenues include intercompany revenues of $982 million in 2008, $638 million in 2007 and $531 million in 2006.

Note 10 - Quarterly Financial Data (Unaudited)

Our quarterly financial data for 2008, 2007 and 2006 are summarized below. The variance in our quarterly earnings is the result of the seasonal nature of our primary business.

In millions, except per share amounts	March 31	June 30	Sept. 30	Dec. 31
2008				
Operating revenues	$1,012	$444	$539	$805
Operating income	188	6	126	158
Net income (loss)	89	(11)	65	74
Basic earnings (loss) per share	1.17	(0.15)	0.85	0.97
Diluted earnings (loss) per share	1.16	(0.15)	0.85	0.97
2007				
Operating revenues	$973	$467	$369	$685
Operating income	216	78	55	140
Net income	102	30	13	66
Basic earnings per share	1.31	0.40	0.17	0.86
Diluted earnings per share	1.30	0.40	0.17	0.86
2006				
Operating revenues	$1,044	$436	$434	$707
Operating income	228	60	90	110
Net income	110	19	36	47
Basic earnings per share	1.42	0.25	0.46	0.60
Diluted earnings per share	1.41	0.25	0.46	0.60

Our basic and diluted earnings per common share are calculated based on the weighted daily average number of common shares and common share equivalents outstanding during the quarter. Those totals differ from the basic and diluted earnings per share shown in the statements of consolidated income, which are based on the weighted average number of common shares and common share equivalents outstanding during the entire year.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None

ITEM 9A. CONTROLS AND PROCEDURES

Conclusions Regarding the Effectiveness of Disclosure Controls and Procedures

Under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, we conducted an evaluation of our disclosure controls and procedures, as such term is defined under Rule 13a-15(e) promulgated under the Securities Exchange Act of 1934, as amended (the Exchange Act). No system of controls, no matter how well-designed and operated, can provide absolute assurance that the objectives of the system of controls are met, and no evaluation of controls can provide assurance that the system of controls has operated effectively in all cases. Our disclosure controls and procedures however are designed to provide reasonable assurance that the objectives of disclosure controls and procedures are met.

Based on this evaluation, our principal executive officer and our principal financial officer concluded that our disclosure controls and procedures were effective as of December 31, 2008, in providing a reasonable level of assurance that information we are required to disclose in reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods in SEC rules and forms, including a reasonable level of assurance that information required to be disclosed by us in such reports is accumulated and communicated to our management, including our principal executive officer and our principal financial officer, as appropriate to allow timely decisions regarding required disclosure.

Changes in Internal Control over Financial Reporting

There were no changes in our internal control over financial reporting identified in connection with the above-referenced evaluation by management of the effectiveness of our internal control over financial reporting that occurred during the fourth quarter ended December 31, 2008, that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Reports of Management and Independent Registered Public Accounting Firm on Internal Control Over Financial Reporting

Management has assessed, and our independent registered public accounting firm, PricewaterhouseCoopers LLP, has audited, our internal control over financial reporting as of December 31, 2008. The unqualified reports of management and PricewaterhouseCoopers LLP thereon are included in Item 8 of this Annual Report on Form 10-K and are incorporated by reference herein.

ITEM 9B. OTHER INFORMATION.

None

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

The information required by this item with respect to directors will be set forth under the captions "Proposal I -Election of Directors", - "Corporate Governance - Ethics and Compliance Program," – "Committees of the Board" and "- Audit Committee" in the Proxy Statement for our 2009 Annual Meeting of Shareholders or in a subsequent amendment to this report. The information required by this item with respect to the executive officers is set forth at Part I, Item 4 of this report under the caption "Executive Officers of the Registrant." The information required by this item with respect to Section 16(a) beneficial ownership reporting compliance will be set forth under the caption "Section 16(a) Beneficial Ownership Reporting Compliance" in the Proxy Statement or subsequent amendment referred to above. All such information that is provided in the Proxy Statement is incorporated herein by reference.

ITEM 11. EXECUTIVE COMPENSATION

The information required by this item will be set forth under the captions "Compensation and Management Development Committee Report," "Compensation and Management Development Committee Interlocks and Insider Participation," "Director Compensation," "Compensation Discussion and Analysis" and "Executive Compensation" in the Proxy Statement or subsequent amendment referred to in Item 10 above. All such information that is provided in the Proxy Statement is incorporated herein by reference, except for the information under the caption "Compensation and Management Development Committee Report" which is specifically not so incorporated herein by reference.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

The information required by this item will be set forth under the captions "Share Ownership" and "Executive Compensation -- Equity Compensation Plan Information" in the Proxy Statement or subsequent amendment referred to in Item 10 above.

All such information that is provided in the Proxy Statement is incorporated herein by reference.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS AND DIRECTOR INDEPENDENCE

The information required by this item will be set forth under the captions "Corporate Governance – Director Independence" and "- Policy on Related Person Transactions" and "Certain Relationships and Related Transactions" in the Proxy Statement or subsequent amendment referred to in Item 10 above. All such information that is provided in the Proxy Statement is incorporated herein by reference.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

The information required by this item will be set forth under the caption "Proposal 3 – Ratification of the Appointment of PricewaterhouseCoopers LLP as Our Independent Registered Public Accounting Firm for 2009" in the Proxy Statement or subsequent amendment to referred to in Item 10 above. All such information that is provided in the Proxy Statement is incorporated herein by reference.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a) Documents Filed as Part of This Report.

(1) Financial Statements Included in Item 8 are the following:

- Report of Independent Registered Public Accounting Firm
- Management's Report on Internal Control Over Financial Reporting
- Consolidated Balance Sheets as of December 31, 2008 and 2007
- Statements of Consolidated Income for the years ended December 31, 2008, 2007, and 2006
- Statements of Consolidated Common Shareholders' Equity for the years ended December 31, 2008, 2007 and 2006
- Statements of Consolidated Cash Flows for the years ended December 31, 2008, 2007, and 2006
- Notes to Consolidated Financial Statements

(2) Financial Statement Schedules

Financial Statement Schedule II. Valuation and Qualifying Accounts - Allowance for Uncollectible Accounts and Income Tax Valuations for Each of the Three Years in the Period Ended December 31, 2008.

Schedules other than those referred to above are omitted and are not applicable or not required, or the required information is shown in the financial statements or notes thereto.

(3) Exhibits

Where an exhibit is filed by incorporation by reference to a previously filed registration statement or report, such registration statement or report is identified in parentheses.

3.1 Amended and Restated Articles of Incorporation filed November 2, 2005, with the Secretary of State of the state of Georgia (Exhibit 3.1, AGL Resources Inc. Form 8-K dated November 2, 2005).

3.2 Bylaws, as amended on December 10, 2008 (Exhibit 3.2, AGL Resources, Inc. Form 8-K dated December 16, 2008).

4.1.a Specimen form of Common Stock certificate (Exhibit 4.1, AGL Resources Inc. Form 10-Q for the fiscal quarter ended September 30, 2007).

4.1.b Specimen AGL Capital Corporation 6.00% Senior Notes due 2034 (Exhibit 4.1, AGL Resources Inc. Form 8-K dated September 27, 2004).

4.1.c Specimen AGL Capital Corporation 4.95% Senior Notes due 2015. (Exhibit 4.1, AGL Resources Inc. Form 8-K dated December 21, 2004).

4.1.d Specimen AGL Capital Corporation 6.375% Senior Secured Notes due 2016. (Exhibit 4.1, AGL Resources Inc. Form 8-K dated December 11, 2007).

4.1.e Specimen AGL Capital Corporation 7.125% Senior Secured Notes due 2011 (Exhibit 4.1.f, AGL Resources Inc. Form 10-K for the fiscal year ended December 31, 2007).

4.1.f Specimen AGL Capital Corporation 4.45% Senior Secured Notes due 2013 (Exhibit 4.1.g, AGL Resources Inc. Form 10-K for the fiscal year ended December 31, 2007).

4.2.a Indenture, dated as of December 1, 1989, between Atlanta Gas Light Company and Bankers Trust Company, as Trustee (Exhibit 4(a), Atlanta Gas Light Company registration statement on Form S-3, No. 33-32274).

4.2.b First Supplemental Indenture dated as of March 16, 1992, between Atlanta Gas Light Company and NationsBank of Georgia, National Association, as Successor Trustee (Exhibit 4(a), Atlanta Gas Light Company registration statement on Form S-3, No. 33-

46419).

4.2.c Indenture, dated February 20, 2001 among AGL Capital Corporation, AGL Resources Inc. and The Bank of New York, as Trustee (Exhibit 4.2, AGL Resources Inc. registration statement on Form S-3, filed on September 17, 2001, No. 333-69500).

4.3.a Form of Guarantee of AGL Resources Inc. dated as of December 14, 2007 regarding the AGL Capital Corporation 6.375% Senior Note due 2016 (Exhibit 4.2, AGL Resources Inc. Form 8-K dated December 11, 2007).

4.3.b Form of Guarantee of AGL Resources Inc. dated as of September 27, 2004 regarding the AGL Capital Corporation 6.00% Senior Note due 2034 (Exhibit 4.1, AGL Resources Inc. Form 8-K dated September 27, 2004).

4.3.c Form of Guarantee of AGL Resources Inc. dated as of December 20, 2004 regarding the AGL Capital Corporation 4.95% Senior Note due 2015 (Exhibit 4.1, AGL Resources Inc. Form 8-K dated December 21, 2004).

4.3.d Form of Guarantee of AGL Resources Inc. dated as of March 31, 2001 regarding the AGL Capital Corporation 7.125% Senior Note due 2011 (Exhibit 4.3.d, AGL Resources Inc. Form 10-K for the fiscal year ended December 31, 2007).

4.3.e Form of Guarantee of AGL Resources Inc. dated as of July 2, 2003 regarding the AGL Capital Corporation 4.45% Senior Note due 2013 (Exhibit 4.3.e, AGL Resources Inc. Form 10-K for the fiscal year ended December 31, 2007).

10.1 Director and Executive Compensation Contracts, Plans and Arrangements.

Director Compensation Contracts, Plans and Arrangements

10.1.a AGL Resources Inc. Amended and Restated 1996 Non-Employee Directors Equity Compensation Plan (Exhibit 10.1, AGL Resources Inc. Form 10-Q for the quarter ended September 30, 2002).

10.1.b First Amendment to the AGL Resources Inc. Amended and Restated 1996 Non-Employee Directors Equity Compensation Plan (Exhibit 10.1.o, AGL Resources Inc. Form 10-K for the fiscal year ended December 31, 2002).

10.1.c Second Amendment to the AGL Resources Inc. Amended and Restated 1996 Non-Employee Directors Equity Compensation Plan (Exhibit 10.1.k, AGL Resources Inc. Form 10-Q for the quarter ended June 30, 2007).

10.1.d AGL Resources Inc. 2006 Non-Employee Directors Equity Compensation Plan (incorporated herein by reference to Annex C of the AGL Resources Inc. Proxy Statement for the Annual Meeting of Shareholders held May 3, 2006 filed on March 20, 2006).

10.1.e First Amendment to the AGL Resources Inc. 2006 Non-Employee Directors Equity Compensation Plan (Exhibit 10.1.i, AGL Resources Inc. Form 10-Q for the quarter ended June 30, 2007).

10.1.f Second Amendment to the AGL Resources Inc. 2006 Non-Employee Directors Equity Compensation Plan.

10.1.g AGL Resources Inc. 1998 Common Stock Equivalent Plan for Non-Employee Directors (Exhibit 10.1.b, AGL Resources Inc. Form 10-Q for the quarter ended December 31, 1997).

10.1.h First Amendment to the AGL Resources Inc. 1998 Common Stock Equivalent Plan for Non-Employee Directors (Exhibit 10.5, AGL Resources Inc. Form 10-Q for the quarter ended March 31, 2000).

10.1.i Second Amendment to the AGL Resources Inc. 1998 Common Stock Equivalent Plan for Non-Employee Directors (Exhibit 10.4, AGL Resources Inc. Form 10-Q for the quarter ended September 30, 2002).

10.1.j Third Amendment to the AGL Resources Inc. 1998 Common Stock Equivalent Plan for Non-Employee Directors (Exhibit 10.5, AGL Resources Inc. Form 10-Q for the quarter ended September 30, 2002).

10.1.k Fourth Amendment to the AGL Resources Inc. 1998 Common Stock Equivalent Plan for Non-Employee Directors (Exhibit 10.1.m, AGL Resources Inc. Form 10-Q for the quarter ended June 30, 2007).

10.1.l Fifth Amendment to the AGL Resources Inc. 1998 Common Stock Equivalent Plan for Non-Employee Directors.

10.1.m Description of Directors' Compensation (Exhibit 10.1, AGL Resources Inc. Form 8-K dated December 1, 2004).

10.1.n Form of Stock Award Agreement for Non-Employee Directors (Exhibit 10.1.aj, AGL Resources Inc. Form 10-K for the fiscal year ended December 31, 2004).

10.1.o Form on Nonqualified Stock Option Agreement for Non-Employee Directors (Exhibit 10.1.ak, AGL Resources Inc. Form 10-K for the fiscal year ended December 31, 2004).

10.1.p Form of Director Indemnification Agreement, dated April 28, 2004, between AGL Resources Inc., on behalf of itself and the Indemnities named therein (Exhibit 10.3, AGL Resources Inc. Form 10-Q for the quarter ended June 30, 2004).

Executive Compensation Contracts, Plans and Arrangements

10.1.aa AGL Resources Inc. Long-Term Incentive Plan (1999), as amended and restated as of January 1, 2002 (Exhibit 99.2, AGL Resources Inc. Form 10-Q for the quarter ended March 31, 2002).

10.1.ab First amendment to the AGL Resources Inc. Long-Term Incentive Plan (1999), as amended and restated (Exhibit 10.1.b, AGL Resources Inc. Form 10-K for the fiscal year ended December 31, 2004).

10.1.ac Second amendment to the AGL Resources Inc. Long-Term Incentive Plan (1999), as amended and restated (Exhibit 10.1.l, AGL Resources Inc. Form 10-Q for the quarter ended June 30, 2007).

10.1.ad Third amendment to the AGL Resources Inc. Long-Term Incentive Plan (1999), as amended and restated.

10.1.ae AGL Resources Inc. Officer Incentive Plan (Exhibit 10.2, AGL Resources Inc. Form 10-Q for the quarter ended June 30, 2001).

10.1.af First amendment to the AGL Resources Inc. Officer Incentive Plan (Exhibit 10.1.j, AGL Resources Inc. Form 10-Q for the quarter ended June 30, 2007).

10.1.ag Second amendment to the AGL Resources Inc. Officer Incentive Plan.

10.1.ah AGL Resources Inc. 2007 Omnibus Performance Incentive Plan (Annex A of AGL Resources Inc.'s Schedule 14A, File No. 001-14174, filed with the Securities and Exchange Commission on March 19, 2007).

10.1.ai First Amendment to the AGL Resources Inc. 2007 Omnibus Performance Incentive Plan.

10.1.aj Form of Incentive Stock Option Agreement - AGL Resources Inc. 2007 Omnibus Performance Incentive Plan (Exhibit 10.1.b, AGL Resources Inc. Form 10-Q for the quarter ended June 30, 2007).

10.1.ak Form of Nonqualified Stock Option Agreement - AGL Resources Inc. 2007 Omnibus Performance Incentive Plan (Exhibit 10.1.c, AGL Resources Inc. Form 10-Q for the quarter ended June 30, 2007).

10.1.al Form of Performance Cash Award Agreement - AGL Resources Inc. 2007 Omnibus Performance Incentive Plan (Exhibit 10.1.d, AGL Resources Inc. Form 10-Q for the quarter ended June 30, 2007).

10.1.am Form of Restricted Stock Agreement (performance based) - AGL Resources Inc. 2007 Omnibus Performance Incentive Plan (Exhibit 10.1.e, AGL Resources Inc. Form 10-Q for the quarter ended June 30, 2007).

10.1.an Form of Restricted Stock Agreement (time based) - AGL Resources Inc. 2007 Omnibus Performance Incentive Plan (Exhibit 10.1.f, AGL Resources Inc. Form 10-Q for the quarter ended June 30, 2007).

10.1.ao Form of Restricted Stock Unit Agreement - AGL Resources Inc. 2007 Omnibus Performance Incentive Plan. (Exhibit 10.1.g, AGL Resources Inc. Form 10-Q for the quarter ended June 30, 2007)

10.1.ap Form of Stock Appreciation Rights Agreement - AGL Resources Inc. 2007 Omnibus Performance Incentive Plan (Exhibit 10.1.h, AGL Resources Inc. Form 10-Q for the quarter ended June 30, 2007).

10.1.aq Form of Incentive Stock Option Agreement, Nonqualified Stock Option Agreement and Restricted Stock Agreement for key employees (Exhibit 10.1, AGL Resources Inc. Form 10-Q for the quarter ended September 30, 2004).

10.1.ar Form of Performance Unit Agreement for key employees (Exhibit 10.1.e, AGL Resources Inc. Form 10-K for the fiscal year ended December 31, 2004).

10.1.as Forms of Nonqualified Stock Option Agreement without the reload provision (LTIP and Officer Plan) (Exhibit 10.1, AGL Resources Inc. Form 8-K dated March 15, 2005).

10.1.at Form of Nonqualified Stock Option Agreement with the reload provision (Officer Plan) (Exhibit 10.2, AGL Resources Inc. Form 8-K dated March 15, 2005).

10.1.au Form of Restricted Stock Unit Agreement and Performance Cash Unit Agreement for key employees (Exhibit 10.1 and 10.2, respectively, AGL Resources Inc. Form 8-K dated February 24, 2006).

10.1.av AGL Resources Inc. Nonqualified Savings Plan as amended and restated as of January 1, 2009.

10.1.aw AGL Resources Inc. Annual Incentive Plan - 2007 (Exhibit 10.1, AGL Resources Inc. Form 8-K dated August 6, 2007).

10.1.ax Description of Annual Incentive Compensation Arrangement for Douglas N. Schantz (Exhibit 10.1.ax, AGL Resources Inc. Form 10-K for the fiscal year ended December 31, 2007).

10.1.ay Description of Supplemental Executive Retirement Plan for John W. Somerhalder II.

10.1.az AGL Resources Inc. Excess Benefit Plan as amended and restated as of January 1, 2009.

10.1.ba Continuity Agreement, dated December 1, 2007, by and between AGL Resources Inc., on behalf of itself and AGL Services Company (its wholly owned subsidiary) and John W. Somerhalder (Exhibit 10.1.a AGL Resources, Inc. Form 8-K dated January 8, 2008).

10.1.bb Continuity Agreement, dated December 1, 2007, by and between AGL Resources Inc., on behalf of itself and AGL Services Company (its wholly owned subsidiary) and Andrew W. Evans (Exhibit 10.1.b AGL Resources, Inc. Form 8-K dated January 8, 2008).

10.1.bc Continuity Agreement, dated December 1, 2007, by and between AGL Resources Inc., on behalf of itself and AGL Services Company (its wholly owned subsidiary) and Kevin P. Madden (Exhibit 10.1.c AGL Resources, Inc. Form 8-K dated January 8, 2008).

10.1.bd Continuity Agreement, dated December 1, 2007, by and between AGL Resources Inc., on behalf of itself and AGL Services Company (its wholly owned subsidiary) and Douglas N. Schantz (Exhibit 10.1.d AGL Resources, Inc. Form 8-K dated January 8, 2008).

10.1.be Continuity Agreement, dated December 1, 2007, by and between AGL Resources Inc., on behalf of itself and AGL Services Company (its wholly owned subsidiary) and Paul R. Shlanta (Exhibit 10.1.bl, AGL Resources Inc. Form 10-K for the fiscal year ended December 31, 2007).

10.1.bf Form of AGL Resources Inc. Executive Post Employment Medical Benefit Plan (Exhibit 10.1.d, AGL Resources Inc. Form 10-Q for the quarter ended June 30, 2003).

10.1.bg Description of compensation for each of John W. Somerhalder, Andrew W. Evans, Kevin P. Madden, Douglas N. Schantz and Paul R. Shlanta (incorporated herein by reference to the Compensation Discussion and Analysis section of the AGL Resources Inc. Proxy Statement for the Annual Meeting of Shareholders held April 30, 2008 filed on March 19, 2008).

10.2 Guaranty Agreement, effective December 13, 2005, by and between Atlanta Gas Light Company and AGL Resources Inc. (Exhibit 10.2, AGL Resources Inc. Form 10-K for the fiscal year ended December 31, 2007).

10.3 Form of Commercial Paper Dealer Agreement between AGL Capital Corporation, as Issuer, AGL Resources Inc., as Guarantor, and the Dealers named therein, dated September 25, 2000 (Exhibit 10.79, AGL Resources Inc. Form 10-K for the fiscal year ended September 30, 2000).

10.4 Guarantee of AGL Resources Inc., dated October 5, 2000, of payments on promissory notes issued by AGL Capital Corporation (AGLCC) pursuant to the Issuing and Paying Agency Agreement dated September 25, 2000, between AGLCC and The Bank of New York (Exhibit 10.80, AGL Resources Inc. Form 10-K for the fiscal year ended September 30, 2000).

10.5 Issuing and Paying Agency Agreement, dated September 25, 2000, between AGL Capital Corporation and The Bank of New York. (Exhibit 10.81, AGL Resources Inc. Form 10-K for the fiscal year ended September 30, 2000).

10.6.a Amended and Restated Master Environmental Management Services Agreement, dated July 25, 2002 by and between Atlanta Gas Light Company and The RETEC Group, Inc. (Exhibit 10.2, AGL Resources Inc. Form 10-Q for the quarter ended June 30, 2003). (Confidential treatment pursuant to 17 CFR Sections 200.80 (b) and 240.24-b has been granted regarding certain portions of this exhibit, which portions

have been filed separately with the Commission).

10.6.b Modification to the Amended and Restated Master Environmental Management Services Agreement, dated July 25, 2002 by and between Atlanta Gas Light Company and The RETEC Group, Inc.

10.6.c Term Extension to the Amended and Restated Master Environmental Management Services Agreement, dated July 25, 2002 by and between Atlanta Gas Light Company and The RETEC Group, Inc.

10.6.d Modification to the Amended and Restated Master Environmental Management Services Agreement, dated July 25, 2002 by and between Atlanta Gas Light Company and The RETEC Group, Inc.

10.6.e Second Modification to the Amended and Restated Master Environmental Management Services Agreement, dated July 25, 2002 by and between Atlanta Gas Light Company and The RETEC Group, Inc.

10.6.f Third Modification to the Amended and Restated Master Environmental Management Services Agreement, dated July 25, 2002 by and between Atlanta Gas Light Company and The RETEC Group, Inc.

10.7 Credit Agreement dated as of August 31, 2006, by and among AGL Resources Inc., AGL Capital Corporation, SunTrust Bank, as administrative agent, Wachovia Bank, National Association, as syndication agent, JPMorgan Chase Bank, N.A., The Bank of Tokyo-Mitsubishi UFJ, Ltd. and Calyon New York Branch, as co-documentation agents, and the several other banks and other financial institutions named therein (Exhibit 10, AGL Resources Inc. Form 8-K dated August 31, 2006).

10.8 SouthStar Energy Services LLC Amended and Restated Agreement, dated April 1, 2004 by and between Georgia Natural Gas Company and Piedmont Energy Company (Exhibit 10, AGL Resources Inc. Form 10-Q for the quarter ended March 31, 2004).

10.9 Letter of Credit and Security Agreement dated as of September 4, 2008 by and among Pivotal Utility Holdings, Inc. as borrower, AGL Resources Inc. as Guarantor, Bank of America, N.A. as Administrative Agent, The Bank of Tokyo-Mitsubishi UFJ, LTD. as Syndication Agent and Bank of America, N.A. as Issuing Bank (Exhibit 10.1, AGL Resources Inc. Form 10-Q for the quarter ended September 30, 2008).

10.10 Credit Agreement as of September 30, 2008 by and among AGL Resources Inc., AGL Capital Corporation, Wachovia Bank, N.A. as Administrative Agent, Wachovia Capital Markets, LLC as sole lead arranger and sole lead bookrunner. SunTrust Bank, NA, The Bank of Tokyo-Mitsubishi UFJ, LTD., Calyon New York Brand and The Royal Bank of Scotland PLC as Co-Documentation Agents (Exhibit 10.1, AGL Resources Inc. Form 8-K dated September 30, 2008).

14 AGL Resources Inc. Code of Ethics for its Chief Executive Officer and its Senior Financial Officers (Exhibit 14, AGL Resources Inc. Form 10-K for the year ended December 31, 2004).

21 Subsidiaries of AGL Resources Inc.

23 Consent of PricewaterhouseCoopers LLP, independent registered public accounting firm.

24 Powers of Attorney (included on signature page hereto).

31.1 Certification of John W. Somerhalder II pursuant to Rule 13a – 14(a).

31.2 Certification of Andrew W. Evans pursuant to Rule 13a – 14(a).

32.1 Certification of John W. Somerhalder II pursuant to 18 U.S.C. Section 1350.

32.2 Certification of Andrew W. Evans pursuant to 18 U.S.C. Section 1350.

(b) Exhibits filed as part of this report.

See Item 15(a)(3).

(c) Financial statement schedules filed as part of this report.

See Item 15(a)(2).

SIGNATURES

In accordance with Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned; thereunto duly authorized, on February 5, 2009.

AGL RESOURCES INC.

By: /s/ John W. Somerhalder II
John W. Somerhalder II
Chairman, President and Chief Executive Officer

Power of Attorney

KNOW ALL MEN BY THESE PRESENTS, that each person whose signature appears below constitutes and appoints John W. Somerhalder II, Andrew W. Evans, Paul R. Shlanta and Bryan E. Seas, and each of them, his or her true and lawful attorneys-in-fact and agents, with full power of substitution and resubstitution, for him or her and in his or her name, place and stead, in any and all capacities, to sign any and all amendments to this Annual Report on Form 10-K for the year ended December 31, 2008, and to file the same, with all exhibits thereto and other documents in connection therewith, with the Securities and Exchange Commission, granting unto said attorneys-in-fact and agents, and each of them, full power and authority to do and perform each and every act and thing requisite or necessary to be done, as fully to all intents and purposes as he or she might or could do in person, hereby ratifying and confirming all that said attorneys-in-fact and agents or any of them, or their or his substitute or substitutes, may lawfully do or cause to be done by virtue hereof.

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities indicated as of February 5, 2009.

Signatures	Title
/s/ John W. Somerhalder II John W. Somerhalder II	Chairman, President and Chief Executive Officer (Principal Executive Officer)
/s/ Andrew W. Evans Andrew W. Evans	Executive Vice President and Chief Financial Officer (Principal Financial Officer)
/s/ Bryan E. Seas Bryan E. Seas	Senior Vice President, Controller and Chief Accounting Officer (Principal Accounting Officer)
/s/ Sandra N. Bane Sandra N. Bane	Director
/s/ Thomas D. Bell, Jr. Thomas D. Bell, Jr.	Director
/s/ Charles R. Crisp Charles R. Crisp	Director
/s/ Arthur E. Johnson Arthur E. Johnson	Director
/s/ Wyck A. Knox, Jr. Wyck A. Knox, Jr.	Director
/s/ Dennis M. Love Dennis M. Love	Director
/s/ Charles H. McTier Charles H. McTier	Director
/s/ Dean R. O'Hare Dean R. O'Hare	Director
/s/ D. Raymond Riddle D. Raymond Riddle	Director
/s/ James A. Rubright James A. Rubright	Director
/s/ Felker W. Ward, Jr. Felker W. Ward, Jr.	Director
/s/ Bettina M. Whyte Bettina M. Whyte	Director
/s/ Henry C. Wolf Henry C. Wolf	Director

Schedule II

AGL Resources Inc. and Subsidiaries

VALUATION AND QUALIFYING ACCOUNTS - ALLOWANCE FOR UNCOLLECTIBLE ACCOUNTS AND INCOME TAX VALUATION FOR EACH OF THE THREE YEARS IN THE PERIOD ENDED DECEMBER 31, 2008.

In millions	Allowance for uncollectible accounts	Income tax valuation
Balance at December 31, 2005	**$15**	**$9**
Provisions charged to income in 2006	22	-
Accounts written off as uncollectible, net in 2006	(22)	-
Decrease due to change in circumstances	-	(6)
Balance at December 31, 2006	**15**	**3**
Provisions charged to income in 2007	19	-
Accounts written off as uncollectible, net in 2007	(20)	-
Balance at December 31, 2007	**14**	**3**
Provisions charged to income in 2008	27	-
Accounts written off as uncollectible, net in 2008	(25)	-
Balance at December 31, 2008	**$16**	**$3**

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

(Mark One)

☑ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended December 31, 2007

OR

☐ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from to

Commission File Number 1-14174

AGL RESOURCES INC.

(Exact name of registrant as specified in its charter)

Georgia	**58-2210952**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
Ten Peachtree Place NE, Atlanta, Georgia 30309	**404-584-4000**
(Address and zip code of principal executive offices)	(Registrant's telephone number, including area code)

Securities registered pursuant to Section 12(b) of the Act:

Title of Class	Name of each exchange on which registered
Common Stock, $5 Par Value	**New York Stock Exchange**

Securities registered pursuant to Section 12(g) of the Act: **None**

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 under the Securities Act.
Yes ☑ No ☐

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Securities Act.
Yes ☐ No ☑

Indicate by check mark whether the registrant: (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months, and (2) has been subject to such filing requirements for the past 90 days.
Yes ☑ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer or a non-accelerated filer.
Large accelerated filer ☑ Accelerated filer ☐ Non-accelerated filer ☐

Indicate by check mark whether the registrant is a shell company (as defined in Exchange Act Rule 12b-2). Yes ☐ No ☑

The aggregate market value of the registrant's voting and non-voting common equity held by non-affiliates of the registrant, computed by reference to the price at which the registrant's common stock was last sold as of the last business day of the registrant's most recently completed second fiscal quarter, was $3,148,134,781

The number of shares of the registrant's common stock outstanding as of January 31, 2008 was 76,439,305.

DOCUMENTS INCORPORATED BY REFERENCE:

Portions of the Proxy Statement for the 2008 Annual Meeting of Shareholders ("Proxy Statement") to be held April 30, 2008, are incorporated by reference in Part III.

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GLOSSARY OF KEY TERMS

Atlanta Gas Light	Atlanta Gas Light Company
AGL Capital	AGL Capital Corporation
AGL Networks	AGL Networks, LLC
AGSC	AGL Services Company
AIP	Annual Incentive Plan
Bcf	Billion cubic feet
Chattanooga Gas	Chattanooga Gas Company
Compass Energy	Compass Energy Services, Inc.
Credit Facility	Credit agreement supporting our commercial paper program
Deregulation Act	1997 Natural Gas Competition and Deregulation Act
Dominion Ohio	Dominion East of Ohio, a Cleveland, Ohio based natural gas company; a subsidiary of Dominion Resources, Inc.
EBIT	Earnings before interest and taxes, a non-GAAP measure that includes operating income, other income, equity in SouthStar's income, minority interest in SouthStar's earnings, donations and gain on sales of assets and excludes interest and income tax expense; as an indicator of our operating performance, EBIT should not be considered an alternative to, or more meaningful than, operating income or net income as determined in accordance with GAAP
EITF	Emerging Issues Task Force
Energy Act	Energy Policy Act of 2005
ERC	Environmental remediation costs
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
Fitch	Fitch Ratings
Florida Commission	Florida Public Service Commission
GAAP	Accounting principles generally accepted in the United States of America
Georgia Commission	Georgia Public Service Commission
Golden Triangle Storage	Golden Triangle Storage, Inc.
Heating Season	The period from November to March when natural gas usage and operating revenues are generally higher because more customers are connected to our distribution systems when weather is colder
Jefferson Island	Jefferson Island Storage & Hub, LLC
LIBOR	London interbank offered rate
LNG	Liquefied natural gas
LOCOM	Lower of weighted average cost or current market price
Louisiana DNR	Louisiana Department of Natural Resources
Maryland Commission	Maryland Public Service Commission
Marketers	Marketers selling retail natural gas in Georgia and certificated by the Georgia Commission
Medium-term notes	Notes issued by Atlanta Gas Light with scheduled maturities between 2012 and 2027 bearing interest rates ranging from 6.6% to 9.1%
MGP	Manufactured gas plant
Moody's	Moody's Investors Service
New Jersey Commission	New Jersey Board of Public Utilities
NUI	NUI Corporation
NYMEX	New York Mercantile Exchange, Inc.
OCI	Other comprehensive income
Operating margin	A measure of income, calculated as revenues minus cost of gas, that excludes operation and maintenance expense, depreciation and amortization, taxes other than income taxes, and the gain or loss on the sale of our assets; these items are included in our calculation of operating income as reflected in our statements of consolidated income.
Piedmont	Piedmont Natural Gas
Pivotal Propane	Pivotal Propane of Virginia, Inc.
Pivotal Utility	Pivotal Utility Holdings, Inc., doing business as Elizabethtown Gas, Elkton Gas and Florida City Gas
PGA	Purchased gas adjustment
PRP	Pipeline replacement program for Atlanta Gas Light
S&P	Standard & Poor's Ratings Services
Saltville	Saltville Gas Storage Company
SEC	Securities and Exchange Commission
Sequent	Sequent Energy Management, L.P.
SFAS	Statement of Financial Accounting Standards
SNG	Southern Natural Gas Company
SouthStar	SouthStar Energy Services LLC
Tennessee Commission	Tennessee Regulatory Authority
VaR	Value at risk is defined as the maximum potential loss in portfolio value over a specified time period that is not expected to be exceeded within a given degree of probability
Virginia Natural Gas	Virginia Natural Gas, Inc.
Virginia Commission	Virginia State Corporation Commission
WACOG	Weighted average cost of goods
WNA	Weather normalization adjustment

REFERENCED ACCOUNTING STANDARDS

APB 25	APB Opinion No. 25, "Accounting for Stock Issued to Employees"
EITF 98-10	EITF Issue No. 98-10, "Accounting for Contracts Involved in Energy Trading and Risk Management Activities"
EITF 99-02	EITF Issue No. 99-02, "Accounting for Weather Derivatives"
EITF 00-11	EITF Issue No. 00-11, "Lessor's Evaluation of Whether Leases of Certain Integral Equipment Meet the Ownership Transfer Requirements of FASB Statement No. 13, *Accounting for Leases*, for Leases of Real Estate"
EITF 02-03	EITF Issue No. 02-03, "Issues Involved in Accounting for Contracts under EITF Issue No. 98-10, 'Accounting for Contracts Involved in Energy Trading and Risk Management Activities'"
FIN 39	FASB Interpretation No. (FIN) 39 "Offsetting of Amounts Related to Certain Contracts"
FSP FIN 39-1	FASB Staff Position 39-1 "Amendment of FIN 39"
FIN 46 & FIN 46R	FIN 46, "Consolidation of Variable Interest Entities"
FIN 47	FIN 47, "Accounting for Conditional Asset Retirement Obligations, an interpretation of FASB Statement No. 143"
FIN 48	FIN 48, "Accounting for Uncertainty in Income Taxes, an interpretation of SFAS Statement No. 109"
SFAS 5	SFAS No. 5, "Accounting for Contingencies"
SFAS 13	SFAS No. 13, "Accounting for Leases"
SFAS 66	SFAS No. 66, "Accounting for Sales of Real Estate"
SFAS 71	SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation"
SFAS 87	SFAS No. 87, "Employers' Accounting for Pensions"
SFAS 106	SFAS No. 106, "Employers' Accounting for Postretirement Benefits Other Than Pensions"
SFAS 109	SFAS No. 109, "Accounting for Income Taxes"
SFAS 123 & SFAS 123R	SFAS No. 123, "Accounting for Stock-Based Compensation"
SFAS 133	SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities"
SFAS 141	SFAS No. 141, "Business Combinations"
SFAS 142	SFAS No. 142, "Goodwill and Other Intangible Assets"
SFAS 148	SFAS No. 148, "Accounting for Stock-Based Compensation – Transition and Disclosure"
SFAS 149	SFAS No. 149, "Amendment of SFAS 133 on Derivative Instruments and Hedging Activities"
SFAS 157	SFAS No. 157, "Fair Value Measurements"
SFAS 158	SFAS No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans"
SFAS 159	SFAS No. 159, "The Fair Value Option for Financial Assets and Liabilities"
SFAS 160	SFAS No. 160, "Noncontrolling Interests in Consolidated Financial Statements"

PART I

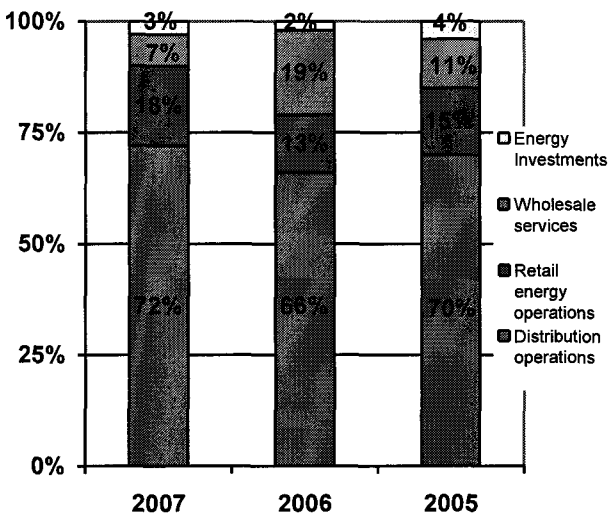
ITEM 1. BUSINESS

Nature of Our Business

Unless the context requires otherwise, references to "we," "us," "our," the "company" and "AGL Resources" are intended to mean consolidated AGL Resources Inc. and its subsidiaries.

We are an energy services holding company whose principal business is the distribution of natural gas in six states - Florida, Georgia, Maryland, New Jersey, Tennessee and Virginia. We generate nearly all our operating revenues through the sale, distribution, transportation and storage of natural gas. Our six utilities serve more than 2.2 million end-use customers, making us the largest distributor of natural gas in the southeastern and mid-Atlantic regions of the United States based on customer count. We are involved in several related and complementary businesses, including retail natural gas marketing to end-use customers primarily in Georgia; natural gas asset management and related logistics activities for each of our utilities as well as for nonaffiliated companies; natural gas storage arbitrage and related activities; and the development and operation of high-deliverability natural gas storage assets. We also own and operate a small telecommunications business that constructs and operates conduit and fiber infrastructure within select metropolitan areas.

We manage these businesses through four operating segments and a nonoperating corporate segment. Each operating segment's percentage contribution to the total operating EBIT for the last three years is indicated in the following chart.



Over the last three years, on average, we have derived approximately 85% of our EBIT from our regulated natural gas distribution business and the sale of natural gas to end-use customers primarily in Georgia through SouthStar. This statistic is significant because it represents the portion of our earnings that directly results from the underlying business of supplying natural gas to retail customers. SouthStar, which is subject to a different regulatory framework from our utilities, is an integral part of the retail framework for providing natural gas service to end-use customers in Georgia.

We derived the remaining percentage (15% or less for the last three years) of our EBIT principally from businesses that are complementary to our natural gas distribution business. We engage in natural gas asset management and the operation of high-deliverability natural gas underground storage as ancillary activities to our utility franchises. These businesses allow us to be opportunistic in capturing incremental value at the wholesale level and provide us with deepened business insight about natural gas market dynamics. Given the volatile and changing nature of the natural gas resource base in North America and globally, we believe that participation in these related businesses strengthens our business.

Operating revenues, operating margin, operating expenses and EBIT for each of our segments are presented in the following table for 2007, 2006 and 2005.

In millions	Operating revenues	Operating margin (1)	Operating expenses	EBIT (1)
2007				
Distribution operations	$1,665	$820	$485	$338
Retail energy operations	892	188	75	83
Wholesale services	83	77	43	34
Energy investments	42	40	25	15
Corporate (2)	(188)	-	8	(7)
Consolidated	$2,494	$1,125	$636	$463
2006				
Distribution operations	$1,624	$807	$499	$310
Retail energy operations	930	156	68	63
Wholesale services	182	139	49	90
Energy investments	41	36	26	10
Corporate (2)	(156)	1	9	(9)
Consolidated	$2,621	$1,139	$651	$464
2005				
Distribution operations	$1,753	$814	$518	$299
Retail energy operations	996	146	61	63
Wholesale services	95	92	42	49
Energy investments	56	40	23	19
Corporate (2)	(182)	-	6	(11)
Consolidated	$2,718	$1,092	$650	$419

(1) These are non-GAAP measurements. A reconciliation of operating margin and EBIT to our operating income and net income is contained in "Results of Operations" herein.
(2) Includes intercompany eliminations

Distribution Operations

The distribution operations segment is the largest component of our business and includes six natural gas local distribution utilities. These utilities construct, manage and maintain intrastate natural gas pipelines and distribution facilities and include:

- Atlanta Gas Light
- Chattanooga Gas
- Elizabethtown Gas
- Elkton Gas
- Florida City Gas
- Virginia Natural Gas

Regulatory Environment

Each utility operates subject to regulations of the state regulatory agency in its service territories with respect to rates charged to our customers and various service and safety matters. Rates charged to our customers vary according to customer class (residential, commercial or industrial) and rate jurisdiction. Rates are set at levels that allow recovery of all prudently incurred costs, including a return on rate base sufficient to pay interest on debt and provide a reasonable return on common equity. Rate base generally consists of the original cost of utility plant in service, working capital, inventories and certain other assets; less accumulated depreciation on utility plant in service and net deferred income tax liabilities, and may include certain other additions or deductions.

Atlanta Gas Light does not sell natural gas directly to its customers and does not need or utilize a PGA. All of our other utilities are authorized to use a PGA mechanism that allows them to adjust their rates to reflect changes in the wholesale cost of natural gas and to ensure they recover 100% of the costs incurred in purchasing gas for their customers. We continuously monitor the performance of our utilities to determine whether rates need to be further adjusted through the regulatory process. We have fixed rate settlements in three of our six jurisdictions in Georgia, New Jersey and Virginia.

Atlanta Gas Light's natural gas market was deregulated in 1997 with the Deregulation Act. Prior to this act, Atlanta Gas Light was the supplier and seller of natural gas to its customers. Today, Marketers sell natural gas to end-use customers in Georgia and handle customer billing functions. The Marketers file their rates monthly with the Georgia Commission. Atlanta Gas Light's role includes:

- distributing natural gas for Marketers
- constructing, operating and maintaining the gas system infrastructure, including responding to customer service calls and leaks
- reading meters and maintaining underlying customer premise information for Marketers

Atlanta Gas Light recognizes revenue under a straight-fixed-variable rate design whereby Atlanta Gas Light charges rates to its customers based primarily on monthly fixed charges. The Marketers bill these charges directly to their customers. This mechanism minimizes the seasonality of revenues since the monthly fixed charge is not volumetric or directly weather dependent. Weather indirectly influences the number of customers that have active accounts during the heating season, and this has a seasonal impact on Atlanta Gas Light's revenues since generally more customers are connected in periods of colder weather than in periods of warmer weather.

Regulatory Agreements In September 2007, the Georgia Commission approved our request to obtain an undivided interest in pipelines connecting our Georgia service territory to liquefied natural gas facilities at Elba Island, Georgia. We along with SNG have undertaken this pipeline project in an effort to diversify our sources of natural gas. We currently receive the majority of our natural gas supply from a production region in and around the Gulf of Mexico and generally, demand for this natural gas is growing faster than supply. This project is contingent upon FERC approval and therefore SNG and ourselves jointly filed an application with the FERC in October 2007. We anticipate that we will receive FERC approval in 2008. Construction is expected to begin in 2008 and to be completed in 2009.

In December 2007, the Florida Commission approved our request to include the amortization of certain components of the purchase price we paid for Florida City Gas in our calculation of return on equity. The costs will not be amortized for financial reporting purposes in accordance with GAAP but will be amortized over a period of 5 to 30 years for our regulatory reporting to the Florida Commission in connection with the Florida Commission's review of Florida City Gas' return on equity. Additionally and under the same order, the Florida Commission approved a five-year base rate stay-out beginning October 2007, whereby base rates will not be increased, except for certain unforeseen acts beyond our control. The five-year stay-out provision does not preclude the Florida Commission from initiating over earning or other proceedings.

A November 2004 agreement between Elizabethtown Gas and the New Jersey Commission approved our acquisition of NUI Corporation. This agreement included, among other things, a base rate

freeze for Elizabethtown Gas for the five-year period from November 2004 to October 2009. Beginning with the annual measurement period in December 2007, 75% of Elizabethtown Gas' earnings in excess of an 11% return on equity would be shared with rate payers in the fourth and fifth years of the base rate stay-out period.

Weather Normalization Certain of our non-Georgia jurisdictions have various regulatory mechanisms that allow us to recover our costs in the event of unusual weather, but they are not direct offsets to the potential impacts of weather and customer consumption on earnings. The tariffs of Elizabethtown Gas, Virginia Natural Gas, and Chattanooga Gas contain WNA provisions that are designed to help stabilize operating results by increasing base rate amounts charged to customers when weather is warmer than normal and decreasing amounts charged when weather is colder than normal. The WNA is most effective in a reasonable temperature range relative to normal weather using historical averages. The following table provides certain regulatory information for our largest utilities.

	Atlanta Gas Light	Elizabethtown Gas	Virginia Natural Gas	Florida City Gas	Chattanooga Gas
State regulator	Georgia Commission	New Jersey Commission	Virginia Commission	Florida Commission	Tennessee Commission
Current rates effective until	May 2010	Jan. 2010	Aug. 2011	N/A	Jan. 2011
Authorized return on rate base (1)	8.53%	7.95%	9.24%	7.36%	7.89%
Estimated 2007 return on rate base (2) (4)	8.59%	8.46%	7.90%	6.09%	7.53%
Authorized return on equity	10.9%	10.0%	10.9%	11.25%	10.2%
Estimated 2007 return on equity (2) (4)	11.03%	10.32%	8.96%	7.04%	9.40%
Authorized rate base % of equity (3)	47.9%	53.0%	52.4%	36.8%	44.8%
Rate base included in 2007 return on equity (in millions) (3) (4)	$1,271	$441	$350	$146	$100

(1) The authorized return on rate base, return on equity, and percentage of equity reflected above were those authorized as of December 31, 2007.
(2) Estimate based on principles consistent with utility ratemaking in each jurisdiction. Returns are not necessarily consistent with GAAP returns.
(3) Estimated based on 13-month average.
(4) Florida City Gas includes the impacts of the acquisition adjustment, as approved by the Florida Commission in December 2007, in its rate base, return on rate base and return on equity calculations.

Customer Demand All of our utilities face competition from other energy products. Our principal competition arises from electric utilities and oil and propane providers serving the residential and commercial markets throughout our service areas and the potential displacement or replacement of natural gas appliances with electric appliances. The primary competitive factors are the prices for competing sources of energy as compared to natural gas and the desirability of natural gas heating versus alternative heating sources.

Competition for space heating and general household and small commercial energy needs generally occurs at the initial installation phase when the customer or builder makes decisions as to which types of equipment to install. Customers generally continue to use the chosen energy source for the life of the equipment. Customer demand for natural gas could be affected by numerous factors, including:

- changes in the availability or price of natural gas and other forms of energy
- general economic conditions
- energy conservation
- legislation and regulations
- the capability to convert from natural gas to alternative fuels
- weather
- new housing starts

In some of our service areas, net growth continues to be slowed due to the number of customers who leave our systems because of higher natural gas prices, slower economic growth in some of our service areas and competition from alternative fuel sources, including incentives offered by the local electric utilities to switch to electric alternatives.

Through our targeted marketing and customer retention programs, we have improved the retention of our existing customers. Additionally, these activities have enabled us to obtain new customers, although at a lower rate than expected, due in part to downturns in the general economy and the housing and related mortgage markets. We expect these conditions to continue for an extended period of time and that such conditions could impact our net customer growth. Consequently, we will focus even more on our marketing and customer retention efforts.

These efforts include working to add residential customers, multifamily complexes and high-value commercial customers that use natural gas for purposes other than space heating. In addition, we

partner with numerous entities to market the benefits of gas appliances and to identify potential retention options early in the process for those customers who might consider converting to alternative fuels.

Collective Bargaining Agreements In 2007, collective bargaining agreements, representing 55 employees at Atlanta Gas Light, Chattanooga Gas and Elizabethtown Gas were terminated as a result of the decertification of the respective unions. Accordingly, these 55 employees are no longer represented by a bargaining agreement and now fall under our standard human resources pay and benefit plans and policies. In January 2008, approximately 55 Florida City Gas employees filed for decertification of their union. The vote is expected to occur in February 2008.

The following table provides information about the collective bargaining agreements to which our natural gas local distribution utilities are parties. Additionally, we believe that our relations with our employees are good.

	Affiliated subsidiary	Approximate # of employees	Date of contract expiration
Teamsters (Local Nos. 769 and 385)	Florida City Gas	55	March 2008
Utility Workers Union of America (Local No. 424)	Elizabethtown Gas	160	November 2009
International Brotherhood of Electrical Workers (Local No. 50)	Virginia Natural Gas	140	May 2010
	Total	355	

Retail Energy Operations

Our retail energy operations segment consists of SouthStar, a joint venture owned 70% by our subsidiary, Georgia Natural Gas Company, and 30% by Piedmont. SouthStar markets natural gas and related services under the trade name Georgia Natural Gas to retail customers on an unregulated basis, primarily in Georgia as well as to commercial and industrial customers, principally in Florida, Tennessee, North Carolina, South Carolina and Alabama. Based on its market share, SouthStar is the largest Marketer of natural gas in Georgia, with average customers in excess of 530,000 over the last three years.

SouthStar is governed by an executive committee, which is comprised of six members, three representatives from AGL Resources and three from Piedmont. Under a joint venture agreement, all significant management decisions require the unanimous approval of the SouthStar executive committee; accordingly, our 70% financial interest is considered to be noncontrolling. Although our ownership interest in the SouthStar partnership is 70%, under an amended and restated joint venture agreement (Restated Agreement) executed in March 2004, SouthStar's earnings are allocated 75% to us and 25% to Piedmont except for earnings related to customers in Ohio and Florida, which are allocated 70% to us and 30% to Piedmont. We record the earnings allocated to Piedmont as a minority interest in our consolidated statements of income, and we record Piedmont's portion of SouthStar's capital as a minority interest in our consolidated balance sheets.

The Restated Agreement includes a provision granting us three opportunities to exercise an option to purchase Piedmont's ownership interest in SouthStar. Our first option exercise opportunity was on November 1, 2007, which we did not exercise and we have two remaining opportunities on November 1, 2008 and 2009, to purchase certain portions of Piedmont's interest, both of which would be effective on January 1 of the following year. If we were to exercise our option on November 1, 2008, Piedmont, at its discretion, could require us to purchase their entire ownership interest. The purchase price would be based on the fair market value of SouthStar.

In August 2006, SouthStar was awarded the right to supply a total of approximately 10 Bcf of natural gas to customers of Dominion Ohio through August 2008 (approximately 5 Bcf/year). As part of this agreement, SouthStar manages the supply, transportation and storage of natural gas on behalf of Dominion Ohio. The Dominion Ohio agreement did not materially affect our results of operations in 2007. SouthStar's entrance into the Ohio market is part of its continued growth strategy.

SouthStar's operations also are sensitive to customer consumption patterns similar to those affecting our utility operations. SouthStar uses a variety of hedging strategies, such as futures, options, swaps, weather derivative instruments and other risk management tools, to mitigate the potential effect of these issues on its operations.

Competition SouthStar competes with other energy marketers, including Marketers in Georgia, to provide natural gas and related services to customers in Georgia and the Southeast. In addition, similar to our distribution operations, SouthStar faces competition based on customer preferences for natural gas compared to other energy products and the comparative prices of those products. SouthStar's principal competitors for other non-natural gas energy products relates to electric utilities and the potential displacement or replacement of natural gas appliances with electric appliances. This competition with other energy products has been exacerbated by price volatility in the wholesale natural gas commodity market and related significant increases in the cost of natural gas billed to SouthStar's customers, especially during portions of 2005 and 2006.

Operating margin SouthStar generates operating margin primarily in three ways. The first is through the sale of natural gas to retail customers in the residential, commercial and industrial sectors, primarily in Georgia where SouthStar captures a spread between wholesale and retail natural gas prices. The second way is through the collection of monthly service fees and customer late payment fees.

SouthStar evaluates the combination of these two retail price components to ensure such pricing is structured to cover related retail customer costs, such as bad debt expense, customer service and billing, and lost and unaccounted-for gas, and to provide a reasonable profit, as well as being competitive to attract new customers and maintain market share. SouthStar's operating margin is impacted by seasonal weather, natural gas prices, customer growth and SouthStar's related market share in Georgia, which has historically been approximately 35%, based on number of customers. SouthStar employs strategies to attract and retain a higher credit-quality customer base. These strategies result not only in higher operating margin, as these customers tend to utilize higher volumes of natural gas, but also help to mitigate bad debt expense due to the higher credit-quality of customers.

The third way SouthStar generates operating margin is through its commercial operations of optimizing storage and transportation assets and effectively

managing commodity risk, which enables SouthStar to maintain competitive retail prices and operating margin. SouthStar is allocated storage and pipeline capacity that is used to supply natural gas to its customers in Georgia. Through hedging transactions, SouthStar manages exposures arising from changing commodity prices using natural gas storage transactions to capture operating margin from natural gas pricing differences that occur over time. SouthStar's risk management policies allow the use of derivative instruments for hedging and risk management purposes but prohibit the use of derivative instruments for speculative purposes.

SouthStar accounts for its natural gas inventories at the lower of weighted average cost or current market price. SouthStar evaluates the weighted average cost of its natural gas inventories against market prices and determines whether any declines in market prices below the weighted average cost are other than temporary. For declines considered to be other than temporary, SouthStar records adjustments to cost of gas (LOCOM adjustments) in our consolidated statement of income to reduce the weighted average cost of the natural gas inventory to the current market price. SouthStar recorded a LOCOM adjustment of $6 million in 2006. SouthStar did not record a LOCOM adjustment in 2007 or 2005.

SouthStar also enters into weather derivative instruments in order to preserve operating margin profits in the event of warmer-than-normal weather in the winter months. These contracts are accounted for using the intrinsic value method under EITF 99-02. The weather derivative contracts contain settlement provisions based on cumulative heating degree days for the covered periods. SouthStar entered into weather derivatives (swaps and options) for both the 2006 to 2007, and 2007 to 2008 heating seasons. SouthStar recorded net gains on these weather derivatives of approximately $4 million in 2007 and $5 million in 2006. These gains were largely offset by corresponding losses of operating margin due to the warm weather the hedges were designed to protect against. SouthStar had no weather derivatives in 2005 and therefore no gains or losses were recorded during 2005.

Wholesale Services

Our wholesale services segment, which consists primarily of Sequent, focuses on asset management, transportation, storage, producer and peaking services and wholesale marketing. Sequent captures economic value from idle or underutilized natural gas assets, which are typically amassed by companies through investments in or contractual rights to natural gas transportation and storage assets. Operating margin is typically created in this business by participating in transactions that balance the needs of varying markets and time horizons.

In addition, Sequent takes advantage of arbitrage opportunities within the natural gas supply, storage and transportation markets to generate earnings, and its profitability is correlated to volatility in these markets. Natural gas market volatility can result from a number of factors, such as weather fluctuations or the change in supply of, or demand for, natural gas in different regions of the country. Sequent seeks to capture value from the price disparity among geographic locations and various time horizons created by this volatility. In doing so, Sequent also seeks to mitigate the risks associated with this volatility and protect its operating margin through a variety of risk management and hedging activities.

Sequent provides its customers with natural gas from the major producing regions and market hubs primarily in the eastern and mid-continental United States. Sequent purchases transportation and storage capacity to meet its delivery requirements and customer obligations in the marketplace and its customers benefit from its logistics expertise and ability to deliver natural gas at prices that are advantageous relative to other alternatives. Sequent has entered into agreements that have facilitated the expansion of its operations into the western United States and Canada and plans to pursue additional opportunities in these regions during 2008. Sequent continues to work on projects and transactions to extend its operating territory and is entering into agreements of longer duration, as well as evaluating opportunities to expand its business focus and models including its commercial and industrial customer base through acquisitions and organic growth.

Competition Sequent competes for asset management business with other energy wholesalers, often through a competitive bidding process. There has been significant consolidation of energy wholesale operations, particularly among major natural gas producers. Financial institutions have also entered the marketplace. As a result, energy wholesalers have become increasingly willing to place bids for asset management transactions that are priced to capture market share. We expect this trend to continue in the near term, which could result in downward pressure on the volume of asset management transactions and the related operating margin available in this portion of Sequent's business.

Asset Management Transactions Sequent's asset management customers include affiliated utilities, nonaffiliated utilities, municipal utilities, power generators and large industrial customers. These customers, due to seasonal demand or levels of

activity, may have contracts for transportation and storage capacity, which may exceed their actual requirements. Sequent enters into structured agreements with these customers, whereby Sequent, on behalf of the customer, optimizes the transportation and storage capacity during periods when customers do not use it for their own needs. Sequent may capture incremental operating margin through optimization, and either share margins with the customers or pay them a fixed amount.

The following table provides additional information on Sequent's asset management agreements with its affiliated utilities.

In millions	Expiration date	Timing of payment	Type of fee structure	% Shared or annual fee	Profit sharing / fees payments 2007	2006	2005
Elkton Gas	Mar 2008	Monthly	Fixed-fee	(A)	$-	$-	$-
Chattanooga Gas	Mar 2008	Annually	Profit -sharing	50%	2	4	2
Elizabethtown Gas	Mar 2008	Monthly	Fixed -fee	$4	6	4	-
Florida City Gas	Mar 2008	Annually	Profit -sharing	50%	1	-	-
Virginia Natural Gas	Mar 2009	Annually	Profit -sharing	(B)	7	2	5
Atlanta Gas Light	Mar 2012	Quarterly	Profit -sharing	60%	9	6	4
Total					$25	$16	$11

(A) Annual fixed fee is approximately $11,000.
(B) Profit sharing is based on a tiered sharing structure.

In October 2007, the Georgia Commission extended the asset management agreement between Sequent and Atlanta Gas Light to March 2012. Under the terms of the extended agreement, the sharing percentages are unchanged; however the agreement now includes guaranteed minimum annual payments to be made by Sequent of approximately $4 million. The contract year under the extended agreement will be April 1 to March 31 with Sequent making quarterly sharing payments. Sequent is actively negotiating the renewal of its remaining affiliate asset management agreements scheduled to expire in 2008, which require regulatory approval.

Transportation Transactions Sequent contracts for natural gas transportation capacity and participates in transactions that manage the natural gas commodity and transportation costs in an attempt to achieve the lowest cost to serve its various markets. Sequent seeks to optimize this process on a daily basis as market conditions change by evaluating all the natural gas supplies, transportation alternatives and markets to which it has access and identifying the least-cost alternatives to serve the various markets. This enables Sequent to capture geographic pricing differences across these various markets as delivered natural gas prices change.

As Sequent executes transactions to secure transportation capacity, it often enters into forward financial contracts to hedge its positions. The hedging instruments are derivatives, and Sequent reflects changes in the derivatives' fair value in its reported operating results. During 2007, Sequent reported unrealized gains of $5 million associated with transportation capacity hedges, most of which are expected to be realized as these positions are settled in 2008. During 2006, Sequent reported unrealized gains of $12 million associated with transportation capacity hedges. The majority of this amount was realized during 2007 as the positions were settled. Sequent did not report any significant gains or losses on these types of hedges during 2005.

Producer Services Sequent's producer services business primarily focuses on aggregating natural gas supply from various small and medium-sized producers located throughout the natural gas production areas of the United States, principally in the Gulf Coast region. Sequent provides producers with certain logistical and risk management services that offer producers attractive options to move their supply into the pipeline grid. Aggregating volumes of natural gas from these producers allows Sequent to provide markets to producers who seek a reliable outlet for their natural gas production.

Park and Loan Transactions Sequent routinely enters into park and loan transactions with various pipelines, which allow it to park gas on or borrow gas from the pipeline in one period and reclaim gas from or repay gas to the pipeline in a subsequent period. The economics of these transactions are evaluated and price risks are managed in much the same way traditional reservoir and salt dome storage transactions are evaluated and managed.

Sequent enters into forward NYMEX contracts to hedge its park and loan transactions. While the hedging instruments mitigate the price risk associated with the delivery and receipt of natural gas, they can also result in volatility in Sequent's reported results during the period before the initial delivery or receipt of natural gas. During this period, if the forward NYMEX prices in the months of delivery and receipt do not change in equal amounts, Sequent will report a net unrealized gain or loss on the hedges.

Although Sequent's quarterly results were modestly impacted by unrealized hedge losses during 2007 and 2006, on an annual basis Sequent did not report any significant gains or losses on park and loan hedges during 2007, 2006, or 2005.

Mark-to-Market Versus Lower of Average Cost or Market Sequent purchases natural gas for storage when the current market price it pays plus the cost for transportation and storage is less than the market price it could receive in the future. Sequent attempts to mitigate substantially all of the commodity price risk associated with its storage portfolio and uses derivative instruments to reduce the risk associated with future changes in the price of natural gas. Sequent sells NYMEX futures contracts or over-the-counter derivatives in forward months to substantially lock in the operating margin it will ultimately realize when the stored gas is actually sold.

We view Sequent's trading margins from two perspectives. First, we base our commercial decisions on economic value, which is defined as the locked-in gain to be realized in the statement of income at the time the physical gas is withdrawn from storage and ultimately sold and the derivative instrument used to hedge natural gas price risk on that physical storage is settled. Second is the GAAP reported value both prior to and at the point of physical withdrawal. The GAAP amount is impacted by the process of accounting for the financial hedging instruments in interim periods at fair value between the time the natural gas is injected into storage and when it is ultimately withdrawn and the financial instruments are settled. The change in the fair value of the hedging instruments is recognized in earnings in the period of change and is recorded as unrealized gains or losses. The actual value, less any interim recognition of gains or losses on hedges and adjustments for LOCOM, is realized when the natural gas is delivered to its ultimate customer.

Sequent accounts for natural gas stored in inventory differently than the derivatives Sequent uses to mitigate the commodity price risk associated with its storage portfolio. The natural gas that Sequent purchases and injects into storage is accounted for at the lower of average cost or current market value. The derivatives that Sequent uses to mitigate commodity price risk are accounted for at fair value and marked to market each period. This difference in accounting treatment can result in volatility in Sequent's reported results, even though the expected operating margin is essentially unchanged from the date the transactions were consummated. These accounting differences also affect the comparability of Sequent's period-over-period results, since changes in forward NYMEX prices do not increase and decrease on a consistent basis from year to year. During most of 2007 and 2006, Sequent's reported results were positively impacted by decreases in forward NYMEX prices, which resulted in the recognition of unrealized gains; however, the impact was more significant for 2006. During 2005, the reported results were negatively impacted by increases in forward NYMEX prices. As a result the more significant unrealized gains during 2006 increased the unfavorable variance between 2007 and 2006 and had a positive impact on the favorable variance between 2006 and 2005.

Energy Investments

Our energy investments segment includes a number of businesses that are related and complementary to our primary business. The most significant of these businesses is our natural gas storage business, which develops, acquires and operates high-deliverability salt-dome storage assets in the Gulf Coast region of the United States. While this business also can generate additional revenue during times of peak market demand for natural gas storage services, the majority of our storage services are covered under medium to long-term contracts at a fixed market rate.

Jefferson Island This wholly owned subsidiary operates a salt dome storage and hub facility in Louisiana, approximately eight miles from the Henry Hub. The storage facility is regulated by the Louisiana DNR and by the FERC, which has limited regulatory authority over the storage and transportation services. The facility consists of two salt dome gas storage caverns with approximately 9.72 Bcf of total capacity and about 7.23 Bcf of working gas capacity. The facility has approximately 0.72 Bcf/day withdrawal capacity and 0.36 Bcf/day injection capacity. Jefferson Island provides storage and hub services through its direct connection to the Henry Hub via the Sabine Pipeline and its interconnection with seven other pipelines in the area. Jefferson Island's entire portfolio is under firm subscription for the current heating season.

In August 2006, the Office of Mineral Resources of the Louisiana DNR informed Jefferson Island that its mineral lease – which authorizes salt extraction to create two new storage caverns – at Lake Peigneur had been terminated. The Louisiana DNR identified two bases for the termination: (1) failure to make certain mining leasehold payments in a timely manner, and (2) the absence of salt mining operations for six months.

In September 2006, Jefferson Island filed suit against the State of Louisiana to maintain its lease to complete an ongoing natural gas storage expansion project in Louisiana. The project would add two salt dome storage caverns under Lake Peigneur to the

two caverns currently owned and operated by Jefferson Island. In its suit, Jefferson Island alleges that the Louisiana DNR accepted all leasehold payments without reservation and never provided Jefferson Island with notice and opportunity to cure, as required by state law. In its answer to the suit, the State denied that anyone with proper authority approved late payments. As to the second basis for termination, the suit contends that Jefferson Island's lease with the State of Louisiana was amended in 2004 so that mining operations are no longer required to maintain the lease. The State's answer denies that the 2004 amendment was properly authorized. During early 2008 we plan to intensify our efforts with the state of Louisiana to move the expansion project forward. If we are unable to reach a settlement, we are not able to predict the outcome of the litigation. As of January 2008, our current estimate of costs incurred that would be considered unusable if the Louisiana DNR was successful in terminating our lease and causing us to cease the expansion project is approximately $6 million.

Golden Triangle Storage In December 2006, we announced that our wholly-owned subsidiary, Golden Triangle Storage, plans to build a natural gas storage facility in the Beaumont, Texas area in the Spindletop salt dome. The project will initially consist of two underground salt dome storage caverns approximately a half-mile to a mile below ground that will hold about 12 Bcf of working natural gas storage capacity initially, or a total cavern capacity of approximately 17 Bcf. The facility potentially can be expanded to a total of five caverns with 28 Bcf of working natural gas storage capacity in the future based on customer interest. Golden Triangle Storage also intends to build an approximately nine-mile natural gas pipeline to connect the storage facility with three interstate and three intrastate pipelines. In May 2007, Golden Triangle Storage held a non-binding open season for service offerings at the proposed facility, which resulted in indications of market support for the facility.

Our current cost estimate for this facility is up to $265 million, but the actual cost will depend upon the facility's configuration, materials and drilling costs, the amount and cost of pad gas (which includes volumes of non-working natural gas used to maintain the operational integrity of the cavern facility), and financing costs. This estimate could change due to changes in these factors, among others, as we refine our engineering estimates.

In December 2007, Golden Triangle Storage received an order from the FERC granting a Certificate of Public Convenience and Necessity to construct and operate the storage facility and approving market-based rates for services to be provided. We accepted this FERC order in January 2008. The FERC will serve as the lead agency overseeing the participation of a number of other federal, state and local agencies in reviewing and permitting the facility. Timelines associated with our commencement of commercial operations remain on track with initial construction on the first cavern expected to begin in the first half of 2008.

AGL Networks This wholly owned subsidiary provides telecommunications conduit and dark fiber. AGL Networks leases and sells its fiber to a variety of customers in the Atlanta, Georgia and Phoenix, Arizona metropolitan areas, with a small presence in other cities in the United States. Its customers include local, regional and national telecommunications companies, internet service providers, educational institutions and other commercial entities. AGL Networks typically provides underground conduit and dark fiber to its customers under leasing arrangements with terms that vary from one to twenty years. In addition, AGL Networks offers telecommunications construction services to its customers. AGL Networks' competitors are any entities that have laid or will lay conduit and fiber on the same route as AGL Networks in the respective metropolitan areas.

Corporate

Our corporate segment includes our nonoperating business units, including AGSC and AGL Capital. AGL Capital, our wholly owned subsidiary, provides for our ongoing financing needs through a commercial paper program, the issuance of various debt and hybrid securities, and other financing arrangements.

We allocate substantially all of AGSC's operating expenses and interest costs to our operating segments in accordance with various regulations. Our corporate segment also includes intercompany eliminations for transactions between our operating business segments. Our EBIT results include the impact of these allocations to the various operating segments. The acquisition of additional assets, such as NUI and Jefferson Island, typically enables us to allocate corporate costs across a larger number of businesses and, as a result, lower the relative allocations charged to those business units we owned prior to the acquisition of the new businesses.

Our corporate segment also includes Pivotal Energy Development, which coordinates among our related operating segments the development, construction or acquisition of assets in the southeastern, mid-Atlantic and northeastern regions in order to extend our natural gas capabilities and improve system reliability while enhancing service to our customers in those areas. The focus of Pivotal Energy Development's commercial activities is to improve the economics of

system reliability and natural gas deliverability in these targeted regions.

Additional Information

For additional information on our segments, see Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations" under the caption "Results of Operations" and "Note 9, Segment Information," set forth in Item 8, "Financial Statements and Supplementary Data."

Information on our environmental remediation efforts, is contained in "Note 7, Commitments and Contingencies," set forth in Item 8, "Financial Statements and Supplementary Data."

Hedges

Changes in commodity prices subject a significant portion of our operations to earnings variability. Our nonutility businesses principally use physical and financial arrangements to reduce the risks associated with both weather-related seasonal fluctuations and changing commodity prices. In addition, because these economic hedges are generally not designated for hedge accounting treatment, our reported earnings for the wholesale services and retail energy operations segments reflect changes in the fair values of certain derivatives. These values may change significantly from period to period and are reflected as gains or losses within our operating margin or our OCI for those derivative instruments that qualify and are designated as accounting hedges.

Seasonality

The operating revenues and EBIT of our distribution operations, retail energy operations and wholesale services segments are seasonal. During the heating season, natural gas usage and operating revenues are generally higher because more customers are connected to our distribution systems and natural gas usage is higher in periods of colder weather than in periods of warmer weather.

Approximately 61% of these segments' operating revenues and 69% of these segments' EBIT for the year ended December 31, 2007 were generated during the heating season and are reflected in our statements of consolidated income for the quarters ended March 31, 2007 and December 31, 2007. Our base operating expenses, excluding cost of gas, interest expense and certain incentive compensation costs, are incurred relatively equally over any given year. Thus, our operating results vary significantly from quarter to quarter as a result of seasonality. Seasonality also affects the comparison of certain balance sheet items such as receivables, unbilled revenue, inventories and short-term debt across quarters. However, these items are comparable when reviewing our annual results.

Available Information

Detailed information about us is contained in our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, proxy statements and other reports, and amendments to those reports, that we file with or furnish to the SEC. These reports are available free of charge at our website, www.aglresources.com, as soon as reasonably practicable after we electronically file such reports with or furnish such reports to the SEC. However, our website and any contents thereof should not be considered to be incorporated by reference into this document. We will furnish copies of such reports free of charge upon written request to our Investor Relations department. You can contact our Investor Relations department at:

AGL Resources Inc.
Investor Relations - Dept. 1071
P.O. Box 4569
Atlanta, GA 30309-4569
404-584-3801

In Part III of this Form 10-K, we incorporate by reference from our Proxy Statement for our 2008 annual meeting of shareholders certain information. We expect to file that Proxy Statement with the SEC on or about March 19, 2008, and we will make it available on our website as soon as reasonably practicable. Please refer to the Proxy Statement when it is available.

Additionally, our corporate governance guidelines, code of ethics, code of business conduct and the charters of each of our Board of Directors committees are available on our website. We will furnish copies of such information free of charge upon written request to our Investor Relations department.

ITEM 1A. RISK FACTORS

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

Certain expectations and projections regarding our future performance referenced in this report, in other materials we file with the SEC or otherwise release to the public, and on our website are forward-looking statements. Senior officers may also make verbal statements to analysts, investors, regulators, the media and others that are forward-looking. Forward-looking statements involve matters that are not historical facts, such as statements in "Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations" and elsewhere regarding our future operations, prospects, strategies, financial condition, economic performance (including growth and earnings), industry conditions and demand for our products and services. We have tried, whenever possible, to identify these statements by using words such as "anticipate," "assume," "believe," "can," "could," "estimate," "expect," "forecast," "future," "goal," "indicate," "intend," "may," "outlook," "plan," "potential," "predict," "project," "seek," "should," "target," "will," "would," and similar expressions.

You are cautioned not to place undue reliance on our forward-looking statements. Our forward-looking statements are not guarantees of future performance and are based on currently available competitive, financial and economic data along with our operating plans. While we believe that our expectations for the future are reasonable in view of the currently available information, our expectations are subject to future events, risks and inherent uncertainties, as well as potentially inaccurate assumptions, and there are numerous factors - many beyond our control - that could cause results to differ significantly from our expectations. Such events, risks and uncertainties include, but are not limited to those set forth below and in the other documents that we file with the SEC. We note these factors for investors as permitted by the Private Securities Litigation Reform Act of 1995. There also may be other factors that we cannot anticipate or that are not described in this report, generally because we do not perceive them to be material, which could cause results to differ significantly from our expectations.

Forward-looking statements are only as of the date they are made, and we do not undertake any obligation to update these statements to reflect subsequent circumstances or events. You are advised, however, to review any further disclosures we make on related subjects in our Form 10-Q and Form 8-K reports to the SEC.

Risks Related to Our Business

Risks related to the regulation of our businesses could affect the rates we are able to charge, our costs and our profitability.

Our businesses are subject to regulation by federal, state and local regulatory authorities. In particular, at the federal level our businesses are regulated by the FERC. At the state level, our businesses are regulated by the Georgia Commission, the Tennessee Commission, the New Jersey Commission, the Florida Commission, the Virginia Commission and the Maryland Commission.

These authorities regulate many aspects of our operations, including construction and maintenance of facilities, operations, safety, rates that we charge customers, rates of return, the authorized cost of capital, recovery of pipeline replacement and environmental remediation costs, relationships with our affiliates, and carrying costs we charge Marketers selling retail natural gas in Georgia for gas held in storage for their customer accounts. Our ability to obtain rate increases and rate supplements to maintain our current rates of return and recover regulatory assets and liabilities recorded in accordance with SFAS 71 depends on regulatory discretion, and there can be no assurance that we will be able to obtain rate increases or rate supplements or continue receiving our currently authorized rates of return including the recovery of our regulatory assets and liabilities. In addition, if we fail to comply with applicable regulations, we could be subject to fines, penalties or other enforcement action by the authorities that regulate our operations, or otherwise be subject to material costs and liabilities.

Deregulation in the natural gas industry is the separation of the provision and pricing of local distribution gas services into discrete components. Deregulation typically focuses on the separation of the gas distribution business from the gas sales business and is intended to cause the opening of the formerly regulated sales business to alternative unregulated suppliers of gas sales services.

In 1997, the Georgia legislature enacted the Deregulation Act. To date, Georgia is the only state in the nation that has fully deregulated gas distribution operations, which ultimately resulted in Atlanta Gas Light exiting the retail natural gas sales business while retaining its gas distribution operations. Marketers then assumed the retail gas sales responsibility at deregulated prices. The deregulation process required Atlanta Gas Light to completely reorganize its operations and personnel at significant expense. It is possible that the legislature could reverse or amend portions of the

deregulation process and require or permit Atlanta Gas Light to provide retail gas sales service once again or require our retail energy operations segment, SouthStar, to change the nature of how it provides natural gas and the rates used to charge certain customers. In addition, the Georgia Commission has statutory authority on an emergency basis to order Atlanta Gas Light to provide temporarily the same retail gas service that it provided prior to deregulation. If any of these events were to occur, we would incur costs to reverse the restructuring process or potentially lose the earnings opportunity embedded within the current marketing framework. Furthermore, the Georgia Commission has authority to change the terms under which we charge Marketers for certain supply-related services, which could also affect our future earnings.

Our business is subject to environmental regulation in all jurisdictions in which we operate, and our costs to comply are significant. Any changes in existing environmental regulation could affect our results of operations and financial condition.

Our operations and properties are subject to extensive environmental regulation pursuant to a variety of federal, state and municipal laws and regulations. Such environmental legislation imposes, among other things, restrictions, liabilities and obligations in connection with storage, transportation, treatment and disposal of hazardous substances and waste and in connection with spills, releases and emissions of various substances into the environment. Environmental legislation also requires that our facilities, sites and other properties associated with our operations be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. Our current costs to comply with these laws and regulations are significant to our results of operations and financial condition. Failure to comply with these laws and regulations and failure to obtain any required permits and licenses may expose us to fines, penalties or interruptions in our operations that could be material to our results of operations.

In addition, claims against us under environmental laws and regulations could result in material costs and liabilities. Existing environmental regulations could also be revised or reinterpreted, new laws and regulations could be adopted or become applicable to us or our facilities, and future changes in environmental laws and regulations could occur. With the trend toward stricter standards, greater regulation, more extensive permit requirements and an increase in the number and types of assets operated by us subject to environmental regulation, our environmental expenditures could increase in the future, particularly if those costs are not fully recoverable from our customers. Additionally, the discovery of presently unknown environmental conditions could give rise to expenditures and liabilities, including fines or penalties, which could have a material adverse effect on our business, results of operations or financial condition.

There are a number of legislative and regulatory proposals to address greenhouse gas emissions such as carbon dioxide, which are in various phases of discussion or implementation. The outcome of federal and state actions to address global climate change could result in a variety of regulatory programs including potential new regulations, additional charges to fund energy efficiency activities, or other regulatory actions. These actions could:

- result in increased costs associated with our operations
- Increase other costs to our business
- affect the demand for natural gas and
- impact the prices we charge our customers.

Because natural gas is a fossil fuel with low carbon content, it is possible that future carbon constraints could create additional demand for natural gas, both for production of electricity and direct use in homes and businesses.

Our infrastructure improvement and customer growth may be restricted by the capital-intensive nature of our business.

We must construct additions to our natural gas distribution system to continue the expansion of our customer base. We may also need to construct expansions of our existing natural gas storage facilities or develop and construct new natural gas storage facilities. The cost of this construction may be affected by the cost of obtaining government and other approvals, development project delays, adequacy of supply of diversified vendors, or unexpected changes in project costs. Weather, general economic conditions and the cost of funds to finance our capital projects can materially alter the cost, and projected construction schedule and completion timeline of a project. Our cash flows may not be fully adequate to finance the cost of this construction. As a result, we may be required to fund a portion of our cash needs through borrowings or the issuance of common stock, or both. For our distribution operations segment, this may limit our ability to expand our infrastructure to connect new customers due to limits on the amount we can economically invest, which shifts costs to potential customers and may make it uneconomical for them to connect to our distribution systems. For our natural gas storage business, this may significantly reduce our earnings and return on investment from what

would be expected for this business, or may impair our ability to complete the expansions or development projects.

Transporting and storing natural gas involves numerous risks that may result in accidents and other operating risks and costs.

Our gas distribution activities involve a variety of inherent hazards and operating risks, such as leaks, accidents and mechanical problems, which could cause substantial financial losses. In addition, these risks could result in loss of human life, significant damage to property, environmental pollution and impairment of our operations, which in turn could lead to substantial losses to us. In accordance with customary industry practice, we maintain insurance against some, but not all, of these risks and losses. The location of pipelines and storage facilities near populated areas, including residential areas, commercial business centers and industrial sites, could increase the level of damages resulting from these risks. The occurrence of any of these events not fully covered by insurance could adversely affect our financial position and results of operations.

We face increasing competition, and if we are unable to compete effectively, our revenues, operating results and financial condition will be adversely affected and may limit our ability to grow our business.

The natural gas business is highly competitive, and we are facing increasing competition from other companies that supply energy, including electric companies, oil and propane providers and, in some cases, energy marketing and trading companies. In particular, the success of our investment in SouthStar is affected by the competition SouthStar faces from other energy marketers providing retail natural gas services in the Southeast. Natural gas competes with other forms of energy. The primary competitive factor is price. Changes in the price or availability of natural gas relative to other forms of energy and the ability of end-users to convert to alternative fuels affect the demand for natural gas. In the case of commercial, industrial and agricultural customers, adverse economic conditions, including higher gas costs, could also cause these customers to bypass or disconnect from our systems in favor of special competitive contracts with lower per-unit costs.

Our wholesale services segment competes with national and regional full-service energy providers, energy merchants and producers and pipelines for sales based on our ability to aggregate competitively priced commodities with transportation and storage capacity. Some of our competitors are larger and better capitalized than we are and have more national and global exposure than we do. The consolidation of this industry and the pricing to gain market share may affect our operating margin. We expect this trend to continue in the near term, and the increasing competition for asset management deals could result in downward pressure on the volume of transactions and the related operating margin available in this portion of Sequent's business.

A significant portion of our accounts receivable is subject to collection risks, due in part to a concentration of credit risk in Georgia and at Sequent.

We have accounts receivable collection risk in Georgia due to a concentration of credit risk related to the provision of natural gas services to Marketers. At December 31, 2007, Atlanta Gas Light had 12 certificated and active Marketers in Georgia, four of which (based on customer count and including SouthStar) accounted for approximately 38% of our consolidated operating margin for 2007. As a result, Atlanta Gas Light depends on a concentrated number of customers for revenues. The failure of these Marketers to pay Atlanta Gas Light could adversely affect Atlanta Gas Light's business and results of operations and expose it to difficulties in collecting Atlanta Gas Light's accounts receivable. The provisions of Atlanta Gas Light's tariff allow it to obtain security support in an amount equal to a minimum of two times a Marketer's highest month's estimated bill. Additionally, SouthStar markets directly to end-use customers and has periodically experienced credit losses as a result of severe cold weather or high prices for natural gas that increase customers' bills and, consequently, impair customers' ability to pay.

Sequent often extends credit to its counterparties. Despite performing credit analyses prior to extending credit and seeking to effectuate netting agreements, Sequent is exposed to the risk that it may not be able to collect amounts owed to it. If the counterparty to such a transaction fails to perform and any collateral Sequent has secured is inadequate, Sequent could experience material financial losses. Further, Sequent has a concentration of credit risk, which could subject a significant portion of its credit exposure to collection risks. Approximately 53% of Sequent's credit exposure is concentrated in 20 counterparties. Although most of this concentration is with counterparties that are either load-serving utilities or end-use customers that have supplied some level of credit support, default by any of these counterparties in their obligations to pay amounts due Sequent could result in credit losses that would negatively impact our wholesale services segment.

The asset management arrangements between Sequent and our local distribution companies, and between Sequent and its nonaffiliated customers, may not be renewed or may be renewed at lower levels, which could have a significant impact on Sequent's business.

Sequent currently manages the storage and transportation assets of our affiliates Atlanta Gas Light, Chattanooga Gas, Elizabethtown Gas, Elkton Gas, Florida City Gas, and Virginia Natural Gas and shares profits it earns from the management of those assets with those customers and their respective customers, except at Elizabethtown Gas and Elkton Gas where Sequent is assessed annual fixed-fees payable in monthly installments. Additionally, for the newly extended Atlanta Gas Light asset management agreement, Sequent will be required to make annual minimum payments of approximately $4 million payable on a quarterly basis. Entry into and renewal of these agreements are subject to regulatory approval and four are subject to renewal in 2008. In addition, Sequent has asset management agreements with certain nonaffiliated customers. Sequent's results could be significantly impacted if these agreements are not renewed or are amended or renewed with less favorable terms.

We are exposed to market risk and may incur losses in wholesale services and retail energy operations.

The commodity, storage and transportation portfolios at Sequent and the commodity and storage portfolios at SouthStar consist of contracts to buy and sell natural gas commodities, including contracts that are settled by the delivery of the commodity or cash. If the values of these contracts change in a direction or manner that we do not anticipate, we could experience financial losses from our trading activities. Based on a 95% confidence interval and employing a 1-day holding period for all positions, Sequent's and SouthStar's portfolio of positions as of December 31, 2007 had a 1-day holding period VaR of $1.2 million and $0.03 million, respectively.

***Our accounting results may not be indicative of* the risks we are taking or the economic results we expect for wholesale services.**

Although Sequent enters into various contracts to hedge the value of our energy assets and operations, the timing of the recognition of profits or losses on the hedges does not always correspond to the profits or losses on the item being hedged. The difference in accounting can result in volatility in Sequent's reported results, even though the expected operating margin is essentially unchanged from the date the transactions were consummated.

Changes in weather conditions may affect our earnings.

Weather conditions and other natural phenomena can have a large impact on our earnings. Severe weather conditions can impact our suppliers and the pipelines that deliver gas to our distribution system. Extended mild weather, during either the winter period or summer period, can have a significant impact on demand for and cost of natural gas.

We have a WNA mechanism for Elizabethtown Gas and Chattanooga Gas that partially offsets the impact of unusually cold or warm weather on residential and commercial customer billings and our operating margin. At Elizabethtown Gas we could be required to return a portion of any WNA surcharge to its customers if Elizabethtown Gas' return on equity exceeds its authorized return on equity of 10%.

Additionally, Virginia Natural Gas has a WNA mechanism for its residential customers that partially offsets the impact of unusually cold or warm weather. In September 2007, the Virginia Commission approved Virginia Natural Gas' application for an Experimental Weather Normalization Adjustment Rider (the Rider) for its commercial customers. The Rider applies to the 2007 and 2008 heating seasons, with an opportunity for Virginia Natural Gas to extend the Rider for additional years.

These WNA regulatory mechanisms are most effective in a reasonable temperature range relative to normal weather using historical averages. The protection afforded by the WNA depends on continued regulatory approval. The loss of this continued regulatory approval could make us more susceptible to weather-related earnings fluctuations.

Changes in weather conditions may also impact SouthStar's earnings. As a result, SouthStar uses a variety of weather derivative instruments to mitigate the impact on its operating margin in the event of warmer than normal weather in the winter months. However, these instruments do not fully protect SouthStar's earnings from the effects of unusually warm weather.

A decrease in the availability of adequate pipeline transportation capacity could reduce our revenues and profits.

Our gas supply depends on the availability of adequate pipeline transportation and storage capacity. We purchase a substantial portion of our gas supply from interstate sources. Interstate pipeline companies transport the gas to our system. A decrease in interstate pipeline capacity available to us or an increase in competition for interstate

pipeline transportation and storage service could reduce our normal interstate supply of gas.

Our profitability may decline if the counterparties to Sequent's asset management transactions fail to perform in accordance with Sequent's agreements.

Sequent focuses on capturing the value from idle or underutilized energy assets, typically by executing transactions that balance the needs of various markets and time horizons. Sequent is exposed to the risk that counterparties to our transactions will not perform their obligations. Should the counterparties to these arrangements fail to perform, we might be forced to enter into alternative hedging arrangements, honor the underlying commitment at then-current market prices or return a significant portion of the consideration received for gas. In such events, we might incur additional losses to the extent of amounts, if any, already paid to or received from counterparties.

We could incur additional material costs for the environmental condition of some of our assets, including former manufactured gas plants.

We are generally responsible for all on-site and certain off-site liabilities associated with the environmental condition of the natural gas assets that we have operated, acquired or developed, regardless of when the liabilities arose and whether they are or were known or unknown. In addition, in connection with certain acquisitions and sales of assets, we may obtain, or be required to provide, indemnification against certain environmental liabilities. Before natural gas was widely available, we manufactured gas from coal and other fuels. Those manufacturing operations were known as MGPs, which we ceased operating in the 1950s.

We have identified ten sites in Georgia and three in Florida where we own all or part of an MGP site. We are required to investigate possible environmental contamination at those MGP sites and, if necessary, clean up any contamination. As of December 31, 2006, the soil and sediment remediation program was complete for all Georgia sites, although groundwater cleanup continues. As of December 31, 2007, projected costs associated with the MGP sites associated with Atlanta Gas Light were $35 million. For elements of the MGP program where we still cannot provide engineering cost estimates, considerable variability remains in future cost estimates.

In addition, we are associated with former sites in New Jersey, North Carolina and other states that we assumed with our acquisition of NUI in November 2004. Material cleanups of these sites have not been completed nor are precise estimates available for future cleanup costs and therefore considerable variability remains in future cost estimates. For the New Jersey sites, cleanup cost estimates range from $61 million to $119 million. Costs have been estimated for only one of the non-New Jersey sites, for which current estimates range from $11 million to $20 million.

Inflation and increased gas costs could adversely impact our ability to control operating expenses, increase our level of indebtedness and adversely impact our customer base.

Inflation has caused increases in certain operating expenses that have required us to replace assets at higher costs. We attempt to control costs in part through implementation of best practices and business process improvements, many of which are facilitated through investments in information systems and technology. We have a process in place to continually review the adequacy of our utility gas rates in relation to the increasing cost of providing service and the inherent regulatory lag in adjusting those gas rates. Historically, we have been able to budget and control operating expenses and investments within the amounts authorized to be collected in rates, and we intend to continue to do so. However, any inability by us to control our expenses in a reasonable manner would adversely influence our future results.

Rapid increases in the price of purchased gas cause us to experience a significant increase in short-term debt because we must pay suppliers for gas when it is purchased, which can be significantly in advance of when these costs may be recovered through the collection of monthly customer bills for gas delivered. Increases in purchased gas costs also slow our utility collection efforts as customers are more likely to delay the payment of their gas bills, leading to higher-than-normal accounts receivable. This situation results in higher short-term debt levels and increased bad debt expense. Should the price of purchased gas increase significantly during the upcoming heating season, we would expect increases in our short-term debt, accounts receivable and bad debt expense during 2008.

Finally, higher costs of natural gas in recent years have already caused many of our utility customers to conserve in the use of our gas services and could lead to even more customers utilizing such conservation methods or switching to other competing products. The higher costs have also allowed competition from products utilizing alternative energy sources for applications that have traditionally used natural gas, encouraging some customers to move away from natural gas fired

equipment to equipment fueled by other energy sources.

The cost of providing pension and postretirement health care benefits to eligible employees and qualified retirees is subject to changes in pension fund values and changing demographics and may have a material adverse effect on our financial results.

We have defined benefit pension and postretirement health care benefit plans for the benefit of substantially all full-time employees and qualified retirees. The cost of providing these benefits to eligible current and former employees is subject to changes in the market value of our pension fund assets, changing demographics, including longer life expectancy of beneficiaries, changes in health care cost trends, and an expected increase in the number of eligible former employees over the next five years.

Any sustained declines in equity markets and reductions in bond yields may have a material adverse effect on the value of our pension funds. In these circumstances, we may be required to recognize an increased pension expense or a charge to our statement of consolidated income to the extent that the pension fund values are less than the total anticipated liability under the plans.

Natural disasters, terrorist activities and the potential for military and other actions could adversely affect our businesses.

Natural disasters may damage our assets. The threat of terrorism and the impact of retaliatory military and other action by the United States and its allies may lead to increased political, economic and financial market instability and volatility in the price of natural gas that could affect our operations. In addition, future acts of terrorism could be directed against companies operating in the United States, and companies in the energy industry may face a heightened risk of exposure to acts of terrorism. These developments have subjected our operations to increased risks. The insurance industry has also been disrupted by these events. As a result, the availability of insurance covering risks against which we and our competitors typically insure may be limited. In addition, the insurance we are able to obtain may have higher deductibles, higher premiums and more restrictive policy terms.

Risks Related to Our Corporate and Financial Structure

We depend on our ability to successfully access the capital and financial markets. Any inability to access the capital or financial markets may limit our ability to execute our business plan or pursue improvements that we may rely on for future growth.

We rely on access to both short-term money markets (in the form of commercial paper and lines of credit) and long-term capital markets as a source of liquidity for capital and operating requirements not satisfied by the cash flow from our operations. If we are not able to access financial markets at competitive rates, our ability to implement our business plan and strategy will be affected. Certain market disruptions may increase our cost of borrowing or affect our ability to access one or more financial markets. Such market disruptions could result from:

- adverse economic conditions
- adverse general capital market conditions
- poor performance and health of the utility industry in general
- bankruptcy or financial distress of unrelated energy companies or Marketers
- significant decrease in the demand for natural gas
- adverse regulatory actions that affect our local gas distribution companies and our natural gas storage business
- terrorist attacks on our facilities or our suppliers
- extreme weather conditions

If we breach any of the financial covenants under our various credit facilities, our debt service obligations could be accelerated.

Our existing Credit Facility and the SouthStar line of credit contain financial covenants. If we breach any of the financial covenants under these agreements, our debt repayment obligations under them could be accelerated. In such event, we may not be able to refinance or repay all our indebtedness, which would result in a material adverse effect on our business, results of operations and financial condition.

A downgrade in our credit rating could negatively affect our ability to access capital.

Our senior unsecured debt is currently assigned a rating of BBB+ by S&P, Baa1 by Moody's and A- by Fitch. Our commercial paper currently is rated A2 by S&P, P2 by Moody's and F2 by Fitch. If the rating agencies downgrade our ratings, particularly below investment grade, it may significantly limit our access to the commercial paper market and our borrowing costs would increase. In addition, we would likely be required to pay a higher interest rate in future financings and our potential pool of investors and funding sources would likely decrease.

Additionally, if our credit rating by either S&P or Moody's falls to non-investment grade status, we will

be required to provide additional support for certain customers of our wholesale business. As of December 31, 2007, if our credit rating had fallen below investment grade, we would have been required to provide collateral of approximately $26 million to continue conducting our wholesale services business with certain counterparties.

We are vulnerable to interest rate risk with respect to our debt, which could lead to changes in interest expense and adversely affect our earnings.

We are subject to interest rate risk in connection with the issuance of fixed-rate and variable-rate debt. In order to maintain our desired mix of fixed-rate and variable-rate debt, we use interest rate swap agreements and exchange fixed-rate and variable-rate interest payment obligations over the life of the arrangements, without exchange of the underlying principal amounts. See Item 7A, "Quantitative and Qualitative Disclosures About Market Risk." We cannot ensure that we will be successful in structuring such swap agreements to manage our risks effectively. If we are unable to do so, our earnings may be reduced. In addition, higher interest rates, all other things equal, reduce the earnings that we derive from transactions where we capture the difference between authorized returns and short-term borrowings.

We are a holding company and are dependent on cash flow from our subsidiaries, which may not be available in the amounts and at the times we need.

A portion of our outstanding debt was issued by our wholly-owned subsidiary, AGL Capital, which we fully and unconditionally guarantee. Since we are a holding company and have no operations separate from our investment in our subsidiaries, we are dependent on cash in the form of dividends or other distributions from our subsidiaries to meet our cash requirements. The ability of our subsidiaries to pay dividends and make other distributions is subject to applicable state law. Refer to Item 5 "Market for the Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities" for additional dividend restriction information.

The use of derivative contracts in the normal course of our business could result in financial losses that negatively impact our results of operations.

We use derivatives, including futures, forwards and swaps, to manage our commodity and financial market risks. We could recognize financial losses on these contracts as a result of volatility in the market values of the underlying commodities or if a counterparty fails to perform under a contract. In the absence of actively quoted market prices and pricing information from external sources, the valuation of these financial instruments can involve management's judgment or use of estimates. As a result, changes in the underlying assumptions or use of alternative valuation methods could adversely affect the value of the reported fair value of these contracts.

As a result of cross-default provisions in our borrowing arrangements, we may be unable to satisfy all our outstanding obligations in the event of a default on our part.

Our Credit Facility under which our debt is issued contains cross-default provisions. Accordingly, should an event of default occur under some of our debt agreements, we face the prospect of being in default under other of our debt agreements, obliged in such instance to satisfy a large portion of our outstanding indebtedness and unable to satisfy all our outstanding obligations simultaneously.

ITEM 1B. UNRESOLVED STAFF COMMENTS

We do not have any unresolved comments from the SEC staff regarding our periodic or current reports under the Securities Exchange Act of 1934, as amended.

ITEM 2. PROPERTIES

Distribution Operations As of December 31, 2007, the properties of our distribution operations segment represented approximately 91% of the net property, plant and equipment in our consolidated balance sheet. This property primarily includes assets used for the distribution of natural gas to our customers in our service areas, including more than 44,000 miles of distribution and transmission mains. We have approximately 7.35 Bcf of LNG storage capacity in five LNG plants located in Georgia, New Jersey and Tennessee. In addition, we own three propane storage facilities in Virginia and Georgia that have a combined storage capacity of approximately 4.5 million gallons. These LNG plants and propane facilities supplement the gas supply during peak usage periods.

Energy Investments The properties in our energy investments segment are primarily investments that are complementary to our distribution operations or provide services consistent with our core enterprises, including a natural gas storage and hub facility in Louisiana located approximately eight miles from the Henry Hub. The Henry Hub is the largest centralized point for natural gas spot and futures trading in the United States. The NYMEX uses the Henry Hub as the point of delivery for its natural gas futures

contracts. Many natural gas marketers also use the Henry Hub as their physical contract delivery point or their price benchmark for spot trades of natural gas. Our natural gas storage and hub facility consists of two salt dome gas storage caverns with approximately 9.72 Bcf of total capacity and about 7.23 Bcf of working gas capacity. The facility has approximately 0.72 Bcf/day withdrawal capacity and 0.36 Bcf/day injection capacity. We completed a project during 2005 to expand compression capability, enabling us to increase the number of times a customer can inject and withdraw their total gas inventory annually from 10 to 12.

In addition, energy investments' properties include telecommunications conduit and fiber in public rights-of-way that are leased to our customers primarily in Atlanta and Phoenix. This includes over 93,000 fiber miles, a 17,000 mile increase compared to 2006, of which approximately 29% of our dark fiber in Atlanta and 28% of our dark fiber in Phoenix has been leased.

Retail Energy Operations, Wholesale Services and Corporate The properties used at our retail energy operations, wholesale services and corporate segments consist primarily of leased and owned office space in Atlanta and Houston and their contents, including furniture and fixtures. The majority of our Atlanta-based employees are located at our corporate headquarters, a leased building with approximately 227,000 square feet of office space. In addition, our retail energy operations segment leases approximately 30,200 square feet at another office building in Atlanta. We lease approximately 50,000 square feet of office space for our employees in Houston.

We own or lease additional office, warehouse and other facilities throughout our operating areas. We consider our properties and the properties of our subsidiaries to be well maintained, in good operating condition and suitable for their intended purpose. We expect additional or substitute space to be available as needed to accommodate expansion of our operations.

ITEM 3. LEGAL PROCEEDINGS

The nature of our business ordinarily results in periodic regulatory proceedings before various state and federal authorities. In addition, we are party, as both plaintiff and defendant, to a number of lawsuits related to our business on an ongoing basis. Management believes that the outcome of all regulatory proceedings and litigation in which we are currently involved will not have a material adverse effect on our consolidated financial condition or results of operations. Information regarding some of these proceedings is contained in Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations" under the caption "Results of Operations" and in Note 7 "Commitments and Contingencies" to our consolidated financial statements under the caption "Litigation" set forth in Item 8, "Financial Statements and Supplementary Data."

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

No matters were submitted to a vote of our security holders during the fourth quarter ended December 31, 2007.

EXECUTIVE OFFICERS OF THE REGISTRANT

Set forth below are the names, ages and positions of our executive officers along with their business experience during the past five years. All officers serve at the discretion of our Board of Directors. All information is as of the date of the filing of this report.

Name, age and position with the company	Periods served
John W. Somerhalder II, Age 52 (1)	
Chairman, President and Chief Executive Officer	October 2007 - Present
President and Chief Executive Officer	March 2006 – October 2007
Andrew W. Evans, Age 41	
Executive Vice President and Chief Financial Officer	May 2006 – Present
Senior Vice President and Chief Financial Officer	September 2005 – May 2006
Vice President and Treasurer	April 2002 – September 2005
Ralph Cleveland, Age 45	
Senior Vice President, Engineering and Operations	November 2004 - Present
Vice President, Engineering and Construction	June 2002 – November 2004
Henry P. Linginfelter, Age 47	
Executive Vice President, Utility Operations	June 2007 - Present
Senior Vice President, Mid-Atlantic Operations	November 2004– June 2007
President, Virginia Natural Gas, Inc.	October 2000 – November 2004
Kevin P. Madden, Age 55	
Executive Vice President, External Affairs	November 2005 – Present
Executive Vice President, Distribution and Pipeline Operations	April 2002 – November 2005
Melanie M. Platt, Age 53	
Senior Vice President, Human Resources	September 2004 – Present
Senior Vice President and Chief Administrative Officer	November 2002 – September 2004
Douglas N. Schantz, Age 52 (2)	
President, Sequent Energy Management, L.P.	May 2003 – Present
Paul R. Shlanta, Age 50	
Executive Vice President, General Counsel and Chief Ethics and Compliance Officer	September 2005 – Present
Senior Vice President, General Counsel and Chief Corporate Compliance Officer	September 2002 – September 2005

(1) Mr. Somerhalder was executive vice president of El Paso Corporation (NYSE: EP) from 2000 until May 2005, and he continued service under a professional services agreement from May 2005 until March 2006.

(2) Mr. Schantz served as vice president of the gas origination division at Cinergy Marketing & Trading, LP, an affiliate of Cinergy Corp (NYSE: CIN) from September 2000 to April 2003.

PART II

ITEM 5. MARKET FOR THE REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Holders of Common Stock, Stock Price and Dividend Information

Our common stock is listed on the New York Stock Exchange under the symbol ATG. At January 31, 2008, there were 10,697 record holders of our common stock. Quarterly information concerning our high and low stock prices and cash dividends paid in 2007 and 2006 is as follows:

	Sales price of common stock		Cash dividend per common
Quarter ended:	**High**	**Low**	**share**
2007			
March 31, 2007	$42.99	$38.20	$0.41
June 30, 2007	44.67	39.52	0.41
September 30, 2007	41.51	35.24	0.41
December 31, 2007	41.16	35.42	0.41
			$1.64
2006			
March 31, 2006	$36.48	$34.40	$0.37
June 30, 2006	38.13	34.43	0.37
September 30, 2006	40.00	34.76	0.37
December 31, 2006	40.09	36.04	0.37
			$1.48

We have historically paid dividends to common shareholders four times a year: March 1, June 1, September 1 and December 1. We have paid 240 consecutive quarterly dividends beginning in 1948. Our common shareholders may receive dividends when declared at the discretion of our Board of Directors. See Item 7 "Management's Discussion and Analysis of Financial Condition and Results of Operations – Liquidity and Capital Resources – Cash Flow from Financing Activities – Dividends on Common Stock." Dividends may be paid in cash, stock or other form of payment, and payment of future dividends will depend on our future earnings, cash flow, financial requirements and other factors, some of which are noted below. In certain cases, our ability to pay dividends to our common shareholders is limited by the following:

- our ability to satisfy our obligations under certain financing agreements, including debt-to-capitalization and total shareholders' equity covenants
- our ability to satisfy our obligations to any preferred shareholders

Under Georgia law, the payment of cash dividends to the holders of our common stock is limited to our legally available assets and subject to the prior payment of dividends on any outstanding shares of preferred stock. Our assets are not legally available for paying cash dividends if, after payment of the dividend:

- we could not pay our debts as they become due in the usual course of business, or
- our total assets would be less than our total liabilities plus, subject to some exceptions, any amounts necessary to satisfy (upon dissolution) the preferential rights of shareholders whose preferential rights are superior to those of the shareholders receiving the dividends

Issuer Purchases of Equity Securities

The following table sets forth information regarding purchases of our common stock by us and any affiliated purchasers during the three months ended December 31, 2007. Stock repurchases may be made in the open market or in private transactions at times and in amounts that we deem appropriate. However, there is no guarantee as to the exact number of additional shares that may be repurchased, and we may terminate or limit the stock repurchase program at any time. We will hold the repurchased shares as treasury shares.

Period	Total number of shares purchased (1) (2) (3)	Average price paid per share	Total number of shares purchased as part of publicly announced plans or programs (3)	Maximum number of shares that may yet be purchased under the publicly announced plans or programs (3)
October 2007	446,788	$38.99	446,788	5,084,912
November 2007	133,961	38.63	133,961	4,950,951
December 2007	2,592	37.48	-	4,950,951
Total fourth quarter	583,341	$38.90	580,749	

(1) The total number of shares purchased includes an aggregate of 2,592 shares surrendered to us to satisfy tax withholding obligations in connection with the vesting of shares of restricted stock and/or the exercise of stock options.

(2) On March 20, 2001, our Board of Directors approved the purchase of up to 600,000 shares of our common stock in the open market to be used for issuances under the Officer Incentive Plan (Officer Plan). We did not purchase any shares for such purposes in the fourth quarter of 2007. As of December 31, 2007, we had purchased a total 297,234 of the 600,000 shares authorized for purchase, leaving 302,766 shares available for purchase under this program.

(3) On February 3, 2006, we announced that our Board of Directors had authorized a plan to repurchase up to a total of 8 million shares of our common stock, excluding the shares remaining available for purchase in connection with the Officer Plan as described in note (2) above, over a five-year period.

The information required by this item regarding securities authorized for issuance under our equity compensation plans will be set forth under the caption "Executive Compensation – Equity Compensation Plan Information" in the Proxy Statement for our 2008 Annual Meeting of Shareholders or in a subsequent amendment to this report. All such information will be incorporated by reference from the Proxy Statement in Item 12, "Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters" hereof or set forth in such amendment to this report.

ITEM 6. SELECTED FINANCIAL DATA

Selected financial data about AGL Resources for the last five years is set forth in the table below. You should read the data in the table in conjunction with the consolidated financial statements and related notes set forth in Item 8, "Financial Statements and Supplementary Data."

Dollars and shares in millions, except per share amounts	2007	2006	2005	2004	2003
Income statement data					
Operating revenues	$2,494	$2,621	$2,718	$1,832	$983
Cost of gas	1,369	1,482	1,626	995	339
Operating margin (1)	1,125	1,139	1,092	837	644
Operating expenses					
Operation and maintenance	451	473	477	377	283
Depreciation and amortization	144	138	133	99	91
Taxes other than income taxes	41	40	40	29	28
Total operating expenses	636	651	650	505	402
Gain on sale of Caroline Street campus	-	-	-	-	16
Operating income	489	488	442	332	258
Equity in earnings of SouthStar Energy Services LLC	-	-	-	-	46
Other income (expense)	4	(1)	(1)	-	(6)
Minority interest	(30)	(23)	(22)	(18)	-
Earnings before interest and taxes (EBIT) (1)	463	464	419	314	298
Interest expense	125	123	109	71	75
Earnings before income taxes	338	341	310	243	223
Income taxes	127	129	117	90	87
Income before cumulative effect of change in accounting principle	211	212	193	153	136
Cumulative effect of change in accounting principle, net of $5 in income taxes	-	-	-	-	(8)
Net income	$211	$212	$193	$153	$128
Common stock data					
Weighted average shares outstanding basic	77.1	77.6	77.3	66.3	63.1
Weighted average shares outstanding diluted	77.4	78.0	77.8	67.0	63.7
Total shares outstanding (2)	76.4	77.7	77.8	76.7	64.5
Earnings per share - basic	$2.74	$2.73	$2.50	$2.30	$2.03
Earnings per share - diluted	$2.72	$2.72	$2.48	$2.28	$2.01
Dividends declared per share	$1.64	$1.48	$1.30	$1.15	$1.11
Dividend payout ratio	60%	54%	52%	50%	55%
Dividend yield	4.4%	3.8%	3.7%	3.5%	3.8%
Book value per share (3)	$21.74	$20.72	$19.27	$18.04	$14.66
Price-earnings ratio	13.7	14.3	13.9	14.5	14.3
Stock price market range	$35.24-$44.67	$34.40-$40.09	$32.00-$39.32	$26.50-$33.65	$21.90-$29.35
Market value per share (4)	$37.64	$38.91	$34.81	$33.24	$29.10
Market value (2)	$2,876	$3,023	$2,708	$2,551	$1,877
Balance sheet data (2)					
Total assets	$6,268	$6,147	$6,320	$5,637	$3,972
Property, plant and equipment – net	3,566	3,436	3,333	3,178	2,345
Working capital	166	156	73	(20)	(306)
Total debt	2,254	2,161	2,137	1,957	1,340
Common shareholders' equity	1,661	1,609	1,499	1,385	945
Cash flow data					
Net cash provided by operating activities	$376	$354	$80	$287	$122
Property, plant and equipment expenditures	259	253	267	264	158
Net borrowings and (payments) of short-term debt	52	6	188	(480)	(82)
Financial ratios (2)					
Total debt	58%	57%	59%	59%	59%
Common shareholders' equity	42%	43%	41%	41%	41%
Total	100%	100%	100%	100%	100%
Return on average common shareholders' equity	12.9%	13.6%	13.4%	13.1%	15.5%

(1) These are non-GAAP measurements. A reconciliation of operating margin and EBIT to our operating income and net income is contained in Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations-AGL Resources-Results of Operations."
(2) As of the last day of the fiscal period.
(3) Common shareholders' equity divided by total outstanding common shares as of the last day of the fiscal period.
(4) Closing price of common stock on the New York Stock Exchange as of the last trading day of the fiscal period.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Overview

We are an energy services holding company whose principal business is the distribution of natural gas in six states - Florida, Georgia, Maryland, New Jersey, Tennessee and Virginia. Our six utilities serve more than 2.2 million end-use customers, making us the largest distributor of natural gas in the southeastern and mid-Atlantic regions of the United States based on customer count. We are involved in various related businesses, including retail natural gas marketing to end-use customers primarily in Georgia; natural gas asset management and related logistics activities for our own utilities as well as for nonaffiliated companies; natural gas storage arbitrage and related activities; and the development and operation of high-deliverability underground natural gas storage assets. We also own and operate a small telecommunications business that constructs and operates conduit and fiber infrastructure within select metropolitan areas. We manage these businesses through four operating segments – distribution operations, retail energy operations, wholesale services and energy investments – and a nonoperating corporate segment. As of January 31, 2008, we employed a total of 2,332 employees across these five segments.

The distribution operations segment is the largest component of our business and is subject to regulation and oversight by agencies in each of the six states we serve. These agencies approve natural gas rates designed to provide us the opportunity to generate revenues to recover the cost of natural gas delivered to our customers and our fixed and variable costs such as depreciation, interest, maintenance and overhead costs, and to earn a reasonable return for our shareholders. With the exception of Atlanta Gas Light, our largest utility, the earnings of our regulated utilities can be affected by customer consumption patterns that are a function of weather conditions and price levels for natural gas. Various mechanisms exist that limit our exposure to weather changes within typical ranges in all of our jurisdictions. Our retail energy operations segment, which consists of SouthStar, also is weather sensitive and uses a variety of hedging strategies, such as weather derivative instruments and other risk management tools, to mitigate potential weather impacts. Our Sequent subsidiary within our wholesale services segment is relatively temperature sensitive, but has greater opportunity to capture margin as price volatility increases. Our energy investments segment's primary activity is our natural gas storage business, which develops, acquires and operates high-deliverability salt-dome storage assets in the Gulf Coast region of the United States. While this business also can generate additional revenue during times of peak market demand for natural gas storage services, the majority of our storage services are covered under medium to long-term contracts at a fixed market rate.

Executive Summary

In support of our goals for 2007, we focused our efforts around five key operating priorities as discussed below.

Marketing and customer retention investments in distribution operations and retail energy operations

We targeted overall net customer growth rates for our distribution operations business in the range of 1% to 1.5%. In each of our utility service areas, we implemented targeted marketing and growth programs aimed at emphasizing natural gas as the fuel of choice for customers and expanding the use of natural gas through a variety of promotional activities. In 2007, we grew our average customer count by approximately 21,000, a 0.9% increase as compared to last year. While this increase is slightly below our targeted range, the increase in the growth rate is an improvement over our relatively flat customer growth in 2006. Last year we had slower customer growth coming out of the winter heating season due in part to much higher natural gas prices, warmer weather and a higher average customer attrition rate of 1.9% in 2006 as compared to 1.2% in 2007, which reflects a 37% improvement. Our customer growth rate was negatively impacted by the downturn in the housing market during 2007; factors which are expected to continue to have a negative impact on customer growth in 2008. We continue to focus significant efforts in our distribution operations business on improving our net customer growth trends, despite the overall economy and the industry-wide challenges of rising natural gas prices, competition from alternative fuels and declining natural gas usage per customer.

These factors also impact customer growth at SouthStar where we are also focused on similar customer growth initiatives. We will continue to enter new markets and improve the overall profitability of its customers through a variety of enhancements to existing, and the implementation of new, product offerings and pricing plans. In 2007, SouthStar grew its average customer count by approximately 7,000 or a 1.3% increase over last year.

Return to normal weather and usage patterns

In 2007, we saw average customer usage patterns related to natural gas price and weather conditions

return to levels more consistent with historical averages. As the weather grew colder, compared to last year, and moved closer to 10-year average weather patterns primarily in Maryland, New Jersey and Virginia, we saw the conservation that occurred a year ago largely reverse itself and return to expected levels. Due to these factors, coupled with our targeted marketing and growth programs mentioned above, our overall throughput in 2007 at distribution operations increased 1% as compared to prior year and 3% at SouthStar for its customers in Georgia. While we saw these improvements in throughput and weather that was colder than last year by 10% in Maryland, 17% in New Jersey and 6% in Virginia, weather did not completely return to normal and consequently our earnings continue to be negatively impacted by warmer-than-normal weather. We attempt to stabilize and mitigate the impact to our earnings due to weather through hedging activities at SouthStar and through WNA regulatory mechanisms in distribution operations. While our hedging activities in 2007 at SouthStar largely offset the negative impact to earnings due to weather that was warmer than normal, distribution operations earnings were negatively impacted by $9 million due to weather that was warmer than normal and because the WNA regulatory mechanisms did not completely offset the negative impact to earnings from decreased consumption resulting from the warmer weather. These WNA regulatory mechanisms are most effective in reasonable temperature ranges relative to normal weather using historical averages due in part to their inherent design but also due to customer consumption patterns that are affected by weather conditions other than temperature. These other weather conditions include wind, cloud cover, precipitation and the duration of colder weather, among others, that are not captured in weather normalization adjustments, which are based primarily on average temperatures.

There are a number of legislative and regulatory proposals to address greenhouse gas emissions such as carbon dioxide, which are in various phases of discussion or implementation. We continue to actively monitor these proposals and discussions because the results could negatively impact our operations through reduced demand for natural gas and increased costs to our business. While we are unable to predict the outcome and quantify any impacts from these discussions and proposals at this point, we are active in promoting natural gas as the cleanest and most efficient burning fossil fuel with the lowest carbon content as compared to oil and coal.

Volatility in wholesale markets

Lower volatility in the natural gas markets, as compared to last year, has limited Sequent's asset optimization and arbitrage opportunities to generate operating margin in 2007. An important component of Sequent's business is its ability to capture operating margin based on seasonal and locational spreads, both of which were significantly reduced in 2007 as compared to 2006. We continue to expect less volatility in the natural gas markets and, therefore, we expect Sequent's abilities to capture economic value from asset optimization and arbitrage opportunities to be more consistent with those captured in 2007 as opposed to 2006 and 2005.

Operational efficiency and cost control

We continue to focus on operating our business as efficiently as possible, especially within our distribution operations and corporate segments through control of our operating costs. One of the key metrics we monitor in distribution operations is our operation and maintenance expenses per customer that was $145 per customer for 2007 as compared to $156 per customer in 2006, a 7% decrease year-over-year. This decrease was largely driven by a decrease in incentive compensation for employees at distribution operations and corporate as compared to last year due to lower payouts resulting from lower earnings per share in 2007 as compared to our AIP earning per share goals. Additionally in 2006 our earnings per share results were at the top end of the goals under the AIP, resulting in higher incentive compensation for 2006.

We further utilize outside vendors to assist us with the execution of business processes that are ancillary to our delivery of natural gas and related to the performance of basic business functions. This allows us to control operating costs, increase the efficiency through which these functions are executed and improve our service levels to customers. Most recently, we partnered with third parties in India to provide certain call center operations, as well as certain support functions related to information technology, finance, supply chain and engineering.

New market growth and regulatory opportunities

The four previous operating priorities require us to actively and continuously monitor the emerging issues and trends within our current operations and industry to allow us to take advantage of opportunities that complement and add value to our existing business operations. In 2007, we continued to expand Sequent's operations into the western United States and Canada, as well as SouthStar's operations into Ohio and Florida. Further, in October 2007, we acquired and have included within our wholesale services operating segment Compass Energy, which has enabled us to serve a broader geography of commercial and industrial customers.

Additionally, we continued to focus our efforts around our storage business, particularly our Golden Triangle Storage underground natural gas storage project. We achieved a significant milestone in this project at the end of 2007 as the FERC issued an order granting a Certificate of Public Convenience and Necessity to construct and operate the underground storage project and approving market-based rates for the services Golden Triangle Storage will provide. In January 2008, we accepted the FERC's certificate and expect construction to begin in the first half of 2008.

In distribution operations, we were also successful with certain regulatory initiatives that are critical to the fundamentals of our business as they help to preserve the long-term success and earnings potential of our utility businesses. In September 2007, we received approval from the Georgia Commission on our capacity supply plan in Georgia, and a key part of that agreement was the ability to diversify our supply sources by gaining more access to the Elba Island LNG facility. As a result, we have negotiated an agreement with SNG to obtain an undivided interest in pipelines connecting our Georgia service territory to the Elba Island LNG facility and have filed a joint application with the FERC for approval of the project, which is expected to cost $22 million. In October 2007, the Georgia Commission approved the extension of the asset management agreement between Sequent and Atlanta Gas Light through March 2012. We are actively working with the respective commissions to renew or amend the existing agreements set to expire in 2008 in our other jurisdictions.

In September 2007, the Virginia Commission approved Virginia Natural Gas' WNA rider for commercial customers that applies to the 2007 and 2008 heating seasons. In Florida, we received approval from the Florida Commission in December 2007 to include the amortization of certain components of the purchase price we paid for Florida City Gas in our return on equity calculation for regulatory reporting purposes. Additionally, the Florida Commission's approval included provisions for a five-year stay out. As a result, Florida City Gas' base rates will not change during this period, except for unforeseen events beyond our control and the Florida Commission initiating base rate proceedings.

In November 2007, Elkton Gas filed a base rate case with the Maryland Commission requesting a rate increase of less than $1 million. Starting in 2009 through 2011, we will be required to file base rate cases for Atlanta Gas Light, Virginia Natural Gas, Elizabethtown Gas and Chattanooga Gas. While we are unable to predict the outcome of these base rate proceedings, we will focus on incorporating and potentially proposing regulatory solutions into our base rate filings for many of the areas related to our key operation priorities as well as other emerging issues and trends impacting our utilities.

Results of Operations

Revenues We generate nearly all our operating revenues through the sale, distribution and storage of natural gas. We include in our consolidated revenues an estimate of revenues from natural gas distributed, but not yet billed, to residential and commercial customers from the latest meter reading date to the end of the reporting period. The following table provides more information regarding the components of our operating revenues.

In millions	2007	2006	2005
Residential	$1,143	$1,127	$1,177
Commercial	500	460	452
Transportation	401	434	450
Industrial	250	310	412
Other	200	290	227
Total operating revenues	$2,494	$2,621	$2,718

Operating margin and EBIT We evaluate the performance of our operating segments using the measures of operating margin and EBIT. We believe operating margin is a better indicator than operating revenues for the contribution resulting from customer growth in our distribution operations segment since the cost of gas can vary significantly and is generally billed directly to our customers. We also consider operating margin to be a better indicator in our retail energy operations, wholesale services and energy investments segments since it is a direct measure of operating margin before overhead costs. We believe EBIT is a useful measurement of our operating segments' performance because it provides information that can be used to evaluate the effectiveness of our businesses from an operational perspective, exclusive of the costs to finance those activities and exclusive of income taxes, neither of which is directly relevant to the efficiency of those operations.

Our operating margin and EBIT are not measures that are considered to be calculated in accordance with GAAP. You should not consider operating margin or EBIT an alternative to, or a more meaningful indicator of, our operating performance than operating income or net income as determined in accordance with GAAP. In addition, our operating margin and EBIT measures may not be comparable to similarly titled measures of other companies. The table below sets forth a reconciliation of our operating margin and EBIT to our operating income and net income, together with other consolidated financial information for the years ended December 31, 2007, 2006 and 2005.

In millions, except per share amounts	**2007**	**2006**	**2005**
Operating revenues	$2,494	$2,621	$2,718
Cost of gas	1,369	1,482	1,626
Operating margin	1,125	1,139	1,092
Operating expenses			
Operation and maintenance	451	473	477
Depreciation and amortization	144	138	133
Taxes other than income	41	40	40
Total operating expenses	636	651	650
Operating income	489	488	442
Other income (expense)	4	(1)	(1)
Minority interest	(30)	(23)	(22)
EBIT	463	464	419
Interest expense	125	123	109
Earnings before income taxes	338	341	310
Income taxes	127	129	117
Net income	$211	$212	$193
Earnings per common share:			
Basic	$2.74	$2.73	$2.50
Diluted	$2.72	$2.72	$2.48
Weighted average number of common shares outstanding:			
Basic	77.1	77.6	77.3
Diluted	77.4	78.0	77.8

Selected weather, customer and volume metrics for 2007, 2006 and 2005, are presented in the following table.

Weather Heating degree days (1)	Year ended December 31,				2007 vs. 2006 colder (warmer)	2006 vs. 2005 colder (warmer)	2007 vs. normal colder (warmer)	2006 vs. normal colder (warmer)	2005 vs. normal colder (warmer)
	Normal	2007	2006	2005					
Florida	495	326	468	552	(30)%	(15)%	(34)%	(5)%	12%
Georgia	2,582	2,366	2,455	2,739	(4)%	(10)%	(8)%	(5)%	6%
Maryland	4,659	4,621	4,205	4,966	10%	(15)%	(1)%	(10)%	7%
New Jersey	4,588	4,777	4,074	4,931	17%	(17)%	4%	(11)%	7%
Tennessee	2,950	2,722	2,892	3,119	(6)%	(7)%	(8)%	(2)%	6%
Virginia	3,126	3,055	2,870	3,469	6%	(17)%	(2)%	(8)%	11%

(1) Obtained from the National Oceanic and Atmospheric Administration. National Climatic Data Center. Normal represents the ten-year averages from January 1998 to December 2007.

Customers	Year ended December 31,			2007 vs. 2006 % change	2006 vs. 2005 % change
	2007	2006	2005		
Distribution Operations					
Average end-use customers (in thousands)					
Atlanta Gas Light	1,559	1,546	1,545	0.8%	0.1%
Chattanooga Gas	61	61	61	-	-
Elizabethtown Gas	272	269	266	1.1	1.1
Elkton Gas	6	6	6	-	-
Florida City Gas	104	104	103	-	1.0
Virginia Natural Gas	269	264	261	1.9	1.1
Total	2,271	2,250	2,242	0.9%	0.4%
Operation and maintenance expenses per customer	$145	$156	$166	(7)%	(6)%
EBIT per customer	$149	$138	$133	8%	4%
Retail Energy Operations					
Average customers (in thousands)	540	533	531	1.3%	0.4%
Market share in Georgia	35%	35%	35%	-	-

Volumes In billion cubic feet (Bcf)	Year ended December 31,			2007 vs. 2006 % change	2006 vs. 2005 % change
	2007	2006	2005		
Distribution Operations					
Firm	211	199	228	6%	(13)%
Interruptible	108	117	117	(8)%	-
Total	319	316	345	1%	(8)%
Retail Energy Operations					
Georgia firm	38.5	37.2	42.6	3%	(13)%
Ohio and Florida	4.5	1.3	-	246%	100%
Wholesale Services					
Daily physical sales (Bcf / day)	2.35	2.20	2.17	7%	1%

Segment information Operating revenues, operating margin, operating expenses and EBIT information for each of our segments are contained in the following tables for the years ended December 31, 2007, 2006 and 2005.

In millions	Operating revenues	Operating margin (1)	Operating expenses	EBIT (1)
2007				
Distribution operations	$1,665	$820	$485	$338
Retail energy operations	892	188	75	83
Wholesale services	83	77	43	34
Energy investments	42	40	25	15
Corporate (2)	(188)	-	8	(7)
Consolidated	$2,494	$1,125	$636	$463
2006				
Distribution operations	$1,624	$807	$499	$310
Retail energy operations	930	156	68	63
Wholesale services	182	139	49	90
Energy investments	41	36	26	10
Corporate (2)	(156)	1	9	(9)
Consolidated	$2,621	$1,139	$651	$464
2005				
Distribution operations	$1,753	$814	$518	$299
Retail energy operations	996	146	61	63
Wholesale services	95	92	42	49
Energy investments	56	40	23	19
Corporate (2)	(182)	-	6	(11)
Consolidated	$2,718	$1,092	$650	$419

(1) These are non-GAAP measurements. A reconciliation of operating margin and EBIT to our operating income and net income is contained in "Results of Operations" herein.
(2) Includes intercompany eliminations

2007 compared to 2006

In 2007 our net income decreased by $1 million primarily due to decreased EBIT from wholesale services largely due to lower operating margin. This was offset by increased EBIT at distribution operations, retail energy operations and energy investments due to higher operating margins as compared to 2006. Additionally, distribution operations' EBIT contribution increased due to lower operating expenses as compared to 2006. Our basic earnings per share increased by $0.01, primarily due to the reduction in the average number of shares outstanding as a result of our share repurchase program. Our diluted earnings per share were flat.

Operating margin Our operating margin in 2007, decreased $14 million or 1% primarily due to lower operating margin at our wholesale services segment.

Distribution operations' operating margin increased $13 million or 2% primarily due to a 21,000 or .9% increase in customers as compared to last year, a $2 million increase in base rates at Chattanooga Gas (effective January 1, 2007) and a $2 million increase in PRP operating revenues. Distribution operations' operating margin was further increased by slightly overall higher customer usage of 3 Bcf or 1%. However, our customer usage was impacted by weather that, while colder than last year in some of our jurisdictions, was warmer than normal. Our WNA mechanisms in place to mitigate the loss of operating margin due to weather that was still warmer than normal did not fully offset such losses, resulting in a $9 million decrease in operating margin.

Retail energy operations' operating margin increased $32 million or 21%. This was primarily due to an $8 million increase in average customer usage in Georgia, a $2 million increase from the addition of approximately 7,000 or 1.3% customers, $3 million from the advancement into the Ohio market and $2 million in higher late payment fees. Retail energy operations' operating margin was further positively impacted by the combination of retail price spreads and contributions from the optimization of storage and transportation assets and commodity risk management activities, as well as from a prior year LOCOM adjustment of $6 million to reduce weighted average inventory cost to market. Retail energy operations did not record a similar LOCOM adjustment in 2007 resulting in an increase in operating margin as compared to last year. Even though weather was 4% warmer than last year, retail energy operations' use of weather derivatives largely offset the $2 million decline in operating margin due to warmer weather.

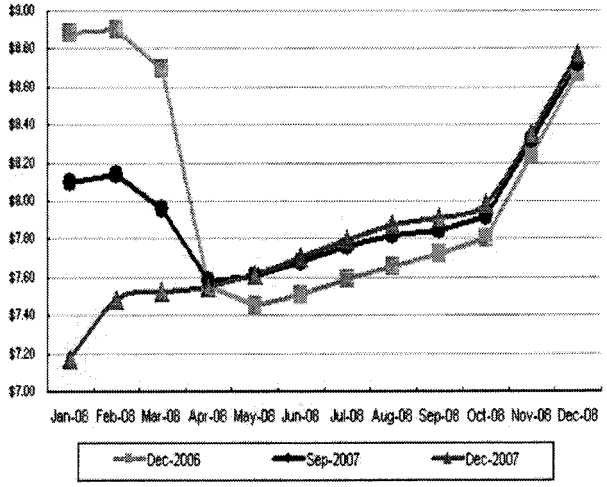
Wholesale services' operating margin decreased $62 million or 45%. This decrease is due to a $36 million reduction in reported hedge gains and a $46 million reduction in commercial activity, due in part to reduced inventory storage spreads and lower volatility in the marketplace. These decreases were partially offset by a $20 million reduction in the required LOCOM adjustments to natural gas inventories for the year ended December 31, 2007, net of $3 million and $22 million in estimated hedging recoveries during 2007 and 2006, respectively. These are indicated in the following table.

In millions	2007	2006	2005
Gain (loss) on storage hedges	$12	$41	$(7)
Gain on transportation hedges	5	12	-
Commercial activity	61	107	102
Inventory LOCOM, net of hedging recoveries	(1)	(21)	(3)
Operating margin	$77	$139	$92

The following graph presents the NYMEX forward natural gas prices as of December 31, 2007, September 30, 2007 and December 31, 2006, for the period of January 2008 through December 2008, and reflects the prices at which wholesale services could

buy natural gas at the Henry Hub for delivery in the same time period.

NYMEX forward curve



Wholesale services' expected natural gas withdrawals from physical salt dome and reservoir storage are presented in the following table along with the operating revenues expected at the time of withdrawal. Wholesale services' expected operating revenues are net of the impact of regulatory sharing and reflect the amounts that it would expect to realize in future periods based on the inventory withdrawal schedule and forward natural gas prices at December 31, 2007. Wholesale services' storage inventory is economically hedged with futures contracts, which results in an overall locked-in margin, timing notwithstanding. Wholesale services' physical salt dome and reservoir volumes are presented in NYMEX equivalent contract units of 10,000 million British thermal units (MMBtu's).

	Three months ended Mar. 31, 2008	June 30, 2008	Dec.31, 2008	Total
Salt dome (WACOG $6.70)	33	-	94	127
Reservoir (WACOG $6.20)	773	24	-	797
Total volumes	806	24	94	924
Expected operating revenues from physical inventory *(in millions)*	$9	$-	$2	$11

Energy investments' operating margin increased $4 million or 11% primarily due to a $2 million increase in revenues at Jefferson Island as a result of increased interruptible margin opportunities and a $2 million increase at AGL Networks as a result of a larger customer base.

Operating expenses Our operating expenses in 2007 decreased $15 million or 2% from 2006. The following table indicates the significant changes in our operating expenses.

In millions	
Operating expenses for year ended Dec. 31, 2006	$651
Decreased incentive compensation costs at distribution operations due to not achieving AIP earnings goals	(14)
Decreased incentive compensation costs at wholesale services due to lower operating margin	(13)
Decreased bad debt expense at retail energy operations	(3)
Increased incentive compensation costs due to growth and improved operations at retail energy operations	3
Increased depreciation and amortization	6
Increased payroll and other operating costs at wholesale services due to continued expansion	7
Increased costs at retail energy operations due to customer care, marketing costs and higher payroll in support of customer and market growth initiatives	5
Other, net primarily at distribution operations due to pension, outside services and reduction in customer service expense	(6)
Operating expenses for year ended Dec. 31, 2007	$636

Our other income increased by $5 million. This was primarily due to lower charitable contributions in 2007 at distribution operations and retail energy operations.

Interest expense The increased interest expense of $2 million or 2% in 2007 was due primarily to higher short-term interest rates and a $3 million premium paid for the early redemption of the $75 million notes payable to AGL Capital Trust I, which was recorded as interest expense in 2007. As indicated in the following table, this was partially offset by lower average debt, primarily from reduced commercial paper borrowings for most of 2007.

In millions	2007	2006	Change
Interest expense	$125	$123	$2
Average debt outstanding (1)	$1,967	$2,023	$(56)
Average rate (2)	6.4%	6.1%	0.3%

(1) Daily average of all outstanding debt.
(2) Excluding $3 million premium paid for early redemption of debt, average rate in 2007 would have been 6.2%.

Income tax expense The decrease in income tax expense of $2 million or 2% in 2007, compared to the same period in 2006 was primarily due to lower consolidated earnings and a slightly lower effective tax rate of 37.6% in 2007 compared to an effective tax rate of 37.8% in 2006. The decrease in our effective tax rate was primarily a result of our 2007 investment in a guaranteed affordable housing tax credit fund. We expect our effective tax rate in 2008 to remain consistent with our 2007 rate. For more information on our income taxes, including a

reconciliation between the statutory federal income tax rate and the effective rate, see Note 8.

2006 compared to 2005

In 2006 our net income increased by $19 million or 10%, our basic earnings per share increased by $0.23 or 9% and our diluted earnings per share increased by $0.24. This was primarily due to increased EBIT of $41 million in wholesale services which primarily reflected the recognition of unrealized hedge gains during 2006, as forward NYMEX prices declined significantly. In contrast, NYMEX price increases experienced during 2005 had the opposite effect, but to a lesser extent. In the distribution operations segment, EBIT improved by $11 million, due to reduced operating expenses of $19 million, offset by lower operating margin of $7 million. Our retail energy operations segment's EBIT was flat compared to 2005. The energy investments segment's EBIT was down $9 million primarily due to the loss of EBIT contributions as the result of the sale in 2005 of certain assets that were originally acquired with the 2004 acquisition of NUI.

Operating margin Our operating margin increased $47 million or 4% from 2005. This was primarily due to increases at wholesale services and retail energy operations offset by declines at distribution operations.

Wholesale services increased its operating margin $47 million or 51% as compared to 2005 due to significant arbitrage opportunities brought on by natural gas price volatility and periods of extreme weather. Forward NYMEX prices decreased during 2006, especially during the third and fourth quarters, and this resulted in the wholesale services segment recognizing $41 million of storage hedge gains in 2006, compared to the recognition of $7 million of storage hedge losses in 2005. In addition, wholesale services recognized $12 million in gains associated with the financial instruments used to hedge its transportation capacity. There were no significant gains or losses associated with transportation hedges recognized in the prior period. Consequently, wholesale services experienced a net change of $60 million from its hedging activities for 2006 compared to 2005.

In addition, as a result of decreasing NYMEX prices the wholesale services segment evaluated the weighted average cost of its natural gas inventory and recorded LOCOM adjustments totaling $43 million in 2006; however, as inventory was physically withdrawn from storage during the year, $22 million of the 2006 adjustments were recovered and reflected in 2006 operating revenues when the original economic results were realized as the related hedging derivatives were settled. In 2005, wholesale services recorded LOCOM adjustments of $3 million.

The results of the wholesale services segment also reflect improved commercial activities of approximately $5 million associated with larger seasonal storage spreads during the first half of 2006 and above average temperatures during the late summer months. These conditions offset the impacts of mild weather during the winter and early summer and the lower level of market volatility that we experienced compared to the hurricane activity in the Gulf of Mexico in 2005.

Retail energy operation's operating margin increased by $10 million or 7% principally driven by improved retail price spreads, higher contributions from the optimization of storage and transportation assets and effective risk management, and an increase of approximately 2,000 average customers in 2006 as compared to 2005. These factors contributed $34 million in operating margin contributions, but was offset by $16 million in lower operating margin from customer conservation and lower consumption due to weather that was approximately 10% warmer than 2005, net of $5 million in net gains on weather derivatives. Operating margin was further negatively impacted by an adjustment in 2006 of $6 million to reduce inventory to market for which no LOCOM adjustment was recorded in 2005, and from $2 million in lower late payment fees and interruptible operating margin contributions.

Operating margin for the distribution operations segment decreased $7 million or 1% primarily from warmer weather affecting customer usage and from our exiting the New Jersey and Florida appliance businesses. The operating margin at Elizabethtown Gas decreased $3 million with 17% warmer weather than in 2005. Virginia Natural Gas' operating margin decreased $4 million with 17% warmer weather, and the operating margin at Florida City Gas decreased $2 million with 15% warmer weather. Further, our exiting of the New Jersey and Florida appliance businesses reduced operating margin by $3 million. This reduction was partially offset by a net increase in operating margin at Atlanta Gas Light of $6 million consisting of $5 million in gas storage carrying costs from higher average inventory balances and $2 million in PRP revenues from the continuing expenditures under the program, offset primarily by $2 million as a result of the effect of the Georgia Commission's June 2005 Rate Order.

Operating margin at energy investments decreased $4 million or 10% largely due to the loss of $9 million of operating margin contributions from certain assets we acquired with the 2004 acquisition of NUI but sold in 2005. Jefferson Island's operating margin increased by $1 million compared to the prior year, in

part due to increases in both firm and interruptible operating margin opportunities. AGL Networks' operating margin increased by $1 million compared to the prior year due to a larger customer base. Pivotal Propane contributed a $2 million increase primarily in the first quarter of 2006 as it did not become operational until April 2005.

Operating expenses Our operating expenses increased $1 million or 0.2% from the same period in 2005. The following table sets forth the significant components of operating expenses:

In millions	
Operating expenses for 2005	$650
Increased payroll, incentive compensation and corporate overhead allocated costs at wholesale services to support growth	7
Increased bad debt expenses at retail energy operations and distribution operations	4
Lower expenses resulting from energy investment assets sold in 2005	(8)
Lower expenses at distribution operations related to workforce and facilities restructurings in 2005 and 2006	(15)
Increased depreciation and amortization	5
Other	8
Operating expenses for 2006	$651

Interest expense Interest expense for 2006 increased by $14 million or 13% as compared to 2005. As indicated in the following table, higher short-term interest rates and higher debt outstanding combined to increase our interest expense in 2006 relative to the previous year. The increase of $200 million in average debt outstanding for 2006 compared to 2005 was due to additional debt incurred as a result of higher working capital requirements.

In millions	**2006**	**2005**	**Change**
Total interest expense	$123	$109	$14
Average debt outstanding (1)	2,023	1,823	200
Average interest rate	6.1%	6.0%	0.1%

(1) Daily average of all outstanding debt.

Income tax expense The increase in income tax expense of $12 million or 10% for 2006 compared to 2005 reflected additional income taxes primarily due to higher corporate earnings year over year.

Liquidity and Capital Resources

Our primary sources of liquidity are cash provided by operating activities, short term borrowings under our commercial paper program (which is supported by our Credit Facility) and borrowings under lines of credit. Additionally from time to time, we raise funds from the public debt and equity capital markets through our existing shelf registration statement to fund our liquidity and capital resource needs. We believe these sources will continue to allow us to meet our needs for working capital, construction expenditures, anticipated debt redemptions, interest payments on debt obligations, dividend payments, common share repurchases and other cash needs.

Our issuance of various securities, including long-term and short-term debt, is subject to customary approval or authorization by state and federal regulatory bodies including state public service commissions and the SEC. Furthermore, a substantial portion of our consolidated assets, earnings and cash flow is derived from the operation of our regulated utility subsidiaries, whose legal authority to pay dividends or make other distributions to us is subject to regulation.

We will continue to evaluate our need to increase available liquidity based on our view of working capital requirements, including the impact of changes in natural gas prices, liquidity requirements established by rating agencies and other factors. See Item 1A, "Risk Factors," for additional information on items that could impact our liquidity and capital resource requirements. The following table provides a summary of our operating, investing and financing activities for the last three years.

In millions	2007	2006	2005
Net cash provided by (used in):			
Operating activities	$376	$354	$80
Investing activities	(253)	(248)	(194)
Financing activities	(122)	(118)	97
Net increase (decrease) in cash and cash equivalents	$1	$(12)	$(17)

Cash Flow from Operating Activities We prepare our statement of cash flows using the indirect method. Under this method, we reconcile net income to cash flows from operating activities by adjusting net income for those items that impact net income but may not result in actual cash receipts or payments during the period. These reconciling items include depreciation and amortization, changes in risk management assets and liabilities, undistributed earnings from equity investments, deferred income taxes and changes in the consolidated balance sheet for working capital from the beginning to the end of the period.

Our operations are seasonal in nature, with the business depending to a great extent on the first and fourth quarters of each year. As a result of this seasonality, our natural gas inventories, which usually peak on November 1 and largely are drawn down in the heating season, provide a source of cash as this asset is used to satisfy winter sales demand. The establishment and price fluctuations of our natural gas inventories which meet customer

demand during the winter heating season can cause significant variations in our cash flow from operations from period to period and are reflected in changes to our working capital.

Year-over-year changes in our operating cash flows are attributable primarily to working capital changes within our distribution operations, retail energy operations and wholesale services segments resulting from the impact of weather, the price of natural gas, the timing of customer collections, payments for natural gas purchases and deferred gas cost recoveries as our business has grown and prices for natural gas have increased. The increase in natural gas prices directly impacts the cost of gas stored in inventory.

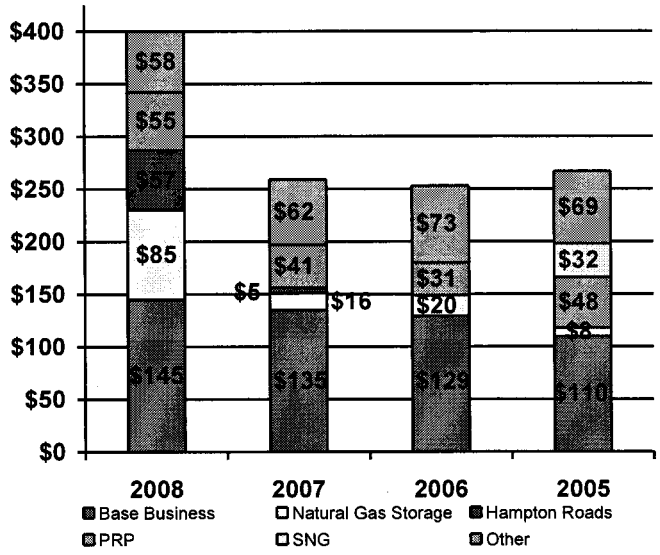
2007 compared to 2006 In 2007, our net cash flow provided from operating activities was $376 million, an increase of $22 million or 6% from 2006. The increase was due to higher realized gains on our energy marketing and risk management assets and liabilities and lower cash requirements for our natural gas inventories due to price and inventory volume fluctuations. This was offset by increased cash payments for income taxes due to realized gains on our energy marketing and risk management activities and higher working capital requirements.

2006 compared to 2005 In 2006, our net cash flow provided from operating activities was $354 million, an increase of $274 million or 343% from 2005. The increase was primarily a result of higher earnings in 2006 of $19 million and the recovery of working capital during 2006 that was deployed in late 2005 due to higher natural gas commodity prices and colder weather in the 2005 heating season. A primary contributor to the recovery of working capital was a $157 million decrease in the amount of natural gas inventory purchases by Sequent and our utilities.

Cash Flow from Investing Activities Our investing activities consisted primarily of property, plant and equipment (PP&E) expenditures. The majority of our PP&E expenditures are within our distribution operations segment, which includes our investments in new construction and infrastructure improvements.

Our estimated PP&E expenditures of approximately $400 million in 2008 and actual PP&E expenditures of $259 million in 2007, $253 million in 2006 and $267 million in 2005 are presented in the following chart. Our estimated expenditures in 2008 include discretionary spending for capital projects principally within the base business and natural gas storage categories. In determining whether to proceed with these projects, we evaluate such discretionary capital projects in relation to a number of factors including our authorized returns on rate base, other returns on invested capital for projects of a similar nature, capital structure and credit ratings, among others. As such, we will make adjustments to these discretionary expenditures as necessary based upon these factors. Our estimated and actual PP&E expenditures are shown within the following categories.

- **Base business** – new construction and infrastructure improvements at our distribution operations segment
- **Natural gas storage** – salt-dome cavern expansions at Golden Triangle and Jefferson Island
- **Hampton Roads** – Virginia Natural Gas' pipeline project, which will connect its northern and southern systems
- **PRP** – Atlanta Gas Light's program to replace all bare steel and cast iron pipe in its system in Georgia
- **SNG** – a 250-mile pipeline in Georgia acquired from Southern Natural Gas (SNG) in 2005
- **Other** – primarily includes information technology, building and leasehold improvements and AGL Networks' telecommunication expenditures



In 2007, our PP&E expenditures were $6 million or 2% higher than in 2006. This was primarily due to an increase in PRP expenditures of $10 million as we replaced larger-diameter pipe in more densely populated areas and $5 million in expenditures for the Hampton Roads project. This was offset by decreased expenditures of $4 million on our storage projects.

The decrease of $14 million or 5% in PP&E expenditures in 2006 compared to 2005 was primarily due to the SNG pipeline acquisition of $32

million, which occurred in 2005, and $17 million in reduced PRP expenditures, primarily as a result of the June 2005 agreement with the Georgia Commission, which extended the PRP program by five years. This was offset by increased base business expenditures of $19 million, primarily as our utilities expanded their new construction investments. We also incurred higher information technology expenditures of $13 million, which included $5 million at retail energy operations, primarily due to the implementation of a new energy trading and risk management system and enhancements to the retail billing system. Additionally in 2006, we spent $12 million in additional PP&E expenditures at Jefferson Island as it began work on a salt-dome storage expansion project which would add a third and fourth storage cavern. In 2005, our cash flows from investing activities were positively impacted as we sold our 50% interest in Saltville Gas Storage Company (Saltville) and associated subsidiaries for $66 million to a subsidiary of Duke Energy Corporation. We acquired Saltville through our acquisition of NUI in 2004.

Cash Flow from Financing Activities Our financing activities are primarily composed of borrowings and payments of short-term debt, payments of medium-term notes, and notes payable to AGL Capital Trust I and II, borrowings of senior notes, distributions to minority interests, cash dividends on our common stock issuances, purchases and issuances of treasury shares and the use of interest rate swaps for the purpose of hedging interest rate risk. Our capitalization and financing strategy is intended to ensure that we are properly capitalized with the appropriate mix of equity and debt securities. This strategy includes active management of the percentage of total debt relative to total capitalization, appropriate mix of debt with fixed to floating interest rates (our variable debt target is 20% to 45% of total debt), as well as the term and interest rate profile of our debt securities.

As of December 31, 2007, our variable rate debt was $840 million or 37% of our total debt, compared to $733 million or 34% as of December 31, 2006. The increased variable-rate debt was principally due to higher commercial paper borrowings. As of December 31, 2007, our commercial paper borrowings were $58 million or 11% higher than the same time last year, primarily a result of a $42 million increase in common share repurchases in 2007 and slightly higher working capital needs. For more information on our debt, see Note 6.

Credit Ratings We also work to maintain or improve our credit ratings on our debt to manage our existing financing costs and enhance our ability to raise additional capital on favorable terms. Factors we consider important in assessing our credit ratings include our balance sheet leverage, capital spending, earnings, cash flow generation, available liquidity and overall business risks. We do not have any trigger events in our debt instruments that are tied to changes in our specified credit ratings or our stock price and have not entered into any agreements that would require us to issue equity based on credit ratings or other trigger events.

Improvements in our operating performance led to our credit outlook being raised from negative to stable by S&P in late 2007. The following table summarizes our credit ratings as of December 31, 2007.

	S&P	Moody's	Fitch
Corporate rating	A-		
Commercial paper	A-2	P-2	F-2
Senior unsecured	BBB+	Baa1	A-
Ratings outlook	Stable	Stable	Stable

Our credit ratings may be subject to revision or withdrawal at any time by the assigning rating organization, and each rating should be evaluated independently of any other rating. We cannot ensure that a rating will remain in effect for any given period of time or that a rating will not be lowered or withdrawn entirely by a rating agency if, in its judgment, circumstances so warrant. If the rating agencies downgrade our ratings, particularly below investment grade, it may significantly limit our access to the commercial paper market and our borrowing costs would increase. In addition, we would likely be required to pay a higher interest rate in future financings, and our potential pool of investors and funding sources would decrease.

Default Events Our debt instruments and other financial obligations include provisions that, if not complied with, could require early payment, additional collateral support or similar actions. Our most important default events include maintaining covenants with respect to a maximum leverage ratio, insolvency events, nonpayment of scheduled principal or interest payments, and acceleration of other financial obligations and change of control provisions.

Our Credit Facility's financial covenant requires us to maintain a ratio of total debt to total capitalization of no greater than 70%; however, our goal is to maintain this ratio at levels between 50% and 60%. We are currently in compliance with all existing debt provisions and covenants. We believe that accomplishing these capitalization objectives and maintaining sufficient cash flow are necessary to maintain our investment-grade credit ratings and to allow us access to capital at reasonable costs. The components of our capital structure, as of the dates indicated, are summarized in the following table.

In millions	Dec. 31, 2007		Dec. 31, 2006	
Short-term debt	$580	15%	$539	14%
Long-term debt (1)	1,674	43	1,622	43
Total debt	2,254	58	2,161	57
Common shareholders' equity	1,661	42	1,609	43
Total capitalization	$3,915	100%	$3,770	100%

(1) Net of interest rate swaps.

Short-term Debt Our short-term debt is composed of borrowings under our commercial paper program, lines of credit at Sequent, SouthStar and Pivotal Utility, the current portion of our medium-term notes (for 2006) and the current portion of our capital leases. Our short-term debt financing generally increases between June and December because our payments for natural gas and pipeline capacity are generally made to suppliers prior to the collection of accounts receivable from our customers. We typically reduce short-term debt balances in the spring because a significant portion of our current assets are converted into cash at the end of the winter heating season.

In June and August 2007 we extended Sequent's $45 million unsecured lines of credit through June ($25 million) and August ($20 million) 2008. Sequent's lines of credit are used solely for the posting of margin deposits for NYMEX transactions. In August 2007, we extended Pivotal Utility's $20 million unsecured line of credit through August 2008. This line of credit supports Elizabethtown Gas' New Jersey Commission mandated hedging program and is used solely for the posting of margin deposits. These lines of credit bear interest at the federal funds effective rate plus 0.4% and are unconditionally guaranteed by us.

Under the terms of our Credit Facility, which expires in August 2011, the aggregate principal amount available is $1 billion and we can request an option to increase the aggregate principal amount available for borrowing to $1.25 billion on not more than three occasions during each calendar year.

As of December 31, 2007 and 2006, we had no outstanding borrowings under the Credit Facility. However, the availability of borrowings and unused credit under our Credit Facility is limited and subject to conditions specified within the Credit Facility, which we currently meet. These conditions include:

- the maintenance of a ratio of total debt to total capitalization of no greater than 70%. As of December 31, 2007, our ratio of total debt of 58% to total capitalization was within our targeted and required ranges, and was consistent with our ratio of 57% at December 31, 2006
- the continued accuracy of representations and warranties contained in the agreement

Long-term Debt Our long-term debt matures more than one year from the balance sheet date and consists of medium-term notes, senior notes, gas facility revenue bonds, and capital leases. The following represents our long-term debt activity in 2007.

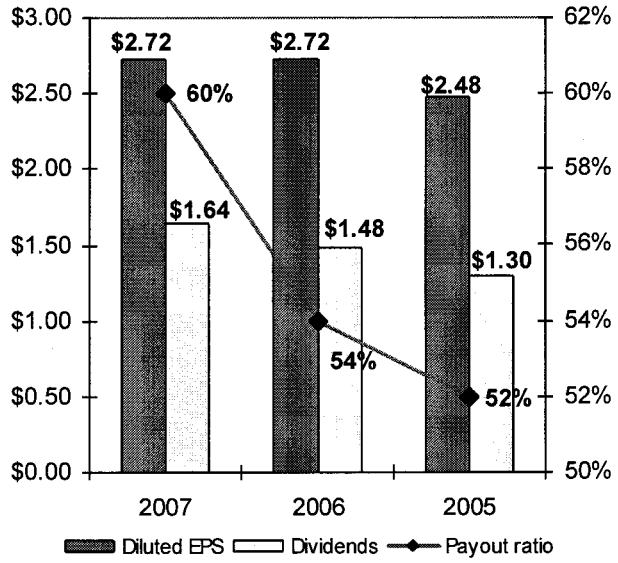
- In January 2007, we used proceeds from the sale of commercial paper to redeem $11 million of 7% medium-term notes previously scheduled to mature in January 2015.
- In June 2007 we refinanced $55 million of our gas facility revenue bonds due June 2032.The original bonds had a fixed interest rate of 5.7% per year and were refinanced with $55 million of adjustable-rate gas facility revenue bonds. The maturity date of these bonds remains June 2032 and there is a 35-day auction period where the interest rate adjusts every 35 days. The interest rate at December 31, 2007, was 4.7%.
- In July 2007, we used the proceeds from the sale of commercial paper to pay to AGL Capital Trust I the $75 million principal amount of 8.17% junior subordinated debentures plus a $3 million premium for early redemption of the junior subordinated debentures, and to pay a $2 million note representing our common securities interest in AGL Capital Trust I.
- In December 2007, AGL Capital issued $125 million of 6.375% senior notes. The senior notes are part of a series of notes issued by AGL Capital in June 2006. Both sets of notes are now part of a single series with an aggregate of $300 million in principal outstanding. The proceeds of the note issuance, equal to approximately $123 million, were used to pay down short-term indebtedness incurred under our commercial paper program.

Minority Interest As a result of our consolidation of SouthStar's accounts effective January 1, 2004, we recorded Piedmont's portion of SouthStar's contributed capital as a minority interest in our consolidated balance sheets. A cash distribution of $23 million in 2007, $22 million in 2006 and $19 million in 2005 for SouthStar's dividend distributions to Piedmont were recorded in our consolidated statement of cash flows as a financing activity.

Dividends on Common Stock Our $12 million or 11% increase in common stock dividend payments in

2007 compared to 2006, and $11 million or 11% increase in payments in 2006 compared to 2005, resulted from increases in the amount of our quarterly common stock dividends per share.

In 2007, our dividend payout ratio was 60%. This is an increase of 11% from our payout ratio of 54% in 2006. We expect that our dividend payout ratio will remain consistent with the dividend payout ratios of our peer companies, which is currently in a range of 60% to 65%. Our diluted earnings per share and dividends declared per share along with our payout ratio for the last three years are presented in the following chart.



For information about restrictions on our ability to pay dividends on our common stock, see Note 5 "Common Shareholders' Equity".

Share Repurchases In March 2001 our Board of Directors approved the purchase of up to 600,000 shares of our common stock to be used for issuances under the Officer Incentive Plan. During 2007, we purchased 10,667 shares. As of December 31, 2007, we had purchased a total 297,234 shares, leaving 302,766 shares available for purchase.

In February 2006, our Board of Directors authorized a plan to purchase up to 8 million shares of our outstanding common stock over a five-year period. These purchases are intended principally to offset share issuances under our employee and non-employee director incentive compensation plans and our dividend reinvestment and stock purchase plans. Stock purchases under this program may be made in the open market or in private transactions at times and in amounts that we deem appropriate. There is no guarantee as to the exact number of shares that we will purchase, and we can terminate or limit the program at any time.

For the year ended December 31, 2007, we purchased approximately 2 million shares of our common stock at an average cost of $39.56 per share and an aggregate cost of $80 million. During the same period in 2006, we purchased approximately 1 million shares of our common stock at a weighted average cost of $36.67 per share and an aggregate cost of $38 million. This represented an increase of $42 million or 111% from last year. We hold the purchased shares as treasury shares. For more information on our share repurchases see Item 5 "Market for the Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities."

Shelf Registration In August 2007, we filed a new shelf registration with the SEC. The debt securities and related guarantees will be issued by AGL Capital under an indenture dated as of February 20, 2001, as supplemented and modified, as necessary, among AGL Capital, AGL Resources and The Bank of New York Trust Company, N.A., as trustee. The indenture provides for the issuance from time to time of debt securities in an unlimited dollar amount and an unlimited number of series subject to our Credit Facility's financial covenants related to total debt to total capitalization. The debt securities will be guaranteed by AGL Resources. This replaces the previous shelf registration, filed in October 2004, which had $782 million available to be issued.

Contractual Obligations and Commitments We have incurred various contractual obligations and financial commitments in the normal course of our operating and financing activities that are reasonably likely to have a material effect on liquidity or the availability of requirements for capital resources. Contractual obligations include future cash payments required under existing contractual arrangements, such as debt and lease agreements. These obligations may result from both general financing activities and from commercial arrangements that are directly supported by related revenue-producing activities. The following table illustrates our expected future contractual obligation payments such as debt and lease agreements, and commitments and contingencies as of December 31, 2007.

In millions	Total	2008	2009 & 2010	2011 & 2012	2013 & thereafter
Recorded contractual obligations:					
Long-term debt	$1,674	$-	$2	$315	$1,357
Short-term debt	580	580	-	-	-
ERC (1)	107	10	34	53	10
PRP costs (1)	245	55	112	60	18
Total	$2,606	$645	$148	$428	$1,385

(1) Includes charges recoverable through rate rider mechanisms.

In millions	Total	2008	2009 & 2010	2011 & 2012	2013 & thereafter
Unrecorded contractual obligations and commitments (1):					
Interest charges (2)	$1,176	$100	$200	$157	$719
Pipeline charges, storage capacity and gas supply (3)	1,792	456	637	348	351
Operating leases	154	26	50	34	44
Standby letters of credit, performance / surety bonds	30	24	6	-	-
Asset management agreements (4)	24	8	8	8	-
Total	$3,176	$614	$901	$547	$1,114

(1) In accordance with generally accepted accounting principles, these items are not reflected in our consolidated balance sheet.
(2) Floating rate debt is based on the interest rate as of December 31, 2007 and the maturity of the underlying debt instrument. As of December 31, 2007 we have $39 million of accrued interest on our consolidated balance sheet that will be paid in 2008.
(3) Charges recoverable through a PGA mechanism or alternatively billed to Marketers. Also includes demand charges associated with Sequent.
(4) Represent fixed-fee payments for Sequent's asset management agreements between Atlanta Gas Light ($4 million) and Elizabethtown Gas ($4 million). As of December 31, 2007, we have $1 million of fixed-fee payments are accrued on our consolidated balance sheet, which will be paid in 2008.

Pipeline Charges, Storage Capacity and Gas Supply Contracts. A subsidiary of NUI entered into two 20-year agreements for the firm transportation and storage of natural gas during 2003 with annual aggregate demand charges of approximately $5 million. As a result of our acquisition of NUI and accordance with SFAS 141, we valued the contracts at fair value and established a long-term liability for the excess liability that will be amortized over the remaining lives of the contracts. The gas supply amount includes SouthStar gas commodity purchase commitments of 1.3 Bcf at floating gas prices calculated using forward natural gas prices as of December 31, 2007, and is valued at $98 million.

Operating leases. We have certain operating leases with provisions for step rent or escalation payments and certain lease concessions. We account for these leases by recognizing the future minimum lease payments on a straight-line basis over the respective minimum lease terms, in accordance with SFAS 13. However, this accounting treatment does not affect the future annual operating lease cash obligations as shown herein. We expect to fund these obligations with cash flow from operating and financing activities.

Standby letters of credit and surety bonds. We also have incurred various financial commitments in the normal course of business. Contingent financial commitments represent obligations that become payable only if certain predefined events occur, such as financial guarantees, and include the nature of the guarantee and the maximum potential amount of future payments that could be required of us as the guarantor. We would expect to fund these contingent financial commitments with operating and financing cash flows.

Pension and Postretirement Obligations We calculate any required pension contributions using the projected unit credit cost method. Under this method, we were not required to and did not make any pension contribution during 2007. During 2006, we voluntarily contributed $5 million to the AGL Resources Inc. Retirement Plan.

The state regulatory commissions have phase-ins that defer a portion of the postretirement benefit expense for future recovery. We recorded a regulatory asset for these future recoveries of $12 million as of December 31, 2007 and $13 million as of December 31, 2006. In addition, we recorded a regulatory liability of $4 million as of December 31, 2007 and $4 million as of December 31, 2006 for our expected expenses under the AGL Postretirement

Plan. See Note 3 "Employee Benefit Plans," for additional information about our pension and postretirement plans.

Critical Accounting Policies

The preparation of our financial statements requires us to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses and the related disclosures of contingent assets and liabilities. We based our estimates on historical experience and various other assumptions that we believe to be reasonable under the circumstances, and we evaluate our estimates on an ongoing basis. Our actual results may differ from our estimates. Each of the following critical accounting policies involves complex situations requiring a high degree of judgment either in the application and interpretation of existing literature or in the development of estimates that impact our financial statements.

Pipeline Replacement Program Liabilities Atlanta Gas Light was ordered by the Georgia Commission (through a joint stipulation and a subsequent settlement agreement between Atlanta Gas Light and the Commission staff) to undertake a PRP that would replace all bare steel and cast iron pipe in its system. Approximately 103 miles of cast iron and 533 miles of bare steel pipe still require replacement. If Atlanta Gas Light does not perform in accordance with the initial and amended PRP stipulation, it can be assessed certain nonperformance penalties. However to date, Atlanta Gas Light is in full compliance.

The stipulation also provides for recovery of all prudent costs incurred under the program, which Atlanta Gas Light has recorded as a regulatory asset. The regulatory asset has two components:

- the costs incurred to date that have not yet been recovered through rate riders
- the future expected costs to be recovered through rate riders

The determination of future expected costs associated with our PRP involves judgment. Factors that must be considered in estimating the future expected costs are projected capital expenditure spending, including labor and material costs, and the remaining infrastructure footage to be replaced for the remaining years of the program. We recorded a long-term liability of $190 million as of December 31, 2007 and $202 million as of December 31, 2006, which represented engineering estimates for remaining capital expenditure costs in the PRP. As of December 31, 2007, we had recorded a current liability of $55 million, representing expected PRP expenditures for the next 12 months. We report these estimates on an undiscounted basis. If Atlanta Gas Light's PRP expenditures, subject to future recovery, were $10 million higher or lower its incremental expected annual revenues would have changed by approximately $1 million.

Environmental Remediation Liabilities We historically reported estimates of future remediation costs based on probabilistic models of potential costs. We report these estimates on an undiscounted basis. As we continue to conduct the actual remediation and enter cleanup contracts, we are increasingly able to provide conventional engineering estimates of the likely costs of many elements of the remediation program. These estimates contain various engineering uncertainties, and we continuously attempt to refine and update these engineering estimates.

Our latest available estimate as of December 31, 2007 for those elements of the remediation program with in-place contracts or engineering cost estimates is $15 million for Atlanta Gas Light's Georgia and Florida sites. This is an increase of $2 million from the December 31, 2006 estimate of projected engineering and in-place contracts, resulting from increased cost estimates during 2007. For elements of the remediation program where Atlanta Gas Light still cannot perform engineering cost estimates, considerable variability remains in available estimates. The estimated remaining cost of future actions at these sites is $20 million, which includes approximately $1 million in estimates of certain other costs it pays related to administering the remediation program and remediation of sites currently in the investigation phase. Beyond 2009, these costs cannot be estimated. As of December 31, 2007, we have recorded a liability of $35 million.

Atlanta Gas Light's environmental remediation liability is included in its corresponding regulatory asset. Atlanta Gas Light's estimate does not include other potential expenses, such as unasserted property damage, personal injury or natural resource damage claims, unbudgeted legal expenses, or other costs for which it may be held liable but with respect to which the amount cannot be reasonably forecast. Atlanta Gas Light's recovery of environmental remediation costs is subject to review by the Georgia Commission, which may seek to disallow the recovery of some expenses.

In New Jersey, Elizabethtown Gas is currently conducting remediation activities with oversight from the New Jersey Department of Environmental Protection. Although the actual total cost of future environmental investigation and remediation efforts cannot be estimated with precision, the range of reasonably probable costs is $61 million to $119

million. As of December 31, 2007, we have recorded a liability of $61 million.

The New Jersey Commission has authorized Elizabethtown Gas to recover prudently incurred remediation costs for the New Jersey properties through its remediation adjustment clause. As a result, Elizabethtown Gas has recorded a regulatory asset of approximately $66 million, inclusive of interest, as of December 31, 2007, reflecting the future recovery of both incurred costs and future remediation liabilities in the state of New Jersey. Elizabethtown Gas has also been successful in recovering a portion of remediation costs incurred in New Jersey from its insurance carriers and continues to pursue additional recovery. As of December 31, 2007, the variation between the amounts of the environmental remediation cost liability recorded in the consolidated balance sheet and the associated regulatory asset is due to expenditures for environmental investigation and remediation exceeding recoveries from ratepayers and insurance carriers.

We also own several former NUI remediation sites located outside of New Jersey. One site, in Elizabeth City, North Carolina, is subject to an order by the North Carolina Department of Environment and Natural Resources. Preliminary estimates for investigation and remediation costs range from $11 million to $20 million. As of December 31, 2007, we had recorded a liability of $11 million related to this site. There is one other site in North Carolina where investigation and remediation is probable, although no regulatory order exists and we do not believe costs associated with this site can be reasonably estimated. In addition, there are as many as six other sites with which NUI had some association, although no basis for liability has been asserted. We do not believe that costs to investigate and remediate these sites, if any, can be reasonably estimated at this time.

With respect to these costs, we currently pursue or intend to pursue recovery from ratepayers, former owners and operators and insurance carriers. Although we have been successful in recovering a portion of these remediation costs from our insurance carriers, we are not able to express a belief as to the success of additional recovery efforts. We are working with the regulatory agencies to manage our remediation costs so as to mitigate the impact of such costs on both ratepayers and shareholders.

Derivatives and Hedging Activities SFAS 133, as updated by SFAS 149, established accounting and reporting standards which require that every derivative financial instrument (including certain derivative instruments embedded in other contracts) be recorded in the balance sheet as either an asset or liability measured at its fair value. However, if the derivative transaction qualifies for and is designated as a normal purchase and sale, it is exempted from the fair value accounting treatment of SFAS 133, as updated by SFAS 149, and is accounted for using traditional accrual accounting.

SFAS 133 requires that changes in the derivative's fair value be recognized currently in earnings unless specific hedge accounting criteria are met. If the derivatives meet those criteria, SFAS 133 allows a derivative's gains and losses to offset related results on the hedged item in the income statement in the case of a fair value hedge, or to record the gains and losses in OCI until maturity in the case of a cash flow hedge. Additionally, SFAS 133 requires that a company formally designate a derivative as a hedge as well as document and assess the effectiveness of derivatives associated with transactions that receive hedge accounting treatment. SFAS 133 applies to treasury locks and interest rate swaps executed by AGL Capital and gas commodity contracts executed by Sequent and SouthStar. SFAS 133 also applies to gas commodity contracts executed by Elizabethtown Gas under a New Jersey Commission authorized hedging program that requires gains and losses on these derivatives are reflected in purchased gas costs and ultimately billed to customers. Our derivative and hedging activities are described in further detail in Note 2 "Financial Instruments and Risk Management" and Item 1 "Business."

Commodity-related Derivative Instruments We are exposed to risks associated with changes in the market price of natural gas. Through Sequent and SouthStar, we use derivative instruments to reduce our exposure impact to our results of operations due to the risk of changes in the price of natural gas.

Sequent recognizes the change in value of a derivative instrument as an unrealized gain or loss in revenues in the period when the market value of the instrument changes. Sequent recognizes cash inflows and outflows associated with the settlement of its risk management activities in operating cash flows, and reports these settlements as receivables and payables in the balance sheet separately from the risk management activities reported as energy marketing receivables and trade payables.

We attempt to mitigate substantially all our commodity price risk associated with Sequent's natural gas storage portfolio and lock in the economic margin at the time we enter into purchase transactions for our stored natural gas. We purchase natural gas for storage when the current market price we pay plus storage costs is less than the market price we could receive in the future. We lock in the economic margin by selling NYMEX futures contracts or other over-the-counter derivatives in the forward

months corresponding with our withdrawal periods. We use contracts to sell natural gas at that future price to lock in the operating margin we will ultimately realize when the stored natural gas is actually sold. These contracts meet the definition of a derivative under SFAS 133.

The purchase, storage and sale of natural gas are accounted for differently from the derivatives we use to mitigate the commodity price risk associated with our storage portfolio. That difference in accounting can result in volatility in our reported operating margin, even though the economic margin is essentially unchanged from the date we entered into the transactions. We do not currently use hedge accounting under SFAS 133 to account for this activity.

Natural gas that we purchase and inject into storage is accounted for at the lower of average cost or market value. Under current accounting guidance, we recognize a loss in any period when the market price for natural gas is lower than the carrying amount of our purchased natural gas inventory. Costs to store the natural gas are recognized in the period the costs are incurred. We recognize revenues and cost of natural gas sold in our statement of consolidated income in the period we sell gas and it is delivered out of the storage facility.

The derivatives we use to mitigate commodity price risk and substantially lock in the operating margin upon the sale of stored natural gas are accounted for at fair value and marked to market each period, with changes in fair value recognized as unrealized gains or losses in the period of change. This difference in accounting - the lower of average cost or market basis for our storage inventory versus the fair value accounting for the derivatives used to mitigate commodity price risk - can and does result in volatility in our reported earnings.

Over time, gains or losses on the sale of storage inventory will be substantially offset by losses or gains on the derivatives, resulting in realization of the economic profit margin we expected when we entered into the transactions. This accounting difference causes Sequent's earnings on its storage positions to be affected by natural gas price changes, even though the economic profits remain essentially unchanged.

SouthStar also uses derivative instruments to manage exposures arising from changing commodity prices. SouthStar's objective for holding these derivatives is to minimize volatility in wholesale commodity natural gas prices. A portion of SouthStar's derivative transactions are designated as cash flow hedges under SFAS 133. Derivative gains or losses arising from cash flow hedges are recorded in OCI and are reclassified into earnings in the same period the underlying hedged item is reflected in the income statement. As of December 31, 2007, the ending balance in OCI for derivative transactions designated as cash flow hedges under SFAS 133 was a gain of $3 million, net of minority interest and taxes. Any hedge ineffectiveness, defined as when the gains or losses on the hedging instrument do not offset the losses or gains on the hedged item, is recorded into earnings in the period in which it occurs. SouthStar currently has minimal hedge ineffectiveness. SouthStar's remaining derivative instruments are not designated as hedges under SFAS 133. Therefore, changes in their fair value are recorded in earnings in the period of change.

SouthStar also enters into weather derivative instruments in order to preserve operating margins in the event of warmer-than-normal weather in the winter months. These contracts are accounted for using the intrinsic value method under the guidance of EITF 99-02. Changes in the fair value of these derivatives are recorded in earnings in the period of change. The weather derivative contracts contain strike amount provisions based on cumulative heating degree days for the covered periods. In 2007 and 2006, SouthStar entered into weather derivatives (swaps and options) for the respective winter heating seasons, primarily from November through March. As of December 31, 2007, SouthStar recorded a current asset of $5 million for this hedging activity.

Contingencies Our accounting policies for contingencies cover a variety of business activities, including contingencies for potentially uncollectible receivables, rate matters, and legal and environmental exposures. We accrue for these contingencies when our assessments indicate that it is probable that a liability has been incurred or an asset will not be recovered, and an amount can be reasonably estimated in accordance with SFAS 5. We base our estimates for these liabilities on currently available facts and our estimates of the ultimate outcome or resolution of the liability in the future. Actual results may differ from estimates, and estimates can be, and often are, revised either negatively or positively, depending on actual outcomes or changes in the facts or expectations surrounding each potential exposure.

Pension and Other Postretirement Plans Our pension and other postretirement plan costs and liabilities are determined on an actuarial basis and are affected by numerous assumptions and estimates including the market value of plan assets, estimates of the expected return on plan assets, assumed discount rates and current demographic and actuarial mortality data. We annually review the estimates and assumptions underlying our pension

and other postretirement plan costs and liabilities. The assumed discount rate and the expected return on plan assets are the assumptions that generally have the most significant impact on our pension costs and liabilities. The assumed discount rate, the assumed health care cost trend rate and the assumed rates of retirement generally have the most significant impact on our postretirement plan costs and liabilities.

The discount rate is used principally to calculate the actuarial present value of our pension and postretirement obligations and net pension and postretirement cost. When establishing our discount rate which we have determined to be 6.4% at December 31, 2007, we consider high quality corporate bond rates based on Moody's Corporate AA long-term bond rate of 5.9% and the Citigroup Pension Liability rate of 6.5% at December 31, 2007. We further use these market indices as a comparison to a single equivalent discount rate derived with the assistance of our actuarial advisors. This analysis as of December 31, 2007 produced a single equivalent discount rate of 6.5%.

The actuarial assumptions used may differ materially from actual results due to changing market and economic conditions, higher or lower withdrawal rates, or longer or shorter life spans of participants. These differences may result in a significant impact on the amount of pension expense recorded in future periods.

The expected long-term rate of return on assets is used to calculate the expected return on plan assets component of our annual pension and postretirement plan cost. We estimate the expected return on plan assets by evaluating expected bond returns, equity risk premiums, asset allocations, the effects of active plan management, the impact of periodic plan asset rebalancing and historical performance. We also consider guidance from our investment advisors in making a final determination of our expected rate of return on assets. To the extent the actual rate of return on assets realized over the course of a year is greater than or less than the assumed rate, that year's annual pension or postretirement plan cost is not affected. Rather, this gain or loss reduces or increases future pension or postretirement plan costs.

Prior to 2006, we estimated the assumed health care cost trend rate used in determining our postretirement net expense based on our actual health care cost experience, the effects of recently enacted legislation and general economic conditions. However, starting in 2006, our postretirement plans have been capped at 2.5% for increases in health care costs. Consequently, a one-percentage-point increase or decrease in the assumed health care trend rate does not materially affect the periodic benefit cost for our postretirement plans. A one percentage-point increase in the assumed health care cost trend rate would increase our accumulated projected benefit obligation by $4 million. A one percentage-point decrease in the assumed health care cost trend rate would decrease our accumulated projected benefit obligation by $4 million. Our assumed rate of retirement is estimated based upon an annual review of participant census information as of the measurement date.

At December 31, 2007, our pension and postretirement liability decreased by approximately $45 million, primarily resulting from an after-tax gain to OCI of $24 million ($40 million before tax), $9 million in benefit payments that we funded offset by $4 million in net pension and postretirement benefit costs we recorded in 2007. These changes reflect our funding contributions to the plan, benefit payments out of the plans, and updated valuations for the projected benefit obligation (PBO) and plan assets.

Equity market performance and corporate bond rates have a significant effect on our reported unfunded accumulated benefit obligation (ABO), as the primary factors that drive the value of our unfunded ABO are the assumed discount rate and the actual return on plan assets. Additionally, equity market performance has a significant effect on our market-related value of plan assets (MRVPA), which is a calculated value and differs from the actual market value of plan assets. The MRVPA recognizes differences between the actual market value and expected market value of our plan assets and is determined by our actuaries using a five-year moving weighted average methodology. Gains and losses on plan assets are spread through the MRVPA based on the five-year moving weighted average methodology, which affects the expected return on plan assets component of pension expense.

See "Note 3, Employee Benefit Plans," for additional information on our pension and postretirement plans, which includes our investment policies and strategies, target allocation ranges and weighted average asset allocations for 2007 and 2006.

The actual return on our pension plan assets compared to the expected return on plan assets of 9% will have an impact on our ABO as of December 31, 2008 and our pension expense for 2008. We are unable to determine how this actual return on plan assets will affect future ABO and pension expense, as actuarial assumptions and differences between actual and expected returns on plan assets are determined at the time we complete our actuarial evaluation as of December 31, 2008. Our actual returns may also be positively or negatively impacted as a result of future performance in the equity and bond markets. The following tables illustrate the effect of changing the critical actuarial assumptions, as discussed previously, while holding all other assumptions constant.

AGL Resources Inc. Retirement and Postretirement Plans

In millions		Pension Benefits			Health and Life Benefits
Actuarial assumptions	Percentage-point change in assumption	Increase (decrease) in ABO	Increase (decrease) in cost	Increase (decrease) in obligation	Increase (decrease) in cost
Expected long-term return on plan assets	+/- 1%	$- / -	$(3) / 3		
Discount rate	+/- 1%	(40) / 45	(4) / 4		
Healthcare cost trend rate	+/- 1%			$4 / (4)	$- / -

NUI Corporation Retirement Plan

In millions			Pension Benefits
Actuarial assumptions	Percentage-point change in assumption	Increase (decrease) in ABO	Increase (decrease) in cost
Expected long-term return on plan assets	+/- 1%	$- / -	$(1) / 1
Discount rate	+/- 1%	(5) / 5	- / (1)

Differences between actuarial assumptions and actual plan results are deferred and amortized into cost when the accumulated differences exceed 10% of the greater of the PBO or the MRVPA. If necessary, the excess is amortized over the average remaining service period of active employees.

In addition to the assumptions listed above, the measurement of the plans' obligations and costs depend on other factors such as employee demographics, the level of contributions made to the plans, earnings on the plans' assets and mortality rates.

Income Taxes We account for income taxes in accordance with SFAS 109 and FIN 48 which require that deferred tax assets and liabilities be recognized using enacted tax rates for the effect of temporary differences between the book and tax basis of recorded assets and liabilities. SFAS 109 and FIN 48 also requires that deferred tax assets be reduced by a valuation if it is more likely than not that some portion or all of the deferred tax asset will not be realized. We adopted the provisions of FIN 48 on January 1, 2007. At the date of adoption and as of December 31, 2007, we did not have a liability for unrecognized tax benefits.

Our net long-term deferred tax liability totaled $566 million at December 31, 2007 (see Note 8 "Income Taxes"). This liability is estimated based on the expected future tax consequences of items recognized in the financial statements. After application of the federal statutory tax rate to book income, judgment is required with respect to the timing and deductibility of expense in our income tax returns. For state income tax and other taxes, judgment is also required with respect to the apportionment among the various jurisdictions. A valuation allowance is recorded if we expect that it is more likely than not that our deferred tax assets will not be realized. We had a $3 million valuation allowance on $53 million of deferred tax assets as of December 31, 2007, reflecting the expectation that most of these assets will be realized. In addition, we operate within multiple taxing jurisdictions and we are subject to audit in these jurisdictions. These audits can involve complex issues, which may require an extended period of time to resolve. We maintain a liability for the estimate of potential income tax exposure and in our opinion adequate provisions for income taxes have been made for all years.

Accounting Developments

SFAS 157 In September 2006, the FASB issued SFAS 157, which establishes a framework for measuring fair value and requires expanded disclosures regarding fair value measurements. SFAS 157 does not require any new fair value measurements. However, it eliminates inconsistencies in the guidance provided in previous accounting pronouncements.

SFAS 157 is effective for financial statements issued for fiscal years beginning after November 15, 2007, and interim periods within those fiscal years. Earlier application is encouraged, provided that the reporting entity has not yet issued financial statements for that fiscal year, including financial statements for an interim period within that fiscal year. All valuation adjustments will be recognized as cumulative-effect adjustments to the opening balance of retained earnings for the fiscal year in which SFAS 157 is

initially applied. In December 2007, the FASB provided a one year deferral of SFAS 157 for nonfinancial assets and nonfinancial liabilities, except those that are recognized or disclosed at fair value on a recurring basis, at least annually. We will adopt SFAS 157 on January 1, 2008, for our financial assets and liabilities, which primarily consists of derivatives we record in accordance with SFAS 133, and on January 1, 2009, for our non-financial assets and liabilities. For our financial assets and liabilities, we expect that our adoption of SFAS 157 will primarily impact our disclosures and not have a material impact on our consolidated results of operations, cash flows or financial position. We are currently evaluating the impact with respect to our non-financial assets and liabilities.

SFAS 159 In February 2007, the FASB issued SFAS 159 which is effective for fiscal years beginning after November 15, 2007, but is not required to be adopted. SFAS 159 establishes a framework for measuring fair value for eligible financial assets and liabilities with the intention of reducing earnings volatility. We currently have no financial assets or liabilities eligible for this treatment and have no plans to adopt SFAS 159.

SFAS 160 In December 2007, the FASB issued SFAS 160, which is effective for fiscal years beginning after December 15, 2008. Early adoption is prohibited. SFAS 160 will require us to present our minority interest, to be referred to as a noncontrolling interest, separately within the capitalization section of our consolidated balance sheet. We will adopt SFAS 160 as of January 1, 2009.

FIN 39 was issued in March 1992 and provides guidance related to offsetting payable and receivable amounts related to certain contracts, including derivative contracts. It was effective for financial statements issued for periods beginning after December 15, 1993.

FSP FIN 39-1 was issued in April 2007 and is effective for us on January 1, 2008. FIN 39-1 amends FIN 39 and allows a company to elect to report certain derivative assets and liabilities subject to master netting agreements on either a gross basis or net basis on the balance sheet. The guidance also addresses reporting of collateral amounts relating to the netting agreements. We enter into derivative contracts, but FSP FIN 39-1 will not have a material effect on our consolidated financial condition.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

We are exposed to risks associated with commodity prices, interest rates and credit. Commodity price risk is defined as the potential loss that we may incur as a result of changes in the fair value of natural gas. Interest rate risk results from our portfolio of debt and equity instruments that we issue to provide financing and liquidity for our business. Credit risk results from the extension of credit throughout all aspects of our business but is particularly concentrated at Atlanta Gas Light in distribution operations and in wholesale services.

Our Risk Management Committee (RMC) is responsible for establishing the overall risk management policies and monitoring compliance with, and adherence to, the terms within these policies, including approval and authorization levels and delegation of these levels. Our RMC consists of members of senior management who monitor open commodity price risk positions and other types of risk, corporate exposures, credit exposures and overall results of our risk management activities. It is chaired by our chief risk officer, who is responsible for ensuring that appropriate reporting mechanisms exist for the RMC to perform its monitoring functions. Our risk management activities and related accounting treatments are described in further detail in Note 2, Financial Instruments and Risk Management.

Commodity Price Risk

Retail Energy Operations SouthStar's use of derivatives is governed by a risk management policy, approved and monitored by its Risk and Asset Management Committee, which prohibits the use of derivatives for speculative purposes.

Energy Marketing and Risk Management Activities SouthStar generates operating margin from the active management of storage positions through a variety of hedging transactions and derivative instruments aimed at managing exposures arising from changing commodity prices. SouthStar uses these hedging instruments to lock in economic margins (as spreads between wholesale and retail commodity prices widen between periods) and thereby minimize its exposure to declining operating margins.

We have designated a portion of SouthStar's derivative transactions as cash flow hedges in accordance with SFAS 133. We record derivative gains or losses arising from cash flow hedges in OCI and reclassify them into earnings in the same period as the underlying hedged item occurs and is recorded in earnings. We record any hedge ineffectiveness, defined as when the gains or losses on the hedging instrument do not offset and are greater than the losses or gains on the hedged item, in cost of gas in our consolidated statement of income in the period in which the ineffectiveness occurs. SouthStar currently has minimal hedge

ineffectiveness. We have not designated the remainder of SouthStar's derivative instruments as hedges under SFAS 133 and, accordingly, we record changes in their fair value in earnings in the period of change.

SouthStar recorded a net unrealized loss related to changes in the fair value of derivative instruments utilized in its energy marketing and risk management activities of $7 million during 2007, $14 million of unrealized gains during 2006 and unrealized losses of $4 million during 2005. The following tables illustrate the change in the net fair value of the derivative instruments and energy-trading contracts during 2007, 2006 and 2005 and provide details of the net fair value of contracts outstanding as of December 31, 2007, 2006 and 2005.

In millions	**2007**	**2006**	**2005**
Net fair value of contracts outstanding at beginning of period	$17	$3	$7
Contracts realized or otherwise settled during period	(16)	(3)	(7)
Change in net fair value of contracts	9	17	3
Net fair value of contracts outstanding at end of period	$10	$17	$3

The sources of SouthStar's net fair value at December 31, 2007, are as follows.

In millions	**Prices actively quoted** (1)	**Prices provided by other external sources** (2)
Mature through 2008	$5	$5
Matures after 2008	-	-
Total net fair value	$5	$5

(1) Valued using NYMEX futures prices.
(2) Values primarily related to weather derivative transactions that are valued on an intrinsic basis in accordance with EITF 99-02 as based on heating degree days.

SouthStar routinely utilizes various types of financial and other instruments to mitigate certain commodity price and weather risks inherent in the natural gas industry. These instruments include a variety of exchange-traded and over-the-counter energy contracts, such as forward contracts, futures contracts, options contracts and swap agreements. The following table includes the fair values and average values of SouthStar's energy marketing and risk management assets and liabilities as of December 31, 2007 and 2006. SouthStar bases the average values on monthly averages for the 12 months ended December 31, 2007 and 2006.

	Average values at December 31,	
In millions	**2007**	**2006**
Asset	$11	$11
Liability	4	6

	Fair value at December 31,	
In millions	**2007**	**2006**
Asset	$12	$30
Liability	2	13

Value-at-risk A 95% confidence interval is used to evaluate VaR exposure. A 95% confidence interval means there is a 5% confidence that the actual loss in portfolio value will be greater than the calculated VaR value over the holding period. We calculate VaR based on the variance-covariance technique. This technique requires several assumptions for the basis of the calculation, such as price distribution, price volatility, confidence interval and holding period. Our VaR may not be comparable to a similarly titled measure of another company because, although VaR is a common metric in the energy industry, there is no established industry standard for calculating VaR or for the assumptions underlying such calculations. SouthStar's portfolio of positions for 2007 and 2006, had annual average 1-day holding period VaRs of less than $100,000, and its high, low and period end 1-day holding period VaR were immaterial.

Wholesale Services Sequent routinely uses various types of financial and other instruments to mitigate certain commodity price risks inherent in the natural gas industry. These instruments include a variety of exchange-traded and over-the-counter energy contracts, such as forward contracts, futures contracts, options contracts and financial swap agreements.

Energy Marketing and Risk Management Activities We account for derivative transactions in connection with Sequent's energy marketing activities on a fair value basis in accordance with SFAS 133. We record derivative energy commodity contracts (including both physical transactions and financial instruments) at fair value, with unrealized gains or losses from changes in fair value reflected in our earnings in the period of change.

Sequent's energy-trading contracts are recorded on an accrual basis as required under the EITF 02-03 rescission of EITF 98-10, unless they are derivatives that must be recorded at fair value under SFAS 133.

Sequent recorded a net unrealized loss related to changes in the fair value of derivative instruments utilized in its energy marketing and risk management activities and contract settlement of $62 million

during 2007, $132 million of unrealized gains during 2006 and unrealized losses of $30 million during 2005. The following tables illustrate the change in the net fair value of Sequent's derivative instruments and energy-trading contracts during 2007, 2006 and 2005 and provide details of the net fair value of contracts outstanding as of December 31, 2007, 2006 and 2005.

In millions	2007	2006	2005
Net fair value of contracts outstanding at beginning of period	$119	$(13)	$17
Contracts realized or otherwise settled during period	(102)	17	(47)
Change in net fair value of contracts	40	115	17
Net fair value of contracts outstanding at end of period	$57	$119	$(13)

The sources of Sequent's net fair value at December 31, 2007, are as follows.

In millions	Prices actively quoted (1)	Prices provided by other external sources (2)
Mature through 2008	$19	$31
Mature 2009 – 2010	1	2
Mature 2011 – 2013	-	3
Mature after 2013	-	1
Total net fair value	$20	$37

(1) Valued using NYMEX futures prices.
(2) Valued using basis transactions that represent the cost to transport the commodity from a NYMEX delivery point to the contract delivery point. These transactions are based on quotes obtained either through electronic trading platforms or directly from brokers.

The following table includes the fair values and average values of Sequent's energy marketing and risk management assets and liabilities as of December 31, 2007 and 2006. Sequent bases the average values on monthly averages for the 12 months ended December 31, 2007 and 2006.

	Average values at December 31,	
In millions	2007	2006
Asset	$63	$95
Liability	16	43

	Fair value at December 31,	
In millions	2007	2006
Asset	$70	$133
Liability	13	14

Value-at-risk Sequent employs a systematic approach to evaluating and managing the risks associated with contracts related to wholesale marketing and risk management, including VaR. Similar to SouthStar, Sequent uses a 1-day holding period and a 95% confidence interval to evaluate its VaR exposure.

Sequent's open exposure is managed in accordance with established policies that limit market risk and require daily reporting of potential financial exposure to senior management, including the chief risk officer. Because Sequent generally manages physical gas assets and economically protects its positions by hedging in the futures and over-the-counter markets, its open exposure is generally minimal, permitting Sequent to operate within relatively low VaR limits. Sequent employs daily risk testing, using both VaR and stress testing, to evaluate the risks of its open positions.

Sequent's management actively monitors open commodity positions and the resulting VaR. Sequent continues to maintain a relatively matched book, where its total buy volume is close to its sell volume, with minimal open commodity risk. Based on a 95% confidence interval and employing a 1-day holding period for all positions, Sequent's portfolio of positions for the 12 months ended December 31, 2007, 2006 and 2005 had the following 1-day holding period VaRs.

In millions	2007	2006	2005
Period end	$1.2	$1.3	$0.6
12-month average	1.3	1.2	0.4
High	2.3	2.5	1.1
Low (1)	0.7	0.7	0.0

(1) $0.0 values represent amounts less than $0.1 million.

Interest Rate Risk

Interest rate fluctuations expose our variable-rate debt to changes in interest expense and cash flows. We manage interest expense using a combination of fixed-rate and variable-rate debt. Based on $840 million of variable-rate debt, which includes $579 million of our variable-rate short-term debt, $100 million of variable-rate senior notes and $161 million of variable-rate gas facility revenue bonds outstanding at December 31, 2007, a 100 basis point change in market interest rates from 5.56% to 6.56% would have resulted in an increase in pretax interest expense of $8 million on an annualized basis.

To facilitate the achievement of desired fixed-rate to variable-rate debt ratios, AGL Capital entered into interest rate swaps whereby it agreed to exchange, fixed rate debt for floating-rate debt. The swaps exchange at specified intervals, the difference between fixed and variable amounts calculated by reference to agreed-on notional principal amounts. These swaps are designated to hedge the fair values of $100 million of the $300 million senior notes due in 2011.

In August 2007, we executed a treasury-lock agreement covering a notional amount totaling $125 million to hedge the interest rate risk associated with

our $125 million senior notes offering in December 2007. The 10-year treasury interest rate was locked in at a weighted average rate of 4.5%. The treasury-lock agreements settled and we paid $5 million in December 2007 in connection with our issuance of $125 million in senior notes. The $5 million is included within OCI (net of $2 million in income taxes) and will be amortized over the remaining life of the senior notes (through July 2016) as interest expense.

Credit Risk

Distribution Operations Atlanta Gas Light has a concentration of credit risk as it bills only 12 Marketers in Georgia for its services. The credit risk exposure to Marketers varies with the time of the year, with exposure at its lowest in the nonpeak summer months and highest in the peak winter months. Marketers are responsible for the retail sale of natural gas to end-use customers in Georgia. These retail functions include customer service, billing, collections, and the purchase and sale of the natural gas commodity. The provisions of Atlanta Gas Light's tariff allow Atlanta Gas Light to obtain security support in an amount equal to a minimum of two times a Marketer's highest month's estimated bill from Atlanta Gas Light. For 2007, the four largest Marketers based on customer count, one of which was SouthStar, accounted for approximately 38% of our consolidated operating margin and 52% of distribution operations' operating margin.

Several factors are designed to mitigate our risks from the increased concentration of credit that has resulted from deregulation. In addition to the security support described above, Atlanta Gas Light bills intrastate delivery service to Marketers in advance rather than in arrears. We accept credit support in the form of cash deposits, letters of credit/surety bonds from acceptable issuers and corporate guarantees from investment-grade entities. The RMC reviews on a monthly basis the adequacy of credit support coverage, credit rating profiles of credit support providers and payment status of each Marketer. We believe that adequate policies and procedures have been put in place to properly quantify, manage and report on Atlanta Gas Light's credit risk exposure to Marketers.

Atlanta Gas Light also faces potential credit risk in connection with assignments of interstate pipeline transportation and storage capacity to Marketers. Although Atlanta Gas Light assigns this capacity to Marketers, in the event that a Marketer fails to pay the interstate pipelines for the capacity, the interstate pipelines would in all likelihood seek repayment from Atlanta Gas Light.

Retail Energy Operations SouthStar obtains credit scores for its firm residential and small commercial customers using a national credit reporting agency, enrolling only those customers that meet or exceed SouthStar's credit threshold.

SouthStar considers potential interruptible and large commercial customers based on a review of publicly available financial statements and review of commercially available credit reports. Prior to entering into a physical transaction, SouthStar also assigns physical wholesale counterparties an internal credit rating and credit limit based on the counterparties' Moody's, S&P and Fitch ratings, commercially available credit reports and audited financial statements.

Wholesale Services Sequent has established credit policies to determine and monitor the creditworthiness of counterparties, as well as the quality of pledged collateral. Sequent also utilizes master netting agreements whenever possible to mitigate exposure to counterparty credit risk. When Sequent is engaged in more than one outstanding derivative transaction with the same counterparty and it also has a legally enforceable netting agreement with that counterparty, the "net" mark-to-market exposure represents the netting of the positive and negative exposures with that counterparty and a reasonable measure of Sequent's credit risk. Sequent also uses other netting agreements with certain counterparties with whom it conducts significant transactions.

Master netting agreements enable Sequent to net certain assets and liabilities by counterparty. Sequent also nets across product lines and against cash collateral provided the master netting and cash collateral agreements include such provisions. Additionally, Sequent may require counterparties to pledge additional collateral when deemed necessary. Sequent conducts credit evaluations and obtains appropriate internal approvals for its counterparty's line of credit before any transaction with the counterparty is executed. In most cases, the counterparty must have a minimum long-term debt rating of Baa3 from Moody's and BBB- from S&P. Generally, Sequent requires credit enhancements by way of guaranty, cash deposit or letter of credit for transaction counterparties that do not meet the minimum ratings threshold.

Sequent, which provides services to retail marketers and utility and industrial customers, also has a concentration of credit risk as measured by its 30-day receivable exposure plus forward exposure. As of December 31, 2007, Sequent's top 20 counterparties represented approximately 53% of the total counterparty exposure of $366 million, derived by adding together the top 20 counterparties' exposures and dividing by the total of Sequent's counterparties' exposures.

As of December 31, 2007, Sequent's counterparties, or the counterparties' guarantors, had a weighted average S&P equivalent credit rating of A-, which is consistent with the prior year. The S&P equivalent credit rating is determined by a process of converting the lower of the S&P or Moody's ratings to an internal rating ranging from 9 to 1, with 9 being equivalent to AAA/Aaa by S&P and Moody's and 1 being D or Default by S&P and Moody's. A counterparty that does not have an external rating is assigned an internal rating based on the strength of the financial ratios of that counterparty. To arrive at the weighted average credit rating, each counterparty's assigned internal rating is multiplied by the counterparty's credit exposure and summed for all counterparties. That sum is divided by the aggregate total counterparties' exposures, and this numeric value is then converted to an S&P equivalent.

The following table shows Sequent's commodity receivable and payable positions as of December 31, 2007 and 2006.

	As of December 31,			
	Gross receivables		**Gross payables**	
In millions	**2007**	**2006**	**2007**	**2006**
Netting agreements in place:				
Counterparty is investment grade	$437	$359	$356	$297
Counterparty is non-investment grade	24	62	18	52
Counterparty has no external rating	135	75	204	156
No netting agreements in place:				
Counterparty is investment grade	3	9	-	5
Amount recorded on balance sheet	$599	$505	$578	$510

Sequent has certain trade and credit contracts that have explicit minimum credit rating requirements. These credit rating requirements typically give counterparties the right to suspend or terminate credit if our credit ratings are downgraded to non-investment grade status. Under such circumstances, Sequent would need to post collateral to continue transacting business with some of its counterparties. Posting collateral would have a negative effect on our liquidity. If such collateral were not posted, Sequent's ability to continue transacting business with these counterparties would be impaired. If at December 31, 2007, Sequent's credit ratings had been downgraded to non-investment grade status, the required amounts to satisfy potential collateral demands under such agreements between Sequent and its counterparties would have totaled $26 million.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

AGL Resources Inc.
Consolidated Balance Sheets - Assets

In millions	As of December 31, 2007	December 31, 2006
Current assets		
Cash and cash equivalents	$21	$20
Receivables		
Energy marketing	599	505
Gas	212	197
Unbilled revenues	179	172
Other	13	21
Less allowance for uncollectible accounts	(14)	(15)
Total receivables	989	880
Inventories		
Natural gas stored underground	521	568
Other	30	29
Total inventories	551	597
Energy marketing and risk management assets	78	159
Unrecovered PRP costs – current portion	31	27
Unrecovered environmental remediation costs – current portion	23	27
Other current assets	118	112
Total current assets	1,811	1,822
Property, plant and equipment		
Property, plant and equipment	5,177	4,976
Less accumulated depreciation	1,611	1,540
Property, plant and equipment – net	3,566	3,436
Deferred debits and other assets		
Goodwill	420	420
Unrecovered PRP costs	254	247
Unrecovered environmental remediation costs	135	143
Other	82	79
Total deferred debits and other assets	891	889
Total assets	$6,268	$6,147

See Notes to Consolidated Financial Statements.

AGL Resources Inc.
Consolidated Balance Sheets - Liabilities and Capitalization

In millions, except share amounts	As of December 31, 2007	December 31, 2006
Current liabilities		
Short-term debt	$580	$539
Energy marketing trade payable	578	510
Accounts payable – trade	172	213
Accrued PRP costs – current portion	55	35
Accrued interest	39	37
Customer deposits	35	42
Deferred purchased gas adjustment	28	24
Accrued wages and salaries	24	50
Energy marketing and risk management liabilities – current portion	18	41
Accrued environmental remediation costs – current portion	10	13
Other current liabilities	106	162
Total current liabilities	1,645	1,666
Accumulated deferred income taxes	566	505
Long-term liabilities (excluding long-term debt)		
Accrued PRP costs	190	202
Accumulated removal costs	169	162
Accrued environmental remediation costs	97	83
Accrued pension obligations	43	78
Accrued postretirement benefit costs	24	32
Other long-term liabilities	152	146
Total long-term liabilities (excluding long-term debt)	675	703
Commitments and contingencies (see Note 7)		
Minority interest	47	42
Capitalization		
Long-term debt	1,674	1,622
Common shareholders' equity, $5 par value; 750 million shares authorized; 76.4 million and 77.7 million shares outstanding at December 31, 2007 and 2006	1,661	1,609
Total capitalization	3,335	3,231
Total liabilities and capitalization	$6,268	$6,147

See Notes to Consolidated Financial Statements.

AGL Resources Inc.
Statements of Consolidated Income

In millions, except per share amounts	Years ended December 31, 2007	2006	2005
Operating revenues	$2,494	$2,621	$2,718
Operating expenses			
Cost of gas	1,369	1,482	1,626
Operation and maintenance	451	473	477
Depreciation and amortization	144	138	133
Taxes other than income taxes	41	40	40
Total operating expenses	2,005	2,133	2,276
Operating income	489	488	442
Other income (expenses)	4	(1)	(1)
Minority interest	(30)	(23)	(22)
Interest expense	(125)	(123)	(109)
Earnings before income taxes	338	341	310
Income taxes	127	129	117
Net income	$211	$212	$193
Per common share data			
Basic earnings per common share	$2.74	$2.73	$2.50
Diluted earnings per common share	$2.72	$2.72	$2.48
Cash dividends declared per common share	$1.64	$1.48	$1.30
Weighted average number of common shares outstanding			
Basic	77.1	77.6	77.3
Diluted	77.4	78.0	77.8

See Notes to Consolidated Financial Statements.

AGL Resources Inc.
Statements of Consolidated Common Shareholders' Equity

In millions, except per share amounts	Common stock Shares	Common stock Amount	Premium on common stock	Earnings reinvested	Other comprehensive loss	Shares held in treasury and trust	Total
Balance as of December 31, 2004	76.7	384	632	415	(46)	-	1,385
Comprehensive income:							
Net income	-	-	-	193	-	-	193
OCI - loss resulting from unfunded pension and postretirement obligation (net of tax of $3)	-	-	-	-	(5)	-	(5)
Unrealized loss from hedging activities (net of tax of $1)	-	-	-	-	(2)	-	(2)
Total comprehensive income							186
Dividends on common stock ($1.30 per share)	-	-	-	(100)	-	-	(100)
Issuance of common shares:							
Benefit, stock compensation, dividend reinvestment and stock purchase plans (net of tax of $9)	1.1	5	23	-	-	-	28
Balance as of December 31, 2005	77.8	389	655	508	(53)	-	1,499
Comprehensive income:							
Net income	-	-	-	212	-	-	212
OCI - gain resulting from unfunded pension and postretirement obligation (net of tax of $7)	-	-	-	-	11	-	11
Unrealized gain from hedging activities (net of tax of $7)	-	-	-	-	10	-	10
Total comprehensive income							233
Dividends on common stock ($1.48 per share)	-	-	1	(115)	-	3	(111)
Benefit, stock compensation, dividend reinvestment and stock purchase plans	0.3	1	2	-	-	-	3
Issuance of treasury shares	0.6	-	(3)	(4)	-	21	14
Purchase of treasury shares	(1.0)	-	-	-	-	(38)	(38)
Stock-based compensation expense (net of tax of $5)	-	-	9	-	-	-	9
Balance as of December 31, 2006	77.7	390	664	601	(32)	(14)	1,609
Comprehensive income:							
Net income	-	-	-	211	-	-	211
OCI - gain resulting from unfunded pension and postretirement obligation (net of tax of $16)	-	-	-	-	24	-	24
Unrealized gain from hedging activities (net of tax of $3)	-	-	-	-	(5)	-	(5)
Total comprehensive income							230
Dividends on common stock ($1.64 per share)	-	-	-	(127)	-	4	(123)
Issuance of treasury shares	0.7	-	(6)	(5)	-	27	16
Purchase of treasury shares	(2.0)	-	-	-	-	(80)	(80)
Stock-based compensation expense (net of tax of $3)	-	-	9	-	-	-	9
Balance as of December 31, 2007	76.4	$390	$667	$680	$(13)	$(63)	$1,661

See Notes to Consolidated Financial Statements.

AGL Resources Inc.
Statements of Consolidated Cash Flows

In millions	Years ended December 31, 2007	2006	2005
Cash flows from operating activities			
Net income	$211	$212	$193
Adjustments to reconcile net income to net cash flow provided by operating activities			
Depreciation and amortization	144	138	133
Change in energy marketing and risk management assets and liabilities	69	(130)	27
Minority interest	30	23	22
Deferred income taxes	30	133	17
Changes in certain assets and liabilities			
Inventories	46	(54)	(211)
Gas, unbilled and other receivables	(15)	170	(170)
Energy marketing receivables and energy marketing trade payables, net	(26)	(95)	93
Accrued expenses	(34)	15	12
Trade payables	(41)	(53)	57
Other – net	(38)	(5)	(93)
Net cash flow provided by operating activities	376	354	80
Cash flows from investing activities			
Expenditures for property, plant and equipment	(259)	(253)	(267)
Sale of Saltville	-	-	66
Other	6	5	7
Net cash flow used in investing activities	(253)	(248)	(194)
Cash flows from financing activities			
Dividends paid on common shares	(123)	(111)	(100)
Purchase of treasury shares	(80)	(38)	-
Payments of trust preferred securities	(75)	(150)	-
Distribution to minority interest	(23)	(22)	(19)
Payments of medium-term notes	(11)	-	-
Issuances of senior notes	125	175	-
Net payments and borrowings of short-term debt	52	6	188
Issuance of treasury shares	16	14	-
Sale of common stock	-	3	28
Other	(3)	5	-
Net cash flow (used in) provided by financing activities	(122)	(118)	97
Net increase (decrease) in cash and cash equivalents	1	(12)	(17)
Cash and cash equivalents at beginning of period	20	32	49
Cash and cash equivalents at end of period	$21	$20	$32
Cash paid during the period for			
Interest	$127	$109	$115
Income taxes	118	37	89

See Notes to Consolidated Financial Statements.

Notes to Consolidated Financial Statements

Note 1 - Accounting Policies and Methods of Application

General

AGL Resources Inc. is an energy services holding company that conducts substantially all its operations through its subsidiaries. Unless the context requires otherwise, references to "we," "us," "our," the "company", or "AGL Resources" mean consolidated AGL Resources Inc. and its subsidiaries. We have prepared the accompanying consolidated financial statements under the rules of the SEC. For a glossary of key terms and referenced accounting standards, see page 4.

Basis of Presentation

Our consolidated financial statements as of and for the period ended December 31, 2007, include our accounts, the accounts of our majority-owned and controlled subsidiaries and the accounts of variable interest entities for which we are the primary beneficiary. This means that our accounts are combined with the subsidiaries' accounts. We have eliminated any intercompany profits and transactions in consolidation; however, we have not eliminated intercompany profits when such amounts are probable of recovery under the affiliates' rate regulation process. Certain amounts from prior periods have been reclassified and revised to conform to the current period presentation.

We currently own a noncontrolling 70% financial interest in SouthStar and Piedmont owns the remaining 30%. Our 70% interest is noncontrolling because all significant management decisions require approval by both owners. We record the earnings allocated to Piedmont as a minority interest in our consolidated statements of income and we record Piedmont's portion of SouthStar's capital as a minority interest in our consolidated balance sheets.

We are the primary beneficiary of SouthStar's activities and have determined that SouthStar is a variable interest entity as defined by FIN 46 revised in December 2003, FIN 46R. We determined that SouthStar was a variable interest entity because our equal voting rights with Piedmont are not proportional to our economic obligation to absorb 75% of any losses or residual returns from SouthStar, except those losses and returns related to customers in Ohio and Florida. Earnings related to SouthStar's customers in Ohio and Florida are allocated 70% to us and 30% to Piedmont. In addition, SouthStar obtains substantially all its transportation capacity for delivery of natural gas through our wholly owned subsidiary, Atlanta Gas Light.

Prior to our sale of Saltville in August 2005, we used the equity method to account for and report our 50% interest in Saltville. Saltville was a joint venture with a subsidiary of Duke Energy Corporate to develop a high-deliverability natural gas storage facility in Saltville, Virginia. We used the equity method because we exercised significant influence over but did not control the entity and because we were not the primary beneficiary as defined by FIN 46R.

Cash and Cash Equivalents

Our cash and cash equivalents consist primarily of cash on deposit, money market accounts and certificates of deposit with original maturities of three months or less.

Receivables and Allowance for Uncollectible Accounts

Our receivables consist of natural gas sales and transportation services billed to residential, commercial, industrial and other customers. We bill customers monthly, and accounts receivable are due within 30 days. For the majority of our receivables, we establish an allowance for doubtful accounts based on our collection experience. On certain other receivables where we are aware of a specific customer's inability or reluctance to pay, we record an allowance for doubtful accounts against amounts due to reduce the net receivable balance to the amount we reasonably expect to collect. However, if circumstances change, our estimate of the recoverability of accounts receivable could be different. Circumstances that could affect our estimates include, but are not limited to, customer credit issues, the level of natural gas prices, customer deposits and general economic conditions. We write off accounts once we deem them to be uncollectible.

Inventories

For our distribution operations subsidiaries, we record natural gas stored underground at weighted average costs. For Sequent and SouthStar, we account for natural gas inventory at the lower of weighted average cost or market.

Sequent and SouthStar evaluate the average cost of their natural gas inventories against market prices to determine whether any declines in market prices below the average cost are other than temporary. For any declines considered to be other than temporary, adjustments are recorded to reduce the weighted average cost of the natural gas inventory to market. Consequently, as a result of declining natural gas prices, Sequent recorded an adjustment against cost

of gas to reduce the value of its inventories to market value of $4 million in 2007, $43 million in 2006 and $3 million in 2005. SouthStar recorded a $6 million adjustment in 2006, but was not required to make a similar adjustment in 2007 or 2005.

For volumes of gas stored under park and loan arrangements that are payable or to be repaid at predetermined dates to third parties, we record the inventory at fair value. Materials and supplies inventories are stated at the lower of average cost or market.

In Georgia's competitive environment, Marketers including SouthStar, our marketing subsidiary, began selling natural gas in 1998 to firm end-use customers at market-based prices. Part of the unbundling process, which resulted from deregulation that provides for this competitive environment, is the assignment to Marketers of certain pipeline services that Atlanta Gas Light has under contract. Atlanta Gas Light assigns, on a monthly basis, the majority of the pipeline storage services that it has under contract to Marketers, along with a corresponding amount of inventory.

Property, Plant and Equipment

A summary of our PP&E by classification as of December 31, 2007 and 2006 is provided in the following table.

In millions	2007	2006
Transmission and distribution	$4,193	$4,047
Storage	285	267
Other	509	454
Construction work in progress	190	208
Total gross PP&E	5,177	4,976
Accumulated depreciation	(1,611)	(1,540)
Total net PP&E	$3,566	$3,436

Distribution Operations PP&E expenditures consist of property and equipment that is in use, being held for future use and under construction. We report PP&E at its original cost, which includes:

- material and labor
- contractor costs
- construction overhead costs
- an allowance for funds used during construction (AFUDC) which represents the estimated cost of funds used to finance the construction of major projects and is capitalized in rate base for ratemaking purposes when the completed projects are placed in service

We charge property retired or otherwise disposed of to accumulated depreciation since such costs are recovered in rates.

Retail Energy Operations, Wholesale Services, Energy Investments and Corporate PP&E expenditures include property that is in use and under construction, and we report it at cost. We record a gain or loss for retired or otherwise disposed-of property. Natural gas in storage at Jefferson Island that is retained as pad gas (volumes of non-working natural gas used to maintain the operational integrity of the cavern facility) is classified as non-depreciable property, plant and equipment and is valued at cost.

Depreciation Expense

We compute depreciation expense for distribution operations by applying composite, straight-line rates (approved by the state regulatory agencies) to the investment in depreciable property. The composite straight-line depreciation rate for depreciable property -- excluding transportation equipment for Atlanta Gas Light, Virginia Natural Gas and Chattanooga Gas -- was approximately 2.5% during 2007, 2.5% during 2006 and 2.6% during 2005. The composite, straight-line rate for Elizabethtown Gas, Florida City Gas and Elkton Gas was approximately 3.2 % for 2007, 3.0% during 2006 and 3.1% in 2005. We depreciate transportation equipment on a straight-line basis over a period of 5 to 10 years. We compute depreciation expense for other segments on a straight-line basis up to 35 years based on the useful life of the asset.

AFUDC

The applicable state regulatory agencies authorize Atlanta Gas Light, Elizabethtown Gas and Chattanooga Gas to record the cost of debt and equity funds as part of the cost of construction projects in our consolidated balance sheets and as AFUDC in the statements of consolidated income. The Georgia Commission has authorized a rate of 8.53%, and the Tennessee Commission has authorized a rate of 7.89%.Prior to January 1, 2007, the Tennessee Commission had authorized a rate of 7.43%. The New Jersey Commission has authorized a variable rate based on the FERC method of accounting for AFUDC. At December 31, 2007 the rate was 5.2%. The total AFUDC for 2007 was $4 million, 2006 was $5 million and 2005 was $4 million. The capital expenditures of our other regulated utilities do not qualify for AFUDC treatment.

Goodwill

We have included $420 million of goodwill in our consolidated balance sheets as of December 31, 2007, of which $229 million is related to our acquisition of NUI in November 2004; $170 million is related to our acquisition of Virginia Natural Gas in 2000; $14 million is related to our acquisition of Jefferson Island in October 2004 and $7 million is related to our acquisition of Chattanooga Gas in 1988.

SFAS 142 requires us to perform an annual goodwill impairment test at a reporting unit level which generally equates to our operating segments as discussed in Note 9 "Segment Information." We have not recognized any impairment charges in 2007, 2006 or 2005. We also assess goodwill for impairment if events or changes in circumstances may indicate an impairment of goodwill exists. When such events or circumstances are present, we assess the recoverability of long-lived assets by determining whether the carrying value will be recovered through the expected future cash flows. In the event the sum of the expected future cash flows resulting from the use of the asset is less than the carrying value of the asset, we record an impairment loss equal to the excess of the asset's carrying value over its fair value. We conduct this assessment principally through a review of financial results, changes in state and federal legislation and regulation, regulatory and legal proceedings and the periodic regulatory filings for our regulated utilities.

Taxes

Income taxes The reporting of our assets and liabilities for financial accounting purposes differs from the reporting for income tax purposes. The principal differences between net income and taxable income relate to the timing of deductions, primarily due to the benefits of tax depreciation since we generally depreciate assets for tax purposes over a shorter period of time than for book purposes. The determination of our provision for income taxes requires significant judgment, the use of estimates, and the interpretation and application of complex tax laws. Significant judgment is required in assessing the timing and amounts of deductible and taxable items. We report the tax effects of depreciation and other differences in those items as deferred income tax assets or liabilities in our consolidated balance sheets in accordance with SFAS 109 and FIN 48. Investment tax credits of approximately $16 million previously deducted for income tax purposes for Atlanta Gas Light, Elizabethtown Gas, Florida City Gas and Elkton Gas have been deferred for financial accounting purposes and are being amortized as credits to income over the estimated lives of the related properties in accordance with regulatory requirements.

State and local taxes We collect and remit various taxes on behalf of various governmental authorities. We record these amounts in our consolidated balance sheets except taxes in the state of Florida which we are required to include in revenues and operating expenses. These Florida related taxes are not material for any periods presented.

Revenues

Distribution operations We record revenues when services are provided to customers. Those revenues are based on rates approved by the state regulatory commissions of our utilities.

As required by the Georgia Commission, in July 1998, Atlanta Gas Light began billing Marketers in equal monthly installments for each residential, commercial and industrial customer's distribution costs. As required by the Georgia Commission, effective February 1, 2001, Atlanta Gas Light implemented a seasonal rate design for the calculation of each residential customer's annual straight-fixed-variable (SFV) capacity charge, which is billed to Marketers and reflects the historic volumetric usage pattern for the entire residential class. Generally, this change results in residential customers being billed by Marketers for a higher capacity charge in the winter months and a lower charge in the summer months. This requirement has an operating cash flow impact but does not change revenue recognition. As a result, Atlanta Gas Light continues to recognize its residential SFV capacity revenues for financial reporting purposes in equal monthly installments.

Any difference between the billings under the seasonal rate design and the SFV revenue recognized is deferred and reconciled to actual billings on an annual basis. Atlanta Gas Light had unrecovered seasonal rates of approximately $11 million as of December 31, 2007 and 2006 (included as current assets in the consolidated balance sheets) related to the difference between the billings under the seasonal rate design and the SFV revenue recognized.

The Elizabethtown Gas, Virginia Natural Gas, Florida City Gas, Chattanooga Gas and Elkton Gas rate structures include volumetric rate designs that allow recovery of costs through gas usage. Revenues from sales and transportation services are recognized in the same period in which the related volumes are delivered to customers. Revenues from residential and certain commercial and industrial customers are recognized on the basis of scheduled meter readings. In addition, revenues are recorded for

estimated deliveries of gas not yet billed to these customers, from the last meter reading date to the end of the accounting period. These are included in the consolidated balance sheets as unbilled revenue. For other commercial and industrial customers and all wholesale customers, revenues are based on actual deliveries to the end of the period.

The tariffs for Elizabethtown Gas, Virginia Natural Gas and Chattanooga Gas contain WNA's that partially mitigate the impact of unusually cold or warm weather on customer billings and operating margin. The WNA's purpose is to reduce the effect of weather on customer bills by reducing bills when winter weather is colder than normal and increasing bills when weather is warmer than normal.

Retail energy operations We record retail energy operations' revenues when services are provided to customers. Revenues from sales and transportation services are recognized in the same period in which the related volumes are delivered to customers. Sales revenues from residential and certain commercial and industrial customers are recognized on the basis of scheduled meter readings. In addition, revenues are recorded for estimated deliveries of gas not yet billed to these customers, from the most recent meter reading date to the end of the accounting period. These are included in the consolidated balance sheets as unbilled revenue. For other commercial and industrial customers and all wholesale customers, revenues are based on actual deliveries to the end of the period.

Wholesale services We record wholesale services' revenues when services are provided to customers. Profits from sales between segments are eliminated in the corporate segment and are recognized as goods or services sold to end-use customers. Transactions that qualify as derivatives under SFAS 133 are recorded at fair value with changes in fair value recognized in earnings in the period of change and characterized as unrealized gains or losses.

Energy investments We record operating revenues at Jefferson Island in the period in which actual volumes are transported and storage services are provided. The majority of our storage services are covered under medium to long-term contracts at a fixed market rate.

We record operating revenues at AGL Networks from leases of dark fiber pursuant to indefeasible rights-of-use (IRU) agreements as services are provided. Dark fiber IRU agreements generally require the customer to make a down payment upon execution of the agreement; however in some cases AGL Networks receives up to the entire lease payment at the inception of the lease and recognizes ratably over the lease term. AGL Networks had deferred revenue in our consolidated balance sheet of $38 million at December 31, 2007 and $37 million at December 31, 2006. In addition, AGL Networks recognizes sales revenues upon the execution of certain sales-type agreements for dark fiber when the agreements provide for the transfer of legal title to the dark fiber to the customer at the end of the agreement's term. This sales-type accounting treatment is in accordance with EITF 00-11 and SFAS 66, which provides that such transactions meet the criteria for sales-type lease accounting if the agreement obligates the lessor to convey ownership of the underlying asset to the lessee by the end of the lease term.

Cost of gas

Excluding Atlanta Gas Light, we charge our utility customers for natural gas consumed using PGA mechanisms set by the state regulatory agencies. Under the PGA, we defer (that is, include as a current asset or liability in the consolidated balance sheets and exclude from the statements of consolidated income) the difference between the actual cost of gas and what is collected from or billed to customers in a given period. The deferred amount is either billed or refunded to our customers prospectively through adjustments to the commodity rate.

Our retail energy operations customers are charged for natural gas consumed. We also include within our cost of gas amounts for fuel and lost and unaccounted for gas, adjustments to reduce the value of our inventories to market value and for gains and losses associated with derivatives.

Comprehensive Income

Our comprehensive income includes net income plus OCI, which includes other gains and losses affecting shareholders' equity that GAAP excludes from net income. Such items consist primarily of unrealized gains and losses on certain derivatives designated as cash flow hedges and overfunded or unfunded pension obligation adjustments. The following table illustrates our OCI activity during 2007, 2006 and 2005.

In millions	2007	2006	2005
Cash flow hedges:			
Net derivative unrealized gains arising during the period (net of $7 and $3 in taxes)	$-	$11	$5
Less reclassification of realized gains included in income (net of $3, $1 and $4 in taxes)	(5)	(1)	(7)
Over funded (unfunded) pension obligation (net of $16, $7 and $3 in taxes)	24	11	(5)
Total	$19	$21	$(7)

Earnings Per Common Share

We compute basic earnings per common share by dividing our income available to common shareholders by the daily weighted average number of common shares outstanding. Diluted earnings per common share reflect the potential reduction in earnings per common share that could occur when potentially dilutive common shares are added to common shares outstanding.

We derive our potentially dilutive common shares by calculating the number of shares issuable under restricted stock, restricted stock units and stock options. The future issuance of shares underlying the restricted stock and restricted stock units depends on the satisfaction of certain performance criteria. The future issuance of shares underlying the outstanding stock options depends on whether the exercise prices of the stock options are less than the average market price of the common shares for the respective periods. There were no material antidilutive options in 2007, 2006 or 2005. The following table shows the calculation of our diluted earnings per share for the periods presented if performance units currently earned under the plan ultimately vest and if stock options currently exercisable at prices below the average market prices are exercised.

In millions	2007	2006	2005
Denominator for basic earnings per share (1)	77.1	77.6	77.3
Assumed exercise of potential common shares	0.3	0.4	0.5
Denominator for diluted earnings per share	77.4	78.0	77.8

(1) Daily weighted average shares outstanding.

Regulatory Assets and Liabilities

We have recorded regulatory assets and liabilities in our consolidated balance sheets in accordance with SFAS 71. Our regulatory assets and liabilities, and associated liabilities for our unrecovered PRP costs, unrecovered ERC and the associated assets and liabilities for our Elizabethtown Gas hedging program, are summarized in the following table.

In millions	December 31, 2007	2006
Regulatory assets		
Unrecovered PRP costs	$285	$274
Unrecovered ERC (1)	158	170
Elizabethtown Gas hedging program	-	16
Unrecovered postretirement benefit costs	12	13
Unrecovered seasonal rates	11	11
Unrecovered PGA	23	14
Other	23	20
Total regulatory assets	512	518
Associated assets		
Elizabethtown Gas hedging program	4	-
Total regulatory and associated assets	$516	$518
Regulatory liabilities		
Accumulated removal costs	$169	$162
Elizabethtown Gas hedging program	4	-
Unamortized investment tax credit	16	18
Deferred PGA	28	24
Regulatory tax liability	20	22
Other	19	18
Total regulatory liabilities	256	244
Associated liabilities		
PRP costs	245	237
ERC (1)	96	87
Elizabethtown Gas hedging program	-	16
Total associated liabilities	341	340
Total regulatory and associated liabilities	$597	$584

(1) For a discussion of ERC, see Note 7.

Our regulatory assets are recoverable through either rate riders or base rates specifically authorized by a state regulatory commission. Base rates are designed to provide both a recovery of cost and a return on investment during the period rates are in effect. As such, all our regulatory assets are subject to review by the respective state regulatory commission during any future rate proceedings. In the event that the provisions of SFAS 71 were no longer applicable, we would recognize a write-off of net regulatory assets (regulatory assets less regulatory liabilities) that would result in a charge to net income, and be classified as an extraordinary item. Although the natural gas distribution industry is becoming increasingly competitive, our utility operations continue to recover their costs through cost-based rates established by the state regulatory commissions. As a result, we believe that the accounting prescribed under SFAS 71 remains appropriate. It is also our opinion that all regulatory assets are recoverable in future rate proceedings, and therefore we have not recorded any regulatory assets that are recoverable but are not yet included in base rates or contemplated in a rate rider.

All the regulatory assets included in the preceding table are included in base rates except for the unrecovered PRP costs, unrecovered ERC and the deferred PGA, which are recovered through specific rate riders on a dollar for dollar basis. The rate riders that authorize recovery of unrecovered PRP costs and the deferred PGA include both a recovery of costs and a return on investment during the recovery period. We have two rate riders that authorize the recovery of unrecovered ERC. The ERC rate rider for Atlanta Gas Light only allows for recovery of the costs incurred and the recovery period occurs over the five years after the expense is incurred. ERC associated with the investigation and remediation of Elizabethtown Gas remediation sites located in the state of New Jersey are recovered under a remediation adjustment clause and include the carrying cost on unrecovered amounts not currently in rates. Elizabethtown Gas' hedging program asset and liability reflect unrealized losses or gains that will be recovered from or passed to rate payers through the PGA on a dollar for dollar basis, once the losses or gains are realized. Unrecovered postretirement benefit costs are recoverable through base rates over the next 6 to 25 years based on the remaining recovery period as designated by the applicable state regulatory commissions. Unrecovered seasonal rates reflect the difference between the recognition of a portion of Atlanta Gas Light's residential base rates revenues on a straight-line basis as compared to the collection of the revenues over a seasonal pattern. The unrecovered amounts are fully recoverable through base rates within one year.

The regulatory liabilities are refunded to ratepayers through a rate rider or base rates. If the regulatory liability is included in base rates, the amount is reflected as a reduction to the rate base in setting rates.

Pipeline Replacement Program

Atlanta Gas Light The PRP, ordered by the Georgia Commission to be administered by Atlanta Gas Light, requires, among other things, that Atlanta Gas Light replace all bare steel and cast iron pipe in its system in the state of Georgia within a 10-year period beginning October 1, 1998. Atlanta Gas Light identified, and provided notice to the Georgia Commission of 2,312 miles of pipe to be replaced. Atlanta Gas Light has subsequently identified an additional 320 miles of pipe subject to replacement under this program. If Atlanta Gas Light does not perform in accordance with this order, it will be assessed certain nonperformance penalties.

The order also provides for recovery of all prudent costs incurred in the performance of the program, which Atlanta Gas Light has recorded as a regulatory asset. Atlanta Gas Light will recover from end-use customers, through billings to Marketers, the costs related to the program net of any cost savings from the program. All such amounts will be recovered through a combination of straight fixed variable rates and a pipeline replacement revenue rider. The regulatory asset has two components:

- the costs incurred to date that have not yet been recovered through the rate rider
- the future expected costs to be recovered through the rate rider

On June 10, 2005, Atlanta Gas Light and the Georgia Commission entered into a Settlement Agreement that, among other things, extends Atlanta Gas Light's PRP by five years to require that all replacements be completed by December 2013. The timing of replacements was subsequently specified in an amendment to the PRP stipulation. This amendment, which was approved by the Georgia Commission on December 20, 2005, requires Atlanta Gas Light to replace all cast iron pipe and 70% of all bare steel pipe by December 2010. The remaining 30% of bare steel pipe is required to be replaced by December 2013.

Under the Settlement Agreement, base rates charged to customers will remain unchanged through April 30, 2010, but Atlanta Gas Light will recognize reduced base rate revenues of $5 million on an annual basis through April 30, 2010. The five-year total reduction in recognized base rate revenues of $25 million will be applied to the allowed amount of costs incurred to replace pipe, which will reduce the amounts recovered from customers under the PRP rider. The Settlement Agreement also set the per customer fixed PRP rate that Atlanta Gas Light will charge at $1.29 per customer per month from May 2005 through September 2008 and at $1.95 from October 2008 through December 2013 and includes a provision that allows for a true-up of any over- or under-recovery of PRP revenues that may result from a difference between PRP charges collected through fixed rates and actual PRP revenues recognized through the remainder of the program.

The Settlement Agreement also allows Atlanta Gas Light to recover through the PRP $4 million of the $32 million capital costs associated with its March 2005 purchase of 250 miles of pipeline in central Georgia from Southern Natural Gas Company, a subsidiary of El Paso Corporation. The remaining capital costs are included in Atlanta Gas Light's rate base and collected through base rates.

Atlanta Gas Light has recorded a long-term regulatory asset of $254 million, which represents the expected future collection of both expenditures already incurred and expected future capital

expenditures to be incurred through the remainder of the program. Atlanta Gas Light has also recorded a current asset of $31 million, which represents the expected amount to be collected from customers over the next 12 months. The amounts recovered from the pipeline replacement revenue rider during the last three years were:

- $27 million in 2007
- $27 million in 2006
- $26 million in 2005

As of December 31, 2007, Atlanta Gas Light had recorded a current liability of $55 million, representing expected program expenditures for the next 12 months and a long-term liability of $190 million, representing expected program expenditures starting in 2009 through the end of the program in 2013.

Atlanta Gas Light capitalizes and depreciates the capital expenditure costs incurred from the PRP over the life of the assets. Operation and maintenance costs are expensed as incurred. Recoveries, which are recorded as revenue, are based on a formula that allows Atlanta Gas Light to recover operation and maintenance costs in excess of those included in its current base rates, depreciation expense and an allowed rate of return on capital expenditures. In the near term, the primary financial impact to Atlanta Gas Light from the PRP is reduced cash flow from operating and investing activities, as the timing related to cost recovery does not match the timing of when costs are incurred. However, Atlanta Gas Light is allowed the recovery of carrying costs on the under-recovered balance resulting from the timing difference.

Elizabethtown Gas In August 2006, the New Jersey Commission issued an order adopting a pipeline replacement cost recovery rider program for the replacement of certain 8" cast iron main pipes and any unanticipated 10"-12" cast iron main pipes integral to the replacement of the 8" main pipes. The order allows Elizabethtown Gas to recognize revenues under a deferred recovery mechanism for costs to replace the pipe that exceeds a baseline amount of $3 million. Elizabethtown Gas' recognition of these revenues could be disallowed by the New Jersey Commission if its return on equity exceeds the authorized rate of 10%. The term of the stipulation is from the date of the order through December 31, 2008. Total replacement costs through December 31, 2008 are expected to be $17 million, of which $14 million will be eligible for the deferred recovery mechanism. Revenues recognized and deferred for recovery under the stipulation are estimated to be approximately $1 million. All costs incurred under the program will be included in Elizabethtown Gas' next rate case to be filed in 2009.

Use of Accounting Estimates

The preparation of our financial statements in conformity with GAAP requires us to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses and the related disclosures of contingent assets and liabilities. We based our estimates on historical experience and various other assumptions that we believe to be reasonable under the circumstances, and we evaluate our estimates on an ongoing basis. Each of our estimates involve complex situations requiring a high degree of judgment either in the application and interpretation of existing literature or in the development of estimates that impact our financial statements. The most significant estimates include our PRP accruals, environmental liability accruals, uncollectible accounts and other allowance for contingencies, pension and postretirement obligations, derivative and hedging activities and provision for income taxes. Our actual results could differ from our estimates.

Accounting Developments

SFAS 157 In September 2006, the FASB issued SFAS 157, which establishes a framework for measuring fair value and requires expanded disclosures regarding fair value measurements. SFAS 157 does not require any new fair value measurements. However, it eliminates inconsistencies in the guidance provided in previous accounting pronouncements.

SFAS 157 is effective for financial statements issued for fiscal years beginning after November 15, 2007, and interim periods within those fiscal years. Earlier application is encouraged, provided that the reporting entity has not yet issued financial statements for that fiscal year, including financial statements for an interim period within that fiscal year. All valuation adjustments will be recognized as cumulative-effect adjustments to the opening balance of retained earnings for the fiscal year in which SFAS 157 is initially applied. In December 2007, the FASB provided a one year deferral of SFAS 157 for nonfinancial assets and nonfinancial liabilities, except those that are recognized or disclosed at fair value on a recurring basis, at least annually. We will adopt SFAS 157 on January 1, 2008, for our financial assets and liabilities, which primarily consists of derivatives we record in accordance with SFAS 133, and on January 1, 2009, for our non-financial assets and liabilities. For our financial assets and liabilities, we expect that our adoption of SFAS 157 will primarily impact our disclosures and not have a material impact on our consolidated results of operations, cash flows and financial position. We are currently evaluating the impact with respect to our non-financial assets and liabilities.

SFAS 159 In February 2007, the FASB issued SFAS 159 which is effective for fiscal years beginning after November 15, 2007 but is not required to be adopted. SFAS 159 establishes a framework for measuring fair value for eligible financial assets and liabilities with the intention of reducing earnings volatility. We currently have no financial assets or liabilities eligible for this treatment and have no plans to adopt SFAS 159.

SFAS 160 In December 2007, the FASB issued SFAS 160, which is effective for fiscal years beginning after December 15, 2008. Early adoption is prohibited. SFAS 160 will require us to present our minority interest, now to be referred to as a noncontrolling interest, separately within the capitalization section of our consolidated balance sheet. We will adopt SFAS 160 as of January 1, 2009.

FIN 39 was issued in March 1992 and provides guidance related to offsetting payable and receivable amounts related to certain contracts, including derivative contracts. It was effective for financial statements issued for periods beginning after December 15, 1993.

FSP FIN 39-1 was issued in April 2007 and is effective for us on January 1, 2008. FIN 39-1 amends FIN 39 and allows a company to elect to report certain derivative assets and liabilities subject to master netting agreements on either a gross basis or net basis on the balance sheet. The guidance also addresses reporting of collateral amounts relating to the netting agreements. We enter into derivative contracts, but FSP FIN 39-1 will not have a material effect on our consolidated financial condition.

Note 2 – Financial Instruments and Risk Management

Financial Instruments

The carrying value of cash and cash equivalents, receivables, accounts payable, other current liabilities, derivative assets, derivative liabilities and accrued interest approximate fair value. The following table shows the carrying amounts and fair values of our long-term debt including any current portions included in our consolidated balance sheets.

In millions	Carrying amount (1)	Estimated fair value
As of December 31, 2007	$1,674	$1,710
As of December 31, 2006	1,633	1,716

(1) Includes $11 million of medium-term notes reported as short-term debt in our December 31, 2006, consolidated balance sheets.

The estimated fair values are determined based on interest rates that are currently available for issuance of debt with similar terms and remaining maturities. Considerable judgment is required to develop the fair value estimates; therefore, the values are not necessarily indicative of the amounts that could be realized in a current market exchange. The fair value estimates are based on information available to management as of December 31, 2007.

Risk Management

Our risk management activities are monitored by our Risk Management Committee (RMC). The RMC consists of members of senior management and is charged with reviewing and enforcing our risk management activities. Our risk management policies limit the use of derivative financial instruments and physical transactions within predefined risk tolerances associated with pre-existing or anticipated physical natural gas sales and purchases and system use and storage. We use the following derivative financial instruments and physical transactions to manage commodity price, interest rate, weather and foreign currency risks:

- forward contracts
- futures contracts
- options contracts
- financial swaps
- treasury locks
- weather derivative contracts
- storage and transportation capacity transactions
- foreign currency forward contracts

Interest Rate Swaps

To maintain an effective capital structure, our policy is to borrow funds using a mix of fixed-rate and variable-rate debt. We entered into interest rate swap agreements for the purpose of managing the appropriate mix of risk associated with our fixed-rate and variable-rate debt obligations. We designated these interest rate swaps as fair value hedges in accordance with SFAS 133. We record the gain or loss on fair value hedges in earnings in the period of change, together with the offsetting loss or gain on the hedged item attributable to the interest rate risk being hedged.

As of December 31, 2007, a notional principal amount of $100 million of these interest rate swap agreements effectively converted the interest expense associated with a portion of our senior notes from fixed rates to variable rates based on an interest rate equal to the LIBOR plus a 3.4% spread. The floating rate for our interest rate swap as of December 31, 2007 was 8.8% and was 9.0% as of December 31, 2006. The fair values of our interest

rate swaps were reflected as a long-term liability of $2 million at December 31, 2007, and $6 million at December 31, 2006. For more information on our senior notes, see Note 6.

Treasury Locks

In August 2007, we executed a treasury-lock agreement covering a notional amount totaling $125 million to hedge the interest rate risk associated with our $125 million senior notes offering in December 2007. The 10-year treasury interest rate was locked in at a weighted average rate of 4.5%.

In December 2007, this treasury-lock agreement settled and we paid $5 million with our $125 million senior note issuance. The $5 million is included in our OCI, net of $2 million of income taxes, and will be amortized over the remaining life of the senior notes (through July 2016) as interest expense.

Commodity-related Derivative Instruments

Elizabethtown Gas In accordance with a directive from the New Jersey Commission, Elizabethtown Gas enters into derivative transactions to hedge the impact of market fluctuations in natural gas prices. Pursuant to SFAS 133, such derivative transactions are marked to market each reporting period. In accordance with regulatory requirements, realized gains and losses related to these derivatives are reflected in purchased gas costs and ultimately included in billings to customers. As of December 31, 2007, Elizabethtown Gas had entered into NYMEX futures contracts to purchase approximately 1.2 Bcf of natural gas and over the counter swap contracts with 3 counterparties to purchase approximately 8.1 Bcf of natural gas. Approximately 84% of these contracts have durations of one year or less, and none of these contracts extends beyond October 2009. The fair values of these derivative instruments were reflected as a current asset and liability of $4 million at December 31, 2007 and $16 million at December 31, 2006. For more information on our regulatory assets and liabilities see Note 1.

SouthStar Commodity-related derivative financial instruments (futures, options and swaps) are used by SouthStar to manage exposures arising from changing commodity prices. SouthStar's objective for holding these derivatives is to utilize the most effective method to reduce or eliminate the impact of this exposure. We have designated a portion of SouthStar's derivative transactions as cash flow hedges under SFAS 133. We record derivative gains or losses arising from cash flow hedges in OCI and reclassify them into earnings in the same period as the settlement of the underlying hedged item. We record any hedge ineffectiveness, defined as when the gains or losses on the hedging instrument do not offset and are greater than the losses or gains on the hedged item, in cost of gas in our statement of consolidated income in the period in which it occurs. SouthStar currently has minimal hedge ineffectiveness. We have not designated the remainder of SouthStar's derivative instruments as hedges under SFAS 133 and, accordingly, we record changes in their fair value in earnings in the period of change.

At December 31, 2007, the fair values of these derivatives were reflected in our consolidated financial statements as a current asset of $12 million and a current liability of $2 million representing a net position of 0.1 Bcf.

SouthStar also enters into both exchange and over-the-counter derivative transactions to hedge commodity price risk. Credit risk is mitigated for exchange transactions through the backing of the NYMEX member firms. For over-the-counter transactions, SouthStar utilizes master netting arrangements to reduce overall credit risk. As of December 31, 2007, SouthStar's maximum exposure to any single over-the-counter counterparty was $14 million.

Sequent We are exposed to risks associated with changes in the market price of natural gas. Sequent uses derivative financial instruments to reduce our exposure to the risk of changes in the prices of natural gas. The fair value of these derivative financial instruments reflects the estimated amounts that we would receive or pay to terminate or close the contracts at the reporting date, taking into account the current unrealized gains or losses on open contracts. We use external market quotes and indices to value substantially all the financial instruments we use.

We mitigate substantially all the commodity price risk associated with Sequent's natural gas portfolio by locking in the economic margin at the time we enter into natural gas purchase transactions for our stored natural gas. We purchase natural gas for storage when the difference in the current market price we pay to buy and transport natural gas plus the cost to store the natural gas is less than the market price we can receive in the future, resulting in a positive net operating margin. We use NYMEX futures contracts and other over-the-counter derivatives to sell natural gas at that future price to substantially lock in the operating margin we will ultimately realize when the stored natural gas is actually sold. These futures contracts meet the definition of derivatives under SFAS 133 and are recorded at fair value and marked to market in our consolidated balance sheets, with changes in fair value recorded in earnings in the period of change. The purchase, transportation, storage and sale of natural gas are accounted for on

a weighted average cost or accrual basis, as appropriate rather than on the mark-to-market basis we utilize for the derivatives used to mitigate the commodity price risk associated with our storage portfolio. This difference in accounting can result in volatility in our reported earnings, even though the economic margin is essentially unchanged from the date the transactions were consummated.

At December 31, 2007, Sequent's commodity-related derivative financial instruments represented purchases (long) of 605 Bcf and sales (short) of 576 Bcf with approximately 91% of purchase instruments and 93% of the sales instruments are scheduled to mature in less than 2 years and the remaining 9% and 7%, respectively, in 3 to 9 years. At December 31, 2007, the fair values of these derivatives were reflected in our consolidated financial statements as an asset of $70 million and a liability of $13 million. Sequent recorded net unrealized losses related to changes in the fair value of derivative instruments utilized in its energy marketing and risk management activities and contract settlement of $62 million during 2007, $132 million of unrealized gains during 2006 and $30 million of unrealized losses during 2005.

Weather Derivatives

In 2007 and 2006, SouthStar entered into weather derivative contracts as economic hedges of operating margins in the event of warmer-than-normal weather in the heating season, primarily from November through March. SouthStar accounts for these contracts using the intrinsic value method under the guidelines of EITF 99-02. SouthStar recorded current assets for this hedging activity of $5 million at December 31, 2007 and $7 million at December 31, 2006.

Concentration of Credit Risk

Atlanta Gas Light Concentration of credit risk occurs at Atlanta Gas Light for amounts billed for services and other costs to its customers, which consist of 12 Marketers in Georgia. The credit risk exposure to Marketers varies seasonally, with the lowest exposure in the nonpeak summer months and the highest exposure in the peak winter months. Marketers are responsible for the retail sale of natural gas to end-use customers in Georgia. These retail functions include customer service, billing, collections, and the purchase and sale of natural gas. Atlanta Gas Light's tariff allows it to obtain security support in an amount equal to a minimum of two times a Marketer's highest month's estimated bill from Atlanta Gas Light.

Wholesale Services Sequent has a concentration of credit risk for services it provides to marketers and to utility and industrial counterparties. This credit risk is measured by 30-day receivable exposure plus forward exposure, which is generally concentrated in 20 of its counterparties. Sequent evaluates the credit risk of its counterparties using a S&P equivalent credit rating, which is determined by a process of converting the lower of the S&P or Moody's rating to an internal rating ranging from 9.00 to 1.00, with 9.00 being equivalent to AAA/Aaa by S&P and Moody's and 1.00 being equivalent to D or Default by S&P and Moody's. For a customer without an external rating, Sequent assigns an internal rating based on Sequent's analysis of the strength of its financial ratios. At December 31, 2007, Sequent's top 20 counterparties represented approximately 53% of the total credit exposure of $366 million, derived by adding together the top 20 counterparties' exposures and dividing by the total of Sequent's counterparties' exposures. Sequent's counterparties or the counterparties' guarantors had a weighted average S&P equivalent rating of A- at December 31, 2007.

The weighted average credit rating is obtained by multiplying each customer's assigned internal rating by its credit exposure and then adding the individual results for all counterparties. That total is divided by the aggregate total exposure. This numeric value is converted to an S&P equivalent.

Sequent has established credit policies to determine and monitor the creditworthiness of counterparties, including requirements for posting of collateral or other credit security, as well as the quality of pledged collateral. Collateral or credit security is most often in the form of cash or letters of credit from an investment-grade financial institution, but may also include cash or U.S. Government Securities held by a trustee. When Sequent is engaged in more than one outstanding derivative transaction with the same counterparty and it also has a legally enforceable netting agreement with that counterparty, the "net" mark-to-market exposure represents the netting of the positive and negative exposures with that counterparty and a reasonable measure of Sequent's credit risk. Sequent also uses other netting agreements with certain counterparties with which it conducts significant transactions.

All activities associated with price risk management activities and derivative instruments are included as a component of cash flows from operating activities in our consolidated statements of cash flows. Our derivatives not designated as hedges under SFAS 133, included within operating cash flows as a source (use) of cash was $62 million in 2007, $(132) million in 2006, and $30 million in 2005.

Note 3 - Employee Benefit Plans

Pension Benefits

We sponsor two tax-qualified defined benefit retirement plans for our eligible employees, the AGL Resources Inc. Retirement Plan (AGL Retirement Plan) and the Employees' Retirement Plan of NUI Corporation (NUI Retirement Plan). A defined benefit plan specifies the amount of benefits an eligible participant eventually will receive using information about the participant.

We generally calculate the benefits under the AGL Retirement Plan based on age, years of service and pay. The benefit formula for the AGL Retirement Plan is a career average earnings formula, except for participants who were employees as of July 1, 2000, and who were at least 50 years of age as of that date. For those participants, we use a final average earnings benefit formula, and will continue to use this benefit formula for such participants until June 2010, at which time any of those participants who are still active will accrue future benefits under the career average earnings formula.

The NUI Retirement Plan covers substantially all of NUI's employees who were employed on or before December 31, 2005, except Florida City Gas union employees, who participate in a union-sponsored multiemployer plan. Pension benefits are based on years of credited service and final average compensation.

Effective with our acquisition of NUI in November 2004, we became sponsor of the NUI Retirement Plan. Throughout 2005, we maintained existing benefits for NUI employees, including participation in the NUI Retirement Plan. Beginning in 2006, eligible participants in the NUI Retirement Plan became eligible to participate in the AGL Retirement Plan and the benefits of those participants under the NUI Retirement Plan were frozen as of December 31, 2005, resulting in a $15 million reduction to the NUI Retirement Plan's projected benefit obligation as of December 31, 2005. Participants in the NUI Retirement Plan have the option of receiving a lump sum distribution upon retirement for all benefits earned through December 31, 2005. This resulted in settlement payments of $12 million and an immaterial settlement loss. This option is not permitted under the AGL Retirement Plan, except for accrued benefits valued at less than $10,000.

SFAS 158 In September 2006, the FASB issued SFAS 158, which we adopted prospectively on December 31, 2006. SFAS 158 requires that we recognize all obligations related to defined benefit pensions and other postretirement benefits. This statement requires that we quantify the plans' funding status as an asset or a liability on our consolidated balance sheets.

SFAS 158 further requires that we measure the plans' assets and obligations that determine our funded status as of the end of the fiscal year. We are also required to recognize as a component of OCI the changes in funded status that occurred during the year that are not recognized as part of net periodic benefit cost as explained in SFAS 87, or SFAS 106.

Based on the funded status of our defined benefit pension and postretirement benefit plans as of December 31, 2007, we reported a gain to our OCI of $24 million, a net decrease of $40 million to accrued pension and postretirement obligations and an increase of $16 million to accumulated deferred income taxes. Our adoption of SFAS 158 on December 31, 2006, had no impact on our earnings. The following tables present details about our pension plans.

In millions	AGL Retirement Plan Dec. 31, 2007	AGL Retirement Plan Dec. 31, 2006	NUI Retirement Plan Dec. 31, 2007	NUI Retirement Plan Dec. 31, 2006
Change in benefit obligation				
Benefit obligation at beginning of year	$368	$359	$86	$105
Service cost	7	7	-	-
Interest cost	21	20	5	5
Settlement loss	-	-	-	1
Settlement payments	-	-	-	(12)
Actuarial loss (gain)	(23)	2	(9)	(7)
Benefits paid	(20)	(20)	(8)	(6)
Benefit obligation at end of year	$353	$368	$74	$86
Change in plan assets				
Fair value of plan assets at beginning of year	$303	$286	$72	$85
Actual return on plan assets	30	31	6	4
Employer contribution	-	6	-	1
Settlement payments	-	-	-	(12)
Benefits paid	(20)	(20)	(8)	(6)
Fair value of plan assets at end of year	$313	$303	$70	$72
Amounts recognized in the statement of financial position consist of				
Prepaid benefit cost	$-	$-	$-	$-
Accrued benefit liability	(40)	(65)	(4)	(14)
Accumulated OCI	-	-	-	-
Net amount recognized at year end (1)	$(40)	$(65)	$(4)	$(14)

(1) As of December 31, 2007, the AGL Retirement Plan had current liabilities of $1 million, noncurrent liabilities of $39 million and no noncurrent assets. The NUI Retirement Plan had $4 million of noncurrent liabilities and no noncurrent assets or current liabilities. As of December 31, 2006, the AGL Retirement Plan had current liabilities of $1 million, non-current liabilities of $64 million and no non-current assets. The NUI Retirement Plan had $14 million of non-current liabilities and non-current assets or current liabilities as of December 31, 2006.

The accumulated benefit obligation (ABO) and other information for the AGL Retirement Plan and the NUI Retirement Plan are set forth in the following table.

In millions	AGL Retirement Plan Dec. 31, 2007	AGL Retirement Plan Dec. 31, 2006	NUI Retirement Plan Dec. 31, 2007	NUI Retirement Plan Dec. 31, 2006
Projected benefit obligation	$353	$368	$74	$86
ABO	337	352	74	86
Fair value of plan assets	313	303	70	72
Increase in minimum liability included in OCI	n/a	13	n/a	-
Components of net periodic benefit cost				
Service cost	$7	$7	$-	$-
Interest cost	21	20	5	5
Expected return on plan assets	(25)	(24)	(6)	(7)
Net amortization	(1)	(1)	(1)	(1)
Recognized actuarial loss	7	9	-	-
Net annual pension cost	$9	$11	$(2)	$(3)

There were no other changes in plan assets and benefit obligations recognized for the AGL and NUI Retirement Plans for the year ended December 31, 2007.

The 2008 estimated OCI amortization and expected refunds for the AGL and NUI Retirement Plans are set forth in the following table.

In millions	Retirement Plan AGL	Retirement Plan NUI
Amortization of transition obligation	$-	$-
Amortization of prior service cost	(1)	(1)
Amortization of net loss	3	-
Refunds expected	-	-

The following table sets forth the assumed weighted average discount rates and rates of compensation increase used to determine benefit obligations at December 31.

	AGL and NUI Retirement Plans	
	2007	2006
Discount rate	6.4%	5.8%
Rate of compensation increase	3.7%	4.0%

We consider a number of factors in determining and selecting assumptions for the overall expected long-term rate of return on plan assets. We consider the historical long-term return experience of our assets, the current and expected allocation of our plan assets, and expected long-term rates of return. We derive these expected long-term rates of return with the assistance of our investment advisors and generally base these rates on a 10-year horizon for various asset classes, our expected investments of plan assets and active asset management as opposed to investment in a passive index fund. We base our expected allocation of plan assets on a diversified portfolio consisting of domestic and international equity securities, fixed income, real estate, private equity securities and alternative asset classes.

The following tables present the assumed weighted average discount rate, expected return on plan assets and rate of compensation increase used to determine net periodic benefit cost at the beginning of the period, which was January 1.

	AGL Retirement Plan		
	2007	2006	2005
Discount rate	5.8%	5.5%	5.8%
Expected return on plan assets	9.0%	8.8%	8.8%
Rate of compensation increase	3.7%	4.0%	4.0%

	NUI Retirement Plan		
	2007	2006	2005
Discount rate	5.8%	5.5%	5.8%
Expected return on plan assets	9.0%	8.8%	8.5%
Rate of compensation increase	-%	-%	4.0%

We consider a variety of factors in determining and selecting our assumptions for the discount rate at December 31. We consider certain market indices, including Moody's Corporate AA long-term bond rate, the Citigroup Pension Liability rate our actuaries model and our own payment stream based on these indices to develop our rate. Consequently, we selected a discount rate of 6.4% as of December 31, 2007, following our review of these various factors.

Our actual retirement plans' weighted average asset allocations at December 31, 2007 and 2006 and our target asset allocation ranges are as follows:

	Target Range Asset Allocation	AGL Retirement Plan	
		2007	2006
Equity	30%-80%	68%	67%
Fixed income	10%-40%	25%	25%
Real estate and other	10%-35%	3%	8%
Cash	0%-10%	4%	-

	Target Range Asset Allocation	NUI Retirement Plan	
		2007	2006
Equity	30%-80%	71%	68%
Fixed income	10%-40%	27%	26%
Real estate and other	10%-35%	2%	3%
Cash	0%-10%	-%	3%

The Retirement Plan Investment Committee (the Committee) appointed by our Board of Directors is responsible for overseeing the investments of the retirement plans. Further, we have an Investment Policy (the Policy) for the retirement plans that aims to preserve the retirement plans' capital and maximize investment earnings in excess of inflation within acceptable levels of capital market volatility. To accomplish this goal, the retirement plans' assets are actively managed to optimize long-term return while maintaining a high standard of portfolio quality and proper diversification.

The Policy's risk management strategy establishes a maximum tolerance for risk in terms of volatility to be measured at 75% of the volatility experienced by the S&P 500. We will continue to diversify retirement plan investments to minimize the risk of large losses in a single asset class. The Policy's permissible investments include domestic and international equities (including convertible securities and mutual funds), domestic and international fixed income (corporate and U.S. government obligations), cash and cash equivalents and other suitable investments. The asset mix of these permissible investments is maintained within the Policy's target allocations as included in the preceding tables, but the Committee can vary allocations between various classes or investment managers in order to improve investment results.

Equity market performance and corporate bond rates have a significant effect on our reported unfunded ABO, as the primary factors that drive the value of our unfunded ABO are the assumed discount rate and the actual return on plan assets. Additionally, equity market performance has a significant effect on our market-related value of plan assets (MRVPA), which is a calculated value and differs from the actual market value of plan assets. The MRVPA

recognizes the difference between the actual market value and expected market value of our plan assets and is determined by our actuaries using a five-year moving weighted average methodology. Gains and losses on plan assets are spread through the MRVPA based on the five-year moving weighted average methodology, which affects the expected return on plan assets component of pension expense.

Our employees do not contribute to the retirement plans. We fund the plans by contributing at least the minimum amount required by applicable regulations and as recommended by our actuary. However, we may also contribute in excess of the minimum required amount. We calculate the minimum amount of funding using the projected unit credit cost method. The Pension Protection Act (the Act) of 2006 contains new funding requirements for single employer defined benefit pension plans. The Act establishes a 100% funding target for plan years beginning after December 31, 2007. However, a delayed effective date of 2011 may apply if the pension plan meets the following targets: 92% funded in 2008; 94% funded in 2009; and 96% funded in 2010. In October 2006 we made a voluntary contribution of $5 million to the AGL Resources Inc. Retirement Plan. No contribution was required for the qualified plans in 2007, and we did not make a contribution. Further, no contribution is required for the qualified plans in 2008.

Postretirement Benefits

Until January 1, 2006, we sponsored two defined benefit postretirement health care plans for our eligible employees, the AGL Resources Inc. Postretirement Health Care Plan (AGL Postretirement Plan) and the NUI Corporation Postretirement Health Care Plan (NUI Postretirement Plan), which we acquired upon our acquisition of NUI. Eligibility for these benefits is based on age and years of service.

The NUI Postretirement Plan provided certain medical and dental health care benefits to retirees, other than retirees of Florida City Gas, depending on their age, years of service and start date. The NUI Postretirement Plan was contributory, and NUI funded a portion of these future benefits through a Voluntary Employees' Beneficiary Association. Effective July 2000, NUI no longer offered postretirement benefits other than pension for any new hires. In addition, NUI capped its share of costs at $500 per participant per month for retirees under age 65, and at $150 per participant per month for retirees over age 65. At the beginning of 2006, eligible participants in the NUI Postretirement Plan became eligible to participate in the AGL Postretirement Plan and all participation in this plan ceased, effective January 1, 2006.

The AGL Postretirement Plan covers all eligible AGL Resources employees who were employed as of June 30, 2002, if they reach retirement age while working for us. The state regulatory commissions have approved phase-ins that defer a portion of other postretirement benefits expense for future recovery. We recorded a regulatory asset for these future recoveries of $12 million as of December 31, 2007 and $13 million as of December 31, 2006. In addition, we recorded a regulatory liability of $4 million as of December 31, 2007 and $4 million as of December 31, 2006 for our expected expenses under the AGL Postretirement Plan. We expect to pay $7 million of insurance claims for the postretirement plan in 2008, but we do not anticipate making any additional contributions.

Effective December 8, 2003, the Medicare Prescription Drug, Improvement and Modernization Act of 2003 was signed into law. This act provides for a prescription drug benefit under Medicare (Part D) as well as a federal subsidy to sponsors of retiree health care benefit plans that provide a benefit that is at least actuarially equivalent to Medicare Part D.

On July 1, 2004, the AGL Postretirement Plan was amended to remove prescription drug coverage for Medicare-eligible retirees effective January 1, 2006. Certain grandfathered NUI retirees participating in the NUI Postretirement Plan will continue receiving a prescription drug benefit through some period of time. Medicare-eligible participants receive prescription drug benefits through a Medicare Part D plan offered by a third party and to which AGL subsidizes participant premiums. Medicare-eligible retirees who opt out of the AGL Postretirement Plan are eligible to receive a cash subsidy which may be used towards eligible prescription drug expenses. The following tables present details about our postretirement benefits.

	AGL Postretirement Plan	
In millions	Dec. 31, 2007	Dec. 31, 2006
Change in benefit obligation		
Benefit obligation at beginning of year	$95	$107
Service cost	1	1
Interest cost	6	5
Actuarial (gain) loss	-	(9)
Benefits paid	(8)	(9)
Benefit obligation at end of year	$94	$95
Change in plan assets		
Fair value of plan assets at beginning of year	$63	$59
Actual return on plan assets	7	5
Employer contribution	8	8
Benefits paid	(8)	(9)
Fair value of plan assets at end of year	$70	$63
Amounts recognized in the statement of financial position consist of		
Prepaid benefit cost	$-	$-
Accrued benefit liability	(24)	(32)
Accumulated OCI	-	-
Net amount recognized at year end (1)	$(24)	$(32)

(1) As of December 31, 2007 and 2006, the AGL Postretirement Plan had $24 million and $32 million of noncurrent liabilities, respectively, and no noncurrent assets or current liabilities.

The following table presents details on the components of our net periodic benefit cost for the AGL Postretirement Plan at the balance sheet dates.

In millions	2007	2006
Service cost	$1	$1
Interest cost	6	5
Expected return on plan assets	(5)	(4)
Amortization of prior service cost	(4)	(4)
Recognized actuarial loss	1	1
Net periodic postretirement benefit cost	$(1)	$(1)

There were no other changes in plan assets and benefit obligations recognized for the AGL Postretirement Plan for the year ended December 31, 2007. The 2008 estimated OCI amortization and refunds expected for the AGL Postretirement Plan are set forth in the following table.

In millions	2008
Amortization of transition obligation	$-
Amortization of prior service cost	(4)
Amortization of net loss	-
Refunds expected	-

The following table sets forth the assumed weighted average discount rates and rates of compensation increase used to determine benefit obligations for the AGL postretirement plans at December 31.

	2007	2006 (1)
Discount rate	6.4%	5.8%
Rate of compensation increase	3.7%	4.0%

The following table presents our weighted average assumed rates used to determine benefit obligations at the beginning of the period, January 1 for the AGL Postretirement Plan and December 1 for the NUI Postretirement Plan, and our weighted average assumed rates used to determine net periodic benefit cost at the beginning of this same period.

	AGL Postretirement Plan			NUI Postretirement Plan
	2007	2006	2005	2005 (1)
Discount rate – benefit obligation	6.4%	5.8%	5.5%	5.5%
Discount rate – net periodic benefit cost	5.8%	5.5%	5.8%	5.8%
Expected return on plan assets	9.0%	8.5%	8.8%	3.0%
Rate of compensation increase	3.7%	4.0%	4.0%	-

(1) The NUI postretirement plan was terminated and eligible former participants became eligible to participate in the AGL postretirement plan on January 1, 2006.

For information on the discount rate assumptions used for our postretirement plans, see the discussion contained in this Note 3 under the caption "Pension Benefits."

We consider the same factors in determining and selecting our assumptions for the overall expected long-term rate of return on plan assets as those considered in determining and selecting the overall expected long-term rate of return on plan assets for our retirement plans. For purposes of measuring our accumulated postretirement benefit obligation, the assumed pre-Medicare and post-Medicare health care inflation rates are as follows:

	AGL Postretirement Plan			
	Pre-medicare cost (pre-65 years old)		Post-medicare cost (post-65 years old)	
Assumed health care cost trend rates at December 31,	2007	2006	2007	2006
Health care costs trend rate assumed for next year	2.5%	2.5%	2.5%	2.5%
Rate to which the cost trend rate gradually declines	2.5%	2.5%	2.5%	2.5%
Year that the rate reaches the ultimate trend rate	N/A	N/A	N/A	N/A

Effective January 2006, our health care trend rates for the AGL Postretirement Plan was capped at 2.5%. This cap limits the increase in our contributions to the annual change in the consumer price index (CPI). An annual CPI rate of 2.5% was assumed for future years.

Assumed health care cost trend rates impact the amounts reported for our health care plans. A one-percentage-point change in the assumed health care cost trend rates would have the following effects for the AGL Postretirement Plan and the NUI Postretirement Plan.

	AGL Postretirement Plan One-Percentage-Point	
In millions	Increase	Decrease
Effect on total of service and interest cost	$-	$-
Effect on accumulated postretirement benefit obligation	4	(4)

Our investment policies and strategies for our postretirement plans, including target allocation ranges, are similar to those for our retirement plans. We fund the plans annually; retirees contribute 20% of medical premiums, 50% of the medical premium for spousal coverage and 100% of the dental premium. Our postretirement plans weighted average asset allocations for 2007 and 2006 and our target asset allocation ranges are as follows.

In millions	Target Asset allocation ranges	2007	2006
Equity	30%-80%	73%	66%
Fixed income	10%-40%	26%	32%
Real estate and other	10%-35%	-%	-%
Cash	0%-10%	1%	2%

The following table presents expected benefit payments covering the periods 2008 through 2017 for our retirement plans and postretirement health care plans. There will be benefit payments under these plans beyond 2017.

For the years ended Dec. 31, *(in millions)*	AGL Retirement Plan	NUI Retirement Plan	AGL Postretirement Plan
2008	$20	$6	$7
2009	20	6	7
2010	20	6	7
2011	20	6	7
2012	21	6	7
2013-2017	116	29	36

The following table presents the amounts not yet reflected in net periodic benefit cost and included in accumulated OCI as of December 31, 2007.

In millions	AGL Retirement Plan	NUI Retirement Plan	AGL Postretirement Plan
Transition obligation	$-	$-	$1
Prior service credit	(8)	(13)	(21)
Net loss (gain)	70	(7)	13
Accumulated OCI	62	(20)	(7)
Net amount recognized in statement of financial position.	(40)	(4)	(24)
Cumulative employer contributions in excess of net periodic benefit cost (accrued) prepaid	$22	$(24)	$(31)

There were no other changes in plan assets and benefit obligations recognized in the AGL and NUI Retirement Plans or the AGL Postretirement Plan for the year ended December 31, 2007.

Employee Savings Plan Benefits

We sponsor the Retirement Savings Plus Plan (RSP), a defined contribution benefit plan that allows eligible participants to make contributions to their accounts up to specified limits. Under the RSP, we made matching contributions to participant accounts in the following amounts:

- $6 million in 2007
- $6 million in 2006
- $5 million in 2005

We also sponsor the Nonqualified Savings Plan (NSP), an unfunded, nonqualified plan similar to the RSP. The NSP provides an opportunity for eligible employees who could reach the maximum contribution amount in the RSP to contribute additional amounts for retirement savings. Our contributions to the NSP have not been significant in any year.

Note 4 - Stock-based and Other Incentive Compensation Plans and Agreements

General

We currently sponsor the following stock-based and other incentive compensation plans and agreements:

	Shares issuable upon exercise of outstanding stock options and / or SARs (1)	Shares issuable and / or SARs available for issuance (1)	Details
2007 Omnibus Performance Incentive Plan	44,500	4,806,086	Grants of incentive and nonqualified stock options, stock appreciation rights (SARs), shares of restricted stock, restricted stock units and performance cash awards to key employees.
Long-Term Incentive Plan (1999) (2)	2,249,812	-	Grants of incentive and nonqualified stock options, shares of restricted stock and performance units to key employees.
Long-Term Stock Incentive Plan of 1990 (3)	91,061	-	Grants of incentive and nonqualified stock options, SARs and shares of restricted stock to key employees.
Officer Incentive Plan	87,064	215,702	Grants of nonqualified stock options and shares of restricted stock to new-hire officers.
2006 Non-Employee Directors Equity Compensation Plan	not applicable	189,107	Grants of stock to non-employee directors in connection with non-employee director compensation (for annual retainer, chair retainer and for initial election or appointment).
1996 Non-Employee Directors Equity Compensation Plan	45,061	14,180	Grants of nonqualified stock options and stock to non-employee directors in connection with non-employee director compensation (for annual retainer and for initial election or appointment). The plan was amended in 2002 to eliminate the granting of stock options.
Employee Stock Purchase Plan	not applicable	388,159	Nonqualified, broad-based employee stock purchase plan for eligible employees
Stand-alone SARs	2,761	-	Represents SARs that have been granted to key employees under individual agreements and are settled in cash.

(1) As of December 31, 2007
(2) Following shareholder approval of the Omnibus Performance Incentive Plan, no further grants will be made except for reload options that may be granted under the plan's outstanding options.
(3) Following shareholder approval of the Long-Term Incentive Plan (1999), no further grants will be made except for reload options that may be granted under the plan's outstanding options.

Accounting Treatment and Compensation Expense

Effective January 1, 2006, we adopted SFAS 123R, using the modified prospective application transition method. Financial results for the prior periods presented were not retroactively adjusted to reflect the effects of SFAS 123R.

Prior to January 1, 2006, we accounted for our share-based payment transactions in accordance with SFAS 123, as amended by SFAS 148. This allowed us to rely on APB 25 and related interpretations in accounting for our stock-based compensation plans under the intrinsic value method. SFAS 123R requires us to measure and recognize stock-based compensation expense in our financial statements based on the estimated fair value at the date of grant for our stock-based awards, which include:

- stock options
- stock awards, and
- performance units (restricted stock units and performance cash units)

Performance-based stock awards and performance units contain market conditions. Stock options, restricted stock awards and performance units also contain a service condition. In accordance with SFAS 123R, we recognize compensation expense over the requisite service period for:

- awards granted on or after January 1, 2006 and
- unvested awards previously granted and outstanding as of January 1, 2006

In addition, we estimate forfeitures over the requisite service period when recognizing compensation expense. These estimates are adjusted to the extent that actual forfeitures differ, or are expected to materially differ, from such estimates.

In 2005, we did not record compensation expense related to our stock option grants in our financial statements, which is consistent with the APB 25 requirements. However, at the end of each reporting period, we recorded compensation expense over the requisite service period for our other stock-based and performance cash unit awards. The following table provides additional information on compensation costs and income tax benefits related to our stock-based compensation awards. We recorded these amounts in our consolidated statements of income for the years ended December 31, 2007, 2006 and 2005.

In millions	2007	2006	2005
Compensation costs	$9	$9	$5
Income tax benefits	3	3	8

Prior to our adoption of SFAS 123R, benefits of tax deductions in excess of recognized compensation costs were reported as operating cash flows. SFAS 123R requires excess tax benefits to be reported as a financing cash inflow rather than as a reduction of taxes paid. In 2007 and 2006, our cash flows from financing activities included an immaterial amount for recognized compensation costs in excess of the benefits of tax deductions. In 2005, we included $8 million of such benefits in cash flow provided by operating activities.

If stock-based compensation expense for the year ended December 31, 2005 had been recorded based on the fair value of the awards at the grant dates consistent with the method prescribed by SFAS 123, which has been superseded by SFAS 123R, our net income and earnings per share for the year ended December 31, 2005 would have been reduced to the amounts shown in the following table.

In millions, except per share amounts	2005
Net income, as reported	$193
Deduct: Total stock-based employee compensation expense determined under fair value-based method for all awards, net of related tax effect	1
Pro-forma net income	$192
Earnings per share:	
Basic – as reported	$2.50
Basic – pro-forma	$2.48
Diluted – as reported	$2.48
Diluted – pro-forma	$2.47

Incentive and Nonqualified Stock Options

We grant incentive and nonqualified stock options with a strike price equal to the fair market value on the date of the grant. "Fair market value" is defined under the terms of the applicable plans as the most recent closing price per share of AGL Resources common stock as reported in *The Wall Street Journal*. Stock options generally have a three-year vesting period. Nonqualified options generally expire 10 years after the date of grant. Participants realize value from option grants only to the extent that the fair market value of our common stock on the date of exercise of the option exceeds the fair market value of the common stock on the date of the grant. Compensation expense associated with stock options is generally recorded over the option vesting period; however, for unvested options that are granted to employees who are retirement-eligible, the remaining compensation expense is recorded in the current period rather than over the remaining vesting period.

As of December 31, 2007, we had $4 million of total unrecognized compensation costs related to stock options. These costs are expected to be recognized over the remaining average requisite service period of approximately 2 years. Cash received from stock option exercises for 2007 was $10 million, and the income tax benefit from stock option exercises was $3 million. The following tables summarize activity related to stock options for key employees and non-employee directors.

Stock Options

	Number of options	Weighted average exercise price	Weighted average remaining life (in years)	Aggregate intrinsic value (in millions)
Outstanding – December 31, 2004	2,174,072	$23.23		
Granted	1,014,121	33.80		
Exercised	(846,465)	22.60		
Forfeited	(120,483)	32.38		
Outstanding – December 31, 2005	2,221,245	$27.79		
Granted	914,216	35.81		
Exercised	(543,557)	24.69		
Forfeited	(266,418)	34.93		
Outstanding – December 31, 2006	2,325,486	$30.85	7.2	
Granted	735,196	39.11	9.1	
Exercised	(361,385)	27.78	5.1	
Forfeited	(181,799)	36.75	8.3	
Outstanding – December 31, 2007	2,517,498	$33.28	7.1	$12
Exercisable – December 31, 2007	1,102,536	$28.48	5.4	$10

Unvested Stock Options

	Number of unvested options	Weighted average exercise price	Weighted average remaining vesting period (in years)	Weighted average fair value
Outstanding – December 31, 2006	1,311,814	$35.03	1.8	$4.75
Granted	735,196	39.11	2.1	4.90
Forfeited	(181,799)	36.75	1.3	4.88
Vested	(450,249)	34.73	-	4.73
Outstanding – December 31, 2007	1,414,962	$37.02	1.6	$4.82

Information about outstanding and exercisable options as of December 31, 2007, is as follows.

	Options outstanding			Options Exercisable	
Range of Exercise Prices	Number of options	Weighted average remaining contractual life (in years)	Weighted average exercise price	Number of options	Weighted average exercise price
$16.25 to $20.85	84,399	1.5	$19.98	84,399	$19.98
$20.86 to $25.45	275,719	3.4	21.65	275,719	21.65
$25.46 to $30.05	251,357	5.4	27.06	251,357	27.06
$30.06 to $34.65	441,047	7.0	33.20	270,609	33.17
$34.66 to $39.25	1,408,591	8.5	37.17	212,367	35.93
$39.26 to $43.85	56,385	8.6	41.29	8,085	41.14
Outstanding - Dec. 31, 2007	2,517,498	7.1	$33.28	1,102,536	$28.48

Summarized below are outstanding options that are fully exercisable.

Exercisable at:	Number of options	Weighted average exercise price
December 31, 2005	1,275,689	$23.46
December 31, 2006	1,013,672	$25.45
December 31, 2007	1,102,536	$28.48

In accordance with the fair value method of determining compensation expense, we use the Black-Scholes pricing model. Below are the ranges for per share value and information about the underlying assumptions used in developing the grant date value for each of the grants made during 2007, 2006 and 2005.

	2007	2006	2005
Expected life (years)	7	7	7
Risk-free interest rate % (1)	3.87 – 5.05	4.5 – 5.1	3.9 – 4.5
Expected volatility % (2)	13.2 – 14.3	14.2 – 15.9	17.1 – 17.3
Dividend yield % (3)	3.8 – 4.2	3.7 – 4.2	3.2 – 3.8
Fair value of options granted (4)	$3.55 – $5.98	$4.55– $6.18	$4.57 – $6.01

(1) US Treasury constant maturity - 7 years
(2) Volatility is measured over 7 years, the expected life of the options; weighted average volatility %'s for 2007 was 14.2%, 2006 was 15.8% and in 2005 was 17.3%.
(3) Weighted average dividend yields for 2007 was 4.2%, 2006 was 4.1% and in 2005 was 3.7%
(4) Represents per share value.

Intrinsic value for options is defined as the difference between the current market value and the grant price. Total intrinsic value of options exercised during 2007 was $5 million. With the implementation of our share repurchase program in 2006, we use shares purchased under this program to satisfy share-based exercises to the extent that repurchased shares are available. Otherwise, we issue new shares from our authorized common stock.

Performance Units

In general, a performance unit is an award of the right to receive (i) an equal number of shares of our common stock, which we refer to as a restricted stock unit or (ii) cash, subject to the achievement of certain pre-established performance criteria, which we refer to as a performance cash unit. Performance units are subject to certain transfer restrictions and forfeiture upon termination of employment. The dollar value of restricted stock unit awards is equal to the grant date fair value of the awards, over the requisite service period, determined pursuant to FAS 123R. The dollar value of performance cash unit awards is equal to the grant date fair value of the awards measured against progress towards the performance measure, over the requisite service period, determined pursuant to FAS 123R. No other assumptions are used to value these awards.

Restricted Stock Units In general, a restricted stock unit is an award that represents the opportunity to receive a specified number of shares of our common stock, subject to the achievement of certain pre-established performance criteria. In 2007, we granted to a select group a total of 127,400 restricted stock units (the 2007 restricted stock units), of which 113,700 of these units were outstanding as of December 31, 2007. These restricted stock units had a performance measurement period that ended December 31, 2007, and a performance measure related to a basic earnings per share goal. In February 2008, these restricted stock units were forfeited for failure to meet the performance criteria.

Performance Cash Units In general, a performance cash unit is an award that represents the opportunity to receive a cash award, subject to the achievement of certain pre-established performance criteria. In 2007, we granted performance cash awards to a select group of officers. These awards have a performance measure that is related to annual growth in basic earnings per share, plus the average dividend yield, as adjusted to reflect the effect of economic value created during the performance measurement period by our wholesale services segment. In 2007, the basic earnings per share growth target was not achieved with respect to the 2007 awards. Accruals in connection with these grants are as follows:

Dollars in millions	Units	Measurement period end date	Accrued at Dec. 31, 2007	Maximum aggregate payout
Year of grant				
2005 (1)	23	Dec. 31, 2007	$2	$3
2006	15	Dec. 31, 2008	1	2
2007	23	Dec. 31, 2009	-	3

(1) In February 2008, the 2005 performance cash units vested and resulted in an aggregate payout of $2 million.

Stock and Restricted Stock Awards

In general, we refer to a stock award as an award of our common stock that is 100% vested and not forfeitable as of the date of grant. We refer to restricted stock as an award of our common stock that is subject to time-based vesting or achievement of performance measures. Restricted stock awards are subject to certain transfer restrictions and forfeiture upon termination of employment. The dollar value of both stock awards and restricted stock awards are equal to the grant date fair value of the awards, over the requisite service period, determined pursuant to FAS 123R. No other assumptions are used to value the awards.

Stock Awards – Non-Employee Directors Non-employee director compensation may be paid in shares of our common stock in connection with initial election, the annual retainer, and chair retainers, as applicable. Stock awards for non-employee directors are 100% vested and nonforfeitable as of the date of grant. The following table summarizes activity during 2007, related to stock awards for our non-employee directors.

Restricted Stock Awards	Shares of restricted stock	Weighted average fair value
Issued	10,893	43.85
Forfeited	-	-
Vested	10,893	43.85
Outstanding	-	-

Restricted Stock Awards – Employees From time to time, we may give restricted stock awards to our key employees. The following table summarizes activity during the year ended December 31, 2007, related to restricted stock awards for our key employees.

Restricted Stock Awards	Shares of restricted stock	Weighted average remaining vesting period (in years)	Weighted average fair value
Outstanding – December 31, 2006 (1)	232,431	2.4	$35.49
Issued	224,649	2.4	39.72
Forfeited	(51,583)	1.3	36.55
Vested	(56,461)	-	34.93
Outstanding – December 31, 2007 (1)	349,036	2.1	$38.15

(1) Subject to restriction

Employee Stock Purchase Plan

Under the ESPP, employees may purchase shares of our common stock in quarterly intervals at 85% of fair market value. Employee contributions under the ESPP may not exceed $25,000 per employee during any calendar year.

	2007	2006	2005
Shares purchased on the open market	52,299	45,361	40,927
Average per-share purchase price	$34.69	$31.40	$30.52
Purchase price discount	$313,584	$252,752	$220,847

Stand-alone SARs

We recognize the intrinsic value of the SARs as compensation expense over the vesting period. Compensation expense for 2007, 2006 and 2005 was not material to our consolidated results of operations. A total of 2,761 SARs at a weighted average exercise price of $23.97 were vested and outstanding as of December 31, 2007.

Note 5 - Common Shareholders' Equity

Share Repurchases

In March 2001, our Board of Directors approved the purchase of up to 600,000 shares of our common stock to be used for issuances under the Officer Incentive Plan. In 2007, we purchased 10,667 shares under this plan. As of December 31, 2007, we had purchased a total 297,234 shares, leaving 302,766 shares available for purchase.

In February 2006, our Board of Directors authorized a plan to purchase up to 8 million shares of our outstanding common stock over a five-year period. These purchases are intended to offset share issuances under our employee and non-employee director incentive compensation plans and our dividend reinvestment and stock purchase plans. Stock purchases under this program may be made in the open market or in private transactions at times and in amounts that we deem appropriate. There is no guarantee as to the exact number of shares that we will purchase, and we can terminate or limit the program at any time. We will hold the purchased shares as treasury shares. As of December 31, 2007, we had repurchased 3,049,049 shares at a weighted average price of $38.58.

Dividends

We derive a substantial portion of our consolidated assets, earnings and cash flow from the operation of regulated utility subsidiaries, whose legal authority to pay dividends or make other distributions to us is subject to regulation. Our common shareholders may receive dividends when declared at the discretion of our Board of Directors. Dividends may be paid in cash, stock or other form of payment, and payment of future dividends will depend on our future earnings, cash flow, financial requirements and other factors, some of which are noted below. In certain cases, our ability to pay dividends to our common shareholders is limited by the following:

- our ability to satisfy our obligations under certain financing agreements, including debt-to-capitalization and total shareholders' equity covenants
- our ability to satisfy our obligations to any preferred shareholders

Note 6 - Debt

Our issuance of various securities, including long-term and short-term debt, is subject to customary approval or authorization by state and federal regulatory bodies, including state public service commissions, the SEC and the FERC as granted by the Energy Policy Act of 2005. The following table provides more information on our various securities.

In millions	Year(s) due	Interest rate (1)	Weighted average interest rate (1)	Outstanding as of December 31, 2007	2006
Short-term debt					
Commercial paper	2008	5.6%	5.4%	$566	$508
Pivotal Utility line of credit	2008	4.5	5.4	12	17
Sequent line of credit	2008	4.5	5.4	1	2
Capital leases	2008	4.9	4.9	1	1
Current portion of long-term debt	2008	-	-	-	11
Total short-term debt		**5.6%**	**5.4%**	**$580**	**$539**
Long-term debt - net of current portion					
Senior notes	2011-2034	4.5 – 7.1%	5.8%	$1,275	$1,150
Gas facility revenue bonds	2022-2033	3.8 – 5.3	4.3	199	199
Medium-term notes	2012-2027	6.6 – 9.1	7.8	196	196
Capital leases	2013	4.9	4.9	6	6
Notes payable to Trusts	-	-	-	-	77
AGL Capital interest rate swaps	2011	8.8	8.8	(2)	(6)
Total long-term debt		**6.0%**	**6.1%**	**$1,674**	**$1,622**
Total debt		**5.9%**	**5.9%**	**$2,254**	**$2,161**

(1) As of December 31, 2007.

Short-term Debt

Our short-term debt at December 31, 2007 and 2006 was composed of borrowings under our commercial paper program; current portions of our capital lease obligations and the current portion of our long-term medium-term notes; and lines of credit for Sequent and Pivotal Utility.

Commercial Paper Our commercial paper consists of short-term, unsecured promissory notes with maturities ranging from 2 to 46 days. These unsecured promissory notes are supported by our $1 billion Credit Facility which expires in August 2011. We have the option to increase the aggregate principal amount available for borrowing under the Credit Facility to $1.25 billion on not more than three occasions during each calendar year. As of December 31, 2007 or 2006 we did not have any amounts outstanding under the Credit Facility.

SouthStar Credit Facility SouthStar's five-year $75 million unsecured credit facility expires in November 2011. SouthStar will use this line of credit for working capital and its general corporate needs. On December 31, 2007 and 2006, there were no outstanding borrowings on this line of credit. We do not guarantee or provide any other form of security for the repayment of this credit facility.

Sequent Line of Credit In 2007, we extended Sequent's two lines of credit through June 2008 and August 2008. These unsecured lines of credit, which total $45 million and bear interest at the federal funds effective rate plus 0.4%, are used solely for the posting of margin deposits for NYMEX transactions and are unconditionally guaranteed by us.

Pivotal Utility Line of Credit In August 2007, we extended the Pivotal Utility $20 million line of credit through August 2008. This line of credit supports Elizabethtown Gas' hedging program and bears interest at the federal funds effective rate plus 0.4%, is used solely for the posting of deposits and is unconditionally guaranteed by us. For more information on Elizabethtown Gas' hedging program, see Note 2.

Long-term Debt

Our long-term debt at December 31, 2007 and 2006 matures more than one year from the balance sheet date and consists of medium-term notes: Series A, Series B and Series C, which we issued under an indenture dated December 1, 1989; senior notes; gas facility revenue bonds; notes payable to Trusts; and capital leases. The notes are unsecured and rank on parity with all our other unsecured indebtedness. Our annual maturities of long-term debt are as follows:

Year	Amount (in millions)
2011	$300 (1)
2012	15
2013	230
2015	200
2016	300
2017	22
2021	30
2022	93
2024	20
2026	69
2027	54
2032	55
2033	40
2034	250
Total	$1,678 (2)

(1) Excludes the fair value of $2 million related to our interest rate swaps.
(2) Excludes $2 million of unamortized issuance costs related to our gas facility revenue bonds.

Medium-term notes The following table provides more information on our medium-term notes, which were issued to refinance portions of our existing short-term debt and for general corporate purposes. Our annual maturities of our medium-term notes are as follows:

Issue Date	Amount (in millions)	Interest rate	Maturity
June 1992	$5	8.4%	June 2012
June 1992	5	8.3	June 2012
June 1992	5	8.3	July 2012
July 1997	22	7.2	July 2017
Feb. 1991	30	9.1	Feb. 2021
April 1992	5	8.55	April 2022
April 1992	25	8.7	April 2022
April 1992	6	8.55	April 2022
May 1992	10	8.55	May 2022
Nov. 1996	30	6.55	Nov. 2026
July 1997	53	7.3	July 2027
Total	$196		

Senior Notes The following table provides more information on our senior notes, which were issued to refinance portions of our existing short-term and long-term debt, to finance acquisitions and for general corporate purposes.

Issue date	Amount (in millions)	Interest rate	Maturity
Feb. 2001 (1)	$300	7.125%	Jan 2011
July 2003	225	4.45	Apr 2013
Dec. 2004	200	4.95	Jan 2015
June 2006	175	6.375	Jul 2016
Dec. 2007	125	6.375	Jul 2016
Sep. 2004	250	6.0	Oct 2034
Total	$1,275		

(1) $100 million has been converted to a variable-rate obligation through an interest rate swap we entered into in March 2003. We pay a variable rate determined with a six-month LIBOR plus 3.4%, which was 8.8% at December 31, 2007 and 9.0% at December 31, 2006. The interest rate swap expires in January 2011.

In December 2007, we issued $125 million of senior notes which were part of a series originally issued by us in June 2006 in the amount of $175 million at an interest rate of 6.375%, for a total amount outstanding of $300 million at December 31, 2007. We used $123 million in net proceeds with the issuance to repay commercial paper.

The trustee with respect to all of the above-referenced senior notes is The Bank of New York Trust Company, N.A., pursuant to an indenture dated February 20, 2001. We fully and unconditionally guarantee all of our senior notes.

Gas Facility Revenue Bonds Pivotal Utility is party to a series of loan agreements with the New Jersey Economic Development Authority (NJEDA) pursuant to which the NJEDA has issued a series of gas facility revenue bonds as shown in the following table. We do not guarantee or provide any other form of security for the repayment of this indebtedness.

Issue Date	Amount (in millions)	Interest rate	Maturity
July 1994 (1)	$47	3.8%	Oct. 2022
July 1994 (1)	20	4.9	Oct. 2024
June 1992 (1)	39	3.8	June 2026
June 1992 (1)	55	4.7	June 2032
July 1997	40	5.25	Nov. 2033
Unamortized issuance costs	(2)		
Total	$199		

(1) Interest rate is adjusted every 35 days. Rates indicated are as of December 31, 2007.

In June 2007, we refinanced $55 million of our gas facility revenue bonds due June 2032. The original bonds had a fixed interest rate of 5.7% per year and were refinanced with $55 million of adjustable-rate gas facility revenue bonds. The maturity date of these bonds remains June 2032. The bonds were issued at an initial annual interest rate of 3.8% and have a 35-day auction period where the interest rate will adjust every 35 days.

The variable bonds contain a provision whereby the holder can "put" the bonds back to the issuer. In 1996, Pivotal Utility executed a long-term Standby Bond Purchase Agreement (SBPA) with a syndicate of banks, which was amended and restated in June 2005. Under the terms of the SBPA, as further amended, the participating banks are obligated under certain circumstances to purchase variable bonds that are tendered by the holders thereof and not remarketed by the remarketing agent. Such obligation of the participating banks would remain in effect until the June 2010 expiration of the SBPA, unless it is extended or earlier terminated.

Notes Payable to Trusts In June 1997, we established AGL Capital Trust I (Trust I), a Delaware business trust, of which we own all the common voting securities. Trust I issued and sold $75 million of 8.17% capital securities (liquidation amount $1,000 per capital security) to certain initial investors. Trust I used the proceeds to purchase 8.17% junior subordinated deferrable interest debentures issued by us. Trust I capital securities were subject to mandatory redemption at the time of the repayment of the junior subordinated debentures in June 2037, or the optional prepayment by us after May 2007.

In July 2007, we used the proceeds from the sale of commercial paper to pay Trust I the $75 million principal amount plus a $3 million premium in connection with the early redemption of the junior subordinated debentures, and to pay the $2 million note with respect to our common securities interest in AGL Capital Trust I. The $3 million premium was recorded as interest expense in 2007.

Preferred Securities As of December 31, 2007, we had 10 million shares of authorized, unissued Class A junior participating preferred stock, no par value, and 10 million shares of authorized, unissued preferred stock, no par value.

Capital Leases Our capital leases consist primarily of a sale/leaseback transaction completed in 2002 by Florida City Gas related to its gas meters and other equipment and will be repaid over 11 years. Pursuant to the terms of the lease agreement, Florida City Gas is required to insure the leased equipment during the lease term. In addition, at the expiration of the lease term, Florida City Gas has the option to purchase the leased meters from the lessor at their fair market value.

Default Events

Our Credit Facility financial covenant requires us to maintain a ratio of total debt to total capitalization of no greater than 70%. As of December 31, 2007, this ratio was 58% and was 57% as of December 31, 2006. Our debt instruments and other financial obligations include provisions that, if not complied with, could require early payment, additional collateral support or similar actions. Our most important default events include:

- a maximum leverage ratio
- insolvency events and nonpayment of scheduled principal or interest payments
- acceleration of other financial obligations
- change of control provisions

We do not have any trigger events in our debt instruments that are tied to changes in our specified credit ratings or our stock price and have not entered into any transaction that requires us to issue equity based on credit ratings or other trigger events. We are currently in compliance with all existing debt provisions and covenants.

Note 7 - Commitments and Contingencies

We have incurred various contractual obligations and financial commitments in the normal course of our operating and financing activities that are reasonably likely to have a material affect on liquidity or the availability of requirements for capital resources. Contractual obligations include future cash payments required under existing contractual arrangements, such as debt and lease agreements. These obligations may result from both general financing activities and from commercial arrangements that are directly supported by related revenue-producing activities. The following table illustrates our expected future contractual payments such as debt and lease agreements, and commitment and contingencies as of December 31, 2007.

In millions	Total	2008	2009 & 2010	2011 & 2012	2013 & thereafter
Recorded contractual obligations:					
Long-term debt	$1,674	$-	$2	$315	$1,357
Short-term debt	580	580	-	-	-
ERC (1)	107	10	34	53	10
PRP costs (1)	245	55	112	60	18
Total	$2,606	$645	$148	$428	$1,385

(1) Includes charges recoverable through rate rider mechanisms

In millions	Total	2008	2009 & 2010	2011 & 2012	2013 & thereafter
Unrecorded contractual obligations and commitments (1):					
Interest charges (2)	$1,176	$100	$200	$157	$719
Pipeline charges, storage capacity and gas supply (3)	1,792	456	637	348	351
Operating leases (4)	154	26	50	34	44
Standby letters of credit, performance/ surety bonds	30	24	6	-	-
Asset management agreements (5)	24	8	8	8	-
Total	$3,176	$614	$901	$547	$1,114

(1) In accordance with generally accepted accounting principles, these items are not reflected in our consolidated balance sheet
(2) Floating rate debt is based on the interest rate as of December 31, 2007 and the maturity of the underlying debt instrument. As of December 31, 2007, we have $39 million of accrued interest on our consolidated balance sheet that will be paid in 2008.
(3) Charges recoverable through a PGA mechanism or alternatively billed to Marketers. Also includes demand charges associated with Sequent. SouthStar also includes gas commodity purchase commitments of 1.3 Bcf at floating gas prices calculated using forward natural gas prices as of December 31, 2007, and valued at $98 million.
(4) We have certain operating leases with provisions for step rent or escalation payments and certain lease concessions. We account for these leases by recognizing the future minimum lease payments on a straight-line basis over the respective minimum lease terms, in accordance with SFAS 13. However, this lease accounting treatment does not affect the future annual operating lease cash obligations as shown herein.
(5) Represent fixed-fee payments for Sequent's asset management agreements between Atlanta Gas Light ($4 million) and Elizabethtown Gas ($4 million). As of December 31, 2007, we have $1 million of accrued payments on our consolidated balance sheet, which will be paid in 2008.

Environmental Remediation Costs

We are subject to federal, state and local laws and regulations governing environmental quality and pollution control. These laws and regulations require us to remove or remedy the effect on the environment of the disposal or release of specified substances at current and former operating sites.

Atlanta Gas Light The presence of coal tar and certain other byproducts of a natural gas manufacturing process used to produce natural gas prior to the 1950s has been identified at or near 10 former Atlanta Gas Light operating sites in Georgia and at 3 sites of predecessor companies in Florida. Atlanta Gas Light has active environmental remediation or monitoring programs in effect at 10 of these sites. Two sites in Florida are currently in the investigation or preliminary engineering design phase, and one Georgia site has been deemed compliant with state standards.

Atlanta Gas Light has customarily reported estimates of future remediation costs for these former sites based on probabilistic models of potential costs. These estimates are reported on an undiscounted basis. As cleanup options and plans mature and cleanup contracts are entered into, Atlanta Gas Light is better able to provide conventional engineering estimates of the likely costs of remediation at its former sites. These estimates contain various engineering uncertainties, but Atlanta Gas Light continuously attempts to refine and update these engineering estimates.

Atlanta Gas Light's current estimate for the remaining cost of future actions at its former operating sites is $35 million, which may change depending on whether future measures for groundwater will be required. As of December 31, 2007, we have recorded a liability equal to the low end of that range of $35 million, of which $6 million is expected to be incurred over the next 12 months.

These liabilities do not include other potential expenses, such as unasserted property damage claims, personal injury or natural resource damage claims, unbudgeted legal expenses or other costs for which Atlanta Gas Light may be held liable but for which it cannot reasonably estimate an amount.

The ERC liability is included as a corresponding regulatory asset, which is a combination of accrued ERC and unrecovered cash expenditures for investigation and cleanup costs. Atlanta Gas Light has three ways of recovering investigation and cleanup costs. First, the Georgia Commission has approved an ERC recovery rider. The ERC recovery mechanism allows for recovery of expenditures over a five-year period subsequent to the period in which the expenditures are incurred. Atlanta Gas Light expects to collect $21 million in revenues over the next 12 months under the ERC recovery rider, which is reflected as a current asset. The amounts recovered from the ERC recovery rider during the last three years were:

- $26 million in 2007
- $29 million in 2006
- $28 million in 2005

The second way to recover costs is by exercising the legal rights Atlanta Gas Light believes it has to recover a share of its costs from other potentially responsible parties, typically former owners or operators of these sites. There were no material recoveries from potentially responsible parties during 2007, 2006 or 2005.

The third way to recover costs is from the receipt of net profits from the sale of remediated property.

Elizabethtown Gas In New Jersey, Elizabethtown Gas is currently conducting remediation activities with oversight from the New Jersey Department of Environmental Protection. Although we cannot estimate the actual total cost of future environmental investigation and remediation efforts with precision, based on probabilistic models similar to those used at Atlanta Gas Light's former operating sites, the range of reasonably probable costs is $61 million to $119 million. As of December 31, 2007, we have recorded a liability equal to the low end of that range, or $61 million, of which $4 million in expenditures are expected to be incurred over the next 12 months.

Prudently incurred remediation costs for the New Jersey properties have been authorized by the New Jersey Commission to be recoverable in rates through a remediation adjustment clause. As a result, Elizabethtown Gas has recorded a regulatory asset of approximately $66 million, inclusive of interest, as of December 31, 2007, reflecting the future recovery of both incurred costs and accrued carrying charges. Elizabethtown Gas expects to collect $1 million in revenues over the next 12 months. Elizabethtown Gas has also been successful in recovering a portion of remediation costs incurred in New Jersey from its insurance carriers and continues to pursue additional recovery.

We own a former NUI remediation site in Elizabeth City, North Carolina that is subject to a remediation order by the North Carolina Department of Energy and Natural Resources. We had recorded liabilities of $11 million and $10 million as of December 31, 2007 and 2006, respectively, related to this site.

There is one other site in North Carolina where investigation and remediation is likely, although no remediation order exists and we do not believe costs associated with this site can be reasonably estimated. In addition, there are as many as six other sites with which NUI had some association, although no basis for liability has been asserted, and accordingly we have not accrued any remediation liability. There are currently no cost recovery mechanisms for the environmental remediation sites in North Carolina.

Rental Expense

We incurred rental expense in the amounts of $21 million in 2007, $19 million in 2006 and $25 million in 2005.

Litigation

We are involved in litigation arising in the normal course of business. We believe the ultimate resolution of such litigation will not have a material

adverse effect on our consolidated financial position, results of operations or cash flows.

In August 2006, the Office of Mineral Resources of the Louisiana DNR informed Jefferson Island that its mineral lease – which authorizes salt extraction to create two new storage caverns – at Lake Peigneur had been terminated. The Louisiana DNR identified two bases for the termination: (1) failure to make certain mining leasehold payments in a timely manner, and (2) the absence of salt mining operations for six months.

In September 2006, Jefferson Island filed suit against the State of Louisiana to maintain its lease to complete an ongoing natural gas storage expansion project in Louisiana. The project would add two salt dome storage caverns under Lake Peigneur to the two caverns currently owned and operated by Jefferson Island. In its suit, Jefferson Island alleges that the Louisiana DNR accepted all leasehold payments without reservation and never provided Jefferson Island with notice and opportunity to cure, as required by state law. In its answer to the suit, the State denied that anyone with proper authority approved the late payments. As to the second basis for termination, the suit contends that Jefferson Island's lease with the State of Louisiana was amended in 2004 so that mining operations are no longer required to maintain the lease. The State's answer denies that the 2004 amendment was properly authorized. If we are unable to reach a settlement, we are not able to predict the outcome of the litigation. As of January 2008, our current estimate of costs incurred that would be considered unusable if the Louisiana DNR was successful in terminating our lease and causing us to cease the expansion project is approximately $6 million.

Note 8 - Income Taxes

We have two categories of income taxes in our statements of consolidated income: current and deferred. Current income tax expense consists of federal and state income tax less applicable tax credits related to the current year. Deferred income tax expense generally is equal to the changes in the deferred income tax liability and regulatory tax liability during the year.

Investment and Other Tax Credits

Deferred investment tax credits associated with distribution operations are included as a regulatory liability in our consolidated balance sheets (see Note 1, "Accounting Policies and Methods of Application"). These investment tax credits are being amortized over the estimated life of the related properties as credits to income in accordance with regulatory requirements. In 2007, we invested in a guaranteed affordable housing tax credit fund. We reduce income tax expense in our statements of consolidated income for the investment tax credits and other tax credits associated with our nonregulated subsidiaries, including the affordable housing credits. Components of income tax expense shown in the statements of consolidated income are shown in the following table.

Income Tax Expense The relative split between current and deferred taxes is due to a variety of factors including true ups of prior year tax returns, and most importantly, the timing of our property-related deductions.

In millions	2007	2006	2005
Current income taxes			
Federal	$86	$(4)	$84
State	12	2	18
Deferred income taxes			
Federal	23	115	17
State	7	18	-
Amortization of investment tax credits	(1)	(2)	(2)
Total	$127	$129	$117

The reconciliations between the statutory federal income tax rate, the effective rate and the related amount of tax for the years ended December 31, 2007, 2006 and 2005 are presented in the following tables.

	2007		2006		2005	
In millions	Amount	% of pretax income	Amount	% of pretax income	Amount	% of pretax income
Computed tax expense at statutory rate	$118	35.0%	$119	35.0%	$109	35.0%
State income tax, net of federal income tax benefit	13	3.8	12	3.6	11	3.7
Amortization of investment tax credits	(1)	(0.3)	(2)	(0.5)	(2)	(0.6)
Affordable housing credits	(1)	(0.3)	-	-	-	-
Flexible dividend deduction	(2)	(0.6)	(2)	(0.5)	(2)	(0.6)
Other – net	-	-	2	0.2	1	0.2
Total income tax expense at effective rate	$127	37.6%	$129	37.8%	$117	37.7%

Accumulated Deferred Income Tax Assets and Liabilities

We report some of our assets and liabilities differently for financial accounting purposes than we do for income tax purposes. We report the tax effects of the differences in those items as deferred income tax assets or liabilities in our consolidated balance sheets. We measure the assets and liabilities using income tax rates that are currently in effect. Because of the regulated nature of the utilities' business, we recorded a regulatory tax liability in accordance with SFAS 109, which we are amortizing over approximately 30 years (see Note 1 "Accounting Policies and Methods of Application"). Our deferred tax assets include $35 million related to an unfunded pension and postretirement benefit obligation and did not change from 2006.

As indicated in the following table, our deferred tax assets and liabilities include certain items we acquired from NUI. We have provided a valuation allowance for some of these items that reduce our net deferred tax assets to amounts we believe are more likely than not to be realized in future periods. With respect to our continuing operations, we have net operating losses in various jurisdictions. Components that give rise to the net accumulated deferred income tax liability are as follows.

	As of December 31,	
In millions	2007	2006
Accumulated deferred income tax liabilities		
Property – accelerated depreciation and other property-related items	$568	$520
Mark to market	4	7
Other	44	22
Total accumulated deferred income tax liabilities	616	549
Accumulated deferred income tax assets		
Deferred investment tax credits	6	7
Unfunded pension and postretirement benefit obligation	35	35
Net operating loss – NUI (1)	5	5
Other	7	-
Total accumulated deferred income tax assets	53	47
Valuation allowances (2)	(3)	(3)
Total accumulated deferred income tax assets, net of valuation allowance	50	44
Net accumulated deferred tax liability	$566	$505

(1) Expire in 2021.
(2) Valuation allowance is due to the net operating losses on NUI headquarters that are not usable in New Jersey.

In June 2006, the FASB issued FIN 48, which addressed the determination of whether tax benefits claimed or expected to be claimed on a tax return should be recorded in the financial statements. Under FIN 48, we may recognize the tax benefit from an uncertain tax position only if it is more likely than not that the tax position will be sustained on examination by the taxing authorities, based on the technical merits of the position. The tax benefits recognized in the financial statements from such a position should be measured based on the largest benefit that has a greater than fifty percent likelihood of being realized upon ultimate settlement. FIN 48 also provides guidance on derecognition, classification, interest and penalties on income taxes, accounting in interim periods and requires increased disclosures. We adopted the provisions of FIN 48 on January 1, 2007. At the date of adoption, and as of December 31, 2007, we did not have a liability for unrecognized tax benefits. Based on current information, we do not anticipate that this will change materially in 2008.

We recognize accrued interest and penalties related to uncertain tax positions in operating expenses in the consolidated statements of income, which is consistent with the recognition of these items in prior reporting periods. As of December 31, 2007, we did not have a liability recorded for payment of interest and penalties associated with uncertain tax positions.

We file a U.S. federal consolidated income tax return and various state income tax returns. We are no longer subject to income tax examinations by the Internal Revenue Service or any state for years before 2002.

Note 9 - Segment Information

We are an energy services holding company whose principal business is the distribution of natural gas in six states - Florida, Georgia, Maryland, New Jersey, Tennessee and Virginia. We generate nearly all our operating revenues through the sale, distribution, transportation and storage of natural gas. We are involved in several related and complementary businesses, including retail natural gas marketing to end-use customers primarily in Georgia; natural gas asset management and related logistics activities for each of our utilities as well as for nonaffiliated companies; natural gas storage arbitrage and related activities; and the development and operation of high-deliverability natural gas storage assets. We manage these businesses through four operating segments – distribution operations, retail energy operations, wholesale services and energy investments and a nonoperating corporate segment which includes intercompany eliminations.

We evaluate segment performance based primarily on the non-GAAP measure of EBIT, which includes the effects of corporate expense allocations. EBIT is a non-GAAP measure that includes operating income, other income and expenses and minority interest. Items we do not include in EBIT are financing costs, including interest and debt expense and income taxes, each of which we evaluate on a consolidated level. We believe EBIT is a useful measurement of our performance because it provides information that can be used to evaluate the effectiveness of our businesses from an operational perspective, exclusive of the costs to finance those activities and exclusive of income taxes, neither of which is directly relevant to the efficiency of those operations.

You should not consider EBIT an alternative to, or a more meaningful indicator of, our operating performance than operating income or net income as determined in accordance with GAAP. In addition, our EBIT may not be comparable to a similarly titled measure of another company. The reconciliations of EBIT to operating income and net income for 2007, 2006 and 2005 are presented below.

In millions	2007	2006	2005
Operating revenues	$2,494	$2,621	$2,718
Operating expenses	2,005	2,133	2,276
Operating income	489	488	442
Minority interest	(30)	(23)	(22)
Other income (expense)	4	(1)	(1)
EBIT	463	464	419
Interest expense	125	123	109
Earnings before income taxes	338	341	310
Income taxes	127	129	117
Net income	$211	$212	$193

Summarized income statement, balance sheet and capital expenditure information by segment as of and for the years ended December 31, 2007, 2006 and 2005 is shown in the following tables.

2007

In millions	Distribution operations	Retail energy operations	Wholesale services	Energy investments	Corporate and intercompany eliminations	Consolidated AGL Resources
Operating revenues from external parties	$1,477	$892	$83	$42	$-	$2,494
Intercompany revenues (1)	188	-	-	-	(188)	-
Total operating revenues	1,665	892	83	42	(188)	2,494
Operating expenses						
Cost of gas	845	704	6	2	(188)	1,369
Operation and maintenance	330	69	38	19	(5)	451
Depreciation and amortization	122	5	4	5	8	144
Taxes other than income taxes	33	1	1	1	5	41
Total operating expenses	1,330	779	49	27	(180)	2,005
Operating income (loss)	335	113	34	15	(8)	489
Minority interest	-	(30)	-	-	-	(30)
Other income	3	-	-	-	1	4
EBIT	$338	$83	$34	$15	$(7)	$463
Identifiable and total assets	$4,831	$284	$900	$287	$(34)	$6,268
Goodwill	$406	$-	$-	$14	$-	$420
Capital expenditures	$201	$2	$2	$26	$28	$259

2006

In millions	Distribution operations	Retail energy operations	Wholesale services	Energy investments	Corporate and intercompany eliminations	Consolidated AGL Resources
Operating revenues from external parties	$1,467	$930	$182	$41	$1	$2,621
Intercompany revenues (1)	157	-	-	-	(157)	-
Total operating revenues	1,624	930	182	41	(156)	2,621
Operating expenses						
Cost of gas	817	774	43	5	(157)	1,482
Operation and maintenance	350	64	46	20	(7)	473
Depreciation and amortization	116	3	2	5	12	138
Taxes other than income taxes	33	1	1	1	4	40
Total operating expenses	1,316	842	92	31	(148)	2,133
Operating income (loss)	308	88	90	10	(8)	488
Minority interest	-	(23)	-	-	-	(23)
Other income (expense)	2	(2)	-	-	(1)	(1)
EBIT	$310	$63	$90	$10	$(9)	$464
Identifiable and total assets	$4,565	$298	$849	$373	$62	$6,147
Goodwill	$406	$-	$-	$14	$-	$420
Capital expenditures	$174	$9	$2	$23	$45	$253

2005

In millions	Distribution operations	Retail energy operations	Wholesale services	Energy investments	Corporate and intercompany eliminations	Consolidated AGL Resources
Operating revenues from external parties	$1,571	$996	$95	$56	$-	$2,718
Intercompany revenues (1)	182	-	-	-	(182)	-
Total operating revenues	1,753	996	95	56	(182)	2,718
Operating expenses						
Cost of gas	939	850	3	16	(182)	1,626
Operation and maintenance	372	58	39	17	(9)	477
Depreciation and amortization	114	2	2	5	10	133
Taxes other than income taxes	32	1	1	1	5	40
Total operating expenses	1,457	911	45	39	(176)	2,276
Operating income (loss)	296	85	50	17	(6)	442
Minority interest	-	(22)	-	-	-	(22)
Other income (expense)	3	-	(1)	2	(5)	(1)
EBIT	$299	$63	$49	$19	$(11)	$419
Identifiable and total assets	$4,788	$343	$1,058	$350	$(219)	$6,320
Goodwill	$406	$-	$-	$14	$-	$420
Capital expenditures	$215	$4	$1	$9	$38	$267

(1) Intercompany revenues – Wholesale services records its energy marketing and risk management revenue on a net basis. Wholesale services total operating revenues include intercompany revenues of $638 million in 2007, $531 million in 2006 and $792 million in 2005.

Note 10 - Quarterly Financial Data (Unaudited)

Our quarterly financial data for 2007, 2006 and 2005 are summarized below. The variance in our quarterly earnings is the result of the seasonal nature of our primary business.

In millions, except per share amounts	March 31	June 30	Sept. 30	Dec. 31
2007				
Operating revenues	$973	$467	$369	$685
Operating income	216	78	55	140
Net income	102	30	13	66
Basic earnings per share	1.31	0.40	0.17	0.86
Diluted earnings per share	1.30	0.40	0.17	0.86
2006				
Operating revenues	$1,044	$436	$434	$707
Operating income	228	60	90	110
Net income	110	19	36	47
Basic earnings per share	1.42	0.25	0.46	0.60
Diluted earnings per share	1.41	0.25	0.46	0.60
2005				
Operating revenues	$908	$430	$387	$993
Operating income	181	66	54	141
Net income	88	24	15	66
Basic earnings per share	1.15	0.31	0.19	0.86
Diluted earnings per share	1.14	0.30	0.19	0.85

Our basic and diluted earnings per common share are calculated based on the weighted daily average number of common shares and common share equivalents outstanding during the quarter. Those totals differ from the basic and diluted earnings per share shown in the statements of consolidated income, which are based on the weighted average number of common shares and common share equivalents outstanding during the entire year.

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders of AGL Resources Inc.:

In our opinion, the consolidated financial statements listed in the index appearing under Item 15(a)(1) present fairly, in all material respects, the financial position of AGL Resources Inc. and its subsidiaries at December 31, 2007 and 2006, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2007, in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the accompanying index appearing under Item 15(a)(2) presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2007, based on criteria established in *Internal Control - Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements and financial statement schedule, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in Management's Report on Internal Control Over Financial Reporting appearing under Item 9A. Our responsibility is to express opinions on these financial statements, on the financial statement schedule, and on the Company's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included 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. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

As discussed in Notes 4 and 3, respectively, to the consolidated financial statements, AGL Resources Inc. and subsidiaries changed its method of accounting for stock based compensation plans as of January 1, 2006 and its method of accounting for defined benefit pension and other postretirement plans as of December 31, 2006. In addition, as discussed in Note 8, effective January 1, 2007, the Company changed its method of accounting for uncertain tax positions.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ PricewaterhouseCoopers LLP
Atlanta, Georgia
February 5, 2008

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None

ITEM 9A. CONTROLS AND PROCEDURES

Conclusions Regarding the Effectiveness of Disclosure Controls and Procedures

Under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, we conducted an evaluation of our disclosure controls and procedures, as such term is defined under Rule 13a-15(e) promulgated under the Securities Exchange Act of 1934, as amended (the Exchange Act). Based on this evaluation, our principal executive officer and our principal financial officer concluded that our disclosure controls and procedures were effective as of December 31, 2007, in providing a reasonable level of assurance that information we are required to disclose in reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods in SEC rules and forms, including a reasonable level of assurance that information required to be disclosed by us in such reports is accumulated and communicated to our management, including our principal executive officer and our principal financial officer, as appropriate to allow timely decisions regarding required disclosure.

Management's Report on Internal Control Over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, we conducted an evaluation of the effectiveness of our internal control over financial reporting based on the framework in *Internal Control - Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

Based on our evaluation under the framework in *Internal Control — Integrated Framework* issued by COSO, our management concluded that our internal control over financial reporting was effective as of December 31, 2007, in providing reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

February 5, 2008

/s/ John W Somerhalder II
John W. Somerhalder II
Chairman, President and Chief Executive Officer

/s/ Andrew W. Evans
Andrew W. Evans
Executive Vice President and Chief Financial Officer

Changes in Internal Control over Financial Reporting

There were no changes in our internal control over financial reporting identified in connection with the above-referenced evaluation by management of the effectiveness of our internal control over financial reporting that occurred during the fourth quarter ended December 31, 2007, that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

ITEM 9B. OTHER INFORMATION.

None

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

The information required by this item with respect to directors will be set forth under the captions "Proposal I -Election of Directors", - "Corporate Governance - Ethics and Compliance Program," – "Committees of the Board" and "- Audit Committee" in the Proxy Statement for our 2008 Annual Meeting of Shareholders or in a subsequent amendment to this report. The information required by this item with respect to the executive officers is set forth at Part I, Item 4 of this report under the caption "Executive Officers of the Registrant." The information required by this item with respect to Section 16(a) beneficial ownership reporting compliance will be set forth under the caption "Section 16(a) Beneficial Ownership Reporting Compliance" in the Proxy Statement or subsequent amendment referred to above. All such information that is provided in the Proxy Statement is incorporated herein by reference.

ITEM 11. EXECUTIVE COMPENSATION

The information required by this item will be set forth under the captions "Compensation and Management Development Committee Report," "Compensation and Management Development Committee Interlocks and Insider Participation," "Director Compensation," "Compensation Discussion and Analysis" and "Executive Compensation" in the Proxy Statement or subsequent amendment referred to in Item 10 above.

All such information that is provided in the Proxy Statement is incorporated herein by reference, except for the information under the caption "Compensation and Management Development Committee Report" which is specifically not so incorporated herein by reference.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

The information required by this item will be set forth under the captions "Share Ownership" and "Executive Compensation -- Equity Compensation Plan Information" in the Proxy Statement or subsequent amendment referred to in Item 10 above. All such information that is provided in the Proxy Statement is incorporated herein by reference.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS AND DIRECTOR INDEPENDENCE

The information required by this item will be set forth under the captions "Corporate Governance – Director Independence" and "- Policy on Related Person Transactions" and "Certain Relationships and Related Transactions" in the Proxy Statement or subsequent amendment referred to in Item 10 above. All such information that is provided in the Proxy Statement is incorporated herein by reference.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

The information required by this item will be set forth under the caption "Proposal 2 – Ratification of the Appointment of PricewaterhouseCoopers LLP as Our Independent Registered Public Accounting Firm for 2008" in the Proxy Statement or subsequent amendment to referred to in Item 10 above. All such information that is provided in the Proxy Statement is incorporated herein by reference.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a) Documents Filed as Part of This Report.

(1) Financial Statements Included in Item 8 are the following financial statements:

- Consolidated Balance Sheets as of December 31, 2007 and 2006
- Statements of Consolidated Income for the years ended December 31, 2007, 2006, and 2005
- Statements of Consolidated Common Shareholders' Equity for the years ended December 31, 2007, 2006 and 2005
- Statements of Consolidated Cash Flows for the years ended December 31, 2007, 2006, and 2005
- Notes to Consolidated Financial Statements
- Report of Independent Registered Public Accounting Firm

(2) Financial Statement Schedules

Financial Statement Schedule II. Valuation and Qualifying Accounts - Allowance for Uncollectible Accounts and Income Tax Valuations for Each of the Three Years in the Period Ended December 31, 2007.

Schedules other than those referred to above are omitted and are not applicable or not required, or the required information is shown in the financial statements or notes thereto.

(3) Exhibits

Where an exhibit is filed by incorporation by reference to a previously filed registration statement or report, such registration statement or report is identified in parentheses.

3.1	Amended and Restated Articles of Incorporation filed November 2, 2005, with the Secretary of State of the state of Georgia (Exhibit 3.1, AGL Resources Inc. Form 8-K dated November 2, 2005).
3.2a	Bylaws, as amended on October 26, 2006 (Exhibit 3.2, AGL Resources, Inc. Form 8-K dated November 1, 2006).
3.2b	Bylaws, as amended on October 31, 2007 (Exhibit 3.2, AGL Resources, Inc. Form 8-K dated October 31, 2007).
4.1.a	Specimen form of Common Stock certificate (Exhibit 4.1, AGL Resources Inc. Form 10-K for the fiscal year ended September 30, 1999).
4.1.b	Specimen AGL Capital Corporation 6.00% Senior Notes due 2034 (Exhibit 4.1, AGL Resources Inc. Form 8-K dated September 27, 2004).
4.1.c	Specimen AGL Capital Corporation 4.95% Senior Notes due 2015. (Exhibit 4.1, AGL Resources Inc. Form 8-K dated December 21, 2004).
4.1.d	Specimen form of Right certificate (Exhibit 1, AGL Resources Inc. Form 8-K filed March 6, 1996).

4.1.e Specimen AGL Capital Corporation 6.375% Senior Secured Notes due 2016. (Exhibit 4.1, AGL Resources Inc. Form 8-K dated December 11, 2007).

4.1.f Specimen AGL Capital Corporation 7.125% Senior Secured Notes due 2011.

4.1.g Specimen AGL Capital Corporation 4.45% Senior Secured Notes due 2013.

4.2.a Indenture, dated as of December 1, 1989, between Atlanta Gas Light Company and Bankers Trust Company, as Trustee (Exhibit 4(a), Atlanta Gas Light Company registration statement on Form S-3, No. 33-32274).

4.2.b First Supplemental Indenture dated as of March 16, 1992, between Atlanta Gas Light Company and NationsBank of Georgia, National Association, as Successor Trustee (Exhibit 4(a), Atlanta Gas Light Company registration statement on Form S-3, No. 33-46419).

4.2.c Indenture, dated February 20, 2001 among AGL Capital Corporation, AGL Resources Inc. and The Bank of New York, as Trustee (Exhibit 4.2, AGL Resources Inc. registration statement on Form S-3, filed on September 17, 2001, No. 333-69500).

4.3.a Form of Guarantee of AGL Resources Inc. dated as of December 14, 2007 regarding the AGL Capital Corporation 6.375% Senior Note due 2016 (Exhibit 4.2, AGL Resources Inc. Form 8-K dated December 11, 2007).

4.3.b Form of Guarantee of AGL Resources Inc. dated as of September 27, 2004 regarding the AGL Capital Corporation 6.00% Senior Note due 2034 (Exhibit 4.1, AGL Resources Inc. Form 8-K dated September 27, 2004).

4.3.c Form of Guarantee of AGL Resources Inc. dated as of December 20, 2004 regarding the AGL Capital Corporation 4.95% Senior Note due 2015 (Exhibit 4.1, AGL Resources Inc. Form 8-K dated December 21, 2004).

4.3.d Form of Guarantee of AGL Resources Inc. dated as of March 31, 2001 regarding the AGL Capital Corporation 7.125% Senior Note due 2011.

4.3.e Form of Guarantee of AGL Resources Inc. dated as of July 2, 2003 regarding the AGL Capital Corporation 4.45% Senior Note due 2011.

4.4.a Rights Agreement dated as of March 6, 1996 between AGL Resources Inc. and Wachovia Bank of North Carolina, N.A. as Rights Agent (Exhibit 1, AGL Resources Inc. Form 8-A dated March 6, 1996).

4.4.b Second Amendment to Rights Agreement dated as of June 5, 2002 between AGL Resources Inc. and Equiserve Trust Company, N.A. (Exhibit 1, AGL Resources Inc. Amendment No. 1 to Form 8-A dated June 2, 2002).

10.1 Director and Executive Compensation Contracts, Plans and Arrangements.

Director Compensation Contracts, Plans and Arrangements

10.1.a AGL Resources Inc. Amended and Restated 1996 Non-Employee Directors Equity Compensation Plan (Exhibit 10.1, AGL Resources Inc. Form 10-Q for the quarter ended September 30, 2002).

10.1.b First Amendment to the AGL Resources Inc. Amended and Restated 1996 Non-Employee Directors Equity Compensation Plan (Exhibit 10.1.o, AGL Resources Inc. Form 10-K for the fiscal year ended December 31, 2002).

10.1.c Second Amendment to the AGL Resources Inc. Amended and Restated 1996 Non-Employee Directors Equity Compensation Plan (Exhibit 10.1.k, AGL Resources Inc. Form 10-Q for the quarter ended June 30, 2007).

10.1.d AGL Resources Inc. 2006 Non-Employee Directors Equity Compensation Plan (incorporated herein by reference to Annex C of the AGL Resources Inc. Proxy Statement for the Annual Meeting of Shareholders held May 3, 2006 filed on March 20, 2006).

10.1.e First Amendment to the AGL Resources Inc. 2006 Non-Employee Directors Equity Compensation Plan (Exhibit 10.1.i, AGL Resources Inc. Form 10-Q for the quarter ended June 30, 2007).

10.1.f AGL Resources Inc. 1998 Common Stock Equivalent Plan for Non-Employee Directors (Exhibit 10.1.b, AGL Resources Inc. Form 10-Q for the quarter ended December 31, 1997).

10.1.g First Amendment to the AGL Resources Inc. 1998 Common Stock Equivalent Plan for Non-Employee Directors (Exhibit 10.5, AGL Resources Inc. Form 10-Q for the quarter ended March 31, 2000).

10.1.h Second Amendment to the AGL Resources Inc. 1998 Common Stock Equivalent Plan for Non-Employee Directors (Exhibit 10.4, AGL Resources Inc. Form 10-Q for the quarter ended September 30, 2002).

10.1.i Third Amendment to the AGL Resources Inc. 1998 Common Stock Equivalent Plan for Non-Employee Directors (Exhibit 10.5, AGL Resources Inc. Form 10-Q for the quarter ended September 30, 2002).

10.1.j Fourth Amendment to the AGL Resources Inc. 1998 Common Stock Equivalent Plan for Non-Employee Directors (Exhibit 10.1.m, AGL Resources Inc. Form 10-Q for the quarter ended June 30, 2007).

10.1.k Description of Directors' Compensation (Exhibit 10.1, AGL Resources Inc. Form 8-K dated December 1, 2004).

10.1.l Description of Director's Compensation with respect to the annual retainer and description of Director non-employee share-ownership guidelines (Item 1.01, AGL Resources Inc. Form 8-K dated December 7, 2005).

10.1.m Description of Director's Compensation with respect to the annual retainer and description of Director non-employee share-ownership guidelines (Item 1.01, AGL Resources Inc. Form 8-K dated October 26, 2006).

10.1.n Form of Stock Award Agreement for Non-Employee Directors (Exhibit 10.1.aj, AGL Resources Inc. Form 10-K for the fiscal year ended December 31, 2004).

10.1.o Form on Nonqualified Stock Option Agreement for Non-Employee Directors (Exhibit 10.1.ak, AGL Resources Inc. Form 10-K for the fiscal year ended December 31, 2004).

10.1.p Form of Director Indemnification Agreement, dated April 28, 2004, between AGL Resources Inc., on behalf of itself and the Indemnities named therein (Exhibit 10.3, AGL Resources Inc. Form 10-Q for the quarter ended June 30, 2004).

Executive Compensation Contracts, Plans and Arrangements

10.1.q AGL Resources Inc. Long-Term Stock Incentive Plan of 1990 (Exhibit 10(ii), Atlanta Gas Light Company Form 10-K for the fiscal year ended September 30, 1991).

10.1.r First Amendment to the AGL Resources Inc. Long-Term Stock Incentive Plan of 1990 (Exhibit B to the Atlanta Gas Light Company Proxy Statement for the Annual Meeting of Shareholders held February 5, 1993).

10.1.s Second Amendment to the AGL Resources Inc. Long-Term Stock Incentive Plan of 1990 (Exhibit 10.1.d, AGL Resources Inc. Form 10-K for the fiscal year ended September 30, 1997).

10.1.t Third Amendment to the AGL Resources Inc. Long-Term Stock Incentive Plan of 1990 (Exhibit C to the Proxy Statement and Prospectus filed as a part of Amendment No. 1 to Registration Statement on Form S-4, No. 33-99826).

10.1.u Fourth Amendment to the AGL Resources Inc. Long-Term Stock Incentive Plan of 1990 (Exhibit 10.1.f, AGL Resources Inc. Form 10-K for the fiscal year ended September 30, 1997).

10.1.v Fifth Amendment to the AGL Resources Inc. Long-Term Stock Incentive Plan of 1990 (Exhibit 10.1.g, AGL Resources Inc. Form 10-K for the fiscal year ended September 30, 1997).

10.1.w Sixth Amendment to the AGL Resources Inc. Long-Term Stock Incentive Plan of 1990 (Exhibit 10.1.a, AGL Resources Inc. Form 10-Q for the quarter ended March 31, 1998).

10.1.x Seventh Amendment to the AGL Resources Inc. Long-Term Stock Incentive Plan of 1990 (Exhibit 10.1, AGL Resources Inc. Form 10-Q for the quarter ended December 31, 1998).

10.1.y Eighth Amendment to the AGL Resources Inc. Long-Term Stock Incentive Plan of 1990 (Exhibit 10.1, AGL Resources Inc. Form 10-Q for the quarter ended March 31, 2000).

10.1.z Ninth Amendment to the AGL Resources Inc. Long-Term Stock Incentive Plan 1990 (Exhibit 10.6, AGL Resources Inc. Form 10-Q for the quarter ended September 30, 2002).

10.1.aa Tenth Amendment to the AGL Resources Inc. Long-Term Stock Incentive Plan 1990 (Exhibit 10.1.n, AGL Resources Inc. Form 10-Q for the quarter ended June 30, 2007).

10.1.ab AGL Resources Inc. Long-Term Incentive Plan (1999), as amended and restated as of January 1, 2002 (Exhibit 99.2, AGL Resources Inc. Form 10-Q for the quarter ended March 31, 2002).

10.1.ac First amendment to the AGL Resources Inc. Long-Term Incentive Plan (1999), as amended and restated (Exhibit 10.1.b, AGL Resources Inc. Form 10-K for the fiscal year ended December 31, 2004).

10.1.ad Second amendment to the AGL Resources Inc. Long-Term Incentive Plan (1999), as amended and restated (Exhibit 10.1.l, AGL Resources Inc. Form 10-Q for the quarter ended June 30, 2007).

10.1.ae AGL Resources Inc. Officer Incentive Plan (Exhibit 10.2, AGL Resources Inc. Form 10-Q for the quarter ended June 30, 2001).

10.1.af First amendment to the AGL Resources Inc. Officer Incentive Plan (Exhibit 10.1.j, AGL Resources Inc. Form 10-Q for the quarter ended June 30, 2007).

10.1.ag AGL Resources Inc. 2007 Omnibus Performance Incentive Plan (Annex A of AGL Resources Inc.'s Schedule 14A, File No. 001-14174, filed with the Securities and Exchange Commission on March 19, 2007).

10.1.ah Form of Incentive Stock Option Agreement - AGL Resources Inc. 2007 Omnibus Performance Incentive Plan (Exhibit 10.1.b, AGL Resources Inc. Form 10-Q for the quarter ended June 30, 2007).

10.1.ai Form of Nonqualified Stock Option Agreement - AGL Resources Inc. 2007 Omnibus Performance Incentive Plan (Exhibit 10.1.c, AGL Resources Inc. Form 10-Q for the quarter ended June 30, 2007).

10.1.aj Form of Performance Cash Award Agreement - AGL Resources Inc. 2007 Omnibus Performance Incentive Plan (Exhibit 10.1.d, AGL Resources Inc. Form 10-Q for the quarter ended June 30, 2007).

10.1.ak Form of Restricted Stock Agreement (performance based) - AGL Resources Inc. 2007 Omnibus Performance Incentive Plan (Exhibit 10.1.e, AGL Resources Inc. Form 10-Q for the quarter ended June 30, 2007).

10.1.al Form of Restricted Stock Agreement (time based) - AGL Resources Inc. 2007 Omnibus Performance Incentive Plan (Exhibit 10.1.f, AGL Resources Inc. Form 10-Q for the quarter ended June 30, 2007).

10.1.am Form of Restricted Stock Unit Agreement - AGL Resources Inc. 2007 Omnibus Performance Incentive Plan. (Exhibit 10.1.g, AGL Resources Inc. Form 10-Q for the quarter ended June 30, 2007)

10.1.an Form of Stock Appreciation Rights Agreement - AGL Resources Inc. 2007 Omnibus Performance Incentive Plan (Exhibit 10.1.h, AGL Resources Inc. Form 10-Q for the quarter ended June 30, 2007).

10.1.ao Form of Incentive Stock Option Agreement, Nonqualified Stock Option Agreement and Restricted Stock Agreement for key employees (Exhibit 10.1, AGL Resources Inc. Form 10-Q for the quarter ended September 30, 2004).

10.1.ap Form of Performance Unit Agreement for key employees (Exhibit 10.1.e, AGL Resources Inc. Form 10-K for the fiscal year ended December 31, 2004).

10.1.aq Forms of Nonqualified Stock Option Agreement without the reload provision (LTIP and Officer Plan) (Exhibit 10.1, AGL Resources Inc. Form 8-K dated March 15, 2005).

10.1.ar Form of Nonqualified Stock Option Agreement with the reload provision (Officer Plan) (Exhibit 10.2, AGL Resources Inc. Form 8-K dated March 15, 2005).

10.1.as Form of Restricted Stock Unit Agreement and Performance Cash Unit Agreement for key employees (Exhibit 10.1 and 10.2, respectively, AGL Resources Inc. Form 8-K dated February 24, 2006).

10.1.at AGL Resources Inc. Nonqualified Savings Plan as amended and restated as of January 1, 2007 (Exhibit 10.1.af, AGL Resources Inc. Form 10-K for the fiscal year ended December 31, 2006).

10.1.au AGL Resources Inc. Executive Performance Incentive Plan dated February 2, 2002 (Exhibit 99.1, AGL Resources Inc. Form 10-Q for the quarter ended March 31, 2002).

10.1.av AGL Resources Inc. Annual Incentive Plan - 2006 (Exhibit 10.1, AGL Resources Inc. Form

8-K/A dated February 24, 2006).

10.1.aw AGL Resources Inc. Annual Incentive Plan - 2007 (Exhibit 10.1, AGL Resources Inc. Form 8-K dated August 6, 2007).

10.1.ax Description of Annual Incentive Compensation Arrangement for Douglas N. Schantz.

10.1.ay Continuity Agreement, dated December 1, 2003, by and between AGL Resources Inc., on behalf of itself and AGL Services Company (its wholly owned subsidiary) and Kevin P. Madden (Exhibit 10.1.w, AGL Resources Inc. Form 10-K for the fiscal year ended December 31, 2003).

10.1.az Amendment to Continuity Agreement, dated February 24, 2006, by and between AGL Resources Inc., on behalf of itself and AGL Services Company (its wholly owned subsidiary) and Kevin P. Madden (Exhibit 10.6, AGL Resources Inc. Form 8-K/A dated February 24, 2006).

10.1.ba Continuity Agreement, dated December 1, 2003, by and between AGL Resources Inc., on behalf of itself and AGL Services Company (its wholly owned subsidiary) and Paul R. Shlanta (Exhibit 10.1.z, AGL Resources Inc. Form 10-K for the fiscal year ended December 31, 2003).

10.1.bb Amendment to Continuity Agreement, dated February 24, 2006, by and between AGL Resources Inc., on behalf of itself and AGL Services Company (its wholly owned subsidiary) and Paul R. Shlanta (Exhibit 10.7, AGL Resources Inc. Form 8-K/A dated February 24, 2006).

10.1.bc Continuity Agreement, dated September 30, 2005, by and between AGL Resources Inc., on behalf of itself and AGL Services Company (its wholly owned subsidiary) and Andrew W. Evans (Exhibit 10.1, AGL Resources Inc. Form 8-K dated September 27, 2005).

10.1.bd Amendment to Continuity Agreement, dated February 24, 2006, by and between AGL Resources Inc., on behalf of itself and AGL Services Company (its wholly owned subsidiary) and Andrew W, Evans (Exhibit 10.5, AGL Resources Inc. Form 8-K/A dated February 24, 2006).

10.1.be Continuity Agreement, dated January 1, 2006, by and between AGL Resources, Inc., on behalf of itself and AGL Services Company (its wholly owned subsidiary) and R. Eric Martinez, Jr. (Exhibit 10.4, AGL Resources Inc. Form 8-K/A dated February 24, 2006).

10.1.bf Continuity Agreement, dated March 3, 2006, by and between AGL Resources Inc., on behalf of itself and AGL Services Company (its wholly owned subsidiary) and John W. Somerhalder II (Exhibit 10.2 AGL Resources, Inc. Form 8-K dated March 8, 2006).

10.1.bg Continuity Agreement, dated March 15, 2006, by and between AGL Resources Inc., on behalf of itself and AGL Services Company (its wholly owned subsidiary) and Douglas N. Schantz (Exhibit 10.1.as AGL Resources, Inc. Form 10-K for the fiscal year ended December 31, 2006).

10.1.bh Continuity Agreement, dated December 1, 2007, by and between AGL Resources Inc., on behalf of itself and AGL Services Company (its wholly owned subsidiary) and John W. Somerhalder II (Exhibit 10.1.a AGL Resources, Inc. Form 8-K dated January 8, 2008).

10.1.bi Continuity Agreement, dated December 1, 2007, by and between AGL Resources Inc., on behalf of itself and AGL Services Company (its wholly owned subsidiary) and Andrew W. Evans (Exhibit 10.1.b AGL Resources, Inc. Form 8-K dated January 8, 2008).

10.1.bj Continuity Agreement, dated December 1, 2007, by and between AGL Resources Inc., on behalf of itself and AGL Services Company (its wholly owned subsidiary) and Kevin P. Madden (Exhibit 10.1.c AGL Resources, Inc. Form 8-K dated January 8, 2008).

10.1.bk Continuity Agreement, dated December 1, 2007, by and between AGL Resources Inc., on behalf of itself and AGL Services Company (its wholly owned subsidiary) and Douglas N. Schantz (Exhibit 10.1.d AGL Resources, Inc. Form 8-K dated January 8, 2008).

10.1.bl Continuity Agreement, dated December 1, 2007, by and between AGL Resources Inc., on behalf of itself and AGL Services Company (its wholly owned subsidiary) and Paul R. Shlanta.

10.1.bm Form of AGL Resources Inc. Executive Post Employment Medical Benefit Plan (Exhibit 10.1.d, AGL Resources Inc. Form 10-Q for the quarter ended June 30, 2003).

10.1.bn Description of Compensation Agreement for each of Kevin P. Madden, R. Eric Martinez, Jr., Paul R. Shlanta and Andrew W. Evans (Item 1.01, AGL Resources Inc. Form 8-K, dated February 1, 2006).

10.1.bo Description of Compensation Agreement for each of Andrew W. Evans and R. Eric Martinez, Jr. (Item 1.01, AGL Resources Inc. Form 8-K, dated May 2, 2006).

10.1.bp Description of compensation for each of John W. Somerhalder, Andrew W. Evans, Kevin P. Madden, R. Eric Martinez Jr. and Paul R. Shlanta (Item 1.01, AGL Resources Inc. Form 8-K, dated January 30, 2007).

10.1.bq Description of One-Time Cash Award for D. Raymond Riddle and Chairman of the Board Retainer (Item 5.02, AGL Resources Inc. Form 8-K, dated March 23, 2007).

10.1.br AGL Resources Inc. Share Repurchase Program, dated February 3, 2006 (Item 1.01 AGL Resources Inc. Form 8-K, dated February 1, 2006).

10.2 Guaranty Agreement, effective December 13, 2005, by and between Atlanta Gas Light Company and AGL Resources Inc. (Exhibit 10.2, AGL Resources Inc. Form 10-K for the fiscal year ended December 31, 2006)

10.3 Form of Commercial Paper Dealer Agreement between AGL Capital Corporation, as Issuer, AGL Resources Inc., as Guarantor, and the Dealers named therein, dated September 25, 2000 (Exhibit 10.79, AGL Resources Inc. Form 10-K for the fiscal year ended September 30, 2000).

10.4 Guarantee of AGL Resources Inc., dated October 5, 2000, of payments on promissory notes issued by AGL Capital Corporation (AGLCC) pursuant to the Issuing and Paying Agency Agreement dated September 25, 2000, between AGLCC and The Bank of New York (Exhibit 10.80, AGL Resources Inc. Form 10-K for the fiscal year ended September 30, 2000).

10.5 Issuing and Paying Agency Agreement, dated September 25, 2000, between AGL Capital Corporation and The Bank of New York. (Exhibit 10.81, AGL Resources Inc. Form 10-K for the fiscal year ended September 30, 2000).

10.6 Amended and Restated Master Environmental Management Services Agreement, dated July 25, 2002 by and between Atlanta Gas Light Company and The RETEC Group, Inc. (Exhibit 10.2, AGL Resources Inc. Form 10-Q for the quarter ended June 30, 2003). (Confidential treatment pursuant to 17 CFR Sections 200.80 (b) and 240.24-b has been granted regarding certain portions of this exhibit, which portions have been filed separately with the Commission).

10.7 Credit Agreement dated as of August 31, 2006, by and among AGL Resources Inc., AGL Capital Corporation, SunTrust Bank, as administrative agent, Wachovia Bank, National Association, as syndication agent, JPMorgan Chase Bank, N.A., The Bank of Tokyo-Mitsubishi UFJ, Ltd. and Calyon New York Branch, as co-documentation agents, and the several other banks and other financial institutions named therein (Exhibit 10, AGL Resources Inc. Form 8-K dated August 31, 2006).

10.8 SouthStar Energy Services LLC Agreement, dated April 1, 2004 by and between Georgia Natural Gas Company and Piedmont Energy Company (Exhibit 10, AGL Resources Inc. Form 10-Q for the quarter ended March 31, 2004).

14 AGL Resources Inc. Code of Ethics for its Chief Executive Officer and its Senior Financial Officers (Exhibit 14, AGL Resources Inc. Form 10-K for the year ended December 31, 2004).

21 Subsidiaries of AGL Resources Inc.

23 Consent of PricewaterhouseCoopers LLP, independent registered public accounting firm.

24 Powers of Attorney (included on signature page hereto).

31.1 Certification of John W. Somerhalder II pursuant to Rule 13a – 14(a).

31.2 Certification of Andrew W. Evans pursuant to Rule 13a – 14(a).

32.1 Certification of John W. Somerhalder II pursuant to 18 U.S.C. Section 1350.

32.2 Certification of Andrew W. Evans pursuant to 18 U.S.C. Section 1350.

(b) Exhibits filed as part of this report.

See Item 15(a)(3).

(c) Financial statement schedules filed as part of this report.

See Item 15(a)(2).

SIGNATURES

In accordance with Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned; thereunto duly authorized, on February 6, 2008.

AGL RESOURCES INC.

By: /s/ John W. Somerhalder II
John W. Somerhalder II
Chairman, President and Chief Executive Officer

Power of Attorney

KNOW ALL MEN BY THESE PRESENTS, that each person whose signature appears below constitutes and appoints John W. Somerhalder II, Andrew W. Evans, Paul R. Shlanta and Bryan E. Seas, and each of them, his or her true and lawful attorneys-in-fact and agents, with full power of substitution and resubstitution, for him or her and in his or her name, place and stead, in any and all capacities, to sign any and all amendments to this Annual Report on Form 10-K for the year ended December 31, 2007, and to file the same, with all exhibits thereto and other documents in connection therewith, with the Securities and Exchange Commission, granting unto said attorneys-in-fact and agents, and each of them, full power and authority to do and perform each and every act and thing requisite or necessary to be done, as fully to all intents and purposes as he or she might or could do in person, hereby ratifying and confirming all that said attorneys-in-fact and agents or any of them, or their or his substitute or substitutes, may lawfully do or cause to be done by virtue hereof.

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities indicated as of February 6, 2008.

Signatures	Title
/s/ John W. Somerhalder II John W. Somerhalder II	Chairman, President and Chief Executive Officer (Principal Executive Officer)
/s/ Andrew W. Evans Andrew W. Evans	Executive Vice President and Chief Financial Officer (Principal Financial Officer)
/s/ Bryan E. Seas Bryan E. Seas	Vice President, Controller and Chief Accounting Officer (Principal Accounting Officer)
/s/ Thomas D. Bell, Jr. Thomas D. Bell, Jr.	Director
/s/ Charles R. Crisp Charles R. Crisp	Director
/s/ Michael J. Durham Michael J. Durham	Director
/s/ Arthur E. Johnson Arthur E. Johnson	Director
/s/ Wyck A. Knox, Jr. Wyck A. Knox, Jr.	Director
/s/ Dennis M. Love Dennis M. Love	Director
/s/ Charles H. McTier Charles H. McTier	Director
/s/ Dean R. O'Hare Dean R. O'Hare	Director
/s/ D. Raymond Riddle D. Raymond Riddle	Director
/s/ James A. Rubright James A. Rubright	Director
/s/ Felker W. Ward, Jr. Felker W. Ward, Jr.	Director
/s/ Bettina M. Whyte Bettina M. Whyte	Director
/s/ Henry C. Wolf Henry C. Wolf	Director

Schedule II

AGL Resources Inc. and Subsidiaries

VALUATION AND QUALIFYING ACCOUNTS - ALLOWANCE FOR UNCOLLECTIBLE ACCOUNTS AND INCOME TAX VALUATION FOR EACH OF THE THREE YEARS IN THE PERIOD ENDED DECEMBER 31, 2007.

In millions	Allowance for uncollectible accounts	Income tax valuation
Balance at December 31, 2004	$15	$8
Provisions charged to income in 2005	17	-
Accounts written off as uncollectible, net in 2005	(17)	-
Additional valuation allowances	-	1
Balance at December 31, 2005	15	9
Provisions charged to income in 2006	22	-
Accounts written off as uncollectible, net in 2006	(22)	-
Decrease due to change in circumstances	-	(6)
Balance at December 31, 2006	15	3
Provisions charged to income in 2007	19	-
Accounts written off as uncollectible, net in 2007	(20)	-
Balance at December 31, 2007	$14	$3

ATTACHMENT "E"

Applicant seeks authority to offer non-switched, facilities-based telecommunications services, including non-switched, private line services, facilities-based point-to-point, point-to-multipoint, and multipoint-to-multipoint services, dark fiber and last-mile dedicated connectivity between intrastate locations, both intra-exchange and interexchange, for the provision of voice, data and information services to and between telecommunications service providers and business customers, through the installation, construction, lease, management and sale of fiber optic networks throughout the State of Arizona. Applicant plans to deploy metropolitan fiber optic networks in Arizona, and to lease and sell the dark fiber that comprises these networks to telecommunications service providers and business customers.

ATTACHMENT "F"

The following is a description of AGL Networks, LLC's management team, including each member's respective biographical information:

James Gillis
President and Manager, AGL Networks
James A. Gillis was named president and manager of AGL Networks, LLC in June, 2006, having joined the company in 2003 as vice president of wholesale markets. Mr. Gillis is responsible for leading all aspects of AGL Networks, LLC's operations, including, engineering, operation and construction, sales and all new market and business expansion. He plays a vital role in the development and implementation of a sustainable long term growth strategy for AGL Networks, LLC.

Prior to being named president, Mr. Gillis served as vice president of sales, marketing and business development for AGL Networks, LLC since January 2004. In that role he was responsible for setting an aggressive customer attainment and retention program in the wholesale and enterprise markets as well as evaluating new network and market expansion.

Mr. Gillis was a founding employee of KMC Telecom Holdings, a national facilities based competitive local exchange carrier with 35 operating markets. During his tenure with KMC Telecom Holdings he held positions there as vice president southeast region, vice president market development, vice president carrier sales and senior vice president of data outsourcing. In this last assignment he originated long term agreements that had annual sales of $300M.

He spent the first 10 years of his career with Union Carbide in several sales and sales management roles in Houston, Los Angeles and the New York area. Mr. Gillis has over 25 years of sales and business development experience with the last 15 years in telecommunications.

Mr. Gillis is a graduate of Lycoming College in Williamsport, Pennsylvania.

W. Andy Harrison
Managing Director of Business Operations
Mr. Harrison is the managing director of business operations for AGL Networks, LLC. He is responsible for back-office operations including revenue assurance, budgeting, GIS and record keeping systems, finance, contract management, as well as engineering, field operations, maintenance, and implementation.

Prior to his current assignment, Mr. Harrison served as Atlanta city manager for AGL Networks, LLC. His responsibilities included managing engineering, operation, and construction for AGL Networks, LLC's Atlanta network serving 150 building, 400 route miles, and 46,000 fiber miles. He was also director of project management where he developed project management practices and procedures; and directed network implementation in Richmond, Kansas City, St Louis, and Phoenix.

ATTACHMENT "F"

Mr. Harrison has over 24 years of utility operation, construction, design, and project management experience. During his tenure at Atlanta Gaslight Company, an AGL Resources Inc. utility subsidiary, he served as a design engineer, supervisor of highway coordination, division engineer, and operations supervisor. During his tenure with Atlanta Gaslight Company, all of Atlanta Gaslight Company's DOT permits were submitted and negotiated under his supervision. As division engineer, he directed and coordinated all operations and engineering activities in the central Savannah River area of Georgia.

In addition to his career with the company, Mr. Harrison has served on the following Executive Boards: The Mutual Savings Credit Union, Boy Scouts of America, Georgia Society of Professional Engineers, and American Cancer Society. He is a past state president for the Georgia Society of Professional Engineers (GSPE) and has served as chair of the Loan Committee and Policy and Bylaw's Committee with the Mutual Savings Credit Union.

Mr. Harrison received an A.S. (cum laude) in engineering from Middle Georgia College in 1981 and a B.C.E. (cum laude) from Georgia Institute of Technology in 1983. He received his Professional Engineering license in 1988. He earned a Masters of Business Administration (cum laude) from Kennesaw State University in 2000.

William Peeples
Director of Enterprise Sales and Marketing
Mr. Peeples is the director of enterprise sales and marketing. He has a proven sales and sales management track record with strong leadership skills. These capabilities give him the ability to build and motivate successful teams within AGL Networks, LLC's channel partners. These relationships are critical success factors and continue to fuel AGL Networks, LLC's growth in the enterprise space.

Mr. Peeples is a 28 year veteran at AGL Resources Inc., holding numerous positions in operations, sales and sales management, the last 6 years of which he has spent directly in the telecom sector. He joined AGL Networks, LLC in 2001 when the business unit was in its infancy and was responsible for the development and launch of a go-to-market sales initiative for the business enterprise sector.

Recent career highlights include: 2004 Flame Keeper Award - given to select employees who demonstrate leadership, consistent high performance, produce measurable results and are committed to AGL Resources goals; 2004 AGL Networks, LLC "Salesperson of the Year"; 2002 Associate Vice President of Greater Atlanta Home Builders Association; 2000 Southern Gas Association's Service award for excellence; 1999 & 2000 Atlanta Gas Company's "President's Awards for Excellence".

Mr. Peeples is a lifelong Georgia resident, born in Thomasville and a 1982 graduate from Valdosta State University with a degree in Business Management where he is a member of the Kappa Alpha Order.

ATTACHMENT "F"

James Nolte
Vice President, Wholesale Sales
James Nolte was named vice president of wholesale sales for AGL Networks, LLC in February, 2007. He joined the company in 2004. In his current role, Mr. Nolte has overall responsibility for the strategic direction of the wholesale business at AGL Networks, LLC. He leads a wholesale team that is responsible for developing new business opportunities, providing short and long term sales planning and executing these new business opportunities that enhance the long term value of AGL Networks, LLC's business.

Prior to being named to his current position, Mr. Nolte served as director of sales for wholesale markets, while focusing on strategic accounts for AGL Networks, LLC. He was responsible for developing relationships and new business opportunities with key strategic customers in emerging wireless and wireline wholesale accounts.

Mr. Nolte spent 12 years with AT&T in sales and sales management , 3 years with BellSouth in business development for the BellSouth.net division and 3 years with ICG Communications heading their southeast sales division. At ICG, he directed over 30 sales and operations personnel spread across 4 states. He has over 20 years of sales and business development experience focused in the telecommunications sector.

Mr. Nolte holds an MBA from Goizueta School of Business, Emory University, Atlanta, Georgia.

Deborah A. Silvia
Director of Wholesale, Western Region
Ms. Silvia joined AGL Networks, LLC in September 2004 and was named director sales, wholesale. Her overall responsibilities involve managing the western region wholesale accounts. In this role she sets the strategic direction for AGL Networks, LLC to develop, plan and execute new opportunities with her existing or newly developed clients.

Since joining AGL Networks, LLC, Ms. Silvia has successfully developed and executed several strategic network expansion initiatives. She has an outstanding reputation for developing large projects with her strategic accounts that create a win-win for both parties. These complex projects generally include new network expansion and capitalize on AGL Networks, LLC's ability to build into capacity starved geographic areas and create a solution to serve the client's requirements as well as meet the financial needs of the client.

Ms. Silvia has an extensive background of 15 years in sales and business development.

Prior to joining AGL Networks, LLC, she held the position of vice president of sales, data outsourcing at KMC Telecom.

A native of Newport Rhode Island, Ms. Silvia received her bachelor's of science degree from the University of Rhode Island.

ATTACHMENT "G"

1 Provide the projected total revenue expected to be generated by the provision of telecommunications services to Arizona customers for the first twelve months following certification, adjusted to reflect the maximum rates for which the Applicant requested approval. Adjusted revenues may be calculated as the number of units sold times the maximum charge per unit.

Applicant's total revenue expected to be generated by the provision of telecommunications services to Arizona customers for the first twelve (12) months following certification, adjusted to reflect the maximum rates for which the Applicant requested approval, is approximately $2,000,000.

2 Provide the operating expenses expected to be incurred during the first twelve months of providing telecommunications services to Arizona customers following certification.

Applicant expects to incur operating expenses in the amount of $2,000,000 during the first twelve (12) months of providing telecommunications services to Arizona customers following certification.

3 Provide the net book value (original cost less accumulated depreciation) of all Arizona jurisdictional assets expected to be used in the provision of telecommunications service to Arizona customers at the end of the first twelve months of operation. Assets are not limited to plant and equipment. Items such as office equipment and office supplies should be included in this list.

Applicant estimates the net book value of all Arizona jurisdictional assets expected to be used in its provision of telecommunications services to Arizona customers at the end of the first twelve (12) months of operation will be approximately $20,000,000.

4 If the projected value of all assets is zero, please specifically state this in your response.

Not applicable.

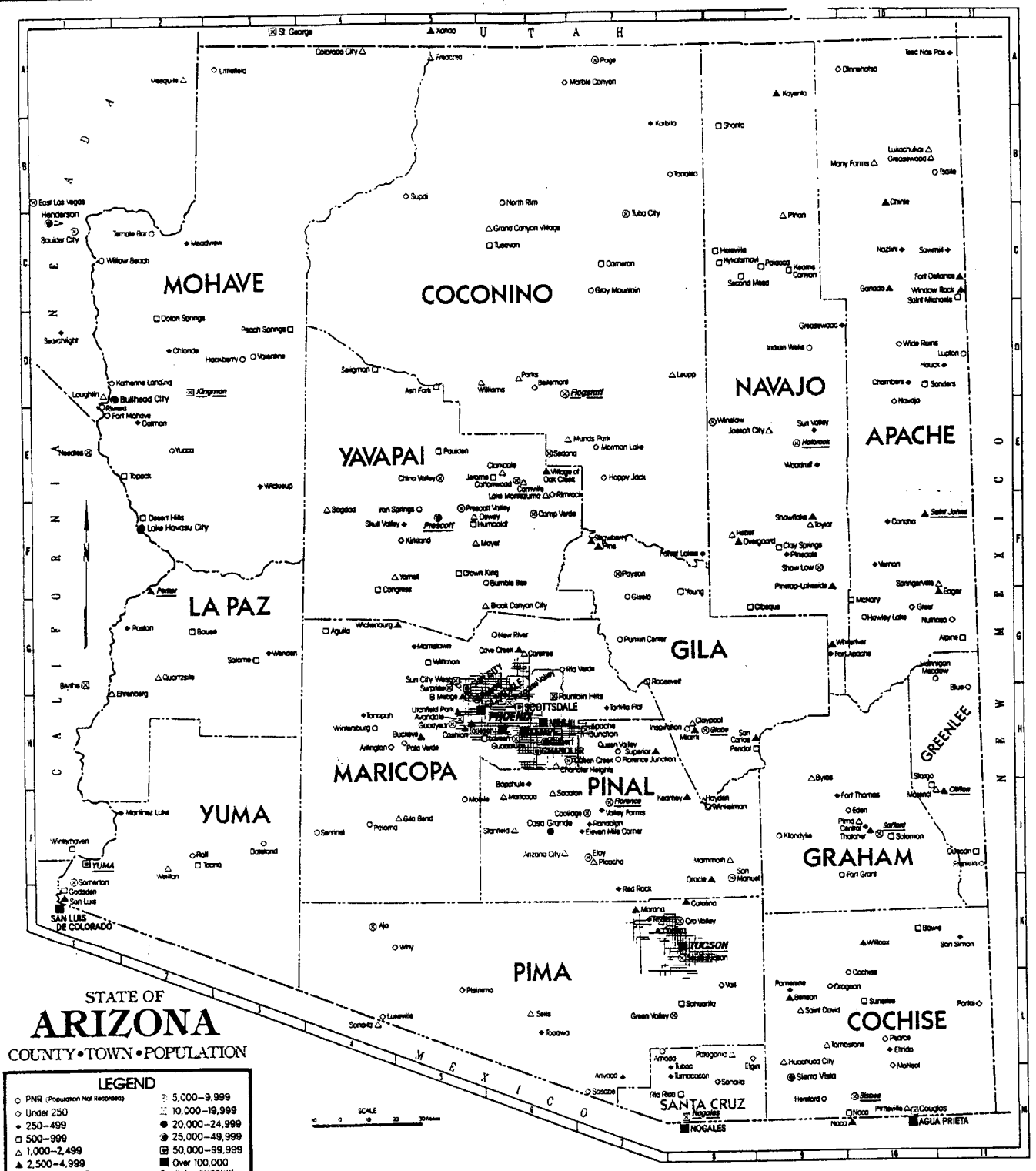
5 If the projected fair value of the assets is different than the projected net book value, also provide the corresponding projected fair value amounts.

Not applicable.

ATTACHMENT "H"

GEOGRAPHIC MARKET TO BE SERVED

A-10 Applicant adopts the statewide map of Arizona attached hereto.



STATE OF ARIZONA

COUNTY • TOWN • POPULATION

LEGEND

- PNR (Population Not Recorded)
- Under 250
- 250–499
- 500–999
- 1,000–2,499
- 2,500–4,999
- Prescott County Seat
- 5,000–9,999
- 10,000–19,999
- 20,000–24,999
- 25,000–49,999
- 50,000–99,999
- Over 100,000
- Capital: PHOENIX

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APACHE COUNTY

Alpine	520	G-11
Chambers	400	D-10
Chinle	3,620	B-10
Concho	250	J-10
Dinnehotso	99	A-9
Eagar	4,800	G-11
Fort Defiance	3,275	C-10
Greasewood	1,400	C-10
Greer	1,095	E-11
Hawley Lake	110	G-10
Houck	400	D-11
Lukachukai	1,300	B-11
Lupton	PNR	D-11
Many Farms	1,840	B-10
Nazlini	1,370	C-10
Nutrioso	100	E-10
Rock Point	400	C-10
Rough Rock	110	C-11
Saint Johns	3,700	J-11
Saint Michaels	300	C-11
Sanders	750	D-11
Sawmill	400	C-11
Springerville	2,160	J-10
Teec Nos Pos	300	A-11
Tsaile	PNR	B-10
Vernon	290	J-10
White Mountain	100	D-10
Window Rock	2,870	C-11

COCHISE COUNTY

Bernardo	4,000	L-9
Bisbee	9,040	M-10
Bowie	700	L-10
Chiricahua	200	L-9
Douglas	14,915	M-10
Hereford	100	M-9
Huachuca City	2,295	L-9
Mistwood	40	M-10
Naco	170	M-9
Pearce	1,080	L-10
Pirtleville	1,750	M-10
Portal	300	L-9
Rodeo	30	L-10
Saint David	1,600	L-9
San Simon	480	L-11
Sierra Vista	36,848	M-9
Tombstone	980	L-10
Turkey Creek	1,910	L-9
Willcox	3,790	L-10

COCONINO COUNTY

Bellemont	300	D-6
Cameron	340	C-7
Flagstaff	44,840	D-6
Forest Lakes	300	F-6
Fredonia	1,440	A-5
Grand Canyon Village	1,400	C-5
Gray Mountain	PNR	C-7
Happy Jack	150	E-7
Kaibito	100	C-7
Leupp	300	D-6
Marble Canyon	150	A-6
Meteor Crater	100	E-7
Moenkopi	1,100	B-7
Munds Park	PNR	E-6
Page	7,888	A-7
Parks	1,260	D-6
Sedona	8,300	E-6
Supai	200	B-5
Tuba City	150	B-7
Tusayan	1,400	B-7
Valle	140	D-6
Williams	2,900	D-6

GILA COUNTY

Claypool	2,400	H-5
Globe	PNR	G-7
Hayden	4,480	H-6
Hayden	1,080	J-6
Inspiration	PNR	H-6
Kearny	PNR	H-6
Miami	2,530	H-6
Naco	4,210	H-7
Peridot	400	H-6
Pine	1,600	J-7
Rural Center	PNR	G-7
Roosevelt	300	G-7
San Carlos	3,200	H-6
Stanfield	1,600	H-7
Winkelman	440	J-6
Young	530	G-6

GRAHAM COUNTY

Bryce	1,370	H-9
Cornell	300	J-10
Eden	110	J-10
Fort Grant	PNR	G-9
Fort Thomas	250	J-9
Klondyke	PNR	J-9
Pima	1,970	J-10
Safford	7,836	J-10
Solomon	560	J-10
Thatcher	2,888	J-10

GREENLEE COUNTY

Blue	30	H-11
Clifton	3,339	J-11
Duncan	980	J-11
Franklin	130	J-11
Hannigan Meadow	PNR	J-11
Morenci	2,040	J-10
Metcalf	PNR	J-11

LA PAZ COUNTY

Bouse	300	G-2
Brenckenridge	1,300	H-2
Parker	3,235	J-2
Poston	300	G-2
Quartzsite	1,800	G-2
Salome	160	G-2
Wenden	160	G-2

MARICOPA COUNTY

Aguila	300	G-4
Arlington	150	H-4
Avondale	17,840	H-5
Buckeye	4,138	H-5
Cashion	1,740	G-5
Cashion	3,014	H-5
Cave Creek	3,848	G-6
Chandler	21,275	H-6
Chandler Heights	1,000	H-6
El Mirage	4,330	H-5
Fountain Hills	10,100	H-6
Gila Bend	3,110	J-3
Gilbert	20,069	H-6
Glendale	149,915	H-5
Goodyear	3,718	H-5
Guadalupe	5,060	H-6
Litchfield	160	H-5
Litchfield Park	4,375	H-5
Mesa	267,896	H-6
Morristown	PNR	H-5
Mount Ord	250	G-5
New River	PNR	G-6
Palo Verde	100	H-5
Paloma	PNR	J-6
Paradise Valley	12,060	H-6
Peoria	46,330	H-5
Phoenix	881,548	H-6
Scottsdale	130,908	H-6
Tempe	141,865	H-6
Tolleson	4,899	H-5
Tonopah	300	H-4
Tonto Pal	1,300	H-7
Wickenburg	3,490	G-5
Wickenburg	PNR	H-4
Wittmann	1,988	G-5

MOHAVE COUNTY

Bullhead City	20,648	D-2
Chloride	300	D-2
Colorado City	3,200	A-4
Dolan Springs	750	D-2
Fort Mohave	PNR	H-1
Hackberry	300	D-2
Kingman	9,290	E-3
Lake Havasu City	41,875	E-2
Oatman	115	E-3
Peach Springs	1,000	D-3
Seligman	PNR	D-3
Valentine	100	D-3
Yucca	300	E-2

NAVAJO COUNTY

Joseph City	1,350	E-9
Kayenta	4,268	A-9
Keams Canyon	300	C-9
Kykotsmovi	600	C-8
Leupp	3,848	A-8
Pinedale	300	F-9
Pinetop-Lakeside	3,288	G-9
Rock Point	1,278	C-9
Polacca	400	C-9
Second Mesa	600	C-9
Shonto	1,500	A-9
Show Low	5,750	F-9
Snowflake	3,680	F-9
Sun Valley	2,884	E-9
Taylor	2,100	F-9
Whiteriver	1,290	G-9
Winslow	9,590	E-9
Woodruff	415	E-9

PIMA COUNTY

Ajo	3,189	K-4
Arivaca	400	M-7
Catalina	3,799	L-8
Catalina	1,280	L-7
Green Valley	8,000	L-8
Littlefield	70	L-4
Marana	3,196	L-7
Oracle	7,200	L-8
Oracle Junction	200	L-8
Pantano	300	L-8
Picacho	400	K-7
Sahuarita	500	L-8
Tucson	330	L-7
Tucson	6,810	L-8
Topawa	300	L-8
Tucson	416,960	L-8
Vail	300	L-8
Why	100	L-4

PINAL COUNTY

Apache Junction	18,878	H-7
Arizona City	1,128	J-6
Bapchule	300	J-6
Casa Grande	20,140	J-6
Coolidge	7,115	J-7
Dudleyville	300	J-7
Eloy	8,680	J-7
Florence	2,170	J-7
Florence Junction	PNR	H-7
Kearny	2,530	J-6
Mammoth	1,900	J-8
Middlemarch	1,620	J-8
Oracle	2,884	L-8
Picacho	1,400	J-7
Queen Valley	PNR	H-7
Randolph	300	J-7
Red Rock	300	L-7
Sacaton	1,680	J-6
Saint Anthony	1,000	J-7
Superior	3,000	H-7
Tortilla Flat	PNR	H-7
Valley Farms	300	J-6
Winkelman	1,000	J-6

SANTA CRUZ COUNTY

Amado	PNR	L-7
Elgin	70	L-8
Patagonia	1,260	M-8
Sonoita	75	L-8
Tubac	250	M-8
Tumacacori	PNR	M-8

YAVAPAI COUNTY

Ash Fork	500	D-6
Bagdad	1,780	F-4
Black Canyon City	3,150	E-6
Humboldt	PNR	F-6
Jerome	1,480	F-5
Kirkland	300	F-5
Mayer	1,000	F-5
Prescott	26,305	F-5
Prescott Valley	8,800	F-5
Rimrock	200	E-6
Sedona	973	D-6
Skull Valley	300	F-5
Village of Oak Creek	2,900	E-6
Yarnell	1,190	F-5

YUMA COUNTY

Dateland	160	J-2
Gadsden	500	K-1
Martinez Lake	250	J-2
Roll	200	J-2
San Luis	4,140	K-1
Somerton	3,028	J-1
Tacna	300	J-2
Wellton	1,060	J-2
Yuma	54,675	J-1

COUNTY POPULATIONS

Apache	69,600
Cochise	105,200
Coconino	76,600
Gila	43,000
Graham	26,600
Greenlee	8,500
La Paz	15,100
Maricopa	2,139,000
Mohave	93,300
Navajo	96,700
Pima	666,000
Pinal	144,000
Santa Cruz	39,900
Yavapai	191,000
Yuma	99,600

Population figures are unofficial estimates provided by the Population Statistics unit of Arizona [illegible]