BEFORE THE TENNESSEE REGULATORY AUTHORITY
NASHVILLE, TENNESSEE

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IN RE:	)	
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REVIEW OF NASHVILLE GAS COMPANY'S IPA RELATING TO ASSET MANAGEMENT FEES	)))	**DOCKET No. 05-00165**

CONSUMER ADVOCATE'S RESPONSE TO NASHVILLE GAS COMPANY'S REQUEST FOR DISCOVERY

Comes now Paul G. Summers, Attorney General and Reporter for the State of Tennessee, through the Consumer Advocate and Protection Division of the Office of the Attorney General ("Consumer Advocate" or "CAPD"), and hereby submits the following supplemental responses to Discovery Request No. 9 propounded by Nashville Gas Company ("NGC" or "Company").

DISCOVERY REQUEST NO. 9: With respect to each person you expect to call as a witness, including any expert witness, regarding this matter, state or provided:

(a) The witness' full name and work address;

RESPONSE: See attached documents.

(b) The subject matter (or subject matters) about which the witness is expected to testify;

RESPONSE: The opinions, recommendations and positions of the Consumer Advocate, as well as the supporting facts, grounds and bases, will be provided in the pre-filed direct testimony of Consumer Advocate witnesses Dr. Steve Brown and Mr. Michael Chrysler.

(c) The substance of the facts and opinions to which any expert is expected to testify;

RESPONSE: See response to 9(b).

(d) A summary of the grounds or basis of each opinion to which such witness is expected to testify;

RESPONSE: See response to 9(b).

(e) Whether or not the expert has prepared a report, letter, or memorandum of his/her findings, conclusions, or opinions;

RESPONSE: No such report, letter or memorandum exits exclusive of the pre-filed direct testimony and attached exhibits.

(f) The witness's background information, including current employer, education, professional and employment history, and qualifications within the field in which the expert is expected to testify;

RESPONSE: See attached documents.

(g) An identification of any matter in which the expert has testified by specifying the name, docket number and forum of each such case, and the dates of the prior testimony;

RESPONSE: See attached documents.

(h) The identity of all documents shown to, delivered to, received from, relied upon, or prepared by any expert witness related to the witness' expected testimony in this case.

RESPONSE: The Consumer Advocate objects to any request seeking all documents related to an issue, shown to, delivered to, received from, prepared by or reviewed by its witnesses. Such a request is ambiguous, overly broad, burdensome and is not likely to lead to the discovery of admissible evidence. Subject to and without waiving any objections stated herein the Consumer Advocate responds to the specific request as follows:

The pre-filed direct testimony submitted by the Consumer Advocate's witnesses in this docket will be complete in the sense that all necessary supporting documents and material, and all such documents and material "relied" upon, will either be supplied or appropriate citations will be made at the time of filing of testimony or that the information will be in some manner submitted into the record by a party to this matter.

Respectfully submitted,

JOE SHIRLEY, B.P.R. # 022287
Assistant Attorney General
Office of the Attorney General
Consumer Advocate and Protection Division
P.O. Box 20207
Nashville, Tennessee 37202
(615) 741-3533

Dated: March 15, 2006

CERTIFICATE OF SERVICE

I hereby certify that a true and exact copy of the foregoing has been served via the methods indicated on this 15th day of March, 2006, to the following:

Via first-class U.S. mail, postage prepaid:

James H. Jeffries IV, Esq.
Moore & Van Allen
100 North Tryon Street, Suite 4700
Charlotte, North Carolina 28202-4003

Via hand delivery:

R. Dale Grimes, Esq.
Bass, Berry & Sims, PLC
2700 First American Center
Nashville, Tennessee 37238-2700

Aaron Rochelle, Esq.
Tennessee Regulatory Authority
460 James Robertson Parkway
Nashville, Tennessee 37243-0505

#93446

JOE SHIRLEY, AAG

NASUCA Committee Resolutions contributed to by Mike Chrysler

(copies attached)

NATIONAL ASSOCIATION OF STATE UTILITY CONSUMER ADVOCATES NASUCA

The National Association of State Utility Consumer Advocates Resolution 2005-03

INFRASTRUCTURE SURCHARGE RESOLUTION

Calling upon state regulatory authorities and legislatures to refuse to allow, or to consider revoking, annual tracking adjustments to rates resulting from additional non-traditional gas, water, sewer or electric infrastructure replacement programs;

Whereas, traditional ratemaking methodologies have allowed investor shareholders to earn a return on new and upgraded mains and electric plant through general rate case reviews allowing the ratepayers being charged for the prudent and necessary system upgrades to be represented in traditional contested rate proceedings in which all items of expense and capital investments are considered; and

Whereas, depreciation provides a "funding" mechanism for natural gas, water, sewer, and electric plant replacement because it reduces net operating income and increases the revenue required from rate payers for an acceptable rate of return during the formal rate proceeding; and

Whereas, traditional ratemaking processes have withstood the test of time, so that all parties represented have an opportunity to have their interests fairly represented; and

Whereas, parties representing the interests of shareholders and company managements may propose "short-circuit" methods focused on single categories of increased expense, in order to "speed up" the recovery of costs outside the normal regulatory process, and to provide regulators ways to avoid the rate review process; and

Whereas, utilities in several states have proposed, either in rate cases or as state legislation, various "tracking methodologies" which, if allowed, would enable them to increase rates through non-traditional ratemaking processes sometimes called DSIC (Distribution System Improvement Charge), DSR (Distribution System Replacement), AMRP (Accelerated Main Replacement Program) PRP (Pipeline Replacement Program) which would allow immediate rate recovery of capital investment for new projects on a year-by-year basis in order to replace certain rate base infrastructure through a surcharge; and

Whereas, if such tracking methodologies were allowed, regulatory authorities may not be able to review such capital investments for prudence, and may not be able to review possible offsetting contemporaneous cost reductions or revenue increases from other utility activities; and

Whereas, if such tracking methodologies are allowed ratepayers will become involuntary investors paying for unreviewed investments that will increase rates;

Whereas, at a time of rising commodity costs, regulators need to understand the potential significant new burden upon consumers caused by a tracking surcharge for plant additions;

THEREFORE BE IT RESOLVED, that NASUCA calls upon state regulatory authorities and legislators to refuse to impose on consumers, or to consider revoking, non-traditional infrastructure surcharges that would increase natural gas, water, sewer or electric utility bills without traditional opportunity for consideration of countervailing cost decreases and revenue increases, and review by all parties including appropriate consumer advocacy offices prior to implementation and to remain committed to traditional ratemaking principles fairly representing the interests of both consumers and stockholders.

BE IT FURTHER RESOLVED, that NASUCA authorizes its Standing Committees to develop specific positions and to take appropriate actions consistent with the terms of this resolution to secure its implementation, with the approval of the Executive Committee of NASUCA. The Standing Committees or the Executive Committee shall notify the membership of any action taken pursuant to this resolution.

Submitted by:

Michael D. Chrysler, Chair, Consumer Protection Committee
June 12, 2005

Approved by NASUCA

Place: New Orleans, LA
Date: June 14, 2005 91974

NATIONAL ASSOCIATION OF STATE UTILITY CONSUMER ADVOCATES NASUCA

The National Association of State Utility Consumer Advocates
Resolution 2005-04

MINIMUM SERVICE QUALITY STANDARDS RESOLUTION

Calling upon state regulatory authorities to establish regular reporting requirements for utilities on service quality and to establish minimum performance standards with appropriate enforcement provisions so that adequate, reliable, and safe service is achieved and maintained; and

Whereas, adequate service quality from providers of gas, electric, water, and telecommunications services is essential to everyday life and affects almost every function of our society, and service inadequacies and interruptions frustrate or disrupt normal functions; and

Whereas, adequate service quality from such providers is also vital to our Nation's economy, our position in the global economy and to national security;

Whereas, gas, electric, water, and telecommunications service providers have a duty to provide service that is adequate, reliable, and safe; and

Whereas, consumers expect and should receive service that is consistently adequate, reliable, and safe; and

Whereas, utility industry developments over the past decade such as mergers, diversification, and changing economic conditions have encouraged utilities to cut costs, reduce staffs and outsource some utility operating functions, and such efforts to economize may have led to deterioration of service quality; and

Whereas, a gradual decline in performance may not be detected for some time if regulators do not keep informed as to service quality through regular monitoring; and

Whereas, by keeping informed, regulators are better able to recognize signs of deterioration and inadequacies so that they can take corrective action to avert major service quality problems that would otherwise be frustrating and disruptive to consumers; and

Whereas, standardized reporting requirements and regular reporting are necessary for regulators to be able to monitor service quality and changes in performance; and

Whereas, reports should address performance areas such as customer relations and billing (e.g., responsiveness of customer call centers, responsiveness to consumer complaints, timeliness of installations and repairs, and accuracy and frequency of billing and meter reading) and operating performance (e.g., frequency and duration of outages, and responsiveness to safety calls); and

Whereas, reporting requirements should be carefully designed to yield accurate data that is uniform and consistent; and

Whereas, in addition to keeping informed about service quality, regulators should establish measurable performance standards that must be met for providers to achieve and maintain a minimum quality of service, to the extent that quality of service is measurable, so that expectations are clear and problems are minimized; and

Whereas, performance standards should be supported by appropriate enforcement provisions; and

Whereas, service quality data and information should be available to the public to encourage companies to achieve good performance results, to assure that regulation is open and effective and to assist consumers who must choose among competitive providers;

THEREFORE BE IT RESOLVED, that NASUCA calls upon state regulatory authorities to establish regular service quality reporting requirements applicable to gas, electric, water, and telecommunications service providers, and to establish minimum performance standards with appropriate enforcement provisions to monitor and promote improvement toward a consistently high level of service quality for their gas, electric, water, and telecommunications customers.

BE IT FURTHER RESOLVED, that NASUCA authorizes its Standing Committees to develop specific positions and to take appropriate actions consistent with the terms of this resolution to secure its implementation, with the approval of the Executive Committee of NASUCA. The Standing Committees or the Executive Committee shall notify the membership of any action taken pursuant to this resolution.

Submitted by:

Michael D. Chrysler, Chair, Consumer Protection Committee
June 12, 2005

Approved by NASUCA:

Place: New Orleans, LA
Date: June 14, 2005

91972

NATIONAL ASSOCIATION OF STATE UTILITY CONSUMER ADVOCATES NASUCA

RESOLUTION

Calling Upon State Regulatory Authorities to resist the efforts of Local Gas Distribution Companies to expand the interpretation of gas cost to include a calculated portion of their uncollectible accounts expense or other non-gas costs in purchased gas cost recovery mechanisms.

Whereas, many natural gas Local Distribution Companies (LDCs) are permitted by State laws or regulations to change rates from time to time to track changes in the cost of natural gas supply and transportation through gas cost adjustments without a review of general rates;

Whereas, many such gas cost adjustment mechanisms provide for the periodic adjustment of rates to true up the difference between gas costs billed to consumers and gas costs incurred;

Whereas, the gas cost adjustment mechanisms have been found justified due to characteristics of the costs associated with purchasing and transporting gas to an LDC's distribution system; i.e., that such cost may make up a sizable portion of the total rate for natural gas service, that such costs are affected by many market conditions that are not within the control of the LDC, that such gas costs are volatile and may change significantly in a short time;

Whereas, some State regulatory authorities have been petitioned by LDCs to broaden the sort of expenses that may be recovered through gas cost adjustment mechanisms to include a portion of the expenses associated with uncollectible charges experienced by the LDC;

Whereas, the characteristics of uncollectible accounts are materially different from gas costs; i.e., while they are somewhat affected by variations in rates caused by changes in gas costs, uncollectible accounts expenses do not make up a sizeable portion of the total rate for natural gas service, they are affected by factors such as staffing and procedures within the control of the LDC, and the changes in uncollectible costs do not tend to be volatile;

Whereas, an expanded definition of gas costs would shift more risk to ratepayers and may remove traditional or performance based incentives for utilities to minimize costs;

THEREFORE BE IT RESOLVED, that NASUCA encourages state regulatory authorities to limit the use of gas cost adjustment mechanisms to the cost of purchasing and transporting natural gas supply to the LDC's distribution system.

BE IT FURTHER RESOLVED, that the Gas Committee of NASUCA, with the approval of the Executive Committee of NASUCA, is authorized to take all steps consistent with this Resolution in order to secure its implementation.

Submitted by:

June, 15, 2004

Approved by NASUCA 91970

NATIONAL ASSOCIATION OF STATE UTILITY CONSUMER ADVOCATES NASUCA

NASUCA RESOLUTION

HIGH WINTER ENERGY COSTS RESOLUTION

WHEREAS the cost of home heating energy has always burdened low income households disproportionately compared with households of all other income levels; and

WHEREAS one of the most effective means of measuring this disparity is to evaluate the energy burden of a household by dividing the cost of home energy by the gross income of the same household to determine the percentage of income needed to meet energy costs; and

WHEREAS in 2005, the National Energy Assistance Directors Association ("NEADA") determined that all low-income households used, on average, 15% of their gross household income for energy costs (6% for heat alone), while all households used, on average, only 3% of their gross household income for energy costs (1% heat alone); and

WHEREAS in 2004, elderly households in receipt of Supplemental Security Income paid nearly 19% of their income for energy, and households in receipt of Aid to Families with Dependent Children paid 26% of their income for energy; and

WHEREAS the Energy Information Administration ("EIA") has forecast dramatic increases in the cost of energy which will have an immediate and deleterious short term effect on the already disproportionate energy burden on low-income households; and

WHEREAS, based on EIA data from September 2005, the average family heating with oil could spend as much as $1,666 during the winter of 2005-2006. This would represent an increase of $403 over the costs for the winter of 2004-2005 and an increase of $714 over the costs for the winter of 2003-2004; and

WHEREAS the EIA anticipates that heating fuel expenditure increases from the winter of 2004 to the winter of 2005 are likely to average 73% for natural gas in the Midwest; 19% for electricity in the South; 31% for heating oil in the Northeast; and 41% for propane in the Midwest; and

WHEREAS, the Center on Budget and Policy Priorities ("CBPP"), an independent, bipartisan research institute, calculated (http://www.cbpp.org/10-6-05bud.htm) that the average low income household (income below the greater of 150% of the federal poverty guidelines or 60% of the state median income) will incur an average heating bill increase of $500 for the 2005-2006 winter; and

WHEREAS the easily predictable outcome of the combination of the extreme energy burden currently facing low-income households and the anticipated increase in home energy costs is the creation of a "perfect storm" which will result in an unparalleled challenge to the energy safety net below low-income households; and

WHEREAS these increased costs for home energy during the winter of 2005-2006 were predicated on the foreseeable actions in the marketplace based upon historically accurate and verifiable facts, factors, formulae and information; and

WHEREAS short-term and long-term effects of Hurricanes Katrina and Rita including the damage and destruction to the production, storage, transportation and infrastructure of the natural gas and crude oil industries, and the resulting escalation of home energy costs as a result of the depletion of reserves and the inability of the industries to quickly recover from the devastation remains to be calculated; and

WHEREAS the severe constraints on state and local government budgets already strain the ability of those entities to reinforce the low income safety net; and

WHEREAS the nonprofit, faith-based, and other community-based organizations, secondarily charged with the task of assisting low-income households with problems such as the imminent energy crisis are similarly constrained by limited resources and increasing energy costs; and

WHEREAS the Low Income Home Energy Assistance Program ("LIHEAP") is a federally-funded, state-administered energy plan designed to provide funding to the states to assist low-income households in meeting the costs of home energy; and

WHEREAS since the winter of 2001-2002, the national appropriation for LIHEAP has wholly failed to match the pace of the increase in home heating costs; and

WHEREAS the anticipated funding for the 2005-2006 LIHEAP Year fails to keep pace with inflation and would fail to be even minimally adequate to compensate for the anticipated spikes in home energy and home heating energy now predicted by the EIA; and

WHEREAS in 2005, NEADA determined that LIHEAP funding between the 2001-2002 and 2004-2005 fiscal year increased by 21.4%, but the share of a low-income households' heating expenditures met by the average LIHEAP grant fell from 49.4% to 25.2% for heating oil, from 52.3% to 33.4% for natural gas, and from 35.5% to 23.1% for propane; and

WHEREAS in 2005, NEADA determined that between 2001-2002 and 2004-2005 the price of oil for heating increased by $624, and the price of natural gas for heating increased by $352, and the price of propane for heating increased by $489, yet, the average LIHEAP grant increased by $3; and

WHEREAS, according to the EIA, while the average cost of home heating fuel for the coming winter may rise precipitously: heating oil by 98%, propane by 55%, and natural gas by 58%, the national appropriation for LIHEAP, since the winter of 2001-2002, has risen by only about 20%; and

WHEREAS the proposed 2005-2006 executive federal budget appropriation called for a decrease in funding of approximately $250 million with no emergency contingency funding; and

WHEREAS the House of Representatives Labor-HHS-Education Appropriations Committee has proposed FY 2006 LIHEAP funding at $2.006 billion in regular funding and no emergency contingency funding, and

WHEREAS the Senate Appropriations Committee has proposed FY 2006 LIHEAP funding at $1.8 billion in regular funding and $300 million in emergency contingency funding; and

WHEREAS the CBPP calculates that, in order to maintain 2005-2006 LIHEAP purchasing power, taking into consideration general inflation, at the same level as 2004-2005 LIHEAP, the national appropriation should increase to $3.025 billion; and

WHEREAS the CBPP calculates that a mere 5% increase in the number of eligible applicants for LIHEAP assistance would require additional national 2005-2006 LIHEAP funding in the amount of $150 million; and

WHEREAS the CBPP calculates that to hold beneficiaries of LIHEAP assistance harmless in the face of the entire expected price increase would require additional 2005-2006 LIHEAP funding in the amount of $2.033 billion; and

WHEREAS the CBPP calculates that the total minimum federal appropriation required for the 2005-2006 LIHEAP is $5.208 billion; and

WHEREAS LIHEAP remains a targeted block grant program with the built-in flexibility and an established federal-state partnership to effectively and efficiently deliver the funding necessary to ease the crisis on increasingly unaffordable energy costs for low-income households; and

WHEREAS the current appropriations and proffered amendments clearly are insufficient to deal with the anticipated increases in home energy costs; *now therefore be it*

RESOLVED that NASUCA urges Congress to appropriate FY 2006 LIHEAP regular funding of at least $5.208 billion, as recommended by CBPP, and to appropriate an additional $500 million for emergency contingency funding to assist low-income households in meeting the exorbitant home energy costs anticipated for the winter of 2005-2006; and

BE IT FURTHER RESOLVED that NASUCA authorizes its Standing Committees to develop specific positions and to take appropriate actions consistent with the terms of this resolution to secure its implementation, with the approval of the Executive Committee of NASUCA. The Standing Committees or the Executive Committee shall notify the membership of any action taken to this resolution.

Submitted by:

Michael D. Chrysler, Chair, Consumer Protection Committee
November 16, 2005

Approved by NASUCA

91969

Steve Brown, Economist

B. A. in History, University of Colorado

Ph.D. and M.A. in International Relations with a specialty in International Economics. University of Denver

M.S. in Regulatory Economics, University of Wyoming

Twenty-five years of experience with the Public Utility industry:

1979 - 1982 Tri-State Generation and Transmission Association - Power Requirements Supervisor & Rate Specialist

1982 - 1984 Arizona Electric Cooperative - Rate Analyst

1984 - 1986 Houston Lighting & Power - Supervisor of Rate Design

1986 - 1995 Iowa Utilities Board - Chief of the Bureau of Energy Efficiency- Auditing, Research & Utilities Specialist

1995 - Present Office of the Attorney General for the State of Tennessee - Consumer Advocate and Protection Division - Economist

Oral and written testimony in numerous rate proceedings before the TPSC and the Tennessee Regulatory Authority. Including the following dockets and/or companies

Dockets

TRA# 04-00288 Petition of Tennessee American Water Co. to adjust rates

Testimony Address: http://www.state.tn.us/tra/orders/2004/0400288bk.pdf

TRA # 04-00034 Petition of Chattanooga Gas to Adjust Rates

Testimony Address: http://www.state.tn.us/tra/orders/2004/0400034dm.pdf

TRA# 03-00491 F.C.C. T.R.O. Review - 03-00491

Testimony Address: http://www.state.tn.us/tra/orders/2003/0300491ib.pdf

Rebuttal Address: http://www.state.tn.us/tra/orders/2003/0300491kn.pdf

TRA# 03-00313 Petition of Nashville Gas to Adjust Rates

Testimony Address: http://www.state.tn.us/tra/orders/2003/0300313z.pdf

TRA# 03-00118 Petition of Tennessee American Water to Adjust Rates

Testimony Address: http://www.state.tn.us/tra/orders/2003/0300118bm.pdf

Rebuttal Address: http://www.state.tn.us/tra/orders/2003/0300118ca.pdf

TRA# 01-00704 Audit of Atmos/U.C.G. IPA

Testimony Address: http://www.state.tn.us/tra/orders/2001/0100704cp.pdf

TRA# 98-00559 BellSouth, C.S.A. Docket

(Testimony is currently unavailable)

TRA# 97-01364 United Cites Gas / Establishment of PBR

(Testimony is currently unavailable)

TRA# 97-01262 Permanent Prices

(Testimony is currently unavailable)

TRA# 97-00982 Petition of Chattanooga Gas to Revise Tariff

Copy Attached

Doc#79072

Before the

TENNESSEE REGULATORY AUTHORITY

IN RE:

PETITION OF CHATTANOOGA GAS COMPANY TO PLACE INTO EFFECT A REVISED NATURAL GAS TARIFF

DOCKET NO. 97-00982

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DIRECT TESTIMONY
OF
STEVE BROWN

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INTRODUCTION

Q. Please state your name.

A. Stephen N. Brown.

Q. Where do you work and what is your job title?

A. I am a Senior Economist in the Consumer Advocate Division, Office of the Attorney General.

Q. What are your responsibilities as Senior Economist?

A. I review companies' petitions for rate changes and follow the economic conditions that affect the companies.

Q. What experience do you have regarding utilities?

A. From 1986 to 1995 I was employed by the Iowa Utilities Board as Chief of the Bureau of Energy Efficiency, Auditing and Research, and Utility Specialist and State Liaison Officer to the U.S. Nuclear Regulatory Commission. From 1984 to 1986 I worked for Houston Lighting & Power as Supervisor of Rate Design. From 1982 to 1984 I worked for Arizona Electric Power Cooperative as a Rate Analyst. From 1979 to 1982 I worked for Tri-State Generation and Transmission Association as Power Requirements Supervisor and Rate Specialist. From 1979 through 1995 my work spanned many issues including cost of service studies, rate design issues, telecommunications issues and matters related to the disposal of nuclear waste.

Q. What is your educational background?

A. I have an M.S. in Regulatory Economics from the University of Wyoming, an M.A. and Ph.D. in International Relations with a specialty in International Economics from the University of Denver, and a B.A. from Colorado State University.

Q. Dr. Brown, have you authored any articles relating to your profession?

A. Yes, my articles have appeared in Public Utilities Fortnightly and the Electricity Journal.

Q. Are you and have you been a member of any professional organizations, Dr. Brown?

A. Yes, I am a past member of the NARUC Staff Committee on Management Analysis, a past trustee of and a member of the Board for the Automatic Meter Reading Association, and a current member of the National Association of Business Economists.

Q. Have you studied mathematics and statistics as part of your education?

A. Yes.

Q. Dr. Brown, do you use mathematics and statistics in combination with economics as part of your profession?

A. Yes.

Q. What were you asked to do with respect to this

case?

A. I was asked to form an opinion on the appropriate market-based common equity return, the appropriate overall cost of capital and the appropriate capital structure for Atlanta Gas Light(AGL) Company's wholly owned subsidiary in Tennessee, Chattanooga Gas (CG)Company, as well as to evaluate and assist in the evaluation of the rate of return proposed by other witnesses in this docket.

<u>OPINION ON EQUITY RETURN</u>

Q. In your opinion what rate of equity return is just and reasonable?

A. In my opinion an equity return of 10.55% is just and reasonable.

Q. Dr. Brown, what did you do to identify this just and reasonable return?

A. I examined a group of natural gas companies comparable to AGL.

<u>AGL IS THE APPROPRIATE COMPANY FOR COMPARISON</u>

Q. Why did you consider AGL the appropriate company for deriving the equity return?

A. CG's common equity is owned completely by AGL and is not publicly traded or available over the counter. Investors who desire a common equity interest in CG have only one way to obtain that interest--acquire common stock in AGL Resources, whose financial fate is determined by its prime subsidiary, AGL.

These facts alone suggest that AGL is central to the equity analysis. Also, in this docket AGL's management is well-represented. The company's witnesses -- Messrs. Thompson, Hinesley, and Overcast and Lisa Wooten -- are employed by AGL directly and none of them ever worked for CG directly. This is ample evidence that AGL management strongly directs CG's activities thus making AGL rather than CG the focus of equity analysis.

The direct involvement of AGL's management in this docket clearly indicates that CG's operations are completely intermingled with AGL's, to the point that CG is an operating company under AGL's management in much the same way that Savannah Gas is an operating company under AGL. When AGL has a rate case in Georgia, Savannah Gas is not singled out as a stand-alone investment of funds which forms the basis for a rate of return. Likewise, CG is not a stand-alone investment that forms the basis for a rate of return. The company's cost-of-capital witness, Dr. Andrews, concedes this point very early in his testimony at page 4 lines 12-13, where he says "I undertake the analysis of CGC **as if it were** [emphasis added by Dr. Brown] a stand-alone investment of funds." To me, the wording **"as if it were"** means one of two things: either CG **is not in fact** a stand-alone investment or he does not know if it is a stand-alone investment.

Finally, Dr. Andrews, at page 48 lines 6-8 of his direct testimony, suggests the capital structure of AGL Resources be used to compute CG's weighted cost of capital. These aspects of the rate filing make it appropriate to determine the cost of capital by using AGL and companies that are comparable to AGL.

Q. Does Dr. Andrews base his cost-of-capital analysis on AGL and companies comparable to AGL?

A. No, but his recommended return includes a premium meant to compensate AGL Resources.

Q. What companies form the basis for Dr. Andrews' cost-of-equity analysis?

A. He selects 22 "small" companies that have actively traded stock, that issue bonds and stocks, and which complete and file regular reports with the Securities and Exchange Commission. In contrast to CG, which is a subsidiary of AGL, many of the 22 companies are parent companies themselves with subsidiaries underneath them. Several of the 22 companies also operate in multi-state jurisdictions.

Q. In your opinion do these "small" companies are a rational basis for a cost-of-equity analysis in this docket?

A. No, I do not. On their face the 22 companies markedly differ from CG, and there is no objective basis for adjusting them so that they would somehow be comparable to CG. Because I focus on AGL, my cost-of-equity analysis uses a completely different set of companies than Dr. Andrews' analysis. A cost-of-equity analysis starts with the selection of comparable companies. To the extent the parties in this docket disagree about the starting point of an analysis, the TRA's job of assessing each analysis becomes more difficult. However, I have other sound and objective reasons for disagreeing with Dr. Andrews' analysis and results, as I will discuss at a later point in my testimony.

COMPARABLE COMPANIES SELECTED BY DR. BROWN

Q. Dr. Brown, what comparable companies did you use in your analysis?

A. I selected a group of companies composed of AGL Resources, Bay State Gas Company, Brooklyn Union Gas Company, Indiana Energy, Laclede Gas, Northwest Natural Gas, Peoples Energy, and Washington Gas Light Company. Like AGL, all of these companies have subsidiaries.

Q. What evidence do you offer to substantiate your assertion that AGL is comparable to the other eight companies?

A. The proof of comparability appears in Schedule 1. The top portion is titled "Market Statistics" and the bottom portion is titled "Financial Behavior." The market statistics show the strong similarity of the companies. For example, as of December 1996 the ratios of the market price to the book value are similar, and so are the equity ratios, dividend yields, the value of the holdings per shareholder and the average number of years the stock is held. However, the market values have a large spread. The smallest value, $343 million, is about only one-fourth of the largest market value.

Q. Dr. Brown, is the difference in market values of the comparables you selected meaningful?

A. No. My examination of the companies shows that they exhibit similar financial behavior, as indicated by the way they responded to the publication *Value Line*'s criticism of the gas distribution industry. That criticism is quoted in Schedule 1. In early 1995 *Value Line* warned investors to be wary of gas companies that paid out more than 80% of their earnings to dividends. Prior to Value Line's warning many payout ratios exceeded 80%. From 1995 to 1996, however, every company lowered its payout ratio to levels below 80%. This deliberate response by all the companies makes it clear that they have comparable financial behavior.

Q. Is your opinion of the equity return different from the equity return recommended by Dr. Andrews?

A. Yes, he recommends a higher, speculative range of 11.5% to 12.5% and prefers 12.25%, a much higher, speculative rate.

Q. Upon what do you base your equity return opinion?

A. I base my opinion on my analysis of AGL's market-based cost of common equity, which is supported by my analysis of comparable companies.

Q. In your opinion what rate of equity return should the Tennessee Regulatory Authority allow in this docket?

A. My opinion is that the Tennessee Regulatory Authority (TRA) adopt the equity return of

10.55%.

TESTS OF RECOMMENDED EQUITY RETURN

Q. Dr. Brown, did you compare your equity return to those of independent sources?

A. Yes. Chart One summarizes the tests I made. I compared my results to the information published by Merrill Lynch regarding the required rates of return for gas distribution companies in general. I also compared my results with the equity returns recently granted by the Illinois Commerce Commission and the Virginia State Corporation Commission to United Cities, a company currently under the TRA's jurisdiction and one that is included in Dr. Andrews' analysis. The Merrill Lynch returns are shown in Schedule 2. Press releases announcing the Illinois and Virginia decisions are attached as Schedules 3 and 4 respectively.

Q. What was your reason for using Merrill Lynch's data?

A. Merrill Lynch's data reflects the marketplace for gas distribution companies, and I have used their data as a basis of comparison in prior rate cases. From January 1995 through May 1997 Merrill Lynch's equity-return estimates have ranged from a high of 11% to a low of about 9%. My recommendation of 10.55% approximates Merrill Lynch's upper limit of recent equity returns for the natural gas distribution industry.

Q. What was your reason for comparing the recent equity awards by two state commissions?

A. My reason for comparison was to consider independent sources. The comparison merely demonstrates that my recommended return is consistent with recent regulatory decisions regarding equity returns in other jurisdictions.

Q. Did you compare the data from Merrill Lynch and from the various states to Dr. Andrews' recommended return to equity?

A. Yes. Dr. Andrews' recommended return substantially exceeds any reasonable return for the industry, and therefore is more than just and reasonable.

Q. Dr. Brown, is the return you are presenting a fair return?

A. Yes. It is a fair return because it compensates the company for ordinary financial risks it is taking to be in the gas distribution business.

Q. What are the sources of ordinary financial risk to the company?

A. The major risk is that the company's expenses would increase faster than its revenues. However, in this case that risk is negligible. The company's rate base, expenses, and sales are based on projected amounts for a 12-month period ending September 1998. These factors are the basis for the prices that come out of this docket. However, the company's prices are likely to be applied almost a full year before the projections are realized.

For there to be any risk, the company's projected expenses would have to be far less than what actually occurs, or the company's projected sales of gas would have to very different from the actual sales. I know of no substantial evidence suggesting that the company's forecasts will create a financial hardship.

Q. **Dr. Brown, is your rate of return sufficiently high to allow the company to attract capital and to maintain creditworthiness?**

A. Yes. An annual return of 10.55% is certainly high enough to attract capital and to maintain creditworthiness. The rate-of-return principles of capital attraction and maintenance of credit were set in the *Bluefield* decision, and the rate of return I recommend considers these factors.

Also, 10.55% is an understatement of the amount that the company actually has an opportunity to earn because the actual annual return is achieved through monthly compounding, which raise the return by approximately one-half a percent to 11%.

<u>DISCUSSION OF MONTHLY COMPOUNDING</u>

Q. **Is the monthly compounding process typical of the financial world?**

A. Yes.

Q. **Do monthly earnings have to be constant for monthly compounding to operate?**

A. No. Schedule 6 shows that compounding occurs with income-losses and with income-gains. The Schedule is based on the actual monthly income and losses of AGL for the fiscal year 1996. The far right-hand column clearly shows that monthly compounding of $1 at an allowed annual return of 10.55% leads to an effective return of 11.0%. With regard to column (6), at the bottom, the total return is shown as 11.02 cents. The total return would equal 10.55 cents only if the monthly return in column (6) is not added into the cumulative balances in columns (5) and (7), i.e., the cumulative balance would have to be $1 throughout the entire year. But this is not how financial processes work - cumulative balances are maintained on a monthly basis and changes to the balances are recorded monthly - not just annually.

Q. Dr. Brown, are you this docket's only cost-of-capital witness who believes that compounding is a typical financial process?

A. No. Dr. Andrews has made several statements indicating his opinion that compounding is a typical financial process:

1. Dr. Andrews, in his direct testimony page 27, line 5 says that "financial processes occur continuously." Therefore, his discounted cash flow (DCF) analysis is predicated on dividends continuously compounding, indicated at page 26 line 18 of his testimony, a situation

where compounding goes on moment-by-moment, a far more rapid rate of compounding than a monthly rate.

2. Dr. Andrews' direct testimony, page 28, lines 15-17, suggests that compounding a return of 9.53% leads to an effective return of 10%, clearly indicating that compounding adds approximately one-half percent to the return. This is the same point that I have made about compounding.

3. Dr. Andrews was cross-examined in Docket 95-02116 and stated that "Financial processes occur smoothly and continuously. They go -- if this makes the point for you -- minute by minute, hour by hour, day by day and they are not interruptible." His statement occurs at page 8, lines 20-23 of the transcript. A copy of the transcript's cover page and page 8 of the transcript are attached to my testimony as Schedule 7, pages 1 and 2 respectively.

4. His statements under cross-examination are consistent with his direct testimony page 28 lines 10-11, where the question is asked if there is "complete equivalency between

the continuous" rate, such as 9.53%, and a so-called "finite" rate, such as 10%. He answers "Yes."

5. His responses in his deposition of September 9 are also consistent with his testimony. For example, at page 58 line 16 of the deposition he was asked how often compounding occurred:

> "Q. Right, and it doesn't even have to be a series of years, it can be series of months, can't it?"

To which Dr. Andrews responded:

> "A. It could be done months, weeks, days."

He was also asked in the deposition, at page 59 line 10, whether he concurred that compounding is typical of financial processes:

> "Q. ...compounding is essentially accepted by all of our financial markets?"

To which he responded:

> "A. Sure."

Q. What does the term "compounding" mean?

A. The term compounding refers to a process that begins with a certain financial resource, generally called the base or the principal, and then the changes in that are added back into the base or the principal to create a new balance. The changes can be either positive or negative, meaning that the principal is either growing or declining.

Two things affect compounding:

The time-frame of compounding -- how quickly is the change added back to the base? It could occur once a decade, once a year, once a month, every day or every second.

The size of the change during the time frame -- does the base change by 1% a month each month or does it change by 2% in some months and 3% in other months?

The financial community puts these concepts together to say things like "your investment is growing at a rate of 10% per year this year, but last year it lost money at annual rate of 3%." Therefore, compounding describes financial gains as well as financial losses and does not have to occur at the same rate from one moment to the next.

Q. Is compounding process related to concept of working capital?

A. No. Working capital encompasses only the funds needed by the company to meet its current liability, i.e., the company has to have the funds available to meet its demands for cash flows.

Q. Why are you referring to working capital?

A. I raise it now to assure the TRA does not view monthly compounding as akin to working capital, where positive and negative cashflows are balanced by short-term lending and short-term borrowing.

Q. Is monthly compounding an accurate description of how a distribution company accumulates annual return even when the company experiences seasonal variations in sales, revenues and expenses?

A. Yes. The returns in the months when sales are high balance the returns in the months when sale are low. This is true whether the annual return is viewed as a sum of compounded monthly returns or as just the sum of twelve monthly returns that are not compounded. However, monthly compounding reflects the true nature of financial transactions. Revenues flow in every working day and are available for immediate reinvestment. The company's stocks and bonds can be bought and sold every working day of the year. The best indication that the compounding process underlies the company's financial transactions is the company's late fee, which is applied to consumers' monthly bills if they are not paid by the past due date. The late fee truly shows that "time is money." The quicker the company has the money, the quicker it can be invested to achieve additional returns. This is a perfect fit with the monthly compounding cycle that typifies financial transactions in our economy. If monthly compounding were not how a gas company accumulated its annual return, there would be no economic basis for charging a late fee.

Q. When Dr. Andrews' recommended equity return of 12.25% is compounded monthly, what return is the company being given an opportunity to earn?

A. The company is being given an opportunity to earn about 12.8%

MORE EVIDENCE THAT AGL IS THE APPROPRIATE COMPANY FOR COMPARISON

Q. If Dr. Andrews' recommended return of 12.25% a just and reasonable return?

A. No. His preference for 12.25% is meant to compensate AGL Resources (the parent of AGL) for the premium the company paid when it purchased CG. At page 3, lines 5-8 of his testimony Dr. Andrews states. "The point estimate is slightly off center in an upward direction in recognition of AGL Resources' long-run inability to earn on a rate base that includes the acquisition premium it paid as part of the price for CGC."

Q. What inferences do you make from Dr. Andrews' statement?

A. The statement confirms that this rate case is about AGL's return and that AGL and companies comparable to AGL should form the basis for an equity analysis. Dr. Andrews' statement also contradicts his later statement at page 4 lines

9-10 where he states: "the source of an investment's financing does not dictate its fair rate of return." His recommendation of 12.25% clearly aims at achieving a return for AGL, the owner of CG.

Q. **Is Dr. Andrews choice of 12.25% as his preferred return consistent with his statement: "I treat CGC as if it were a stand-alone investment of funds?"**

A. No. If CG were a stand-alone investment there would be no reason for Dr. Andrews to consider the acquisition premium as a factor or justification for choosing 12.25%. This justification is Dr. Andrews' tacit recognition that CG is not a stand-alone investment.

Q. **How does Dr. Andrews' supposition of CG as a "stand-alone" investment compare with the testimony of other witnesses for AGL?**

A. His supposition is contrary to the facts presented by Mr. Thompson, whose direct testimony, pages 11 through 22, describes the various support services that AGL provides to CG. For example, at page 17 line 6 Mr. Thompson lists several functions provided by AGL. At page 16 lines 4-15 Mr. Thompson indicates that AGL's Treasury and Corporate Accounting departments handle many transactions for CG. At lines 7-8 he says, "All checks for Chattanooga Gas Company are written by AGL." At page 13 line 11 he describes the various departments that have been eliminated at CG.

Q. **Do you agree with Dr. Andrews' testimony, at page 6 line 8, that CG has "sharply expanded**

demands for financing."

A. No. His statement is contradicted by the capital structure information the company supplied in this docket and in its prior rate case. In docket 95-02116, the company submitted a capital structure of $96.846 million. That structure is attached to my testimony as Schedule 8. In the current docket the company submitted a capital structure of $95.843 million, shown in the company's filing as Exhibit 5 Schedule 9. AGL is withdrawing its investment from Tennessee rather than suffering from a sharply expanded demand for financing

Q. What is the implication of the $1 million decline regarding CG as a "stand-alone investment?"

A. If a stand-alone company's capital dropped by $1 million, there would be an accounting trail, but in this instance there is no trail at all for CG. Therefore, the $1 million difference has to be the result of AGL's decisions and way it adds and subtracts funds to its Tennessee operations.

DERIVATION OF DR. BROWN'S EQUITY RETURN: DCF ANALYSIS

Q. Did you perform an analysis to determine what the return to equity should be for AGL's wholly owned subsidiary?

A. Yes. I performed two analyses: one based on the Discounted Cash Flow (DCF) model and another based on the risk premium model.

Q. **What is the Discounted Cash Flow model?**

A. The DCF model is a standard way that investors evaluate their potential returns. The model defines the cost of common equity as the dividend yield plus the dividend's expected growth rate.

Q. **What is the advantage of using the DCF model?**

A. It does exactly what every investor does. It pays close attention to the company's dividend per share of common stock and to the company's ability to raise or lower the dividend and the dividend yield.

Q. **What is the dividend yield?**

A. Dividend yield is measured as the company's annual dividend divided by the price for the company's stock. I've used the average dividend yield of the comparable companies as a proxy for AGL's dividend yield. The calculations are shown in my Schedule 9. In this instance the calculated dividend yield is 5.17%.

Q. **What did you use to measure dividend growth?**

A. Since AGL's current dividend growth rate is barely above zero, I used the growth rate derived from Value Line's projection of AGL's dividend in the year 2000, which suggests a growth rate of 5.23% in the near future. Thus my estimated DCF equity return is 10.40%, shown in Schedule 9.

Q. **Does the DCF Model account for capital gains that may occur when an investor sells stock?**

A. No. The DCF model avoids entanglement with either capital gain or capital loss because the model is tied directly to dividend yield and dividend growth. In addition, losses and gains are a matter of the investor timing the stock's purchase and sale. The DCF model neither protects investors from risk nor penalizes them for what happens in the stock market.

DERIVATION OF EQUITY RETURN: RISK PREMIUM ANALYSIS

Q. In addition to your DCF model, did you use another method to determine the market based cost of common equity?

A. Yes. I used the risk premium method which defines the cost of equity as the market's current debt yield plus an estimated risk premium. For example, a current debt yield of 7% plus an estimated market wide risk premium of 3% produces an estimated common equity cost of 10%.

Q. Is a risk premium analysis different from a DCF analysis?

A. Yes, the two analyses are completely different. For example, dividend growth and dividend yield are crucial to the DCF analysis, but they have no role whatsoever in a risk premium analysis.

Q. What is the rationale of risk premium analysis?

A. Investors require extra payments to assume additional risk. Economists call this extra payment a risk premium. Equity investments are riskier than debt because equity investments occasionally lose money, thus equity investors require a risk premium or a higher return than debt. For example, equity holders are last in line for the distribution of earnings and also last in line for distribution of liquidation proceeds. In both cases the debt holders are paid first. Any funds left are distributed to the equity holders. Therefore, the cost of equity is the debt yield plus a risk premium for the company.

Q. How did you derive your risk premium model?

A. The model is derived as follows:

$$K_e = R_f + (R_m - R_f) * B_e \quad (1)$$

where

K_e is the cost of equity

R_m is the market rate of return

R_f is the risk free rate of return

B_e is the beta for common stock

and

$$K_d = R_f + (R_m - R_f) * B_d \quad (2)$$

where

K_d is the cost of debt

R_m and R_f are defined above

B_d is the beta for debt

Subtract equation (2) from equation (1) and the result is

$$K_e = K_d + (R_m - R_f) * (B_e - B_d)$$

I treat the beta for debt, B_d, as if it were zero. Since B_d is zero, this raises the cost of common equity that can be derived from this model. Since B_d is zero, the final result is

$$K_e = K_d + (R_m - R_f) * (B_e) \qquad (3)$$

Q. What is the procedure for deriving the cost of equity from this risk premium model?

A. The procedure has six steps:

1. Estimate the market's current cost of debt - K_d.

2. Estimate market-wide rate of return for common equity -R_m.

3. Estimate the market-wide risk-free investment - R_f.

4. Take the difference between steps 2 and 3

5. Multiply the difference by a so-called "Beta" - B_e.

6. Add the result of step 5 to the debt cost in step 1. The result is the estimated cost

of equity from the risk premium model

RISK PREMIUM MODEL: CURRENT COST OF DEBT

Q. What do you use as the current cost of debt - K_d?

A. Since AGL's bonds retain an A rating, I use the monthly average of A-rated bonds for May 1996 through April 1997. Those are shown in Schedule 10 and represent the current trend in capital cost for debt issues of A-rated utility bonds.

Q. What is the value of the K_d?

A. The value of K_d is 7.95%.

Q. Are the A-rated bonds long-term bonds?

A. Not necessarily. For example, the source for this information is the Federal Reserve Board which says these bonds have a maturity of 30 years but call-protection for only 5 years, i.e, after 5 years and depending on the issuing company's discretion, the bonds can be repurchased from the investor.

Q. Is it typical for companies to have call provisions in their bonds?

A. Yes.

Q. What is the purpose of a call provision?

A. It gives the company control and flexibility regarding the disposition of its funds and transfers the risk of interest rate changes from the company to the investor. For example, if a company issues bonds at 10% and six years later interest rates drop to 7%, the company has the option of "calling" the bond from the investor, who then has to find an alternative use for the funds. Continuing with this example, if the company issues bonds at 7% and six years later interest rates rise to 10%, the company has no need to repurchase the bond from the investor, who has the choice of either holding the bond or taking a loss in principal if it is sold.

Q. Why do you use the A rates as a measure of debt cost instead of AGL's embedded debt cost?

A. Risk premium analysis is based on market wide indicators of current debt cost instead of a company-specific embedded cost. Using a company-specific embedded cost would mean that the company with the highest debt cost would also receive the highest return to equity. Conversely, the company with the lowest debt cost would receive the lowest return to equity. Thus using a company-specific debt cost to establish a risk premium would introduce incentives for companies to raise their debt cost as much as possible. That is unreasonable logic and unreasonable financial management. Fortunately, the markets don't work that way. A company's return to equity is not guaranteed to be a certain amount higher than the company's debt cost.

Q. Why do you use the A bond rates as a measure of debt cost instead of the average debt cost of

the comparable companies?

A. The company average would not necessarily reflect current market rates for bonds rated as A, the current rating for AGL's bonds.

<u>RISK PREMIUM MODEL: MARKET RETURN TO COMMON EQUITY</u>

Q. What do you use to estimate R_m, market-wide rate of return for common equity?

A. I use 10.7%, the compound annual growth rate for large company stocks from the period 1925-through 1996. This figure is taken from Ibbotson Associates 1997 Yearbook- Stocks Bonds, Bills and Inflation (SBBI-1997) page 118.

Q. Why are using large company stocks?

A. The comparable companies that I use in my analysis fit into the large company category, defined in SBBI-1997 page 136 as any company exceeding $197.4 million in market value as of September 1996. The smallest market value for my comparable companies is $343 million.

Q. Why are you using historical data to estimate the risk premium?

A. Historical data provides a way to smooth out the wild fluctuations in the risk premium, which is the difference between the risk-free return and market return to common equity. Since return to debt is fairly stable, the fluctuations are caused by the wide swings in the return to equity. For example, if the return to common equity is large in one year, so is the premium, if the return is small the next year, the premium will be negative.

Q. Why are you using the years from 1925 through 1996 to measure the risk premium?

A. Ibbotson provides historical information on the risk premium from 1925 through 1996, and these years represent the entire term for which information is available. Using the entire data avoids any element of subjectivity that may influence the selection of only a portion of the data. Neither Ibbotson nor anyone else I know of recommends using just a portion of the data. SBBI-1997 discusses this issue at pages 152-153: "A proper estimate of the expected risk premium requires a long data series, long enough to give a reliable average without being unduly influenced by very good and very good and very poor short term returns ... More generally, the 71 year period starting with 1926 is representative of what can happen. SBBI-97 also warns: "Some analysts calculate the expected equity risk premium over a shorter, more recent time period...this view is suspect."

Q. Why are you using 10.7% as the estimate of the market-wide rate of return to common equity?

A. I use that figure because it represents normal performance in the market. I have two reasons for saying so.

The first reason is a plain and simple one: 10.7% is the actual compound rate of growth in the value of large companies' common stocks. SBBI-1997, at page 49 states: "One dollar invested in large company stocks at year end 1925, with dividends reinvested, grew to $1370.95 by year end 1996; this represents a compound annual growth rate of 10.7 percent." The year-by-year change in the large companies' value is shown in Schedule 11 column (2).

The second reason is also simple. Not all large companies' stocks have advanced at a compound rate 10.7%. Some companies have earned more than 10.7% and others have earned less. In the 71 year period covered by data, there are literally millions of possible outcomes. But out of the millions of possibilities, the number of possibilities below 10.7% are exactly equal to the number of possibilities above 10.7%. Thus 10.7% is the exact middle of all the possibilities that could have occurred. This idea may be expressed another way: there is a 50% chance that the compound return will be 10.7% and a 50% chance that a $1 investment in 1925 would be worth $1370.95 in 1996. Returns higher than 10.7% have a smaller chance of being achieved.

Schedule 12 and Charts 2 and 3 show the exact odds of achieving 10.7% versus the other possibilities.

Q. How did you derive Schedule 12?

A. I have provided the mathematical details in Appendix A. But the heart of the concept is simple. A $1 investment today has two possible outcomes next year -- a gain or a loss. But in the year after next, there are four possibilities because each possibility in the first year has two possibilities in the second year. The number of possibilities doubles each year. Thus an investment that begins with $1 has 8 possible values three years later, 16 possible values four years later and so forth. The SBBI-97 data on large companies covers seventy one years and literally millions of possibilities. But the odds of each possibility can be easily calculated. I have done that in Schedule 12.

Q. Why have you highlighted certain portions of Schedule 12 and Charts 2 and 3?

A. I highlighted those portions to show the tie-ins of the schedule and the charts back to Schedule 11 and to emphasize the difference between the actual rate of 10.7%, which appears at the bottom of column (2) in Schedule 11 and the figure of 12.7%, which appears at the bottom of column (3), the so-called average of the returns, which I describe as a "biased average."

Q. Why do you consider the average to be biased?

A. The average is biased in the sense that it overstates market returns and leads unwary investors into the mistaken notion that an "average" return has a 50% chance of being achieved, when it does not. The growth rate of 12.7% means that a $1 investment in 1925 is now worth $4768 instead of $1371. Thus the rate of 12.7% is biased.

The bias is created in a very simple way: No one can ever lose more than 100% of their investment, i.e., 100% is the mathematical limit for losses. **However, there is no mathematical limit for an investment's gain.** Therefore, when percentage gains are combined with percentage losses the resulting average is mathematically biased to overstate the true gain in value. An excellent example is provided by Roger Ibbotson, the principal of Ibbotson Associates and the author of SBBI-97. In the July-August 1979 issue of *Financial Analysts Journal*, at page 44, he wrote::

> "Suppose that $1.00 were invested in a common stock portfolio that experienced 100 percent price appreciation in the first year and 50 percent depreciation in the succeeding year. At the end of the first year the portfolio would be worth $2.00; at the end of the second year the portfolio would be $1.00. The [average]...return on the portfolio would be 25 percent ..."

By adding a gain of +100% to a loss of -50%, the net is +50% and the average is 25%. Since the portfolio's value is again $1.00, the actual return is obviously zero, not 25%. Thus, the "average return" is clearly a biased and misleading estimate of the return to equity. This example also shows that the actual return is computed by comparing numbers that represent actual values rather than by averaging numbers expressed as rates of return.

Q. Is there any situation in which the average return is not biased?

A. Yes. If the market always gains, then the average is not biased. In this situation the average return and the actual return are identical. A divergence between the actual return and the average return indicates that losses have occurred. The greater the divergence, the greater the losses in the market.

Q. Is 10.7% derived by comparing two actual values?

A. Yes, it is derived by comparing the market value of large companies' common stock in 1925 with the their value in 1996, which I show in Schedule 11.

Q. Is 12.7%, the biased average in your terms, derived by averaging numbers expressed as rates of return?

A. Yes, it is derived by averaging all the rates of return from 1925 through 1996.

Q. Does the figure 12.7% result from the mathematical bias you described?

A. Yes because there have been several years where the market lost value. This is indicated in Schedule 11 column (2) when the value for an earlier year is greater than the value of a later year. For example, the market index fell from 534.46 in 1989 to 517.5 in 1990.

Q. What are the odds of a company achieving at least a 12.7% return?

A. The odds are less than 1 in 5 or less than 20%, indicating the return represents superior performance rather than normal performance.

Q. What are the odds of a company achieving at least a 10.7% return?

A. The odds are 1 in 2 or 50%, indicating that the return represents normal performance.

Q. Why have you made the effort to explain the differences underlying 10.7% and 12.7%?

A. Market returns vary widely over time, and when people are confronted with extremes the first step in clarifying the situation is to take an average. But with regard to a rate of return, it is a mistake to assume that an average is the mid-point between the extremes and that the average represents a typical value. I want to make this fact clear. In addition, I have not seen any direct testimony presented to the TRA or its predecessor agency where the differences are explained in terms of probability. Without a probability analysis the difference between 10.7% and 12.7% may seem tiny and unimportant. However, when the probability of achieving 12.7% is considered, it is clear that 12.7% is a return representing superior performance in the market rather than normal performance. Thus 12.7% is not a rational basis to set a risk premium rate.

Q. Is it reasonable to describe the risk premium in terms of a probability analysis?

A. Yes. SBBI-97 at page 155 states: "in the investment markets...returns are described by a probability distribution..."

Q. Is the return of 10.7% certain to be achieved?

A. No, there is a 50% chance that it will not be achieved.

Q. Is there disagreement about whether a risk premium should be derived from 10.7% or 12.7%?

A. Yes. The disagreement is generally discussed in terms of a debate about the merits of using the "geometric mean" of market returns versus using the "arithmetic mean" of market returns. The 10.7% figure is the geometric mean of large companies' historical returns, and 12.7% is the arithmetic mean.

Q. Are you using the geometric mean or the arithmetic mean in your risk premium analysis?

A. I use the geometric mean, but I prefer the phrase "actual return." I prefer to call the arithmetic return the "average return."

Q. Do you have support for your choice of the geometric mean over the arithmetic mean?

A. Yes. In addition to the all the reasons I have already described for using the geometric mean, it is also preferred by scholars in statistics and finance as well as professional investment firms. In 1990, Thomas Copeland, et. al. published *Valuation: Measuring and Managing the Value of Companies*. At page 193 they state: "Our opinion is that the best forecast of the risk premium is its long run geometric average." Irving Fisher, considered to be one of the world's greatest statisticians, wrote a book called *The Making of Index Numbers.* In the

1967 edition of the book at pages 29 and 30 Fisher says, "The simple arithmetic average produces one of the very worst index numbers. And if this book has no other effect than to lead to the total abandonment of the simple arithmetic type of index number, it will have served a useful purpose." In 1981 Richard Stevenson and Edward Jennings published, *Fundamentals of Investment 2sd ed.*. At page 272 they say, "Why not simply average the rates of return? Indeed, in certain instances, such a procedure would be satisfactory. However, such an average would generally be meaningless." On March 13, 1990 at page C1 the Wall Street Journal ran the following story, "When Figuring the Rate of Return Don't Be Confused By The Sales Hype." The story compares the average return with the so-called compound return, another common name for the geometric return. The WSJ story says the compound return is "more widely used by investment firms."

There is plenty of support for using the actual market return (the geometric mean) in the risk premium model.

Q. What portions of the risk premium model have you identified thus far?

A. I have identified the debt and equity portions. In terms of the model -- $K_e = K_d + (R_m-R_f)*(B_e)$ --I thus far identified K_d as 7.95% and R_m as 10.7%. I still have to identify R_f, the risk free return and B_e, the beta.

<u>RISK PREMIUM MODEL: RISKFREE RATE</u>

Q. **What represents the market-wide risk-free investment, R_f?**

A. In this case I am using the three-month U.S. Treasury bills. I will show that the three-month rate is based on a long term perspective of the riskless rate and that it is a better concept to use in this case than a long-term bond.

Q. **What is the market-wide risk free rate of return, R_f, based on three-month bills?**

A. The risk free rate is 3.7%, which is the compound annual growth rate in the value of the three-month treasury bills from 1926 to 1996. Schedule 13 shows the 71 year history for returns to Treasury bills, and in the entire time there is no loss. The compound rate of 3.7% is the center of all possible outcomes from a $1 investment in three-month bills in 1925. The average rate is 3.8%. It is slightly higher than the actual rate because there were no gains in several years. The three-month rate is the best measure of a riskless rate.

Q. **Why is the three-month treasury bill the best measure of a riskless rate?**

A. There are three reasons:

1. The three-month bill is a debt instrument. This fits with the risk premium's basic premise: the return to debt is less than the equity return and equity return is determined by referencing debt.

2. Of all the other debt instruments

measures that could be used -- long-term corporate bonds, long-term government bonds, the income portion of long-term government bonds and intermediate term government bonds -- the three-month bill provides the lowest rate. This is consistent with the financial concept that a risk free rate should be lower than rates that reflect risk.

3. A three-month bill is free from losses but the other debt instruments are not, i.e., they are riskier forms of investment than the three-month bill, which is why their rates are higher. Schedule 14 shows the actual return and the average return 1925 to 1996 for each of the debt instruments. For each kind of debt, the difference between columns (2) and (3) indicates the degree to which the losses occur in that particular debt market. Of all the debt instruments, the three-month bill is the safest. Investors are absolutely certain of what cash flows will be received and when they will be received. Unlike the other debt instruments, the three-month bill carries no risk of default or loss of principal.

Q. Is there a contradiction between using the three-month bill as the risk free rate while you are using the cost of A rated bonds in your model?

A. No. I have already said those bonds are not necessarily long-term notes. They have call provisions that transfer the risk of interest rate changes from the company to the investor. The three-month bill allows the investor to do the same thing the company does: avoid the risk of interest-rate changes.

Q. **Is there a way to avoid the risk of losing principal and still use long term bonds?**

A. No. SBBI-97 at page 151 suggests that long-term bonds have so-called "income returns." This return is the income an investor would receive if the bond were purchased and held to maturity rather than selling it. SBBI-97 considers the income return to be the "riskless portion" of an investment in long term bonds. I disagree with this concept because it is irrational.

Q. **Why is the concept irrational?**

A. It is irrational because it assumes an investor can divide a long term bond into a riskless portion and a risky portion. This separation is not credible because a bond is not severable into distinct portions. The purchase of a long term bond always carries the risk that changes in interest rates will cause a change in the bond's value. The concept of "income returns" also suggests that once a long term bond is purchased, the investor will take no action until the bond matures and do nothing in the face of interest rate changes. This behavior is just the opposite of the behavior assumed in a call provision, which gives the issuer the flexibility to act when interest rates change. It is irrational to assume that the issuer of a bond is free to respond to interest rate changes but that the bond's buyer is not.

Q. What portions of the risk premium model have you identified thus far?

A. In terms of the model -- $K_e = K_d + (R_m - R_f) * (B_e)$ -- I have identified K_d as 7.95%, R_m as 10.7% and R_f as 3.7%. The term $(R_m - R_f)$ is equal to 7%. This amount would be smaller, as would my recommended rate of return, if I were to use any debt instrument other than the three-month bill. For example, if I were to use long-term government bonds, the term $(R_m - R_f)$ would be (10.7%-5.1%), which equals 5.6%. This lowers the risk premium equity return by 1.4%, which is the difference between 7% and 5.6%. I still have to identify B_e, the beta.

RISK PREMIUM MODEL: THE BETA

Q. What does beta measure?

A. Beta measures how an individual company's market value changes relative to the change in the value of the entire market. For example, if a company's market value increases from $10 to $11, then the company's value increases by 10%. If the entire market's value increased from $1000 to $1200, then the entire market's value increases by 20%. The beta is calculated as .5, which is the ratio of 10% divided by 20%.

The market itself has a beta of 1. If the company's beta is one, then the company risk premium is the same as the market-wide risk premium. Thus if a company's beta is less than 1, then the company is judged less risky than the market. Beta is also used to compare the relative riskiness. For example, a beta of 0.4

is less risky than a beta of 0.6.

Q. Did you calculate betas for AGL and the comparable companies?

A. Yes, and I also calculated the betas' accuracy. The betas and their tests of statistical accuracy, the T-statistic, appear in Schedule 15, pages 1 and 2 respectively. The average beta shown at the bottom of page 1 Schedule 15 is transferred to Schedule 16, which provides results of the risk premium analysis.

Q. What is the beta's value in your model?

A. The value is .458 and is shown in Schedule 16 at the bottom of column (b).

Q. What is the estimated equity rate of return that is derived from your risk premium model?

A. The model gives a value of 11.14%. In terms of the model -- $K_e = K_d + (R_m - R_f) * (B_e)$ -- the equity return is 11.14% = 7.95 + (10.7%-3.7%)*.458.

Q. Do you use all the betas in Schedule 15 to develop the figure of .458?

A. Yes. I used the average betas that have an average T-statistic greater than 1.

Q. Why did you use the T-statistic and T-statistic greater than 1?

A. In general, the T-statistic indicates how well a summary number represents the group from which the summary number comes. In this case the summary number is a beta, which few people are familiar with. But the T-statistic can also be explained in terms of an average, a summary number which everyone uses almost everyday.

For example, I may know that a certain group of people are, on average, 40 years old. But the average is just a short-hand description of the group. The average alone does not indicate anything about the group's composition. The group could be composed of children younger than 10 and elderly people over 70. The group as a whole just happens to have an average age of 40 even though 40 <u>is not at all representative of anyone in the group</u>. In this case the T-statistic is likely be low, about 1 or less. On the other hand the group could be composed of people between 36 and 42, who as a group, just happen to have an average age of 40, but in this case 40 is fairly representative of anyone in the group. In this case the T-statistic is likely to be high, about 2 or more. The higher the T-statistic, the more likely it is that a group's summary number or average is a good representation of the parts that make up the group. Statisticians express the same idea by saying "the beta is statistically different from zero."

Q. What is the economic significance of the betas' values you found?

A. All the values are far less than 1, which means that AGL and the comparable companies are far less risky investments than the market as a whole. In addition, the values do not vary much for any particular company, which means that investors **<u>do not</u>** perceive any substantial change in risk for these companies.

Q. How did you derive the betas?

A. I used the monthly percentage change in the S&P 500 index to represent the market-wide return and the monthly percentage change in the company's stock price to represent the company's return. The change is calculated as: Price at the end of the month divided by price at the beginning of the month -- the result is converted to a natural logarithm and then the beta is calculated.

Q. Did you compare your betas to those estimated by anyone else?

A. Yes. My betas are larger than those estimated by Dr. Andrews for his companies, shown at Schedule 9 of his direct testimony. The average for his betas is .27. This figure includes 5 negative betas. When Dr. Andrews implements his model he excludes the negative betas and raises his average to .41, which is still lower than the average of my betas, .458.

Q. Is the value of .458 a reasonable value?

A. Yes.

<u>THE APPROPRIATE RETURN OF 10.55%</u>
<u>COMPENSATES FOR MONTHLY COMPOUNDING</u>

Q. What is the range of annual equity returns that you have established?

A. I have established a range of 10.4% to 11.14%.

Q. In your opinion, within the range of 10.4% to

11.14% what value is appropriate?

A. In my opinion the appropriate annual value is 10.55% because this compensates for monthly compounding that creates annual returns. Even though the range's mid point is about 10.8%, this can be converted into a return of 11.3%, an amount well-beyond my upper limit of 11.14%.

Q. Are there other experts who believe that annual returns are achieved by compounding monthly returns?

A. Yes. This financial principle pervades the data in SBBI-97, Ibbotson's 1997 Yearbook. For example, my Schedule 12, column (3) for the year 1996 shows a value of .2307 or 23.07%. My Schedule 17 shows exactly how .2307 is derived. This process is exactly the same as the one shown in my Schedule 6. Monthly compounding is the basis for all the annual returns shown in Dr. Andrew's Schedule 10 and my Schedule 11. But this is normal because SBBI-97 at page 49 explicitly says: "Annual total returns...for each asset class are formed by compounding the monthly returns." Thus in my Schedule 12, column (2) for the year 1996, the amount of 1370.95 equals 1.2307*1113.92, or stated in words:

Annual Return This Year Equals:
12 Most Recent Monthly Returns Multiplied Together, Which Are Then Multiplied by Annual Return Last Year.

Returning to Schedule 17, it is important to notice that .2307 is larger than the sum of the monthly returns in column (2). If those returns were added together they would sum to only

.2148. This is further proof that annual returns are actually achieved by multiplying monthly returns together, i.e., monthly compounding. This also substantiates the findings in my Schedule 6, where an allowed annual return of 10.55% is subdivided into monthly returns that actually yield 11.0% over a 12 month period.

Q. **Isn't it true that monthly compounding introduces an upward bias to a prospective annual rate of return?**

A. Yes, and here is how the bias occurs. Lets say that TRA surveillance form 3.03 line 27 for a month shows an annual return of 11% for a certain company. If there is agreement that annual returns are formed by monthly compounding, then we know that the sum of the monthly returns is 10.55%, but when the returns are multiplied together the annual return is 11%. Now suppose that the company files a rate case and asks for an 11.5% return. If the proposed rate of return were subdivided on a monthly basis, the sum of the proposed monthly returns should be 11% to ensure that when they are compounded monthly, the result does not exceed 11.5%. If the monthly returns sum to 11.5%, then in effect, the allowed rate of return is 12%.

Another way to understand the compounding effect is to consider how the test year rate base is calculated. The rate base is actually an average of the rate base at the beginning of the test year and the rate base at the end of the test year. Thus the value of rate base already includes 6 months of reinvested earnings. Therefore, when a rate of return is applied to the rate base, the company is actually earning on its earnings. This is another way to achieve monthly compounding. If this aspect were implemented in terms of Schedule 6, the beginning balance would not be $1 but about $1.06.

Q. Is there any document in this docket where a proposed annual return is subdivided on a monthly basis?

A. The only one I know of is my Schedule 6.

Q. What equity return do you recommend in this case?

A. I recommend a rate of 10.55%, an amount between my DCF rate of 10.4% and 11.14%, the risk premium rate. I choose 10.55% because I know that monthly compounding gives the company the opportunity to earn a higher return. I also choose 10.55% because I know that the rate base already includes 6 months of reinvested earnings before the rate of return is applied to the rate base, thus giving the company another opportunity to earn a higher return

Q. What compounded return can the company earn with an annual rate of 10.55%?

A. The monthly compounding process gives the company an opportunity to earn approximately 11.0%.

<u>CAPITAL STRUCTURE AND OVERALL RATE OF RETURN</u>

Q. What are your findings regarding capital structure?

A. The capital structure in this case appears in the company's filing as Exhibit 5, Schedule 9. Since the amounts in that schedule are derived from AGL's capital structure, CA data request 42 asked the company to provide support for the calculations. The company's response is attached to my testimony as Schedule 18. None of the projected balances in that document are explained or supported by the company. For example, the preferred stock balance in 1997 is $58.4 but the projected balance in 1998 is $70 million. Despite this hefty increase, no explanation is provided. Continuing with this example, AGL's long term debt is shown as $659.5 million in 1997 and 1998. However, the company's response to CA data request 24 showed a balance of $584.5 million as of April 1997. This is an unexplained difference of $75 million. In addition, the new debt's interest rate is not provided. Also, according to the company's response to CA data request 23, all long term debt and preferred stock is held by AGL instead of its parent holding company, AGL Resources. Therefore, the $75 million cannot be attributed to debt issues by the holding company. Finally, AGL's response to data request 42 does not show how the amount of the CG capital structure, $95.8 million, is derived. Instead, the response shows how $95.8 is allocated to the different aspects of the capital structure.

In sum, the amounts shown in Schedule 18 are different than what I expected, but I do not believe the differences are material to my analysis, which relies on the portions and the estimated costs. However, my recommended overall return is neither an endorsement nor an acceptance of the rate base that will be applied to the overall return. To the extent that the projections in Schedule 18 are not supported, the company's filed rate base is questionable.

Q. What weighted overall capital cost do you recommend?

A. In my opinion a cost of 8.85% before compounding, shown in Schedule 19.

Q. What compounded overall return can the company earn with an annual rate of 8.85%.

A. The company has an opportunity to earn about 9.3%.

ANALYSIS OF METHODS EMPLOYED BY THE COMPANY'S COST OF CAPITAL WITNESS

Q. You have stated that you disagree with Dr. Andrews' analysis, can you explain your reasons?

A. Yes. At page 4 lines 22-23 of his direct testimony he states: "I measure the costs of equity capital of ...small publicly held gas distributing companies and impute their cost of equity to CGC." I have already pointed out an obvious difference between these companies and CG -- they are independent financial entities who have actively traded stock while CG has no actively traded stock because it is a wholly owned subsidiary of AGL. This alone suggests that his analysis is inappropriate. However, after scrutinizing his testimony and his data sources, I conclude that his equity returns -- 14.39%, 14.38%, 14.23% , 12.5%, 12.17% and 11.06% shown at page 47 of his testimony -- are based on an irrational analysis.

SMALL COMPANY APPROACH IS IRRATIONAL

Q. Why is the analysis irrational?

A. The small company data base that he uses does not represent the performance of small companies. Instead, the data base represents the performance of one particular mutual fund out of more than 200 funds that specialize in buying and selling small company stocks. The particular mutual fund used by SBBI-97, the very same one that Dr. Andrews uses, is named the *Dimensional Fund Advisors 9-10 Small Company Mutual Fund* (DFA 9-10 fund). SBBI-97 at page 51 says; "...the small company stock returns series is the total return achieved by the Dimensional Fund Advisors (DFA) Small Company 9-10 Fund."

However, the fund requires an initial purchase of $2 million dollars. This is well beyond the means of stockholders who own the companies used by Dr. Andrews. The fund also has a highly unusual ownership concentration, one that is certainly not representative of a gas distribution utility. In 1996 the fund had assets of $1.18 billion with over $625 million held by five owners that are actually pension funds:

OWNER	OWNERSHIP PERCENTAGE

Charles Schwab & Company Inc.	31.44%
State Farm Insurance	10.76%
Pepsico Inc. Master Trust	8.87%
Owens-Illinois	5.48%
National Electrical Benefit Fund	5.26%

This ownership pattern and the $2 million minimum investment clearly indicates that the so-called "returns to small companies" are actually returns to well-financed pension groups rather than being a return that is accessible to ordinary investors. There would be no incentive for anyone to make a $2 million minimum investment and buy into the DFA 9-10 fund if such returns were accessible to ordinary investors. Also, these returns are derived from the capital gains made by the constant buying and selling of stock, a far different process than the way in which a gas distribution company makes money.

However, even the returns themselves are open to question because the methods used to calculate the fund's return are not equivalent to the *return-on-assets concept used in utility regulation*. *In 1996 the fund's return on assets was 8.75%*. Dr. Andrews' Schedule 6, page 1, the far-left column titled "Small Company Stocks" shows the return as 17.62%. He uses this amount and the remaining figures in that column to develop the return differentials of 9.16%, 7.57% and 6.86% shown on the right side of the schedule. Those amounts are repeated in Schedule 6 page 2 and in his direct testimony, at the bottom of page 45 under the column titled "Equity Diff" and lead to a huge cost of equity, 14.3%.

These figures are not credible, not only for the reasons I have just discussed, but also for *the overlapping directorates of the DFA 9-10 fund and SBBI-97*. Mr. Robert G. Ibbotson is the Chairman and President of Ibbotson Associates, and the publisher and author of SBBI-97. He is also on the Board of Directors of the DFA 9-10 fund. This strongly implies that the small company data used in SBBI-97 is not derived from an independent source and that the data may overstate the actual returns. This possibility is already substantiated by the difference between 8.75%, the return on assets, and the so called return of 17.62% used by Dr. Andrews. Mr. Ibbotson's dual role is indicated in the Statement of Additional Information published March 28, 1997, as a supplement to a prospectus issued the same date by DFA Investment Dimensions Group, Inc.

These factors demonstrate the extraordinary weakness in the small company analogy that Dr. Andrews uses to estimate the cost of equity. But there is another contradiction in the data: in 1994 only 9 of Dr. Andrew's companies were owned by the fund, in 1995 and 1996 only 11 of the companies were owned by the fund. Thus half of Dr. Andrews' companies are not considered "small" by the fund itself.

Taken as whole these factors make it plain that the small company analogy is an irrational approach to setting the equity return in this docket. In my opinion the TRA should disregard the results of Dr. Andrews' small company analysis, shown in his direct testimony at the bottom of page 45.

Q. What are sources of data that support the assertions you have made?

A. My data is taken from four different sources:

1. DFA Investment Dimensions Group Annual Reports for the Years Ended November 30, 1996 and November 30, 1994 and DFA's SEC10K filing for 1995.

2. Statement of Additional Information, Supplement to DFA's Investment Dimensions Group, Inc. Prospectus of March 28, 1997.

3. Morningstar, Inc.'s Reports on Mutual Funds, as of May 31, 1997.

4. SEC Form 10Ks and 10Ka-1 for Dr. Andrews' companies and the DFA Group.

Q. What is Morningstar Inc.?

A. Morningstar is a software and data base firm that maintains records on over 8000 mutual funds and tracks their performance. The company is located in Chicago.

Q. What schedules have you set up from this data?

A. Schedule 20 is a summary of Morningstar's reports on 230 mutual funds that specialize in buying and selling small company stocks. About 30 concentrate on foreign stocks and the remainder focus on domestic stocks. The funds are arranged in descending order according to the amount of the initial minimum investment. The funds managed by the DFA group are among the most expensive funds to purchase. Nearly all of DFA's funds require $2 million minimum investment. For all 230 funds taken as a group, there is a systematic difference between the rate of return on assets and the 1996 return as reported by the funds. The return on assets is much lower than the other so-called return.

This discrepancy was so large that I was compelled to cross-check the accuracy of the Morningstar report on the DFA 9-10 fund against the data in the DFA 1996 annual report. The Morningstar report is Schedule 21 and the DFA report on the fund is Schedule 22. Although the data is not identical they are close enough to be substantially the same. For example, Morningstar reports assets of $1107 billion and the DFA annual report shows assets of $1181 billion. In Schedule 21 I have highlighted the portfolio statistics showing an exact match between Morningstar's data and DFA's. This suggests that Morningstar's calculation of a return on assets is credible even though the DFA report does not provide this measure. Also, the DFA report, the line titled "Net Gain (Losses) on Securities (Realized and Unrealized)" represents capital gains and losses by the fund. Clearly, the fund is completely dependent on capital gains to make a return, unlike a gas distribution company that sells a product and a service. This, too, makes the fund an unreasonable basis to develop returns for a gas distribution company.

Schedule 23 shows DFA's <u>Statement of Additional Information</u>, the cover page and pages 20-22. The fund's method of calculating a return is shown from Schedule 23 page 3, at the bottom, to the schedule's page 4 at the top. The description is vague and not articulated through any readily understood example. This sharply contrasts with the way all parties calculate the return on assets that a gas distribution utility receives. Therefore, returns to mutual funds, such as the amounts in Dr. Andrews' Schedule 6, page 1, the far-left column titled "Small Company Stocks," cannot be used to estimate the *return-on-assets* that is granted to a gas distribution company.

Schedule 24 shows DFA's Statement of Additional Information, pages 10, 11 and 15, which respectively list the company directors and the major owners of the fund. Mr. Ibbotson's name appears at the second page, the third listing from the top. This confirms that the DFA 9-10 fund and SBBI-97 have overlapping directorates. Page 15 confirms the ownership pattern of the fund.

Q. How do you know that investors in Dr. Andrews' 22 small companies would be unable to buy into the DFA fund?

A. My opinion is based on the data I gathered about Dr. Andrews' companies. Schedule 25 column (6) shows the average value of the holdings per shareholder for Dr. Andrews' companies. The maximum value is $53,171 and the average value is $28,195. The DFA fund's initial investment is $2 million, about 50 to 100 times larger than the values shown in column (6). It is impossible for stockholders of Dr. Andrews' companies to buy into the DFA fund.

Q. How do you know that the DFA fund included only half of Dr. Andrews' small companies?

A. I acquired DFA's annual reports for 1994 and 1996 and the company's SEC 10K filing for 1995. Those reports list the companies in the fund.

Schedule 26 shows the results.

Q. Is it your opinion that Dr. Andrews actually used the 22 "small publicly held companies" to estimate the equity returns of 14.3%?

A. No, Dr. Andrews did not use those companies. In my opinion he used the concept of "small companies" to make a link with the purported returns of the DFA fund, which is the real source of the huge equity-return estimates that appear in his direct testimony at the bottom of page 45. Also, nine of Dr. Andrews' companies do not fit the definition of a small company that is given by SBBI-97 at page 136: A small company is one with a market value less than $197.4 million as of September 1996. My Schedule 25 shows 9 of Dr. Andrews' companies exceeding that value on April 30, 1997. This strongly suggests that Dr. Andrews' companies are composed of two dissimilar groups that are viewed differently by the market.

<u>RETURNS OF 12.5% AND 12.17% ARE BASED ON LARGE COMPANY DATA, MISUSE OF DATA AND IRREGULAR, UNSUPPORTED PROCEDURES</u>

Q. Are Dr. Andrews' other returns derived from the small company concept and the DFA fund?

A. No. He uses large companies to derive the returns of 12.5% and 12.17%. The returns appear in his testimony at page 44 lines 21-22 and at page 45 lines 1-2 and are derived from his Schedule 10. The schedule's left side has a column titled "Common Stock Total Returns." This name is wrong. In his note at the bottom of the schedule he says data for the years

1987-1995 is drawn from "Exhibit A-1" of Ibbotson's 1996 yearbook. The correct name is "Table A-1 Large Company Stocks: Total Returns." A portion of the table from the 1996 yearbook is attached to my testimony as Schedule 27. Note the title of column (3) in my Schedule 11 and the exact match between the amounts in column (3) from 1988-1996 and the amounts listed in Dr. Andrews' so-called "Common Stock Total Returns."

Contrary to his assertion, "I measure the costs of equity capital of ... small publicly held gas distributing companies," Dr. Andrews uses large companies without acknowledging the fact nor explaining why he has done so. This undermines his entire analysis, making it an irrational basis to determine a return to equity.

Q. Does Dr. Andrews use the data correctly?

A. No. He limits Schedule 10 to a history of 10 years instead of a 71 year history recommended by SBBI-97.

Q. Are you suggesting that every recommendation of SBBI-97 has to be followed?

A. No. Although SBBI-97 is a useful tool and an authoritative source for some aspects of developing a rate of return, its authors are fallible, as I have already demonstrated with regard to the small company issue. However, it is contradictory to invoke an authoritative source to justify one position and then depart from the source's recommendations in other positions without explaining the reasons for the departure.

Dr. Andrews has departed from the standard practice of using a 71 year history to derive the risk premium differential. His direct testimony offers neither a justification nor an explanation of his reasoning. In their absence, his choice of a 10 year history appears arbitrary and calculated to increase the estimated cost of equity.

For example, his Schedule 10, the line titled "Averages" shows that: .1604 - .0778 = .0826. These values appear in his direct testimony at page 44 line 21:

$$K_e = .0133 + .0778 + (.41)*(.1604-.0778)$$

$$K_e = .125 = 12.5\%$$

However, if Dr. Andrews had taken the data for the 71 year period, as the source recommends, the averages would be different than what he shows in Schedule 10.

The figure of 16.04% would decrease to 12.7%, which is the average return to large companies and which is shown in my Schedule 11 at the bottom of column 3. The figure of 7.78% would decline to 5.2%, which is shown in my Schedule 14 in the line titled "Income Portion of Long-Term Government Bonds" and under the column titled "Biased Average." If these new figures were applied to his equation at page 44 line 21, the new result would be:

$$K_e = .0133 + .052 + (.41)*(.127-.052)$$

$$K_e = .0961 = 9.61\%$$

A similar result occurs in the equation at line 1 of page 45 of his direct testimony, where the new value would be 9.31%.

The use of a 10 year history is vital to Dr. Andrews' results. However, the exact reason he chose this period is not discussed in his testimony. Therefore, I recommend that the TRA disregard the estimates of 12.5% and 12.17% because they are arbitrary and unreasonable.

In fact, his formulation of the risk premium model is irrational.

Q. Why is his risk premium model irrational?

A. Dr. Andrews' model is irrational because it is not tied to the debt markets faced by AGL, the "A" rated bond market, despite his lengthy discussion of AGL's debt quality at page 18 of his testimony. The only place in his analysis where he uses "A" rated corporate debt is in a DCF analysis appearing in his testimony at page 46 lines 16-17, which shows returns of 8.98% and 9.35%. These figures are repeated at page 47 lines 7-8, where he describes these numbers as "DCF Over Various Debt Instruments."

This portion of his testimony contradicts a statement in his deposition of September 9. In that deposition, from page 43 line 24 to page 44 line 3, he states: "One of the lines of analysis that I pursue is the equity over debt cost approach, risk premium approach; and I used some of the costs of the debt that Atlanta Gas had outstanding and found differentials of equity cost over that." However, Dr. Andrews has not used AGL's debt or "A" rated bonds in any risk premium analysis, but only in the DCF analysis he describes at pages 46 and 47 line 7 of his testimony. His highest set of returns --

14.23%, 14.38% and 14.39% derived from his small company analogy, and his second highest set of returns -- 12.5% and 12.17% -- are completely unrelated to the "A" bond market or to AGL's debt.

Q. Is your risk premium model rational?

A. Yes. My risk premium model is based on the general principle that equity returns have to be compared to and exceed corporate debt. In this particular case the debt in question is the "A" bond market. If I expressed the principle instead of the numbers, the model would be:

$$K_e = \text{Current Cost of A Rated Utility Bonds} + (R_m - R_f) * (B_e)$$

Dr. Andrews' model does not begin with corporate debt. Instead, his model begins with the concept of "Long-Term U.S. Govt. Bonds Income Component Returns." If I expressed his idea instead of the numbers, his model would look like:

$$K_e = 1.33\% + \text{Long-Term U.S. Govt. Bonds Income Component Returns} + (R_m - R_f) * (B_e)$$

Therefore, Dr. Andrews' model is based on the idea that equity returns have to be compared to and exceed the returns of long term government bonds instead of corporate debt. This is an irrational basis to begin an analysis because returns to government bonds are always lower than returns to corporate bonds. My Schedule 14 clearly shows that corporate bonds outperform government bonds. Therefore, Dr. Andrews' model has a starting point that is bound to be lower than the starting point in my model. However, he raises the starting point of his model by resorting to a figure of 1.33%. This amount is not related to debt, corporate or government; nor is it related to equity returns of either large or small companies.

Q. What does the 1.33% relate to?

A. The figure is not related to anything because it is a nonsense-number.

Q. How is 1.33% a nonsense-number?

A. Dr. Andrews explains the derivation of 1.33% in his direct testimony, page 44 lines 13-14. The derivation is irrational for two reasons:

1. Dr. Andrews is dealing with numbers that cannot be treated as if they are "per day, per week, per month or per year" numbers. Just as the assertion -- "You are 6 feet tall per month, so in 12 months you will be 6X12=72 feet tall per year" -- is nonsense, so too is Dr. Andrews' number of 1.33%.

   This point becomes clear by examining his derivation of 1.33%. In his Schedule 9 under the "Alpha" column, there is a number, .0011, which is the average of the alphas that have a positive beta. Thus .0011 is the basis for deriving .0133 by the formula at page 44 lines 12-13 of Dr. Andrews' direct testimony:

$$.0133 = (1 + .0011)^{12} - 1$$

Although he does not say that he is deriving his alphas from five years of monthly data, he is. At page 42 lines 6-12 of his testimony Dr. Andrews explains that he derives his betas with five years of monthly data, but every time a statistical regression produces a beta an alpha is created too. This is why his work and mine both have alphas as well as betas.

He treats the value .0011 as if it were a monthly value that can be compounded into an annual figure. This is why he uses 12 in his formula:

$$.0133 = (1 + .0011)^{12} - 1$$

The alphas and betas are derived from the same data and the same months. If the alpha is a monthly rate, isn't the beta a monthly rate, too? If the beta is not a monthly rate, how can the alpha be a monthly rate? If his beta of .41 were compounded monthly the result would be:

$$60.75 = (1 + .41)^{12} - 1$$

If this value were placed into Dr. Andrews' original formula the cost of equity would be:

$$K_e = .0133 + .0778 + (60.75)*(.1604-.0778)$$

$$K_e = 5.10 = 510\%$$

60.75 is produced in exactly the same way as Dr. Andrews' produced .0133. If

60.75 is dismissed as incredible or fictitious, then its counterpart, the "annualized" alpha, is an unreasonable number and .0133 should be rejected, too. Both numbers are unreasonable. It is irrational for Dr. Andrews to treat the alpha as a monthly figure that can be compounded to an annual one. His treatment further suggests that the alpha can be compounded according to the time frame of the data used, i.e., if the alpha and beta are derived from monthly data then the alpha can be compounded monthly, but if the data is weekly, then the alpha can be compounded weekly. This too is irrational.

For example, if I took the weight of 22 people each month for 60 months and then took an average, I can say "based on monthly data the average weight *per person* is 150 pounds" but it would be wrong to say "because I collected my data on a monthly basis each person weighs 150 pounds *per month* and 1800 pounds *per year*." This is the exact logic that Dr. Andrews employs. The difference between this example and Dr. Andrews' irrational procedure is the size of the numbers.

If the beta is .41, as in Dr. Andrews' results, then the value of the company's stock changes 41 cents *per $1 change in the market's value*, whether the market's change is measured over a day, a week, a month or a year -- .41 is not compounded to a higher figure nor reduced to a lower one. The same logic applies to the alpha.

In my opinion the TRA should disregard Dr. Andrews' figure of 1.33% because it is irrational.

2. Dr. Andrews' direct testimony does not provide any tests of statistical accuracy for the alphas in his Schedule 9. In the absence of this data, my opinion is that the alpha should be presumed to be zero.

Earlier I said that every time a statistical regression produces a beta a so-called "alpha" is created too. Since his overall positive beta is .41 while mine is .458, I expected this similarity to be carried through to the alphas, and it is. The values of his alphas are very close to zero, just as they are in my analysis, at Schedule 15 page 3. However, page 4 of Schedule 15 shows the alphas' statistical measures of accuracy, the T-statistics. They are tiny, meaning the alphas are no different than zero.

The typical pattern of alphas, betas and their statistical accuracy are provided in the table below.

Betas	Alphas
Positive Values	Very Close to Zero- May Be Positive or Negative

High T-Statistics Indicate Accuracy	Low T-Statistics Indicate Inaccuracy

Schedule 15 fits this pattern. Dr. Andrews' data should show the same pattern, at least for his positive betas.

When the alphas are no different than zero, they do not add anything to the cost of equity, and there is no need to use the alphas. In this case the formula looks like:

$$0 = (1 + .0000)^{12} - 1$$

The alpha is zero. This is why alphas are thought of as having no value and no meaningful economic interpretation and why they never appear with betas.

I do not know of any financial publication that provides betas <u>and</u> <u>alphas</u> nor do I know of any model that treats the alphas the way Dr. Andrews does.

Q. Did you ask Dr. Andrews to provide the tests of statistical significance for the alphas and betas that he calculated?

A. Yes. He did not supply them, consequently his conclusions are not supported by material and substantial evidence. His response is attached to my testimony as Schedule 28.

Q. Do you have any comment regarding his response?

A. Yes. Since Dr. Andrews has not provided the tests of statistical significance, I am even more concerned that his alphas are really no different than zero. In my analysis the alphas are zero and they are not statistically significant. Also, it is contradictory for Dr. Andrews to calculate sums and averages for the betas and alphas, as he does in his Schedule 9, and then state in his response: "Tests of significance, such as T-statistics from the regressions related to individual stocks cannot be summed or averaged across the composite." I have done exactly that in my analysis. In fact, its results are appropriate.

Q. Why are your results appropriate?

A. All my betas are positive. They are estimated over twelve contiguous 60 month periods, with the first period ending in May 1996 and the last one ending in April 1997. This procedure captures any change in how the company's beta value is responding to the market. I provide tests of statistical significance, and the tests are reasonable. The alphas are zero, their tests of statistical significance indicate the true values are zero, and they play no role at all in my return. All of these factors taken together reinforce the implications of my Schedule 1, which demonstrates the comparability of my group of companies.

In comparison, Dr. Andrews' analysis has 5 negative betas, which he dismisses as "analytically indefensible" at page 43 line 18 of his direct testimony. Dr. Andrews does not explain why the results are "indefensible," but it is clear that if he did not exclude the negative values, his estimated return of 12.5% would be lower. Therefore, the negative betas appear to be indefensible because they would lower the company's return. He relies on the alpha to raise his estimated returns and performs an irrational procedure to boost an estimated return by 1.33%. In addition, he does not provide tests of statistical significance, even when asked to do so. Taken together, these factors indicate that Dr. Andrews' companies do not form a comparable group that is a rational basis for estimating a rate of return. These factors further reinforce what my Schedules 25 and 26 already suggest -- his companies are composed of two dissimilar groups that cannot be a rational basis to set a rate of return in this docket.

Q. What is your opinion regarding Dr. Andrews' statistical analysis is shown in Schedule 9 of his testimony?

A. In my opinion the TRA should disregard the conclusory analysis because it is arbitrary, irrational and unsupported by material and substantial evidence. Therefore, his analysis cannot constitute a basis for a decision.

<u>DCF ANALYSIS IS BIASED UPWARDS</u>

Q. What is your opinion of Dr. Andrews' DCF analysis?

A. His DCF recommendation of 11.06% is derived from Schedule 8, page 2, of his testimony. My opinion is that his result is biased upward by approximately 2% because his rate of 11.06% is based on only 4 companies instead 21. He ignores the results of the 17 other companies that he considers as comparables. Therefore, his recommendation of 11.06% is not representative of the group that he has designated as comparables. On the other hand, if his companies are composed of two groups not comparable to each other, then his decision to ignore some would be rational. However, if this is why he has ignored 17 companies, then this makes all his other analyses irrational, too. For example, of the 17 companies ignored in Schedule 8, 12 of them are used in his Schedule 9 to derive the returns of 12.5% and 12.17%. On its face this is clearly an irrational procedure, and Dr. Andrews offers no explanation. It is my opinion that the TRA should disregard his recommended DCF rate because it is biased and not supported by material and substantial evidence.

RANGE OF 11.5% TO 12.5% IS IRRATIONAL

Q. Do you have any concluding opinions regarding the equity returns suggested by the company's cost-of-capital witness?

A. Yes. In his direct testimony, at page 47 lines 14 and 23, Dr. Andrews concludes his analysis by recommending a range of 11.5% to 12.5%. Dr. Andrews suggests this is a reasonable range because he has found returns that are well above the range. At page 47 lines 18-22 Dr. Andrews says "The Small Stock equity risk premiums...over 14%...cannot be dismissed."

The "small company" premiums can and should be dismissed because:

They are based on 1 mutual fund out of 200;

The fund has a minimum investment requirement of $2 million;

The stockholders of Dr. Andrews' companies cannot afford to buy into such a fund;

The directorates of the Ibbotson Associates and the DFA 9-10 fund overlap - suggesting that the funds' return is not calculated by an independent source;

The fund's return on assets is only 8.75%, an amount provided by Morningstar Inc., a source that is independent of Ibbotson Associates and DFA Investment Dimensions Group - the manger of the DFA 9-10 fund;

The difference between the fund's return on assets and its so-called annual return means that a mutual fund's return cannot and should not be used to grant a utility's return on assets;

The fund relies exclusively on capital gains as the source of its return.

The small-company fund approach is an unfit and irrational method to develop a rate of return that must be supported by ratepayers.

The returns of 12.5% and 12.17%, both are predicated on data that is specific to large companies - not small ones. This invalidates both returns because Dr. Andrews' analysis is based on "small publicly held" companies. Also, I have pointed to several places in the derivation of 12.5% and 12.17%, where Dr. Andrews is silent about the logic that led him to perform crucial procedures or where the procedure is irrational. Considering all these factors, Dr. Andrews' recommended range of 11.5% to 12.5% emerges as irrational.

Q. What is your opinion regarding Dr. Andrews' returns of 14.39%, 14.38%, 14.23%, 12.5%, 12.17% and 11.06%?

A. In my opinion, the returns of 14.39%, 14.38%, 14.23%, 12.5%, 12.17% and 11.06% are unsubstantiated, speculative and more than just and reasonable. They cannot be a basis for the TRA to set the equity return in this docket.

Q. How is your testimony different from that of the company's cost-of-capital witness?

A. In my opinion my testimony is different because I have used reasonable methods and achieved reasonable results. I have explained my methods in pain-staking detail, giving all parties an accurate and true description of all the factors and sources I considered when forming my opinion on the rate of return. Therefore, the equity return of 10.55% is neither confiscation nor extortion an is equitable to ratepayers and the company alike.

Q. Does this conclude your direct testimony?

A. Yes.

Proof of Comparability

Market Statistics

NAME	Ratio of Market Price to Book Price Dec 1996	Equity Ratio Dec 1996	Dividend Yield Dec 1996	Value of Holdings Per Share Holder 4/30/97	Average Number Of Years Stock Is Held By Investor	Market Value 4/30/97 $(Millions)
AGL RESOURCES INC	180%	48 9%	5 40%	$63,334	3 36	1061
BAY ST GAS CO	150%	53 1%	5 61%	$30,949	3 86	343
BROOKLYN UN GAS CO	149%	55 8%	5 05%	$42,951	2 26	1352
INDIANA ENERGY INC	184%	62 5%	4 49%	$58,122	4 25	548
LACLEDE GAS CO	161%	57 1%	5 45%	$35,410	3 98	388
NORTHWEST NAT GAS CO	159%	52 5%	5 05%	$44,355	2 98	545
PEOPLES ENERGY CORP	171%	56 4%	5 42%	$34,172	2 21	1167
PIEDMONT NAT GAS INC	178%	49 7%	4 84%	$37,664	3 37	687
WASHINGTON GAS LT CO	174%	59 4%	5 19%	$45,226	2 98	972
AVERAGE	166%	55 0%	5 50%	$42,958	2 94	792

Financial Behavior

Value Line March 31, 1995
"We advise staying with top quality stocks with payout ratios below 80% We'd be wary of payout ratios above 80%"

▶ Companies Respond In Similar Way To Concerns Of The Financial Community

Dividends Payout Ratios As a Percent of Earnings

	1991	1992	1993	1994	1995	1996
AGL RESOURCES INC	98 1%	91 2%	96 3%	88 9%	78 2%	77 4%
BAY ST GAS CO	99 2%	96 5%	80 0%	77 8%	86 5%	76 0%
BROOKLYN UN GAS CO	87 6%	95 6%	76 3%	73 0%	73 2%	72 4%
INDIANA ENERGY INC	82 9%	82 8%	77 3%	66 7%	73 3%	59 4%
LACLEDE GAS CO	93 8%	102 6%	75 8%	85 9%	97 6%	67 4%
NORTHWEST NAT GAS CO	167 3%	155 0%	67 0%	72 1%	73 1%	60 9%
PEOPLES ENERGY CORP	83 4%	85 4%	84 4%	84 5%	101 1%	61 8%
PIEDMONT NAT GAS INC	97 8%	65 0%	65 5%	74 8%	73 8%	68 9%
WASHINGTON GAS LT CO	92 1%	84 3%	83 2%	78 2%	77 2%	61 6%
AVERAGE	97 9%	97 9%	80 7%	80 1%	83 3%	66 7%

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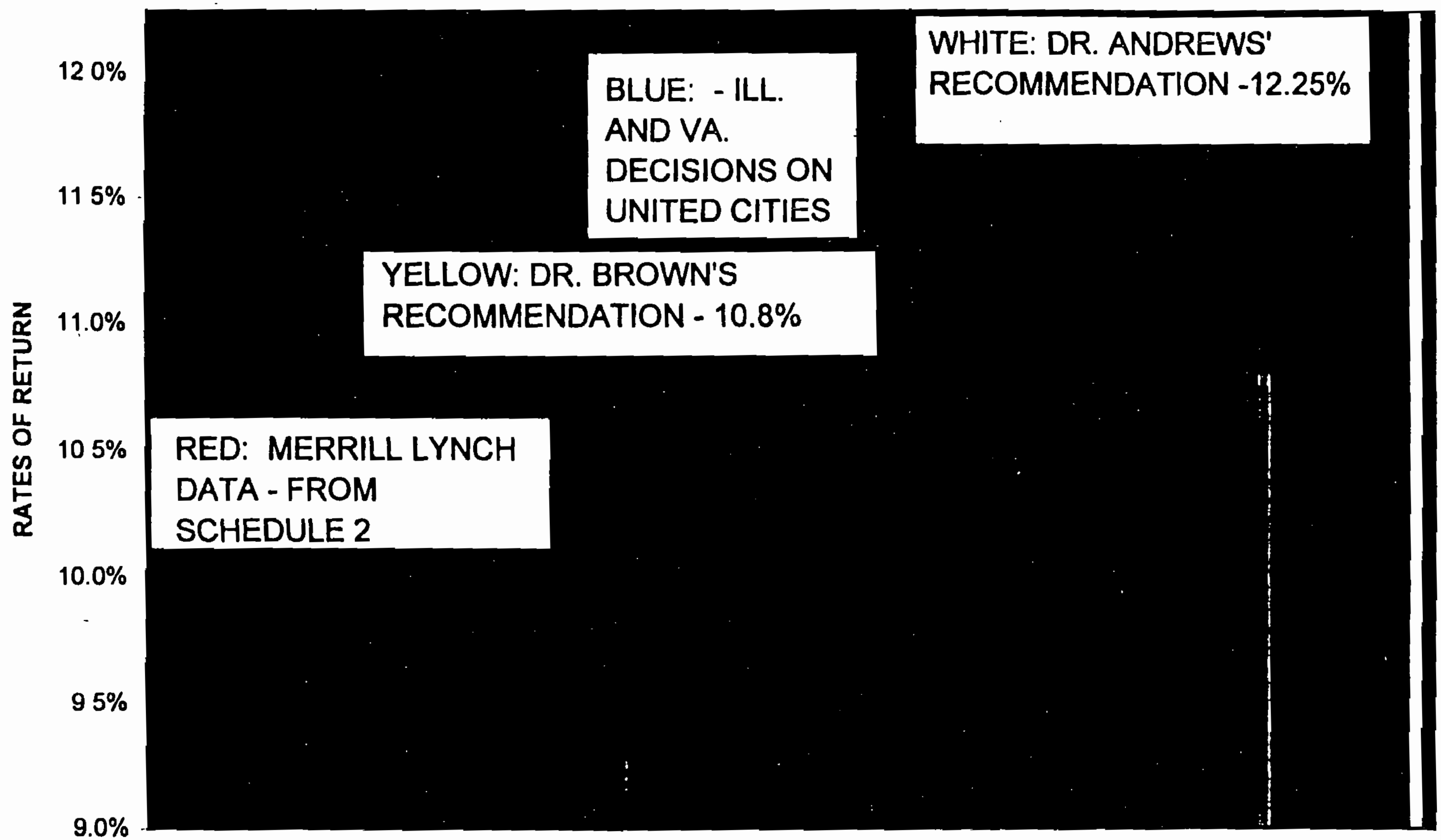
Direct Testimony___
Chart 1 of 3___

Chart 1

ESTIMATIONS OF REQUIRED RATES OF RETURN TO EQUITY FOR AGL'S SUBSIDAIRY - CHATTANOOGA GAS



Merrill Lynch Data

MONTH	DCF RATE	RISK PREMIUM RATE	MAXIMUM OF THE TWO RATES
Jan-95	11 0%	10 4%	11 0%
Feb-95	10 6%	10 3%	10 6%
Mar-95	10 3%	10 2%	10 3%
Apr-95	10 2%	10 1%	10 2%
May-95	10 1%	10 0%	10 1%
Jun-95	10 1%	9 5%	10 1%
Jul-95	10 3%	9 3%	10 3%
Aug-95	10 5%	9 4%	10 5%
Sep-95	10 3%	9 3%	10 3%
Oct-95	10 3%	9 4%	10 3%
Nov-95	9 4%	9 6%	9 6%
Dec-95	9 8%	9 6%	9 8%
Jan-96	8 8%	9 2%	9 2%
Feb-96	8 8%	9 3%	9 3%
Mar-96	9 1%	9 3%	9 3%
Apr-96	9 9%	9 7%	9 9%
May-96	9 9%	9 6%	9 9%
Jun-96	10 0%	9 8%	10 0%
Jul-96	9 7%	9 7%	9 7%
Aug-96	10 0%	9 7%	10 0%
Sep-96	9 6%	9 9%	9 9%
Oct-96	9 6%	9 7%	9 7%
Nov-96	9 5%	9 5%	9 5%
Dec-96	10 4%	9 4%	10 4%
Jan-97	10 2%	10 6%	10 6%
Feb-97	10 2%	10 0%	10 2%
Mar-97	10 5%	10 1%	10 5%
Apr-97	10 5%	10 3%	10 5%
May-97	10 5%	10 1%	10 5%

Source *Merrill Lynch Quantitative Profiles* [Published Monthly]
January 1995 through May 1997 Issues, page 11

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United Cities granted rate increase in Illinois

03:24 p.m Jun 26, 1997 Eastern

BRENTWOOD, Tenn.--(BUSINESS WIRE)--June 26, 1997--**United Cities Gas** Co. (NASDAQ:**UCIT**), a multistate distributor of natural and propane gas, announced today that the Illinois Commerce Commission has granted the company a rate increase of $428,000 in annual revenues.

An overall rate increase of 2.09 percent was granted for approximately 23,000 customers in or near Harrisburg, Metropolis, Vandalia, Virden and Salem, Ill. The rate increase provides **United Cities** with a 9.85 percent return on rate base and a 10.94 percent return on common equity. The increase is the result of an application filed before the Commission in November 1996.

The net rate increase is part of an agreement reached by **United Cities**, **Atmos Energy** Corporation and the Commission in approving the merger of **United Cities** and **Atmos**. In addition, the rate increase will be followed by a three year rate moratorium.

United Cities Gas Company distributes natural and propane gas to approximately 350,000 customers in 10 states. The company is also engaged in other energy-related businesses. (See also http://www.businesswire.com)

Docket No. 97-00982
Exhibit CA-SNB____
Direct Testimony___
Schedule 4_____
Page 1 of 1____

United Cities granted rate increase in Virginia
05 03 p m Jun 02 1997 Eastern

BRENTWOOD Tenn --(BUSINESS WIRE)--June 2 1997--United Cities Gas Co NASDAQ UCIT) a multistate distributor of natural and propane gas announced today that the Virginia State Corporation Commission has granted the company a rate increase of $102 838 in annual revenues by order dated May 27 1997

An overall rate increase of less than one percent was granted for approximately 18 000 current regulated customers The rate increase provides United Cities with a 10 percent return on rate base and an 11 percent return on common equity The increase is the result of an application filed before the Commission in April 1995

Due to the Commission's decision, money over-collected from customers since Sept. 28, 1995, when United Cities began charging interim rates based on its original 3 percent rate increase request, will be credited to customers' accounts with interest The credit amount for customers will vary according to their gas usage during the period interim rates were in effect

United Cities' last rate increase in Virginia was granted in 1989 Since that time rate reductions were implemented in both 1991 and 1994

United Cities Gas Company distributes natural and propane gas to approximately 350,000 customers in 10 states The company is also engaged in other energy-related businesses (See also http //www businesswire com)

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Schedule 6
Page 1 of 1

Effect of Monthly Compounding

	Monthly Net Income for Atlanta Gas-FY 1996 *	Monthly Income as a Percentage of Annual Income	Pattern of Monthly Return Based on Monthly Pattern of Income [col (3) X Allowed Annual Return of 10.55%]	Cumulative Equity Balance at Start of Month	Monthly Return on Equity [col (4) X col (5)]	Cumulative Month End Equity Balance
(1)	(2)	(3)	(4)	(5)	(6)	(7)
Oct-95	3,272	4 1%	0 43%	$1.000	$0 0043	$1 004
Nov-95	9,492	11 8%	1 24%	$1.004	$0 0125	$1 017
Dec-95	17,476	21 7%	2 29%	$1.017	$0.0232	$1 040
Jan-96	18,120	22.5%	2 37%	$1.040	$0.0247	$1 065
Feb-96	14,495	18.0%	1.90%	$1 065	$0 0202	$1 085
Mar-96	13,797	17.1%	1 80%	$1.085	$0 0196	$1 104
Apr-96	5,232	6 5%	0 68%	$1 104	$0.0076	$1 112
May-96	0,836	1 0%	0 11%	$1 112	$0.0012	$1 113
Jun-96	-1,122	-1.4%	-0.15%	$1.113	-$0 0016	$1 112
Jul-96	2,226	2 8%	0.29%	$1.112	$0 0032	$1 115
Aug-96	-0,253	-0.3%	-0.03%	$1.115	-$0 0004	$1 114
Sep-96	-2,918	-3 6%	-0.38%	$1 114	-$0.0043	$1.110
Total	80,653	100 0%	10.55%		$0 1102	

*From CA Data Request 39

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Exhibit CA-SNB____
Direct Testimony____
Schedule 7______
Page 1 of 2____

BEFORE THE TENNESSEE PUBLIC SERVICE COMMISSION

IN THE MATTER OF: Docket No. 9502116

CHATTANOOGA GAS COMPANY

Tuesday, September 26, 1995
Hamilton County Board of Education
Chattanooga, Tennessee 37402

CROSS EXAMINATION OF DR. VICTOR L. ANDREWS

APPEARANCES:

COMMISSION MEMBERS:

Keith Bissell, Chairman,
Steve Hewlett and Sara Kyle

FOR THE CHATTANOOGA GAS COMPANY:

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450 James Robertson Parkway
Nashville, Tennessee 37243-0485

COPY

dividends --

A Where are we?

Q I'm sorry, I've got the wrong page citations here. You can tell me whether you remember saying this or not. I can't find it through your testimony right now. In the case of public utilities dividends paid are constant for certain periods and are increased at irregular intervals even though financial processes underlying their movement may be progressing much more smoothly and constantly; does that sound correct?

A I think I would say smoothly and continuously, but whatever, but yes, that is true.

Q Do you agree --

A It's true as a general rule.

Q So you would agree that a public utility and natural gas public utility, their financial activity is basically smooth and continuous?

A Well, what I said, I think if we had the complete quotation would be that earnings and cash flows progress smoothly and continuously. Financial processes occur smoothly and continuously. They go -- if this makes the point for you -- minute by minute, hour by hour, day by day and they're not interruptable.

Q Just to clarify for the record we found the first segment that we didn't really dispute. It starts

CAPITAL STRUCTURE SUBMITTED IN DOCKET 95-02116
AS EXHIBIT 3 SCHEDULE 9

Docket No 97-00982
Exhibit CA-SNB____
Direct Testimony___
Schedule 8______
Page 1 of 1____

CHATTANOOGA GAS COMPANY
Cost of Capital
For the 12 Months Ending September 30 1996

Line No		Amount	Ratio	Cost	Weighted Cost
1	Short Term Debt	5 190 953	5 36%	8 00%	0 43%
2	Long Term Debt	43 096 531	44 50%	7 96%	3 54%
3	Preferred Stock	4 183 753	4 32%	7 56%	0 33%
4	Common Stock Equity	44 374 900	45 82%	12 50%	5 73%
5	Total	96 846 137	100 00%		10 03%

DCF Recommended Return

DCF SUGGESTED RATE OF RETURN

Company	12/96. Annual Dividend	Average Daily closing Price: 5/1/96 - 4/30/97	Annual Dividend Yield
Atlanta Gas	$1 06	$19.63	5.40%
Bay State	$1.52	$27.08	5.61%
Brooklyn Union	$1 42	$28.14	5.05%
Indiana Energy	$1 11	$24.70	4.49%
LaClede	$1 26	$23 11	5.45%
Northwest Natural	$1 20	$23 77	5.05%
Peoples	$1 83	$33.79	5.42%
Piedmont	$1.15	$23.76	4.84%
Washington Gas Light	$1 14	$21 94	5.19%
	Average Div. Yield		5.17%

	Year of AGL Dividend	
Actual	1996	$1.06
Value-Line Projection	2000	$1.30

AGL DIVIDEND GROWTH RATE	5.23%
DCF Suggested Rate of Return	10.40%

History of A Rated Bonds

1992		1993		1994		1995		1996		1997	
Jan 92	8 72%	Jan-93	8 13%	Jan 94	7 24%	Jan 95	8 75%	Jan 96	7 09%	Jan 97	7 93%
Feb	8 83%	Feb	7 80%	Feb	7 45%	Feb	8 55%	Feb	7 31%	Feb	7 81%
Mar	8 89%	Mar	7 81%	Mar	7 82%	Mar	8 40%	Mar	7 75%	Mar	8 08%
Apr	8 87%	Apr	7 66%	Apr	8 20%	Apr	8 31%	Apr	7 90%	Apr	8 23%
May	8 81%	May	7 75%	May	8 37%	May	7 71%	May	8 20%	May	
Jun	8 70%	Jun	7 59%	Jun	8 30%	Jun	7 60%	Jun	8 13%	Jun	
Jul	8 84%	Jul	7 43%	Jul	8 45%	Jul	7 72%	Jul	8 07%	Jul	
Aug	8 85%	Aug	7 16%	Aug	8 38%	Aug	7 84%	Aug	7 87%	Aug	
Sep	8 62%	Sep	6 94%	Sep	8 62%	Sep	7 55%	Sep	8 06%	Sep	
Oct	8 84%	Oct	6 91%	Oct	8 80%	Oct	7 38%	Oct	7 83%	Oct	
Nov	8 58%	Nov	7 25%	Nov	8 95%	Nov	7 30%	Nov	7 54%	Nov	
Dec	8 37%	Dec	7 28%	Dec	8 78%	Dec	7 10%	Dec	7 63%	Dec	
Average	8 727%	Average	7 459%	Average	8 278%	Average	7 562%	Average	7 762%	Average	8 01%

Average Most Recent 12 Months 7 948%

Sources Federal Reserve Bulletin, Table A26 Subtable 1 35, line 38
Federal Reserve Publications H15(519) and G13(415)

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Direct Testimony____
Schedule 11
Page 1 of 1______

Risk Premium Data for Large Companies: 1925-1996

YEAR	Large Company Total Return Index For Year	Year-To-Year Percentage Change In Large Company Total Return Index
(1)	(2)	(3)
1925	1 00	
1926	1.12	11.60%
1927	1 54	37.54%
1928	2 20	43 58%
1929	2 02	-8.44%
1930	1 52	-24 88%
1931	0 86	-43.34%
1932	0 79	-8 15%
1933	1.21	53.87%
....	.. .. ..	....
....	....	. ...
....	....	... .. .
1988	406 46	16 81%
1989	534 46	31 49%
1990	517 50	-3.17%
1991	675 59	30 55%
1992	727 41	7 67%
1993	800.08	9 99%
1994	810 54	1 31%
1995	1113 92	37.43%
1996	1370 95	23 07%
ACTUAL RETURN / BIASED RETURN	10 7%	12 7%

If $1 Were Invested in 1925 and the Investment Grew by 10.7% Every Year, the Result Would Be $1370.95.

The Average Return, 12.7%, Says the Wealth Accumulated Since 1925 should be $4768. This is Inaccurate.

*Source: Ibbotson Associates 1997 Yearbook:
Column (2) - From Table B-1
Column (3) - From Table A-1

The Table Below Shows The Odds In 1996 Of Achieving The Actual Return
And The Biased Average Return From A $1 Investment In 1925 In A Large Company

	NUMBER OF POSSIBILITIES	ALL POSSIBLE VALUES OF INVESTMENT	ALL POSSIBLE RETURNS	ODDS OF ACHIEVING A RETURN EXACTLY EQUAL TO THE RETURN IN COLUMN (3)	ODDS OF ACHIEVING A RETURN LESS THAN THE RETURN IN COLUMN (3)	ODDS OF ACHIEVING A RETURN MORE THAN THE RETURN IN COLUMN (3)
	(1)	(2)	(3)	(4)	(5)	(6)
	1 0E+0	$0 00	-8 3%	0%	0%	100%
	71 0E+0	$0 00	-7 8%	0%	0%	100%
	2 5E+3	$0 00	-7 3%	0%	0%	100%
	57 2E+3	$0 01	-6 8%	0%	0%	100%
	----	----	----	----	----	----
	----	----	----	----	----	----
	----	----	----	----	----	----
	46 2E+18	$82	6 4%	2%	3%	95%
	68 5E+18	$119	7 0%	3%	5%	92%
	95 8E+18	$173	7 5%	4%	8%	88%
	126 8E+18	$253	8 1%	5%	12%	83%
	158 5E+18	$368	8 7%	7%	17%	76%
	187 3E+18	$536	9 3%	8%	24%	68%
	209 3E+18	$780	9 8%	9%	32%	59%
	221 3E+18	$1,136	10 4%	9%	41%	50%
ACTUAL RETURN	----------	$1,370.95	10.7%	------------	50%	50%
	221 3E+18	$1,654	11 0%	9%	50%	41%
	209 3E+18	$2,409	11 6%	9%	59%	32%
	187 3E+18	$3,508	12 2%	8%	68%	24%
BIASED AVERAGE	----------	$4,768.40	12.7%	7%	75%	18%
	158 5E+18	$5,109	12 8%	7%	76%	17%
	126 8E+18	$7,440	13 4%	5%	83%	12%
	95 8E+18	$10,835	14 0%	4%	88%	8%
	68 5E+18	$15,778	14 6%	3%	92%	5%
	46 2E+18	$22,977	15 2%	2%	95%	3%
	29 4E+18	$33,460	15 8%	1%	97%	2%
	17 6E+18	$48,727	16 4%	1%	98%	1%
	10 0E+18	$70,959	17 0%	0%	99%	0%
	----	----	----	----	----	----
	----	----	----	----	----	----
	----	----	----	----	----	----
	1 0E+0	$854,908,330	33 6%	0%	100%	0%

Chart 2

THE CUMULATIVE PROBABILITY DISTRIBUTION FOR IBBOTSON'S RETURNS TO LARGE COMPANY STOCKS

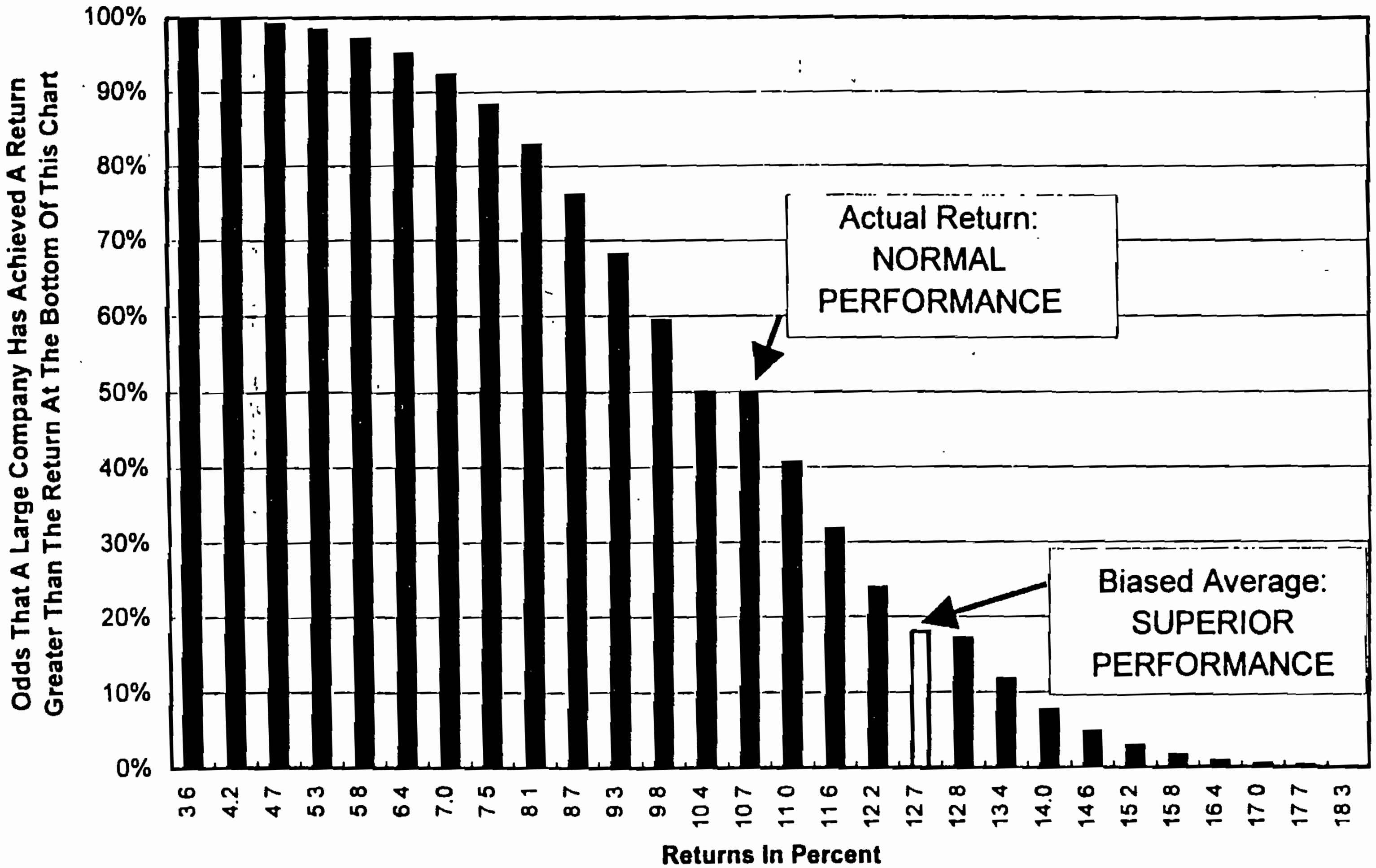
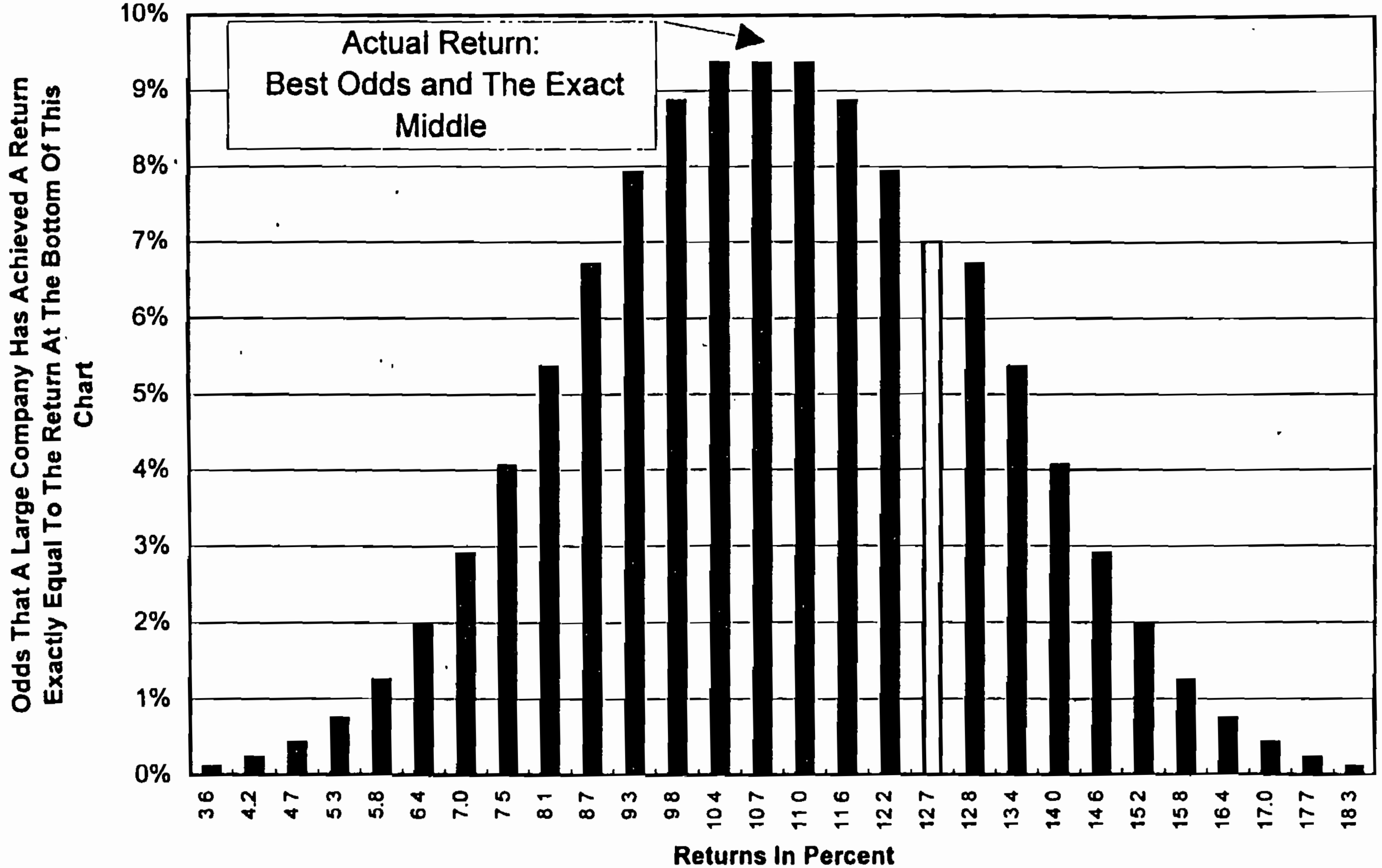


Chart 3

THE PROBABILITY DISTRIBUTION FOR IBBOTSON'S RETURNS TO LARGE COMPANY STOCKS



YEAR (1)	T-Bill Total Return Index For Year (2)	Year-To-Year Percentage Change In T-Bill Total Return Index (3)	YEAR (4)	T-Bill Total Return Index For Year (5)	Year-To-Year Percentage Change In T-Bill Total Return Index (6)
1925	1 00000		1961	1 60400	2 10%
1926	1 03300	3 30%	1962	1 64800	2 74%
1927	1 06500	3 10%	1963	1 70000	3 16%
1928	1 10300	3 57%	1964	1 76000	3 53%
1929	1 15500	4 71%	1965	1 82900	3 92%
1930	1 18300	2 42%	1966	1 91600	4 76%
1931	1 19600	1 10%	1967	1 99700	4 23%
1932	1 20700	0 92%	1968	2 10100	5 21%
1933	1 21100	0 33%	1969	2 23900	6 57%
1934	1 21300	0 17%	1970	2 38500	6 52%
1935	1 21500	0 16%	1971	2 49000	4 40%
1936	1 21700	0 16%	1972	2 58500	3 82%
1937	1 22100	0 33%	1973	2 76400	6 92%
1938	1 22100	0 00%	1974	2 98600	8 03%
1939	1 22100	0 00%	1975	3 15900	5 79%
1940	1 22100	0 00%	1976	3 31900	5 06%
1941	1 22200	0 08%	1977	3 48900	5 12%
1942	1 22500	0 25%	1978	3 74000	7 19%
1943	1 22900	0 33%	1979	4 12800	10 37%
1944	1 23300	0 33%	1980	4 59200	11 24%
1945	1 23700	0 32%	1981	5 26700	14 70%
1946	1 24200	0 40%	1982	5 82200	10 54%
1947	1 24800	0 48%	1983	6 33500	8 81%
1948	1 25800	0 80%	1984	6 95900	9 85%
1949	1 27200	1 11%	1985	7 49600	7 72%
1950	1 28700	1 18%	1986	7 95800	6 16%
1951	1 30600	1 48%	1987	8 39300	5 47%
1952	1 32800	1 68%	1988	8 92600	6 35%
1953	1 35200	1 81%	1989	9 67300	8 37%
1954	1 36400	0 89%	1990	10 42900	7 62%
1955	1 38500	1 54%	1991	11 01200	5 59%
1956	1 41900	2 45%	1992	11 39800	3 51%
1957	1 46400	3 17%	1993	11 72800	2 90%
1958	1 48600	1 50%	1994	12 18600	3 91%
1959	1 53000	2 96%	1995	12 87000	5 61%
1960	1 57100	2 68%	1996	13 54000	5 21%

Actual Return	3 74%	3 79%	Average Return

*Source Ibbotson Associates 1997 Yearbook
Column (2) - From Table B-5
Column (3) - From Table A-14
Column (5) - From Table B-5
Column (6) - From Table A-14

Debt Instruments: Actual and Average Returns

Returns of Debt Instruments 1925-1996

	Actual	Biased Average
Long-Term Corporate Bonds	5 60%	6 00%
Long-Term Government Bonds	5 10%	5.40%
Income Portion of Long-Term Government Bonds	5.10%	5.20%
Intermediate Term Government Bonds	5 20%	5 40%
U S. Treasury Bills	3 70%	3 80%

*Source: Ibbotson Associates 1997 Yearbook Page 118

Risk Premium Results

RISK PREMIUM ANALYSIS BETAS -- FOR AGL AND COMPARABLE COMPANIES REGRESSED AGAINST S&P 500

BETA FOR 60 MONTH PERIOD ENDING	ATLANTA GAS LIGHT (ATG)	BAY ST GAS CO	BROOKLYN UN GAS CO	INDIANA ENERGY INC	LACLEDE GAS CO	NORTHWEST NAT GAS CO	PEOPLES ENERGY CORP	WASHINGTON GAS LT CO	PIEDMONT NATURAL GAS CO	AVERAGE FOR GROUP
May-96	0 532	0 448	0 490	0 087	0 169	0 289	0 784	0 441	0 389	0 401
Jun-96	0 588	0 397	0 456	0 075	0 170	0 198	0 758	0 430	0 392	0 382
Jul-96	0 584	0 422	0 539	0 171	0 141	0 168	0 785	0 300	0 474	0 396
Aug-96	0 590	0 422	0 561	0 178	0 154	0 166	0 806	0 308	0 470	0 406
Sep-96	0 519	0 416	0 618	0 170	0 205	0 158	0 781	0 328	0 438	0 404
Oct-96	0 545	0 429	0 623	0 171	0 189	0 185	0 785	0 329	0 440	0 411
Nov 96	0 520	0 428	0 703	0 272	0 198	0 100	0 773	0 333	0 515	0 427
Dec-96	0 517	0 521	0 886	0 450	0 323	0 287	0 977	0 437	0 479	0 540
Jan-97	0 433	0 397	0 731	0 481	0 364	0 358	0 915	0 422	0 417	0 502
Feb-97	0 439	0 395	0 735	0 475	0 368	0 361	0 912	0 425	0 418	0 503
Mar-97	0 488	0 386	0 717	0 503	0 427	0 311	0 888	0 404	0 347	0 497
Apr-97	0 506	0 383	0 677	0 464	0 463	0 318	0 858	0 394	0 342	0 490
AV RECENT 12 MTHS	0 520	0 420	0 677	0 333	0 283	0 241	0 848	0 368	0 434	0 458

Risk Premium Results

RISK PREMIUM ANALYSIS T-STATISTICS OF BETAS – FOR AGL AND COMPARABLE COMPANIES REGRESSED AGAINST S&P 500

T-STATISTIC OF BETA FOR 60 MONTH PERIOD ENDING	ATLANTA GAS LIGHT (ATG)	BAY ST GAS CO	BROOKLYN UN GAS CO	INDIANA ENERGY INC	LACLEDE GAS CO	NORTHWEST NAT GAS CO	PEOPLES ENERGY CORP	WASHINGTON GAS LT CO	PIEDMONT NATURAL GAS CO	AVERAGE FOR GROUP
May-96	2 569	2 402	2 305	0 361	0 930	1 483	3 222	2 278	1 875	1 934
Jun-96	2 609	2 039	2 073	0 276	0 897	0 988	3 064	2 110	1 791	1 761
Jul-96	2 739	2 203	2 463	0 625	0 764	0 874	3 231	1 468	2 160	1 838
Aug-96	2 712	2 200	2 525	0 652	0 831	0 871	3 261	1 498	2 152	1 856
Sep-96	2 355	2 213	2 935	0 636	1 129	0 828	3 184	1 678	2 033	1 888
Oct-96	2 428	2 260	3 005	0 644	1 036	0 958	3 223	1 689	2 044	1 923
Nov-96	2 321	2 284	3 417	1 069	1 094	0 522	3 189	1 720	2 413	2 003
Dec-96	2 113	2 559	3 935	1 656	1 670	1 406	3 747	2 035	2 047	2 352
Jan-97	1 813	1 870	3 442	1 820	2 025	1 821	3 525	2 006	1 798	2 236
Feb-97	1 842	1 869	3 438	1 791	2 035	1 829	3 515	2 016	1 804	2 238
Mar-97	2 087	1 880	3 435	1 934	2 362	1 812	3 482	1 975	1 535	2 256
Apr-97	2 208	1 929	3 286	1 810	2 591	1 761	3 435	1 970	1 544	2 262
AV RECENT 12 MTHS	2 316	2 129	3 188	1 264	1 554	1 248	3 379	1 605	1 853	2 093

Risk Premium Results

RISK PREMIUM ANALYSIS ALPHAS – FOR AGL AND COMPARABLE COMPANIES REGRESSED AGAINST S&P 500

ALPHA FOR 60 MONTH PERIOD ENDING	ATLANTA GAS LIGHT (ATG)	BAY ST GAS CO	BROOKLYN UN GAS CO	INDIANA ENERGY INC	LACLEDE GAS CO	NORTHWEST NAT GAS CO	PEOPLES ENERGY CORP	WASHINGTON GAS LT CO	PIEDMONT NATURAL GAS CO	AVERAGE FOR GROUP
May-95	-0 003	0 000	0 001	0 007	0 004	0 000	-0 003	0 002	0 004	0 001
Jun-95	-0 003	0 002	0 002	0 009	0 003	0 003	-0 002	0 003	0 005	0 002
Jul-95	-0 003	0 001	0 000	0 005	0 003	0 002	-0 003	0 005	0 002	0 001
Aug-95	-0 002	0 001	0 002	0 006	0 004	0 002	-0 002	0 005	0 002	0 002
Sep-95	-0 003	-0 001	-0 001	0 004	0 003	0 001	-0 003	0 003	0 002	0 001
Oct-95	-0 002	-0 001	-0 001	0 004	0 002	0 001	-0 003	0 003	0 002	0 001
Nov-95	-0 003	-0 001	-0 002	0 001	0 002	0 002	-0 004	0 003	0 001	0 000
Dec-95	-0 002	-0 001	-0 003	0 000	0 002	0 001	-0 005	0 001	0 001	-0 001
Jan-96	-0 001	-0 002	-0 001	-0 001	0 000	0 000	-0 008	0 002	0 000	-0 001
Feb-96	-0 001	-0 002	-0 002	0 000	-0 001	-0 001	-0 008	0 001	0 000	-0 001
Mar-96	-0 003	-0 002	-0 001	0 000	-0 002	0 000	-0 005	0 002	0 002	-0 001
Apr-96	-0 002	-0 001	-0 001	0 000	-0 001	0 002	-0 005	0 002	0 002	-0 001
AV RECENT 12 MTHS	-0 002	-0 001	-0 001	0 003	0 002	0 001	-0 004	0 003	0 002	0 000

Risk Premium Results

RISK PREMIUM ANALYSIS T-STATISTICS OF ALPHAS -- FOR AGL AND COMPARABLE COMPANIES REGRESSED AGAINST S&P 500

T-STATISTIC OF ALPHA FOR 60 MONTH PERIOD ENDING	ATLANTA GAS LIGHT (ATG)	BAY ST GAS CO	BROOKLYN UN GAS CO	INDIANA ENERGY INC	LACLEDE GAS CO	NORTHWEST NAT GAS CO	PEOPLES ENERGY CORP	WASHINGTON GAS LT CO	PIEDMONT NATURAL GAS CO	AVERAGE FOR GROUP
May-96	-0 452	-0 034	0 131	0 905	0 697	0 083	-0 447	0 337	0 577	0 200
Jun-96	-0 408	0 308	0 289	1 180	0 815	0 486	-0 324	0 508	0 705	0 373
Jul-96	-0 410	0 156	0 032	0 645	0 632	0 324	-0 486	0 622	0 335	0 228
Aug-96	-0 323	0 154	0 258	0 702	0 785	0 322	-0 287	0 902	0 302	0 313
Sep-96	-0 453	-0 118	-0 100	0 447	0 620	0 172	-0 381	0 466	0 346	0 111
Oct-96	-0 355	-0 111	-0 206	0 531	0 428	0 189	-0 437	0 473	0 360	0 097
Nov-96	-0 399	-0 098	-0 360	0 068	0 407	0 398	-0 497	0 439	0 215	0 019
Dec-96	-0 358	-0 218	-0 500	0 063	0 421	0 181	-0 717	0 152	0 082	-0 099
Jan-97	-0 191	-0 333	-0 207	-0 141	-0 050	-0 074	-0 822	0 270	0 067	-0 164
Feb-97	-0 189	-0 368	-0 310	0 036	-0 098	-0 165	-0 738	0 171	0 014	-0 183
Mar-97	-0 378	-0 290	-0 208	-0 040	-0 293	0 076	-0 659	0 309	0 313	-0 130
Apr-97	-0 344	-0 189	-0 229	-0 059	-0 269	0 278	-0 685	0 267	0 333	-0 100
AV RECENT 12 MTHS	-0 355	-0 095	-0 117	0 361	0 325	0 189	-0 540	0 426	0 304	0 055

Risk Premium Suggested Rate Of Return

COMPANY	Debt Yield (a)	Beta (b)	Market Risk Premium = 10 7% - 3 7% (c)	Company Risk Premium (d)=(b)X(c)	Company Equity Cost (e)=(a)+(d)
AGL RESOURCES INC (HLDG CO)	7 95%	0 520	6 97%	3 62%	11 57%
BAY ST GAS CO	7 95%	0 420	6 97%	2 93%	10 88%
BROOKLYN UN GAS CO	7.95%	0 677	6 97%	4 72%	12 67%
INDIANA ENERGY INC	7 95%	0 333	6 97%	2 32%	10 27%
LACLEDE GAS CO	7 95%	0 283	6 97%	1 98%	9 92%
NORTHWEST NAT GAS CO	7 95%	0 241	6 97%	1 68%	9 63%
PEOPLES ENERGY CORP	7 95%	0 848	6 97%	5 91%	13 86%
WASHINGTON GAS LT CO	7 95%	0 368	6 97%	2 57%	10 51%
PIEDMONT NATURAL GAS CO	7 95%	0 434	6 97%	3 02%	10 97%
** Av of Comparable Cos	7 95%	0 458	6 97%	0 032	11 14%

**Average Includes All Betas for All Companies Because the Average T-Statistics Are Greater Than 1 T-Statistics Are Shown In The Prior Schedule

Risk Premium Suggested Rate Of Return	11.14%

Any Model Relying on Ibbotson's Data Uses Monthly Compounding

Ibbotson's Annual Returns Are Based on Monthly Compounding

ROW	Month	Monthly Return	Monthly Return Relative to the Value "1"	Cumulative Return in the Year Relative to the Value "1"	Cumulative Return in the Year
	(1)	(2)*	(3)	(4)	(5)
				col (3) x prior entry in col (3)	
-	-	-	100 00%		
1	1/1/96	3.44%	103 44%	103 44%	3.44%
2	2/1/96	0.96%	100 96%	104.43%	4.43%
3	3/1/96	0 96%	100 96%	105 44%	5 44%
4	4/1/96	1.47%	101.47%	106.99%	6 99%
5	5/1/96	2 58%	102.58%	109.75%	9.75%
6	6/1/96	0.41%	100.41%	110 20%	10.20%
7	7/1/96	-4 45%	95.55%	105 29%	5 29%
8	8/1/96	2.12%	102.12%	107 52%	7 52%
9	9/1/96	5.62%	105 62%	113 57%	13 57%
10	10/1/96	2.74%	102 74%	116 68%	16.68%
11	11/1/96	7.59%	107.59%	125 53%	25 53%
12	12/1/96	-1 96%	98 04%	123.07%	$\boxed{23.07\%}$

*Source: Ibbotson Associates 1997 Yearbook Page 181, Table A-1 for 1996

Docket No. 97-00982
Exhibit CA-SNB____
Direct Testimony___
Schedule 18____
Page 1 of 2____

CHATTANOOGA GAS COMPANY

Office of the Consumer Advocate Interrogatory/Data Request - June 4, 1997

Item 42

42. Q. With regard to Exhibit 5 Schedule 9 of the company's filing, show the calculations and provide the data used to develop the figures shown under the column headings "Amount", "Ratio" and "Cost".

A. See attached documentation.

AGL Resources
Projected Capitalization Ratios

	1997	1998	Average	Ratio
Short Term Debt	69,620	81,537	75,579	5.28%
Long Term Debt	659,500	659,500	659,500	46.07%
Preferred Stock	58,469	70,090	64,280	4.49%
Common Stock Equity	619,302	644,902	632,102	44.16%
	1,406,891	1,456,029	1,431,461	100.00%

Chattanooga Gas Company
Test Year Projected Capitalization

	Ratio	Amount
Short Term Debt	5.28%	5,060,518
Long Term Debt	46.07%	44,154,936
Preferred Stock	4.49%	4,303,357
Common Stock Equity	44.16%	42,324,333
	100.00%	95,843,144

AGL Resources
Projected Cost of Capital Components

Long Term Debt	
Projected Balance	659,500,000
Less: Unamortized Loss on Repurchase	1,585,136
Less: Unamortized Debt Discount & Expense	3,702,500
Net Projected Balance	654,212,364
Projected Interest Cost	50,730,000
Projected Cost Rate	7.75%
Short Term Debt	
Projected Average Monthly Balance	49,900,000
Projected Interest Cost	2,892,000
Projected Cost Rate	5.80%
Preferred Stock	
Projected Balance	64,280,000
Projected Dividend Accrual	4,525,000
Projected Cost Rate	7.04%
Common Stock Equity	
Projected Cost Rate	12 25%
See Cost of Equity Testimony & Exhibits	

Recommended Over All Return

		Ratio	Cost	Weighted Cost
1	Short-Term Debt	5 28%	5 80%	0.31%
2	Long-Term Debt	46 07%	7 75%	3 57%
3	Preferred Stock	4 49%	7.04%	0.32%
4	Common Equity	44 16%	10 55%	4.66%
5	Total	100.00%		8 85%

Data on Mutual Funds Specializing in Small Company Stocks; 5-31-97

Company name	Objective	Ticker	Minimum Initial Purchase	Return on Assets %	96 Rtrn %
Standish Small Cap Equity	Small Company	SDSCX	$Closed	9 51	17 36
T Rowe Price Small-Cap Val	Small Company	PRSVX	$Closed	10 36	24 61
MAS Small Cap Value	Small Company	MPSCX	$Closed	9 47	35 15
Montgomery Small Cap R	Small Company	MNSCX	$Closed	12 11	18 69
MFS Aggr Small Cap Eq A	Small Company	MASCX	$Closed	14 24	15 45
Artisan Small Cap	Small Company	ARTSX	$Closed	10 68	11 86
Pioneer Small Company A	Small Company	PSCFX	$Closed	5 07	24 15
Pioneer Small Company B	Small Company	PBSCX	$Closed	5 07	23 21
Pioneer Small Company C	Small Company	PCSCX	$Closed	5 07	n/a
PIMCo Small Cap Growth Instl	Small Company	PSCIX	$Closed	11 07	16 83
GMO Small Cap Value III	Growth	GMSVX	$35,000,000	0	20 16
UAM ICM Small Company	Small Company	ICSCX	$5,000,000	8 89	23 01
Benchmark Small Co Index A	Small Company	BSCAX	$5,000,000	9 37	15 97
Bear Stearns Small Cap Val Y	Small Company	BSVYX	$2,500,000	7 57	15 87
DFA United Kingdom Small Co	Europe Stock	DFUKX	$2,000,000	19 98	29 81
DFA U S Small Cap Value	Small Company	DFSVX	$2,000,000	7 01	22 33
DFA Japanese Small Company	Pacific Stock	DFJSX	$2,000,000	4 35	-22 78
DFA Pacific Rim Small Compny	Pacific Stock	DFRSX	$2,000,000	25 72	14 36
DFA Continental Small Compny	Europe Stock	DFCSX	$2,000,000	14 28	14 32
DFA U S 6-10 Small Company	Small Company	DFSTX	$2,000,000	9 11	17 68
DFA U.S. 9-10 Small Company	Small Company	DFSCX	$2,000,000	8.75	17 65
DFA Intl Small Cap Value	Foreign Stock	DISVX	$2,000,000	10 57	0 95
Lazard Small Cap Instl	Small Company	LZSCX	$1,000,000	8 3	23 93
JPM Instl U S Small Company	Small Company	JUSSX	$1,000,000	9 6	20 84
Crabbe Huson Small Cap Instl	Small Company	CHISX	$1,000,000	3 97	n/a
Lazard Intl Small Cap Instl	Foreign Stock	LZISX	$1,000,000	16 2	15 65
ITT Hartford Small Company Y	Small Company	n/a	$1,000,000	0	n/a
Enterprise Small Co Value Y	Small Company	EIGYX	$1,000,000	7 81	11 83
Munder Small Company Grth Y	Small Company	MULYX	$500,000	11 25	37 17
Compass Small Cap Grth Instl	Small Company	PSGIX	$500,000	11 64	31 58
Compass Small Cap Val Instl	Small Company	PNSEX	$500,000	8 25	19 87
Nations Small Cap Gr Prim A	Small Company	PSCPX	$500,000	9 34	20 72
TCW Galileo Small Cap Growth	Small Company	n/a	$250,000	10 8	17 54
Emerald Small Cap Instl	Small Company	EMSCX	$250,000	10 14	10 69
Hancock Small Cap Equity	Small Company	n/a	$250,000	12 49	13 48
PIMCo Small Cap Value Instl	Small Company	PSVIX	$200,000	9 19	27 72
PIMCo Small Cap Value Admin	Small Company	n/a	$200,000	9 19	27 37
PIMCo Small Cap Growth Admin	Small Company	n/a	$200,000	11 41	16 71
JPM Pierpont U S Small Co	Small Company	PPCAX	$100,000	9 63	20 75
Parkstone Small Cap Instl	Small Company	PKSCX	$100,000	11 45	27 7

Data on Mutual Funds Specializing in Small Company Stocks; 5-31-97

Company name	Objective	Ticker	Minimum Initial Purchase	Return on Assets %	96 Rtrn %
Standish Small Cap Tax-Sen	Small Company	SDCEX	$100,000	11 06	21 23
Turner Small Cap Equity	Small Company	TSCEX	$100,000	11 24	28 85
Avesta Small Capitalization	Small Company	n/a	$100,000	10 78	30 95
Berger Small Cap Value Inst	Small Company	OMNIX	$100,000	8 28	25 6
Kent Small Co Growth Instl	Small Company	KNEEX	$100,000	8 95	19 61
SEI Instl Small Cap Growth A	Small Company	SSCGX	$100,000	10 96	19 14
SEI Instl Small Cap Growth A	Small Company	SSCGX	$100,000	10 96	19 14
59 Wall St Small Company	Small Company	FNSMX	$100,000	10 42	19 12
SEI Instl Small Cap Value A	Small Company	SESVX	$100,000	8	22 13
DLB Global Small Cap	World Stock	DLBSX	$100,000	15 07	9 85
Pictet Intl Small Companies	Foreign Stock	PTSCX	$100,000	14 65	n/a
Rainier Small/Mid Cap Equity	Growth	RIMSX	$25,000	9 37	22 56
Glenmede Small Cap Equity	Small Company	GTCSX	$25,000	9 33	25 1
Target Small Cap Value	Small Company	TASVX	$25,000	9 17	21 84
Target Small Cap Growth	Small Company	TASGX	$25,000	12 36	18 88
Schroder Small Cap	Small Company	WSCVX	$25,000	8 92	23 91
UAM FMA Small Company	Small Company	FMACX	$25,000	8 52	26 2
Quaker Small-Cap Value	Small Company	n/a	$25,000	0	n/a
Hotchkis & Wiley Small Cap	Small Company	HWSCX	$10,000	9 34	14 27
Longleaf Partners Small-Cap	Small Company	LLSCX	$10,000	8 12	30 64
LKCM Small Cap Equity	Small Company	LKSCX	$10,000	8 61	26 95
LKCM Small Cap Equity	Small Company	LKSCX	$10,000	8 61	26 95
CRM Small Cap Value	Small Company	CRMSX	$10,000	5 46	38 95
RCM Small Cap	Small Company	n/a	$10,000	9 71	34 41
Brazos/JMIC Small Cap Growth	Small Company	BJSCX	$10,000	0	n/a
Stratton Small-Cap Yield	Small Company	STSCX	$5,000	9 7	14 97
Compass Small Cap Grth Svc	Small Company	PCGEX	$5,000	11 64	31 39
Compass Small Cap Val Svc	Small Company	PSESX	$5,000	8 25	19 56
Prudential Small Companies C	Small Company	n/a	$5,000	9 09	22 97
Tocqueville Small Cap Val A	Small Company	TSCVX	$5,000	9 78	25 03
PBHG Strategic Small Co PBHG	Small Company	PSSCX	$5,000	0	n/a
Vanguard Index Small Cap Stk	Small Company	NAESX	$3,000	9 32	18 12
Galaxy II Small Co Index Ret	Small Company	ISCIX	$2,500	10 27	19 66
Vista Small Cap Equity A	Small Company	VSEAX	$2,500	10 4	28 8
Vista Small Cap Equity B	Small Company	VSEBX	$2,500	10 4	27 93
T Rowe Price Small Cap Stk	Small Company	OTCFX	$2,500	10 41	21 05
Dreyfus Small Company Value	Small Company	DSCVX	$2,500	7 65	34 15
Galaxy Small Co Equity Ret A	Small Company	GASEX	$2,500	11 05	20 84
BT Investment Small Cap	Small Company	BTSCX	$2,500	11 18	6 9
Scudder Small Company Value	Small Company	SCSUX	$2,500	8 61	23 84

Data on Mutual Funds Specializing in Small Company Stocks; 5-31-97

Company name	Objective	Ticker	Minimum Initial Purchase	Return on Assets %	96 Rtrn %
Warburg Pincus Small Val Com	Small Company	WPSVX	$2,500	8 52	56 2
Galaxy Small Cap Value Ret A	Small Company	SSCEX	$2,500	9 21	26 84
Fidelity Small Cap Stock	Small Company	FDSCX	$2,500	11 18	13 63
Northern Small Cap	Small Company	NOSGX	$2,500	6 92	18 93
Strong Small Cap	Small Company	SCAPX	$2,500	10 12	22 7
Fidelity Japan Small Co	Pacific Stock	FJSCX	$2,500	7 67	-24 59
PIC Small Cap Growth	Small Company	PISCX	$2,000	11 78	18 2
Bridgeway Ultra-Small Co	Small Company	BRUSX	$2,000	10 44	29 74
Sit Small Cap Growth	Small Company	SSMGX	$2,000	12 65	14 97
AARP Small Company Stock	Small Company	ASCSX	$2,000	0	n/a
Columbia Small Cap	Small Company	CMSCX	$2,000	9	n/a
FBR Small Cap Financial	Sp -Financial	n/a	$2,000	8	n/a
FBR Small Cap Growth/Value	Small Company	n/a	$2,000	16 61	n/a
Crabbe Huson Small Cap Prim	Small Company	CHSCX	$2,000	3 97	n/a
Rembrandt Small Cap Inv	Small Company	n/a	$2,000	13 9	19 18
Clover Capital Small Cap Val	Small Company	n/a	$2,000	5 92	n/a
Fremont Intl Small Cap	Foreign Stock	FRISX	$2,000	11 81	12 15
Berger Small Company Growth	Small Company	BESCX	$2,000	11 14	16 77
Federated Small Cap Strat B	Small Company	SMCBX	$1,500	13 04	34 16
Federated Small Cap Strat C	Small Company	SMCCX	$1,500	13 04	33 99
Federated Intl Small Co B	Foreign Stock	ISCBX	$1,500	13 73	n/a
Federated Intl Small Co C	Foreign Stock	ISCCX	$1,500	13 73	n/a
Norwest Advant Small Co Gr I	Small Company	NVSCX	$1,000	8 48	19 82
Colonial Small Cap Value A	Small Company	CSMIX	$1,000	11 02	18 35
Colonial Small Cap Value B	Small Company	CSSBX	$1,000	11 02	17 84
Heritage Small Cap Stock A	Small Company	HRSCX	$1,000	11 71	27 46
Parkstone Small Cap Inv A	Small Company	PKSAX	$1,000	11 45	27 59
Heritage Small Cap Stock C	Small Company	HSCCX	$1,000	11 71	26 45
Parkstone Small Cap Inv C	Small Company	n/a	$1,000	11 45	26 24
Parkstone Small Cap Inv B	Small Company	PKSBX	$1,000	11 45	26 62
Westcore Small-Cap Opport	Small Company	WTSCX	$1,000	8 28	25 58
Goldman Sachs Small Cap Eq A	Small Company	GSSMX	$1,000	6 13	21 84
Goldman Sachs Small Cap Eq B	Small Company	GSQBX	$1,000	6 13	n/a
Gabelli Small Cap Growth	Small Company	GABSX	$1,000	7 54	11 88
Accessor Small to Mid Cap	Small Company	ASMCX	$1,000	11 8	24 74
Munder Small Company Grth A	Small Company	MULAX	$1,000	11 25	36 83
Norwest Advant Small Cap I	Small Company	NVSOX	$1,000	0	n/a
Munder Small Company Grth C	Small Company	n/a	$1,000	11 25	36 23
Munder Small Company Grth B	Small Company	MULBX	$1,000	11 25	35 9
Kemper-Dreman Small Cap A	Small Company	KDSAX	$1,000	8 94	29 6

Data on Mutual Funds Specializing in Small Company Stocks; 5-31-97

Company name	Objective	Ticker	Minimum Initial Purchase	Return on Assets %	96 Rtrn %
ESC Strategic Small Cap A	Small Company	ESCAX	$1,000	9 67	27 43
Kemper-Dreman Small Cap C	Small Company	KDSCX	$1,000	10	29 94
Kemper-Dreman Small Cap B	Small Company	KDSBX	$1,000	8 94	28 54
ESC Strategic Small Cap D	Small Company	ESCDX	$1,000	9 67	26 83
SSgA Small Cap	Small Company	SVSCX	$1,000	11 43	28 79
Bear Stearns Small Cap Val A	Small Company	BSVAX	$1,000	7 57	15 43
Bear Stearns Small Cap Val C	Small Company	BSVCX	$1,000	7 57	14 83
BB&T Small Company Growth A	Small Company	BBBSX	$1,000	11 59	30 77
BB&T Small Company Growth B	Small Company	n/a	$1,000	11 59	30 98
Montgomery Intl Small Cap R	Foreign Stock	MNISX	$1,000	23 45	14 97
Oakmark Small Cap	Small Company	OAKSX	$1,000	8 82	39 79
Kent Small Co Growth Invmt	Small Company	KNEMX	$1,000	8 95	19 15
TCW/DW Small Cap Growth	Small Company	TCSCX	$1,000	11 33	13 71
Invesco European Small Co	Europe Stock	IVECX	$1,000	21 04	31 03
Harris Ins Small-Cap Instl	Small Company	HSCIX	$1,000	10 57	n/a
Harris Ins Small-Cap A	Small Company	n/a	$1,000	10 57	n/a
HSBC Small Cap	Small Company	MSCFX	$1,000	11 9	15 29
Prudential Small Companies A	Small Company	PGOAX	$1,000	9 09	23 92
Schwab Small Cap Index	Small Company	SWSMX	$1,000	9 72	15 49
SEI Instl Small Cap Growth D	Small Company	n/a	$1,000	10 96	18 75
PIMCo Small Cap Value A	Small Company	PCVAX	$1,000	0	n/a
PIMCo Small Cap Value B	Small Company	PCVBX	$1,000	0	n/a
PIMCo Small Cap Value C	Small Company	PCVCX	$1,000	0	n/a
Pegasus Small Cap Opport I	Growth	PSOPX	$1,000	10 56	25 63
Pegasus Small Cap Opport A	Growth	n/a	$1,000	10 56	24 59
Pegasus Small Cap Opport B	Growth	n/a	$1,000	10 56	24 42
Prudential Small Companies B	Small Company	CHNDX	$1,000	9 09	22 97
Evergreen Small Cap Eq Inc Y	Small Company	ESCEX	$1,000	11 29	22 38
Value Line Small-Cap Growth	Small Company	VLSCX	$1,000	11 24	10 35
Evergreen Small Cap Eq Inc A	Small Company	n/a	$1,000	11 29	22 01
Evergreen Small Cap Eq Inc B	Small Company	n/a	$1,000	11 29	21 1
Evergreen Small Cap Eq Inc C	Small Company	n/a	$1,000	11 29	21 1
Norwest Advant Small Co StkA	Small Company	NCSAX	$1,000	12 77	25 98
Norwest Advant Small Co StkI	Small Company	NSCTX	$1,000	12 77	26 03
Norwest Advant Small Co StkB	Small Company	NCSBX	$1,000	12 77	24 91
Arch Small Cap Equity Inv A	Small Company	EMGRX	$1,000	9 87	10 5
Invesco Small Company Value	Small Company	IDSCX	$1,000	9 18	12 46
Preferred Small Cap	Small Company	PSMCX	$1,000	11 78	20 46
Heartland Small Cap Contrar	Small Company	HRSMX	$1,000	10	18 86
Arch Small Cap Equity Inv B	Small Company	n/a	$1,000	9 87	9 82

Data on Mutual Funds Specializing in Small Company Stocks; 5-31-97

Company name	Objective	Ticker	Minimum Initial Purchase	Return on Assets %	96 Rtrn %
North American Small/Mid A	Growth	NSMAX	$1,000	11 94	n/a
North American Small/Mid C	Growth	NSMCX	$1,000	11 94	n/a
North American Small/Mid B	Growth	NSMBX	$1,000	11 94	n/a
Aetna Small Company Sel	Small Company	AESGX	$1,000	10 1	13 62
Gateway Small Cap Index	Small Company	GSCIX	$1,000	9 13	17 04
Invesco Small Company Growth	Small Company	FIEGX	$1,000	12 21	11 62
Aetna Small Company Adv	Small Company	AESAX	$1,000	10 1	12 79
Safeco Small Co Stock NoLoad	Small Company	SFSCX	$1,000	8 08	n/a
PaineWebber Small Cap A	Small Company	PSCAX	$1,000	10 94	17 16
Eastcliff Regional Small Cap	Small Company	EARSX	$1,000	10 12	n/a
PaineWebber Small Cap B	Small Company	PSCBX	$1,000	10 94	16 2
PaineWebber Small Cap C	Small Company	PSCDX	$1,000	10 94	16 22
AAL Small Cap Stock A	Small Company	AASMX	$1,000	9 21	n/a
ITT Hartford Small Company A	Small Company	IHSAX	$1,000	11 36	n/a
ITT Hartford Small Company B	Small Company	n/a	$1,000	0	n/a
Marshall Small-Cap Growth	Small Company	MRSCX	$1,000	0	n/a
Emerald Small Cap Ret	Small Company	n/a	$1,000	10 14	10 05
Keystone Small Co Grth II A	Small Company	KSGAX	$1,000	10 34	n/a
Keystone Small Co Grth II B	Small Company	KSGBX	$1,000	10 34	n/a
Keystone Small Co Grth II C	Small Company	KSGCX	$1,000	10 34	n/a
Dean Witter Intl Small Cap	Foreign Stock	DWISX	$1,000	21 66	1 01
Keystone Small Co Grth (S-4)	Aggressive Growth	KSFOX	$1,000	12 67	0 82
Enterprise Small Co Value A	Small Company	ENSPX	$1,000	7 81	11 28
Kemper Small Cap Equity A	Small Company	KSCAX	$1,000	10 41	14 09
Enterprise Small Co Value B	Small Company	ESCBX	$1,000	7 81	10 77
Kemper Small Cap Equity B	Small Company	KSCBX	$1,000	10 41	12 84
Kemper Small Cap Equity C	Small Company	KSCCX	$1,000	10 41	12 86
Sentinel Small Company A	Small Company	SAGWX	$1,000	10 49	21 3
Sentinel Small Company B	Small Company	n/a	$1,000	10 49	n/a
SunAmerica Small Co Grth A	Small Company	SEGAX	$500	10 23	14 92
SunAmerica Small Co Grth B	Small Company	SEGBX	$500	10 23	14 12
Compass Small Cap Grth Inv A	Small Company	CSGEX	$500	11 64	31 13
Compass Small Cap Val Inv A	Small Company	PSEIX	$500	8 25	19 34
Phoenix Small Cap A	Small Company	PHSAX	$500	12 38	29 96
Federated Small Cap Strat A	Small Company	SMCAX	$500	13 04	35 04
Qualivest Small Comps Val A	Small Company	QSVAX	$500	9 89	20 07
Phoenix Small Cap B	Small Company	PHSCX	$500	12 38	28 93
Qualivest Small Comps Val C	Small Company	n/a	$500	9 89	19 35
RIMCo Monument Small Cap Eq	Small Company	RISCX	$500	10 1	21 92
Federated Intl Small Co A	Foreign Stock	ISCAX	$500	13 73	n/a

Data on Mutual Funds Specializing in Small Company Stocks; 5-31-97

Company name	Objective	Ticker	Minimum Initial Purchase	Return on Assets %	96 Rtrn %
ONE Fund Small Cap	Small Company	n/a	$500	9 34	17 01
GT Global Amer Small Cap Adv	Small Company	n/a	$500	8 85	14 22
GT Global Amer Small Cap A	Small Company	GTSAX	$500	8 85	13 81
GT Global Amer Small Cap B	Small Company	GTSBX	$500	8 85	13 14
First Omaha Small Cap Value	Small Company	n/a	$500	8 52	n/a
Alger Small Capitalization A	Small Company	n/a	$500	12 59	n/a
Alger Small Capitalization B	Small Company	ALSCX	$500	12 59	4 17
Winthrop Small Company Val A	Small Company	WFAGX	$250	9 6	14 58
Keeley Small Cap Value	Small Company	KSCVX	$250	7 83	25 99
Piper Small Company Growth A	Small Company	PJSCX	$250	9 2	11 65
Franklin Small Cap Grth I	Small Company	FRSGX	$100	10 31	27 07
Franklin Small Cap Grth II	Small Company	FRSIX	$100	10 31	26 07
Templeton Global Small Co I	World Stock	TEMGX	$100	18	22 09
Templeton Global Small Co II	World Stock	TESGX	$100	18	21 35
Munder Small Company Grth K	Small Company	MULKX	$0	11 25	36 89
Landmark Small Cap Equity A	Small Company	LSCEX	$0	9 44	37 8
Alger Small Cap Retirement	Small Company	ALSRX	$0	12 02	14 83
Galaxy Small Co Equity Tr	Small Company	GSETX	$0	11 05	21 59
BB&T Small Company Growth Tr	Small Company	BBCGX	$0	11 59	31 19
DFA U S Small Cap Value II	Small Company	DFAVX	$0	7 01	22 07
Warburg Pincus Adv Small Val	Small Company	n/a	$0	8 52	57
Qualivest Small Comps Val Y	Small Company	QSVYX	$0	9 89	20 36
Prudential Small Companies Z	Small Company	PSCZX	$0	9 09	n/a
Pacific Advisors Small Cap	Small Company	PASMX	$0	10 89	43 7
Galaxy Small Cap Value Tr	Small Company	SMCEX	$0	9 21	27 19
Arch Small Cap Equity Tr	Small Company	n/a	$0	9 87	10 98
Arch Small Cap Equity Instl	Small Company	n/a	$0	9 87	10 62
Rembrandt Small Cap Tr	Small Company	RSMCX	$0	13 9	19 42
SEI Instl Inv Small Cap	Small Company	n/a	$0	9 56	n/a
Kemper Small Cap Equity I	Small Company	n/a	$0	10 41	14 54
Brown Capital Small Co Instl	Small Company			10 44	

Morning Star Report on DFA 9-10 Fund

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Page 1 of 3

DFA U.S. 9-10 Small Company
(Data as of 05-31-97)

Investment Objective	Rating	Load	Yield	Assets ($mil)	NAV
Small Company	**	None	0 21%	1107.8	11.65

DFA U.S. 9-10 Small Company Portfolio seeks long-term capital appreciation.

The fund invests in a diverse group of small companies with readily marketable securities. These companies may be traded on the NYSE, the AMEX, or the over-the-counter market, but their market capitalizations must be comparable with those in the smallest quintile of the NYSE The portfolio is rebalanced at least semiannually.

The fund is designed primarily for institutional investors Prior to April 10, 1989, the fund was named DFA Investment Dimensions Small Company Prior to 1983, the fund was named DFA Small Company.

Performance: Annual Return %

	YTD	1996	1995	1994	1993
DFA U S. 9-10 Small Company	4.02	17.65	34.48	3.09	20.97
S&P 500 Index	15.43	22 95	37 53	1 32	10 06

These Figures Match DFA's and Dr. Andrews' Numbers in his Schedule 6, page 1, Far-left Column

Performance: Trailing Return %

	1 Mo	3 Mo	1 Yr	3 Yr Avg	5 Yr Avg
DFA U.S 9-10 Small Company	10 22	1.92	-1.33	18 60	18 41
S&P 500 Index	6.08	7.80	29 40	25.92	18.36

Risk Measures

Morningstar Risk: Above Avg. Beta (3 Yr) 0 78

Morning Star Report on DFA 9-10 Fund

Morningstar Return: Average Std. Deviation (3 Yr) 16 59
R-Squared 32

Top Ten Portfolio Holdings
(Data as of 02-28-97)

Ticker	Amount 000	Security	Value $000	% Net Assets
KUH	186	Kuhlman	4380	0.38
GLE	117	Gleason	4187	0 36
INVX	179	Innovex	3844	0.33
FRC	157	First Republic Bancorp	3654	0.32
ROG	128	Rogers	3459	0 30
HEI	133	HEICO	3430	0.30
CULP	179	Culp	3214	0.28
CDSI	105	Computer Data Systems	3193	0.28
ELMG	142	Electromagnetic Sciences	3173	0.27
APR	160	American Precision Inds	3027	0.26

Portfolio Statistics

Price/Earnings Ratio	21.64	Income Ratio %	0.22
Price/Book Ratio.	2 80	Turnover Ratio %	23 68
Return on Assets %	8.75	Expense Ratio %.	0 61
Median Market Cap ($mil)	123.29		

This figure, 8.75%, is not provided in DFA's Annual Report See Schedule 22, page 2.

These figures are the same as those reported in DFA's 1996 Annual Report

Expenses and Fees

Front-End Load	0.00	12b-1 Fee:	0 00
Deferred Sales Charge:	0 00	Management Fee	0 50
Redemption Fee:	0.00		

Operations

Ticker Symbol: DFSCX

Morning Star Report on DFA 9-10 Fund

Fund Family: DFA Investment Dimensions Group
Address: 1299 Ocean Avenue 11th Floor
Santa Monica, CA 90401
Telephone: 310-395-8005

Fund Manager: Management Team
Manager Tenure NA years
Min. Initial Purchase $2000000

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Direct Testimony____
Schedule 22____
Page 1 of 2____

DFA Investment Dimensions Group Inc.
and
The DFA Investment Trust Company

ANNUAL REPORT

Year Ended November 30, 1996

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Direct Testimony
Schedule 22
Page 2 of 2

DFA INVESTMENT DIMENSIONS GROUP INC.

FINANCIAL HIGHLIGHTS

for a share outstanding throughout each year

The U.S. 9-10 Small Company Portfolio

	Year Ended Nov 30, 1996	Year Ended Nov. 30, 1995	Year Ended Nov. 30, 1994	Year Ended Nov. 30, 1993	Year Ended Nov 30, 1992	Year Ended Nov. 30, 1991	Year Ended Nov 30, 1990	Year Ended Nov 30, 1989	Year Ended Nov 30, 1988	Year Ended Nov 30, 1987
Net Asset Value Beginning of Period	$ 11 03	$ 8 49	$ 8 69	$ 7 75	$ 6 33	$ 5 34	$ 7 74	$ 7 66	$ 7 50	$ 8 94
Income From Investment Operations										
Net Investment Income	0 03	0 05	0 01	0 03	0 04	0 04	0 07	0 07	0 10	0 09
Net Gain (Losses) on Securities (Realized and Unrealized)	1 65	2 61	0 40	1 67	1 53	1 64	(1 77)	0 98	1 48	(1 53)
Total From Investment Operations	1 88	2 66	0 41	1 70	1 57	1 68	(1 70)	1 05	1 58	(1 44)
Less Distributions										
Net Investment Income	(0 01)	(0 04)	(0 03)	(0 05)	(0 05)	(0 07)	(0 08)	(0 09)	(0 11)	—
Net Realized Gains	(0 76)	(0 08)	(0 58)	(0 71)	(0 10)	(0 62)	(0 62)	(0 88)	(1 31)	—
Total Distributions	(0 77)	(0 12)	(0 61)	(0 76)	(0 15)	(0 69)	(0 70)	(0 97)	(1 42)	—
Net Asset Value, End of Period	$ 12 14	$ 11 03	$ 8 49	$ 8 69	$ 7 75	$ 6 33	$ 5 34	$ 7 74	$ 7 66	$ 7 50
Total Return	18 05%	31 37%	5 08%	23 91%	25 24%	39 08%	(24 09)%	16 09%	24 36%	(16 04)%
Net Assets End of Period (thousands)	$1,181,804	$925,474	$659 221	$630,918	$651,313	$722,289	$581,102	$949,291	$912,518	$788 821
Ratio of Expenses to Average Net Assets	0 61%	0 62%	0 65%	0 70%	0 68%	0 64%	0 62%	0 62%	0 62%	0 61%
Ratio of Net Investment Income to Average Net Assets	0 22%	0 45%	0 16%	0 26%	0 53%	0 75%	0 99%	0 86%	1 19%	0 92%
Portfolio Turnover Rate	23 68%	24 65%	16 56%	9 87%	9 72%	10 13%	3 79%	7 66%	25 98%	23 05%
Average Commission Rate (1)	$ 0 0604	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

(1) Computed by dividing the total amount of brokerage commissions paid by the total shares of investment securities purchased and sold during the period for which commissions were charged, as required by the SEC for fiscal years beginning after September 1, 1995

See accompanying Notes to Financial Statements

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Direct Testimony___
Schedule 23____
Page 1 of 4____

DFA INVESTMENT DIMENSIONS GR(

1299 Ocean Avenue, 11th Floor, Santa Monica, California 90401
Telephone: (310) 395-8005

STATEMENT OF ADDITIONAL INFORMATION

March 28, 1997

DFA Investment Dimensions Group Inc. (the "Fund") offers thirty series of shares. This statement of additional information relates to twenty-four of those series (collectively, the "Portfolios"):

U.S. 9-10 Small Company Portfolio
U.S. 6-10 Small Company Portfolio
Enhanced U.S. Large Company Portfolio
U.S. Small Cap Value Portfolio
U.S. Large Cap Value Portfolio
DFA Real Estate Securities Portfolio
Japanese Small Company Portfolio
Pacific Rim Small Company Portfolio
United Kingdom Small Company Portfolio
Emerging Markets Portfolio
Emerging Markets Small Cap Portfolio
DFA Intermediate Government Fixed Income Portfolio
Continental Small Company Portfolio
Large Cap International Portfolio
U.S. Large Company Portfolio
DFA International Small Cap Value Portfolio
International Small Company Portfolio
DFA One-Year Fixed Income Portfolio
DFA Two-Year Corporate Fixed Income Portfolio
DFA Two-Year Global Fixed Income Portfolio
DFA Two-Year Government Portfolio
DFA Five-Year Government Portfolio
DFA Global Fixed Income Portfolio
RWB/DFA International High Book to Market Portfolio

This statement of additional information is not a prospectus but should be read in conjunction with the Portfolios' prospectus dated March 28, 1997, as amended from time to time, which can be obtained from the Fund by writing to the Fund at the above address or by calling the above telephone number.

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from the Series to satisfy the Portfolio's redemption request. Any such redemption t the Portfolio would be in accordance with Rule 18f-1 under the Investment Co Investors may incur brokerage charges and other transaction costs selling securities t payment of redemptions. The International Equity, DFA Two-Year Global Fixed In... Global Fixed Income Portfolios reserve the right to redeem their shares in the currencies in which their investments (and, in respect of the Feeder Portfolios and International Small Company Portfolio, the currencies in which the corresponding Series' investments) are denominated. Investors may incur charges in converting such securities to dollars and the value of the securities may be affected by currency exchange fluctuations.

Shareholders may transfer shares of any Portfolio to another person by making a written request therefore to the Advisor who will transmit the request to the Fund's Transfer Agent. The request should clearly identify the account and number of shares to be transferred, and include the signature of all registered owners and all stock certificates, if any, which are subject to the transfer. The signature on the letter of request, the stock certificate or any stock power must be guaranteed in the same manner as described in the prospectus under "REDEMPTION OF SHARES." As with redemptions, the written request must be received in good order before any transfer can be made.

CALCULATION OF PERFORMANCE DATA

Following are quotations of the annualized percentage total returns for the one-, five-, and ten-year periods ended November 30, 1996 (as applicable) using the standardized method of calculation required by the SEC, which is net of the cost of any current reimbursement fees charged to investors and paid to the Portfolios. Also included is a quotation of the annualized percentage total return for the DFA Two-Year Global Fixed Income Portfolio (for the period from February 9, 1996, the date of commencement of operations), the Enhanced U.S. Large Company Portfolio (for the period from July 3, 1996, the date of commencement of operations) and the International Small Company Portfolio (for the period from October 1, 1996, the date of commencement of operations) to November 30, 1996 using the standardized method of calculation required by the SEC. Reimbursement fees of 1%, 1.5% and 1.5% were in effect from the inception of the Japanese, United Kingdom and Continental Small Company Portfolios, respectively, until June 30, 1995. A reimbursement fee of 1% was in effect from the inception of DFA International Small Cap Value Portfolio until June 30, 1995. Effective June 30, 1995, the amount of the reimbursement fee was reduced with respect to Continental Small Company, Pacific Rim Small Company, Japanese Small Company, Emerging Markets and DFA International Small Cap Value Portfolios, and eliminated with respect to the United Kingdom Small Company Portfolio. The current reimbursement fee for each Portfolio, expressed as a percentage of the net asset value of the shares of the Portfolios, is as follows: Continental Small Company, Pacific Rim Small Company and Emerging Markets Small Cap Portfolios - 1.00%; Japanese Small Company and Emerging Markets Portfolios - .50%; DFA International Small Cap Value Portfolio - .70%; and International Small Company Portfolio - .70%.

A reimbursement fee of 1% was charged to investors in The U.S. 9-10 Small Company Portfolio from December 9, 1986 through June 17, 1988. A reimbursement fee of 0.75% was charged to investors in The Large Cap International Portfolio from the date of its inception until March 5, 1992. In addition, for those Portfolios in effect for less than one, five, or ten years, the time periods during which the Portfolios have been active have been substituted for the periods stated (which in no case extends prior to the effective dates of the Portfolios' registration statements).

	One Year	Five Years	Ten Years
U.S. 9-10 Small Company Portfolio	18.03	20.38	12.35
U.S. 6-10 Small Company Portfolio	18.73	57 Months 13.42	n/a
U.S. Large Company Portfolio	27.48	17.88	71 Months 17.97

U.S. Small Cap Value Portfolio	21.77		
U.S. Large Cap Value Portfolio	22.26	46 Months 16.04	n/a
Enhanced U.S. Large Company Portfolio	4 Months 73.24	n/a	n/a
DFA Real Estate Securities Portfolio	28.24	47 Months 9.63	n/a
Japanese Small Company Portfolio	-6.74	-1.07	8.58
Pacific Rim Small Company Portfolio	17.87	47 Months 18.01	n/a
United Kingdom Small Company Portfolio	26.74	10.30	10.73
Emerging Markets Portfolio	12.61	31 Months 5.89	n/a
Continental Small Company Portfolio	12.83	5.39	103.5 Months 8.31
Large Cap International Portfolio	12.68	64 Months 8.27	n/a
RWB/DFA International High Book to Market Portfolio	14.60	42 Months 10.62	n/a
DFA One-Year Fixed Income Portfolio	5.91	5.28	6.70
DFA Five-Year Government Portfolio	7.54	6.25	114 Months 7.79
DFA Global Fixed Income Portfolio	11.13	8.40	72 Months 8.83
DFA Intermediate Government Fixed Income Portfolio	4.98	7.89	73 Months 9.37
DFA International Small Cap Value Portfolio	7.24	23 Months 2.08	n/a
DFA Two-Year Global Fixed Income Portfolio	10 Months 7.14	n/a	n/a
International Small Company Portfolio	2 Months -0.40	n/a	n/a

As the following formula indicates, the average annual total return is determined by finding the average annual compounded rates of return over the stated time period that would equate a hypothetical initial purchase order of $1,000 to its redeemable value (including capital appreciation/depreciation and dividends and distributions paid and reinvested less any fees charged to a shareholder account) at the end the stated time period. The calculation assumes that all dividends and distributions are reinvested at the public offering price on the reinvestment dates during the period. The quotation assumes the account was completely redeemed at the end of each period and the deduction of all applicable charges and fees. According to the SEC formula:

$$P(1 + T)^n = ERV$$

where:

P = a hypothetical initial payment of $1,000

T = average annual total return

n = number of years

ERV = ending redeemable value of a hypothetical $1,000 payment made at the beginning of the one-, five-, and ten-year periods at the end of the one-, five-, and ten-year periods (or fractional portion thereof).

Following are quotations of the annualized total returns for the one-, five-, and ten-year periods ended November 30, 1996 (as applicable) using a non-standardized method of calculation which is used in communicating performance data in addition to the standardized method required by the SEC. Also included is a quotation of the annualized percentage total return for the DFA Two-Year Global Fixed Income Portfolio (for the period from February 9, 1996, the date of commencement of operations), the Enhanced U.S. Large Company Portfolio (for the period from July 3, 1996, the date of commencement of operations) and the International Small Company Portfolio (for the period from October 1, 1996, the date of commencement of operations) to November 30, 1996 using a non-standardized method of calculation. The non-standardized quotations differ from the standardized in that they are calculated without deduction of any reimbursement fees charged to investors and paid to the Portfolios which would otherwise reduce return quotations for the Portfolios with such fees. Additionally, the non-standardized quotations are presented over time periods which extend prior to the initial investment in the Portfolios (except for The Continental Small Company (and Large Cap International) Portfolios) by using simulated data for the investment strategies of the Portfolios for that portion of the period prior to the initial investment dates. The simulated data excludes the deduction of Portfolio expenses which would otherwise reduce the returns quotations. Non-standardized quotations are also presented for the United Kingdom and Japanese Small Company Portfolios calculated assuming the local currencies of the corresponding Series are invested and redeemed at the beginning and ending dates of the period. The local currency calculations ignore the effect of foreign exchange rates on the investment and only express the returns of the underlying securities of the Series.

	Effective Date/ Initial Investment	One Year	Five Years	Ten Years
U.S. 9-10 Small Company Portfolio	12/22/81 12/22/81	18.03	20.38	12.46
U.S. 6-10 Small Company Portfolio	03/06/92 03/20/92	18.73	17.00	11.57
U.S. Large Company Portfolio	02/26/90 12/31/90	27.48	17.88	15.02
U.S. Small Cap Value Portfolio	09/18/92 03/01/93	21.77	22.14	14.88
U.S. Large Cap Value Portfolio	09/18/92 02/18/93	22.26	20.47	15.32

...ures and forward contracts is generally governed by Section 1256 of the Code. ...ositions generally include listed options on debt securities, options on broad-based ... on futures contracts, regulated futures contracts and certain foreign currency contracts and options thereon.

Absent a tax election to the contrary, each such Section 1256 position held by a Portfolio or Series will be marked-to-market (i.e., treated as if it were sold for fair market value) on the last business day of a Portfolio's or Series' fiscal year, and all gain or loss associated with fiscal year transactions and marked-to-market positions at fiscal year end (except certain currency gain or loss covered by Section 988 of the Code) will generally be treated as 60% long-term capital gain or loss and 40% short-term capital gain or loss. The effect of Section 1256 marked-to-market rules may be to accelerate income or to convert what otherwise would have been long-term capital gains into short-term capital gains or short-term capital losses into long-term capital losses within a Portfolio or Series. The acceleration of income on Section 1256 positions may require a Portfolio or Series to accrue taxable income without the corresponding receipt of cash. In order to generate cash to satisfy the distribution requirements of the Code, a Portfolio or Series may be required to dispose of portfolio securities that it otherwise would have continued to hold or to use cash flows from other sources such as the sale of a Portfolio's or Series' shares. In these ways, any or all of these rules may affect both the amount, character and timing of income distributed to shareholders by a Portfolio.

When a Portfolio (or in the case of a Feeder Portfolio, the corresponding Series) holds an option or contract which substantially diminishes a Portfolio's or Series' risk of loss with respect to another position of a Portfolio or Series (as might occur in some hedging transactions), this combination of positions could be treated as a "straddle" for tax purposes, resulting in possible deferral of losses, adjustments in the holding periods of a Portfolio's or Series' securities and conversion of short-term capital losses into long-term capital losses. Certain tax elections exist for mixed straddles (i.e., straddles comprised of at least one Section 1256 position and at least one non-Section 1256 position) which may reduce or eliminate the operation of these straddle rules.

The Portfolios and those Series taxable as regulated investment companies are also subject to the requirement that less than 30% of their annual gross income be derived from the sale or other disposition of securities and certain other investments held for less than three months ("short-short income"). This requirement may limit a Portfolio's (or in the case of a Feeder Portfolio, the corresponding Series') ability to engage in options, straddles, hedging transactions and forward or futures contracts because these transactions are often consummated in less than three months, may require the sale of portfolio securities held less than three months and may, as in the case of short sales of portfolio securities, reduce the holding periods of certain securities within a Portfolio or Series, resulting in additional short-short income for a Portfolio or Series.

A Portfolio (or in the case of a Feeder Portfolio, the corresponding Series) will monitor its transactions in such options and contracts and may make certain other tax elections in order to mitigate the effect of the above rules and to prevent disqualification of a Portfolio or Series as a regulated investment company under Subchapter M of the Code.

DIRECTORS AND OFFICERS

The names and addresses of the directors and officers of the Fund and a brief statement of their present positions and principal occupations during the past five years is set forth below.

Directors

David G. Booth*, 50, Director, President and Chairman-Chief Executive Officer, Santa Monica, CA. President, Chairman-Chief Executive Officer and Director, Dimensional Fund Advisors Inc., DFA Securities Inc., DFA Australia Ltd., Dimensional Investment Group Inc. (registered investment company) and Dimensional Emerging Markets Fund Inc. (registered investment company). Trustee, President and Chairman-Chief Executive Officer of The DFA Investment Trust Company. Chairman and Director, Dimensional Fund Advisors Ltd.

George M. Constantinides, 49, Director, Chicago, IL. L
Graduate School of Business, University of Chicago. Trustee, Th
Director, Dimensional Investment Group Inc. and Dimensional Em

John P. Gould, 58, Director, Chicago, IL. Steven G. Rothmeier Distinguished Service Professor of Economics, Graduate School of Business, University of Chicago. Trustee, The DFA Investment Trust Company and First Prairie Funds (registered investment companies). Director, Dimensional Investment Group Inc., Dimensional Emerging Markets Fund Inc. and Harbor Investment Advisors. Executive Vice President, Lexecon Inc. (economics, law, strategy and finance consulting).

Roger G. Ibbotson, 53, Director, New Haven, CT. Professor in Practice of Finance, Yale School of Management. Trustee, The DFA Investment Trust Company. Director, Dimensional Investment Group Inc., Dimensional Emerging Markets Fund Inc., Hospital Fund, Inc. (investment management services) and BIRR Portfolio Analysis, Inc. (software products). Chairman and President, Ibbotson Associates, Inc., Chicago, IL (software, data, publishing and consulting).

Merton H. Miller, 73, Director, Chicago, IL. Robert R. McCormick Distinguished Service Professor Emeritus, Graduate School of Business, University of Chicago. Trustee, The DFA Investment Trust Company. Director, Dimensional Investment Group Inc. and Dimensional Emerging Markets Fund Inc. Public Director, Chicago Mercantile Exchange.

Myron S. Scholes, 55, Director, Greenwich, CT. Limited Partner, Long-Term Capital Management L.P. (money manager). Frank E. Buck Professor of Finance, Graduate School of Business and Professor of Law, Law School, Senior Research Fellow, Hoover Institution, (all) Stanford University (on leave). Trustee, The DFA Investment Trust Company. Director, Dimensional Investment Group Inc., Dimensional Emerging Markets Fund Inc., Benham Capital Management Group of Investment Companies and Smith Breedon Group of Investment Companies.

Rex A. Sinquefield*, 52, Director, Chairman and Chief Investment Officer, Santa Monica, CA. Chairman-Chief Investment Officer and Director, Dimensional Fund Advisors Inc., DFA Securities Inc., DFA Australia Ltd., Dimensional Investment Group Inc. and Dimensional Emerging Markets Fund Inc. Trustee, Chairman-Chief Investment Officer of The DFA Investment Trust Company. Chairman, Chief Executive Officer and Director, Dimensional Fund Advisors Ltd.

* Interested Director of the Fund.

Officers

Each of the officers listed below hold the same office in the following entities: Dimensional Fund Advisors Inc., DFA Securities Inc., DFA Australia Ltd., Dimensional Investment Group Inc., The DFA Investment Trust Company, Dimensional Fund Advisors Ltd., and Dimensional Emerging Markets Fund Inc.

Arthur Barlow, 41, Vice President, Santa Monica, CA.

Maureen Connors, 60, Vice President, Santa Monica, CA.

Truman Clark, 55, Vice President, Santa Monica, CA. Consultant until October 1995 and Principal and Manager of Product Development, Wells Fargo Nikko Investment Advisors, San Francisco, CA from 1990-1994.

Robert Deere, 39, Vice President, Santa Monica, CA.

Irene R. Diamant, 46, Vice President and Secretary (for all entities other than Dimensional Fund Advisors Ltd.), Santa Monica, CA.

Margaret East, 56, Secretary, Dimensional Fund Advisors Ltd.

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The Fund commenced offering shares of Emerging Mark International Small Cap Value Portfolio in December, 1994; DFA Two- in February, 1996; Enhanced U.S. Large Company Portfolio in July, 1996, and International Small Company Portfolio in October, 1996. The DFA Two-Year Corporate Fixed Income, DFA Two-Year Government and Emerging Markets Small Cap Portfolios had not commenced operations as of November 30, 1996.

Until September, 1995, The DFA Intermediate Government Fixed Income Portfolio was named The DFA Intermediate Government Bond Portfolio, The DFA Global Fixed Income Portfolio was named The DFA Global Bond Portfolio, The Pacific Rim Small Company Portfolio was named The Asia-Australia Small Company Portfolio, The U.S. Large Cap Value Portfolio was named The U.S. Large Cap High Book to Market Portfolio, The U.S. Small Cap Value Portfolio was named The U.S. Small Cap High Book to Market Portfolio, The U.S. 9-10 Small Company Portfolio was named the Small Company Shares, The DFA One-Year Fixed Income Portfolio was named The DFA Fixed Income Shares, and The Continental Small Company Portfolio was named the Continental European Portfolio. Until February, 1996, RWB/DFA International High Book to Market Portfolio was named DFA International High Book to Market Portfolio. From September, 1995 until December, 1996, The DFA Real Estate Securities Portfolio was named DFA/AEW Real Estate Securities Portfolio.

Coopers and Lybrand L.L.P., the Fund's independent accountants, audits the Fund's financial statements.

PRINCIPAL HOLDERS OF SECURITIES

As of February 28, 1997, the following stockholders owned beneficially at least 5% of the outstanding stock of the Portfolios, as set forth below.

THE U.S. 9-10 SMALL COMPANY PORTFOLIO

Charles Schwab & Company, Inc. - REIN* 101 Montgomery Street San Francisco, CA 94104	25.44%
State Farm Insurance Companies One State Farm Plaza Bloomington, IL 61710	10.76%
Pepsico Inc. Master Trust The Northern Trust Company Trustee P.O. Box 92956 801 South Canal Chicago, IL 60675	8.87%
Charles Schwab & Company, Inc. - REIN* (see address above)	5.97%
Owens-Illinois Master Retirement Trust 34 Exchange Place Jersey City, NJ 07302	5.48%
National Electrical Benefit Fund 1125 15th Street NW Washington, DC 20005	5.26%

THE U.S. 6-10 SMALL COMPANY PORTFOLIO

McKinsey & Company Master Retirement Trust 55 E. 52nd Street New York, NY 10055	26.43%

Data on Dr. Andrews' Companies

COMPANY NAME *	PRICE AS OF 4/30/97	STOCK OUTSTANDING (000)	NUM OF SHARE HOLDERS	SHARES PER STOCKHOLDER	VALUE OF HOLDINGS PER SHAREHOLDER 4/30/97	MARKET VALUE 4/30/97 $(Millions)
(1)	(2)	(3)	(4)	(5) [col (3) / col (4)]	(6) [col (2) X col (5)]	(7) [col (2) X col (3)]
Atmos Energy Corporation	$22 63	16135	28,624	564	$12,753	365
Berkshire Gas Company	$15 13	2177	1,881	1157	$17,505	33
Bay State Gas Company	$25 50	13439	10,820	1242	$31,671	343
Cascade Natural Gas Corporation	$16 38	10824	10840	999	$16,351	177
Colonial Gas Company	$20 00	8518	5931	1436	$28,724	170
Chesapeake Utilities Corporation	$16 75	4453	2213	2012	$33,704	75
Delta Natural Gas Company, Inc	$16 63	2325	2,382	976	$16,227	39
Essex County Gas Company	$24 25	1667	1,336	1248	$30,258	40
Energen Corporation	$30 50	13027	7,700	1692	$51,600	397
Energy North Inc	$21 75	3244	2,300	1410	$30,677	71
Energy West Incorporated	$8 50	2357	1,600	1473	$12,522	20
Mobile Gas Service Corporation	$26 75	3228	1,624	1988	$53,171	86
North Carolina Natural Gas Corporation	$29 63	6613	5,094	1298	$38,459	196
Northwest Natural Gas Company	$24 25	22566	10,859	2078	$50,394	547
Public Service Company of North Carolina, Incorporated	$17 25	19296	11,500	1678	$28,945	333
Pennsylvania Enterprises, Inc	$22 13	9608	6,627	1450	$32,077	213
Providence Energy Corporation	$17 75	5767	6,052	953	$16,914	102
Southeastern Michigan Gas Enterprises, Inc	$17 58	13020	8,509	1530	$26,892	229
United Cities Gas Company	$21 50	13221	7681	1721	$37,007	284
Valley Resources, Inc	$12 25	4266	2824	1511	$18,505	52
Yankee Energy System, Inc	$21 13	10450	28,499	367	$7,746	221
Average	$20 39	8867	7,852	1371	$28,195	190

* Excludes Washington Gas Company
†† Merged With an Electric Power Company

Gas Company Stocks Owned by the DFA 9-10 Fund

COMPANY	Did the U S 9-10 Small Company Mutual Fund Own Stock in Dr Andrews' Comparable Companies? YEAR 94	95	96
Atmos Energy Corporation	NO	NO	NO
Berkshire Gas Company	YES	YES	YES
Bay State Gas Company	NO	NO	NO
Cascade Natural Gas Corporation	YES	YES	YES
Chesapeake Utilities Corporation	YES	YES	YES
Colonial Gas Company	YES	YES	YES
Delta Natural Gas Company, Inc.	YES	YES	YES
Energen Corporation	NO	NO	NO
Energy North Inc	YES	NO	YES
Energy West Incorporated	NO	NO	NO
Essex County Gas Company	NO	YES	YES
Mobile Gas Service Corporation	YES	YES	YES
North Carolina Natural Gas Corporation	NO	NO	YES
Northwest Natural Gas Company	NO	NO	NO
Pennsylvania Enterprises, Inc.	NO	NO	NO
Providence Energy Corporation	YES	YES	YES
Public Service Company of North Carolina, Incorporated	NO	NO	NO
Southeastern Michigan Gas Enterprises, Inc	NO	NO	NO
United Cities Gas Company	NO	NO	NO
Washington Energy	NO	NO	NO
Valley Resources, Inc.	YES	YES	YES
Yankee Energy System, Inc.	NO	NO	NO
TOTAL *NOT* INCLUDED IN PORTFOLIO	13	13	11
TOTAL INCLUDED IN PORTFOLIO	9	9	11

SOURCE 1994 & 1996 - DFA ANNUAL REPORT
SOURCE 1995 1OK REPORT

Table A-1 | Large Company Stocks: Total Returns

(continued)

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From January 1971 to December 1995

YEAR	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	YEAR	JAN-DEC*
1971	0.0419	0.0141	0.0382	0.0377	-0.0367	0.0021	-0.0399	0.0412	-0.0056	-0.0404	0.0027	0.0877	1971	0.1431
1972	0.0194	0.0299	0.0072	0.0057	0.0219	-0.0205	0.0036	0.0391	-0.0036	0.0107	0.0505	0.0131	1972	0.1898
1973	-0.0159	-0.0333	-0.0002	-0.0395	-0.0139	-0.0051	0.0394	-0.0318	0.0415	0.0003	-0.1082	0.0183	1973	-0.1466
1974	-0.0085	0.0019	-0.0217	-0.0373	-0.0272	-0.0128	-0.0759	-0.0828	-0.1170	0.1657	-0.0448	-0.0177	1974	-0.2647
1975	0.1251	0.0674	0.0237	0.0493	0.0509	0.0462	-0.0659	-0.0144	-0.0328	0.0637	0.0313	-0.0096	1975	0.3720
1976	0.1199	-0.0058	0.0326	-0.0099	-0.0073	0.0427	-0.0068	0.0014	0.0247	-0.0206	-0.0009	0.0540	1976	0.2384
1977	-0.0489	-0.0151	-0.0119	0.0014	-0.0150	0.0475	-0.0151	-0.0133	0.0000	-0.0415	0.0370	0.0048	1977	-0.0718
1978	-0.0596	-0.0161	0.0276	0.0870	0.0136	-0.0152	0.0560	0.0340	-0.0048	-0.0891	0.0260	0.0172	1978	0.0656
1979	0.0421	-0.0284	0.0575	0.0036	-0.0168	0.0410	0.0110	0.0611	0.0025	-0.0656	0.0514	0.0192	1979	0.1844
1980	0.0610	0.0031	-0.0987	0.0429	0.0562	0.0296	0.0676	0.0131	0.0281	0.0187	0.1095	-0.0315	1980	0.3242
1981	-0.0438	0.0208	0.0380	-0.0213	0.0062	-0.0080	0.0007	-0.0554	-0.0502	0.0528	0.0441	-0.0265	1981	-0.0491
1982	-0.0163	-0.0512	-0.0060	0.0414	-0.0288	-0.0174	-0.0215	0.1267	0.0110	0.1126	0.0438	0.0173	1982	0.2141
1983	0.0348	0.0260	0.0365	0.0758	-0.0052	0.0382	-0.0313	0.0170	0.0136	-0.0134	0.0233	-0.0061	1983	0.2251
1984	-0.0065	-0.0328	0.0171	0.0069	-0.0534	0.0221	-0.0143	0.1125	0.0002	0.0026	-0.0101	0.0253	1984	0.0627
1985	0.0768	0.0137	0.0018	-0.0032	0.0615	0.0159	-0.0026	-0.0061	-0.0321	0.0447	0.0716	0.0467	1985	0.3216
1986	0.0044	0.0761	0.0554	-0.0124	0.0549	0.0166	-0.0569	0.0748	-0.0822	0.0556	0.0256	-0.0264	1986	0.1847
1987	0.1343	0.0413	0.0272	-0.0088	0.0103	0.0499	0.0498	0.0385	-0.0220	-0.2152	-0.0819	0.0738	1987	0.0523
1988	0.0427	0.0470	-0.0302	0.0108	0.0078	0.0464	-0.0040	-0.0331	0.0424	0.0273	-0.0142	0.0181	1988	0.1681
1989	0.0723	-0.0249	0.0236	0.0516	0.0402	-0.0054	0.0898	0.0193	-0.0039	-0.0233	0.0208	0.0236	1989	0.3149
1990	-0.0671	0.0129	0.0263	-0.0247	0.0975	-0.0070	-0.0032	-0.0903	-0.0492	-0.0037	0.0644	0.0274	1990	-0.0317
1991	0.0442	0.0716	0.0238	0.0028	0.0428	-0.0457	0.0468	0.0235	-0.0164	0.0134	-0.0404	0.1143	1991	0.3055
1992	-0.0186	0.0128	-0.0196	0.0291	0.0054	-0.0145	0.0403	-0.0202	0.0115	0.0036	0.0337	0.0131	1992	0.0767
1993	0.0073	0.0135	0.0215	-0.0245	0.0270	0.0033	-0.0047	0.0381	-0.0074	0.0203	-0.0094	0.0123	1993	0.0999
1994	0.0335	-0.0270	-0.0435	0.0130	0.0163	-0.0247	0.0331	0.0407	-0.0241	0.0229	-0.0367	0.0146	1994	0.0131
1995	0.0260	0.0388	0.0296	0.0291	0.0395	0.0235	0.0333	0.0027	0.0419	-0.0035	0.0440	0.0185	1995	0.3743

* Compound annual return

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Q.47. Regarding the results of Dr. Andrew's regression analysis shown in Schedule 9, produce the T-statistic for each company's alpha and the T-statistic for each company's beta.

A.47. The results of regressions performed on the data for each company listed in Schedule 9 are employed only in summary, aggregated form as average alphas and betas. The average alpha and average beta are analogous to the alpha and beta of a portfolio of common stocks, in this case a "portfolio" of 22 small gas LDC's. Tests of significance, such as T-statistics, from the regressions related to individual stocks intrinsically cannot be summed or averaged across the composite (or portfolio). Accordingly, they were not found in company with the individual regressions and, hence, cannot be supplied as requested.

Victor L. Andrews

Signature

Victor L. Andrews, President, Andrews Financial Associates, Inc.

APPENDIX A

IBBOTSON YEARBOOK'S HYPOTHETICAL DISTRIBUTION OF RETURNS

The derivation of Schedule 12 and Charts two and three is based on the same probability principles used in the example shown in SBBI-97 at pages 154-155. Those pages are attached to and are part of this appendix as Attachments 1 and 2. The hypothetical distribution in the example assumes:

10% is the size of the loss

30% is the size of the gain

50% is the probability of a loss

50% is the probability of a gain.

Starting with an investment of $1, after 1 year there are two possible values, the investment will be worth either $1.3 or 90 cents. After two years there are 4 possibilities, one at $1.69, two outcomes at $1.17 and one at $.81. This shows that the number of possibilities double each year. The example is well-grounded in mathematics and is a simple illustration of a mathematical formula that is over 500 years old. If $1.3 is treated as X and $.9 is treated as Y, the first year after the investment the possible outcomes are:

$$(X + Y)^1 = \underline{1}(\$1.3) + \underline{1}(\$.9)$$

In the second year after the investment the possible outcomes are:

$$(X + Y)^2 = \underline{1}(X^2) + \underline{2}(XY) + \underline{1}(Y^2)$$

$$(\$1.3 + \$.9)^2 = \underline{1}(\$1.69) + \underline{2}(\$1.17) + \underline{1}(\$.81)$$

The underlined values -- 1 and 1 in the first year and 1, 2 ,1 in the second year -- match the total number of possibilities - 2 in the first year and 4 in the second, and the values in the parentheses -- $1.3 and $.9 in the first year and $1.69 ,$1.17, $.81 in the second -- represent the values of the possibilities. There are two important aspects of the example especially in the second year: the geometric mean is the middle value, $1.17, which has a corresponding annual return of 8.2%, is the most likely outcome - 2 chances out of four. Three out of the four chances, 75% of the possibilities, are at or below the middle value. The odds are only 25% that the investment will reach the average of $1.21, which has a corresponding return of 10%.

The heart of the example can be restated.

This information about a distribution:

10% is the size of the loss

30% is the size of the gain

50% is the probability of a loss

50% is the probability of a gain.

Leads to these facts about the distribution:

an 8.2% return is the distribution's middle

a 10% return is the distribution's average

And

the number of possibilities doubles as the years increase: in the first year there are 2 possibilities, 4 in the second, 8 in the third and so forth.

By the time 71 years elapse from 1925 to 1996 the equation above changes to:

$$(X + Y)^{71}$$

Although this term is huge it can be calculated easily with computers, giving the total number of possibilities and the possibilities for each outcome. Attachments 3 and 4 show the possibilities each year, the symmetrical pattern each year and the distribution in percentage terms. The patterns do not depend on the values of X and Y. No matter what values X and Y are, the pattern of possibilities is the same. This is why Chart 3 in my direct testimony is also symmetrical.

ACTUAL DISTRIBUTION OF LARGE COMPANY RETURNS: 1925-1996

Ibbotson's data on large companies covers 71 years. It shows a return of 10.7% as being in the middle of the distribution and an average of return of 12.7%. This is different than the example in the sense that the order of the information is reversed from the example.

The information about the actual distribution:

a 10.7% return is the distribution's middle

a 12.7% return is the distribution's average

50% is the probability of a loss

50% is the probability of a gain.

Leads to these questions about the actual distribution:

What percentage is the size of the loss?

What percentage is the size of the gain?

I calculated the size of the loss to be 8.3% and the size of the gain to be 33.6%. These are the first and last values in column (3) of Schedule 12. I then applied these two figures to the formula

$$(X + Y)^{71}$$

This gives the total number of possible returns, the value of each return ,and the probability of each return in 1996 - given a $1 investment in 1925. This is the data shown in Schedule 12.

The Schedule indicates that the average return, 12.7%, has a less then 20% chance of being achieved in 1996. If the odds were looked at in 1927, the second year after the investment, the chance of achieving the average return would be no more than 25%. The point here is that as time progresses, the average return has a little less of a chance of being achieved. Its odds shrink from no more than 25% in the second year to less than 20% in the 71st year. This is not much of a change, but it highlights why the average return is not considered a useful measure by the sources I quoted. The average return is not the midpoint of the distribution, and the average return gets further and further away from the midpoint as time progresses.

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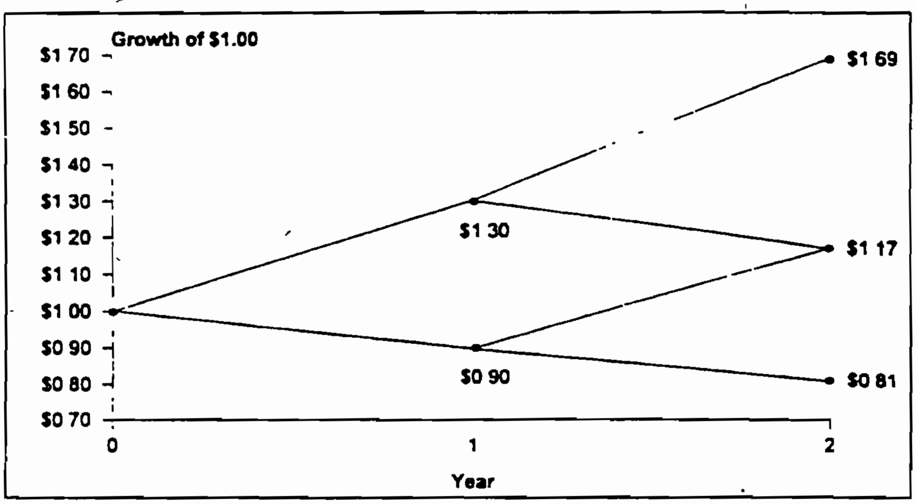
Attachment 1

where the cost of capital is the sum of its parts Therefore, the CAPM expected equity risk premium must be derived by arithmetic, *not geometric*, subtraction.

Arithmetic Versus Geometric Means

The expected equity risk premium should always be calculated using the arithmetic mean. The arithmetic mean is the rate of return which, when compounded over multiple periods, gives the mean of the probability distribution of ending wealth values. (A simple example given below shows that this is true.) This makes the arithmetic mean return appropriate for computing the cost of capital. The discount rate that equates expected (mean) future values with the present value of an investment is that investment's cost of capital. The logic of using the discount rate as the cost of capital is reinforced by noting that investors will discount their expected (mean) ending wealth values from an investment back to the present using the arithmetic mean, for the reason given above. They will, therefore, require such an expected (mean) return prospectively (that is, in the present looking toward the future) to commit their capital to the investment.

For example, assume a stock has an expected return of +10 percent in each year and a standard deviation of 20 percent. Assume further that only two outcomes are possible each year— +30 percent and -10 percent (that is, the mean plus or minus one standard deviation), and that these outcomes are equally likely. (The arithmetic mean of these returns is 10 percent, and the geometric mean is 8.2 percent.) Then the growth of wealth over a two-year period occurs as shown below.



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Attachment 2

Note that the median (middle outcome) and mode (most common outcome) are given by the geometric mean, 8.2 percent, which compounds up to 17 percent over a 2-year period (hence a terminal wealth of $1.17). However, the *expected value*, or probability-weighted average of all possible outcomes, is equal to:

	(.25	×	1.69)	=	0.4225
+	(.50	×	1.17)	=	0.5850
+	(.25	×	0.81)	=	0.2025
TOTAL					1.2100

Now, the rate that must be compounded up to achieve a terminal wealth of $1.21 after 2 years is 10 percent; that is, the expected value of the terminal wealth is given by compounding up the *arithmetic*, not the geometric mean. Since the arithmetic mean equates the expected future value with the present value, it is the discount rate.

Stated another way, the arithmetic mean is correct because an investment with uncertain returns will have a higher expected ending wealth value than an investment that earns, with certainty, its compound or geometric rate of return every year In the above example, compounding at the rate of 8.2 percent for two years yields a terminal wealth of $1.17, based on $1.00 invested. But holding the uncertain investment, with a possibility of high returns (two +30 percent years in a row) as well as low returns (two -10 percent years in a row), yields a higher expected terminal wealth, $1.21 In other words, more money is gained by higher-than-expected returns than is lost by lower-than-expected returns. Therefore, in the investment markets, where returns are described by a probability distribution, the arithmetic mean is the measure that accounts for uncertainty, and is the appropriate one for estimating discount rates and the cost of capital.

Arbitrage Pricing Theory

APT is a model of the expected return on a security. It was originated by Stephen A Ross, and elaborated by Richard Roll. APT treats the expected return on a security (*i.e.*, its cost of capital) as the sum of the payoffs for an indeterminate number of risk factors, where the amount of each risk factor inherent in a given security is estimated. Like the CAPM, APT is a model that is consistent with equilibrium and does not attempt to outguess the market. APT

Distribution of Possibilities for (X + Y)

Center of the Distribution

◄–Ibbotson Example

Distribution	Total Possibilities Each Year	Year
1		0
1 2 1	2	1
1 3 3 1	4	2
1 4 6 4 1	8	3
1 5 10 10 5 1	16	4
1 6 15 20 15 6 1	32	5
1 7 21 35 35 21 7 1	64	6
1 8 28 56 70 56 28 8 1	128	7
1 9 36 84 126 126 84 36 9 1	256	8
	512	9
. . .	. . .	
2 E+18	2 E+21	71

Distribution of Possibilities for (X + Y)
As a Percent of Possibilities
Center of the Distribution

																			Total Possibilities Each Year	Year
									100%											0
								50%		50%									1	1
							25%		50%		25%				Ibbotson Example				4	2
						13%		38%		38%		13%							8	3
					6%		25%		38%		25%		6%						16	4
				3%		16%		31%		31%		16%		3%					32	5
			2%		9%		23%		31%		23%		9%		2%				64	6
		1%		5%		16%		27%		27%		16%		5%		1%			128	7
	0%		3%		11%		22%		27%		22%		11%		3%		0%		256	8
0%		2%		7%		16%		25%		25%		16%		7%		2%		0%	512	9
									.										.	.
									.										.	.
									9%										2. E+21	71

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Look for this seal

ANIMAL CARE CERTIFIED™
www.animalcarecertified.com

When buying eggs

For more information about the Animal Care Certified program or a complete set of the technical guidelines, visit our website www.animalcarecertified.com or write to us:

Animal Care Certified Program
c/o United Egg Producers
1720 Windward Concourse
Suite 230
Alpharetta, GA 30005

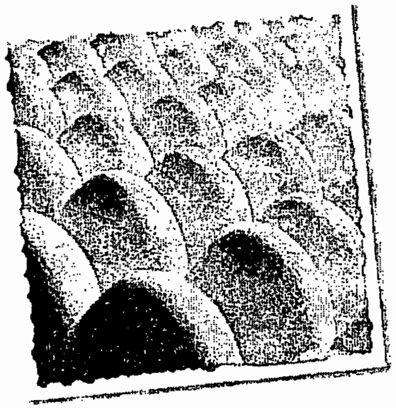
It's your assurance that your eggs are produced under animal care guidelines established by an independent scientific committee and audited by the U.S. Department of Agriculture or the American Registry of Professional Animal Scientists.

To learn more about this seal and what it means, read this brochure or visit www.animalcarecertified.com.

When you see the Animal Care Certified logo on your egg carton, it means that the eggs you are buying came from farmers who voluntarily participate in one of the nation's first programs that establishes guidelines for the proper care of animals.

These guidelines were established by an independent group of animal care scientists and veterinarians and require egg farmers to:

- Protect hens from disease and injury
- Provide adequate cage space for hens
- Provide nutritious food and clean drinking water
- Provide continuous flow of fresh air
- Prevent hens from injuring each other by trimming their beaks
- Transport hens safely and with care



Every farmer that participates in the Animal Care Certified program is audited each year to ensure compliance with the guidelines. These inspections are conducted by personnel from the U.S. Department of Agriculture or the American Registry of Professional Animal Scientists. The program has been endorsed by the Food Marketing Institute and the National Council of Chain Restaurants.

WHAT DOES IT ALL MEAN?

Here's a list of the various labels that you might see on egg cartons:

Animal Care Certified are eggs produced on a farm that voluntarily meets industry guidelines for the proper care of animals. These guidelines were established by an independent group of scientists.

Organic eggs are produced following standards established by the U.S. Department of Agriculture.

Hormone free eggs are from egg-laying hens that are not given hormones, but there are no specific guidelines. Egg-laying hens do not receive hormones anyway.

Cage-free eggs are produced by hens that typically live on the floor of a barn or poultry house, but there are limited specific guidelines.

Free-range eggs are from hens that typically live outdoors or have access to the outdoors, but there are no specific guidelines.

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www.animalcarecertified.com

Publications by Dr. Steve Brown

The Sine Qua Non of Order 636: Cooperative Competition, Information Flow, and Rate Design

Stephen N. Brown

The FERC completed a remarkable turnaround in regulatory philosophy in its gas pipeline restructuring order.

Competition for natural gas supply will promote the nation's economic growth. That idea describes the essence of Federal Energy Regulatory Commission (FERC) Order No. 636 and provides the driving force behind the commission's effort to restructure the natural gas industry. But the FERC's eventual success ultimately depends on the spirit of "cooperative competition". The willingness of individual players to share information about day-to-day pipeline operations and the vital conditions that determine rate design and prices.

The FERC itself is acutely aware of this vulnerability. That is why the commission framed Order 636 with language that simultaneously coaxes, cajoles, and urges the industry to do its patriotic duty (see box)

This language makes FERC's order 636 truly remarkable It tells the pipelines that their traditional way of doing business blocks the spread of competition within the natural gas industry. This finding was unthinkable twenty years ago The natural gas industry was built on the principle of bundled, city-gate, firm sales service. During the industry's early years, certificates of convenience and necessity were issued to pipelines only if they offered such service to distribution companies. The industry's building block is now an unlawful restraint of trade

The pipelines' old virtue is now a vice because the merchant function is gradually fading away In the first quarter of 1984 pipeline sales made up 94 percent of throughput By the second quarter of 1991 pipeline sales totaled only 12 percent of throughput. Nevertheless, in 1991 pipeline sales consumed over 60 percent of peak-day capacity This surprising mismatch between throughput and capacity told the FERC that pipeline sales enjoy a clear advantage over the open-access firm transportation of nonpipeline natural gas:

Free-flowing Information

The FERC intends to solve the fairness problem by establishing equivalency between bundled, city-gate firm sales by the pipeline and open-access firm transportation of nonpipeline natural gas. The solution lies with the idea of "No-Notice Transportation Service." Success will depend on cooperation between the various segments of the industry, as the FERC is quite aware.

> [We] expect the pipelines and all interested participants to craft . the operating conditions needed to

The Spirit of 636

Drawing on Patriotism:

"[We] . . . remind the industry that it is in the nation's best interest and the industry's interest . . to keep gas flowing and deliverable when and where needed and . . . not unreasonably inhibit the meeting of gas purchasers and gas sellers in a competitive market." [Order No. 636, p. 96.]

From Virtue to Vice:

"[The] pipelines' bundled, city-gate, firm sales service is operating, and will continue to operate, in a manner that causes considerable competitive harm to all segments of the natural gas industry . . this harm has an unreasonable impact on gas sellers and is an unlawful restraint of trade " [Order No. 636, p. 39.]

To Level the Field:

"Pipelines and other gas suppliers are not competing on an even basis for sales customers, even where firm transportation is available to move the gas sold by the pipelines' competitors." [Order No. 636, p 32]

An Open Book, But Who Will Read It?

Pipelines In a Fishbowl:

Pipelines will retain operational control, but will perform in a fishbowl, since all buyers and sellers must now constantly monitor pipeline operations

Second-guessing by Customers:

Buyers and sellers are likely to develop "shadow" operations groups that not only will monitor operating conditions, but are also likely to second-guess the pipelines from time to time.

Information Overload:

A tremendous need will arise for accurate, speedy, and voluminous information on storage facilities, receipt and delivery points, pressure, pumping stations, capacity reallocations, and anything else that might be viewed as relevant.

ensure that the pipelines can provide a "no-notice" transportation service pursuant to which firm shippers can receive delivery of gas on demand up to their firm entitlement on a daily basis without incurring daily balancing and scheduling penalties.

To its lasting credit, the FERC recognizes that "no-notice" markets will not be fully competitive without another simultaneous development — the rapid and free flow of information. The FERC clearly says "that pipelines must provide timely and equal access to any and all information necessary for buyers and sellers to arrange gas sales and capacity reallocations." This policy will work only if all players cooperate. Any effort to tilt the scales by withholding or disguising relevant information may easily subvert the FERC's goal of uniting gas purchasers and gas sellers in a competitive market place. The importance of good and timely information cannot be overestimated for a competitive market, whether it's the New York Stock Exchange, the Chicago Board of Trade, or the natural gas industry.

The FERC's policy on information flow has major implications. The pipelines may not yet have realized that the order lays out their operations for all to see. It's just like letting one person cut the cake while others choose which piece they want. For example, the pipelines must make electronic bulletin boards accessible to all users and no one will be granted preferential access to the boards:

> The pipelines must keep daily back-up records of the information displayed on their bulletin boards for at least three years and permit users to review those records . pipelines must also periodically purge transactions from current files when transactions have been completed, so that users do not have to sift through massive amounts of historical data to find current information.

The FERC is right to be cautious, considering the impending modernization of the nation's telecommunications infrastructure and uncertain behavior of the players in the natural gas industry How will the new infrastructure affect the competitiveness of the natural gas industry? Will the pipelines really want to give up their advantage of occupying 60 percent of the peak-day capacity, particularly when their sales are less than 20 percent of annual throughput? Do local distribution companies (LDCs) really want to jump into a competitive market with complexities that rival those of a major stock exchange? Will the upstream and downstream pipelines really cooperate with one another?

Rate Design

The restructuring hearings will not deal with the single biggest rate design issue for pipelines transportation cost recovery through the "straight fixed-variable method" (SFV) This rate design definitely affects the central feature of the FERC's restructuring proposal. The presumed willingness of gas buyers to participate in "no-notice transportation service."

The SFV method removes all fixed costs from the pipeline's commodity charge for transporting gas. For years the FERC allowed significant amounts of fixed costs in the pipeline's commodity charge. The commission now believes such practice inhibits competition by preventing gas purchasers from making accurate comparisons of prices, terms, and conditions offered by various gas sellers. The SFV method corrects this mistake and promotes "head-to-head, gas-on-gas competition "

The FERC prefers the SFV rate design but suggests that it may be avoided by any particular pipeline if the parties agree on an alternative costing method. If the parties can't persuade the FERC to deviate from its preference, or if they lack a consensus on rate design, the SFV method will prevail The odds favor SFV, since rate design is rarely characterized by harmony It's an impossible goal because the customers' load factors are too diverse. In fact, the SFV method reduces costs for customers with high annual load factors, and increases costs for customers with poor load factors. This explains both the support and the opposition to SFV — with a rate design consensus unlikely, there will be no viable alternative.

The SFV method will increase costs for some customer groups The FERC has agreed to limit such increases to 10 percent and to phase in the increase over a four-period after the pipeline's initial compliance filing. But after four years, the phase-in terminates and the limitations expire for SFV-related cost increases. After that customers are on their own; they must adapt to changed circumstances. The burden cannot be laid at the door of producers or pipelines. It falls exclusively on gas consumers and perhaps their agents acting as gas purchasers.

What does this mean for hot new designer rates? It means that "no-notice" transportation rates must strongly reflect the prevailing operating conditions on the pipeline

I'm not advocating a different price for every hour of the year on every different section of the line But I am advocating that the industry get far away from the idea that "one rate fits all." The nature of a competitive market place allows for some tailoring and customizing of individual prices and contract terms Indeed, if the market doesn't exhibit these characteristics at all, then it's not really a competitive market Customizing may be one way to develop a "no-notice" competitive transportation market There's certainly room for this market considering that interruptible transportation now accounts for 51 percent of pipeline deliveries to market

Tailored rate designs ought to reflect a match between the customers needs, the producer's supply, and the pipeline's operating conditions This brings me back to my emphasis on the need for good information More than ever before, there will be an emphasis on the optimal scheduling of pipeline flows, storage, maintenance, controlling, and shifting consumer demand. In this situation command and control of information is paramount because a competitive market inevitably reduces profit margins for the poorly organized and inefficient party To be effective negotiators, gas purchasers and sellers must have the ability to recognize and act on the opportunities offered by the ebb and flow of a pipeline's operating conditions FERC clearly understands this and accordingly has decided to make pipeline operations an open book for both gas buyers and sellers

I hope LDCs and their customers are ready for the responsibilities of a competitive natural gas market The LDCs fit the national pattern already noted by the FERC: Buying a lot of gas on the spot market, using interruptible transportation, and relying on pipeline sales for peak-day purchases, while keeping overall bills below the potential cost of exclusive reliance on pipeline gas. The LDCs have had an extended learning opportunity It's up to them to take this experience and skillfully apply it the emerging market that the FERC is now creating.

The competitive market certainly raises uncertainties at the federal and state levels How will the FERC draw the boundary between proprietary information and information required to make the market competitive? How does state regulation establish risk-sharing between the core customers and an LDC making a gas purchase on their behalf? Will a purchased gas adjustment (PGA) clause continue to serve a useful purpose once pipelines comply with Order 636?

These questions don't exhaust the possibilities, but sooner or later, perhaps in a rate case setting or in a notice of inquiry, the LDCs will have to show their state regulatory body that they've read the open book on pipeline operations and made good use of it This would serve everyone's interest, and the LDCs should avoid putting truth to old sayings "You can lead a horse to water but you can't make it drink," or, in the case of pipeline operations, "seeing a book open does not make its reader think"

Order 636-A: A Short-term Solution?

On July 30 the FERC met and voted to approve Order No 636-A, in which it slightly relaxed its effort to push the natural gas industry into the information age Pipeline capacity released for less than one calendar month will now require neither advanced posting on electronic bulletin boards nor bidding.

But the practicality of omitting short-term transactions from posting and bidding requirements will diminish as the industry learns better how to handle transactions of various sizes and duration. These short-term events cause a nuisance only when the players in the market are not ready to use or interpret the information that they provide. Any competitive market features short-term, low-volume transactions, and there is no inherent reason why such transactions should hinder a competitive market in its allocative efficiency Thus, we can likely expect that the FERC will eventually withdraw Order 636-A and replace it in a subsequent rule making.

Competition Versus Reliability

The importance of pipeline operations cannot be overstated because major changes in public policy towards regulated industry are constrained by technical considerations The FERC's restructuring efforts are no exception At the inception of the "Mega-NOPR," pipeline system reliability was incompatible with competition — one condition precluded the other With the industry's help, the FERC resolved this apparent contradiction and found that system reliability and competition coexist. Neither one preempts the other.

With a little imagination, the FERC might apply this reasoning to the issue of transmission access in the electric power industry All that's needed is to substitute "electric utility" for "pipeline" and "no-notice transmission" for "no-notice transportation" Can the FERC make competition in the electric industry compatible with system reliability? Perhaps not, but the electric industry may soon be hard pressed to explain why system reliability and competition cannot coexist in the power industry

The FERC has offered a number of individual steps that, if taken quickly and cooperatively, will speed the gas industry's adoption of competitive market practices. But I emphasize the *fragility* of the FERC's proposal and the need for cooperation to make the system work. Hot new designer rates won't sell in the market place if the players torpedo the restructuring I agree with the unspoken sentiment expressed by the FERC. Restructuring the industry will work only if the players adopt the spirit of "cooperative competition" That should characterize all bargaining between sellers, buyers, and pipelines.

Stephen N. Brown is chief of the Bureau of Energy Efficiency, Auditing and Research, Utilities Division, of the Iowa Utilities Board

The opinions expressed here do not necessarily represent those of the Iowa Utilities Board

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Science and Technology

So Long, Calvin Coolidge

Meter Reading Approaches the 1990s Promising a Pivotal Market for Communications Infrastructure

By Stephen N. Brown

Federal and state regulators must become knowledgeable about Automatic Meter Reading (AMR) and all that it entails. After all, AMR is a pivotal market that will shape the nation's communications infrastructure by determining whether energy and water industries move toward an intelligent, public-switched communication network or toward radio-based personalized communication networks.

The junction lies in the eventual replacement of roughly 250 million electric, gas, and water meters in the United States, nearly all of which reflect the technology of the 1920s. they must be read manually, they are incapable of implementing time-differentiated rates, they cannot communicate with anything, and their information storage capability is nil They will be replaced by devices embodying today's technology, and that will be compatible with the nation's communication infrastructure.

Radio Networks or Wired Networks?

The infrastructure is being shaped by the century-old competition between radio networks and wired networks. Radio-based cellular and microwave technology use the electromagnetic spectrum and offer the promise of personalized communication networks (PCNs) along with decentralized ownership and splintered control of the nation's communication infrastructure

The AMR market already reflects the struggle over market position and the dichotomies between radio and wired technologies, and between unilateral control and integrated control. AMR products available today encompass various radio offerings, including one combination of spread-spectrum signalling with a power line carrier, as well as telephone-inbound/outbound strategies. Telephone-based products require cooperation between the local exchange carriers and the utility; the spread-spectrum/power-line device is unilaterally operated by the utility. However, there is no dominant AMR strategy or product in the electric, gas, and water industries, also, they have no organized strategy on how to migrate from a 1920's-vintage metering technology to the 1990s. The AMR market today is still immature, disorganized, and untapped, but loaded with potential.

Why?

Because replacing 250 million meters, not to mention possible markets abroad, represents a major demand for new manufactured products that embody new communication technology.

Capable Networks for Energy Industries

More capable networks are needed by the electric utility industry, which is under intense pressure to adopt energy efficiency strategies requiring load monitoring, load management, incentive rates, and perhaps eventually real-time pricing AMR is essential for all these strategies. Therefore, regulators should advocate AMR investments in energy-utility networks, whether radio or cable-based, that:

- have scale economies,
- possess multi-functionality,
- can easily implement rate structure changes;
- are consistent with open-architecture principles,
- avoid redundancy and duplication of another local utility's investments.

The regulatory community should take the lead in advocating economic cooperation between different utility industries—not only for the potential economic benefits but also because the utilities and American business in general do not value economic cooperation

Shorter Replacement Cycles

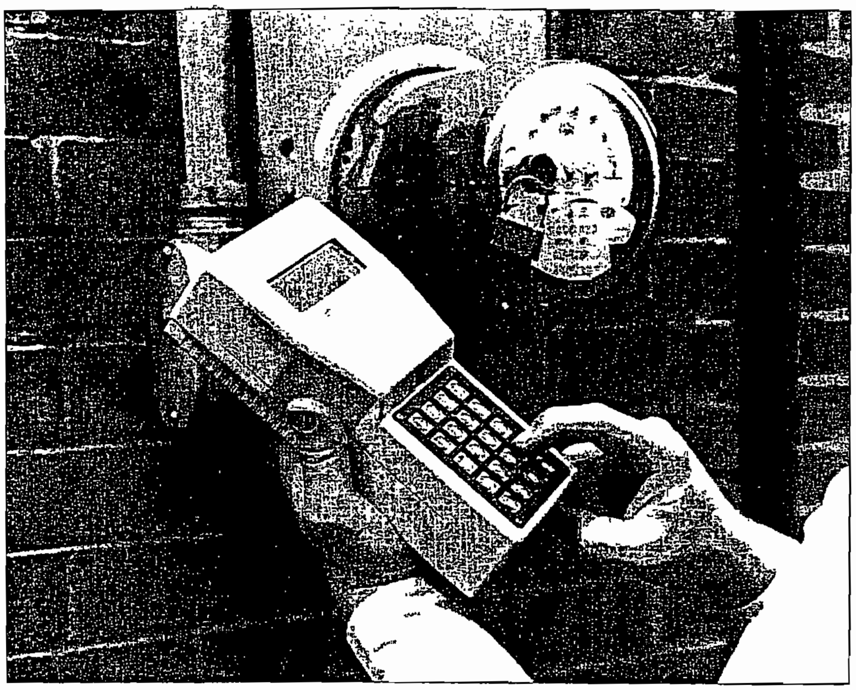
The application to AMR and the regulatory process is this. Regulated industries should be responsive to continual product improvements in AMR Regulators should not expect AMR products to have a 30- to 40-year depreciation schedule, nor should they expect utilities to make automation investments and then not replace them for decades. Product replacements are likely to occur in shorter cycles such as eight to twelve years. This is true for either radio or wired technologies

An important feature of continual product improvement is the role of customer feedback in guiding incremental improvements to the product after it has been introduced This suggests a need for continual cooperation between utilities and AMR manufacturers. In an intelligent network, product improvement means software improvements to create and access data bases that are centralized with regard to a local access transport area (LATA) Without an intelligent network, data bases are located in each local exchange. There are approximately 120-150 LATAs in the country along with several thousand local exchanges Centralizing data bases in LATAs rather than local exchanges reduces the development cycle for new services from years to months.

However, the communications industry has no plans to develop processing capability in digital central office switches An intelligent network offering speed but lacking distributed processing may have little value to electric utilities. Their long-term planning is evolving toward the distributed utility concept: the electrical distribution system becomes the focus of planning, processing, reliability, and power quality control Distribution control was a sideline issue when central station economies of scale dominated the electric power industry, but this situation has changed

The new emphasis is on the distribution sector, which is ready for massive applications of technology that control and manage the end user's consumption AMR software and hardware are aimed at the distribution sector; load management is a distribution function AMR products will also have load management capability Consequently, there's a clear need for processing capability.But where will that capability be located, at the company's headquarters or at selected points in the field, such as a central office?

The processing capability should be located in the field, making the logical choice for processing in an intelligent network digital central office switches All organizations, including utilities, would probably recoil at the idea of a digital central office that processes data, fearing for the data's privacy and reliability Appropriate encryption and validation procedures would make pro-



cessing viable at the central switch, and provide two separate opportunities for cooperation between a phone company and an energy utility: where the local company does not have a digital switch, coordination between the two utilities could result in the installation of a new digital switch Where a digital switch already exists, joint investment in its distributed processing capability will expand the intelligent network's scope. A utility's data bases could be placed in the central switch and accessed on a LATA basis. Without this capability, the intelligent network may be a case of bandwidth overkill for AMR and load management functions, with no thought given to the network's potential for time differentiated pricing or other add-on services for utilities.

Property and Profit

An intelligent network's product improvement is tied directly to software, a concrete, easily recognized aspect of the intelligent network.But in a radio network product improvement is amorphous because a frequency cannot be "owned", and there are no codified private property rights regarding the spectrum Government steps in to allocate the spectrum.In a competitive setting, lack of property rights in the spectrum makes the innovator's profit stream far less secure than for the intelligent network's innovator.In a competitive setting property rights protect the profit stream created by the innovator. For this reason, an intelligent network is more likely to sustain a high rate of innovation than a radio network.In fact, one of the more notable innovations in radio technology thrives on the absence of property rights Spread spectrum technology hops across adjacent radio frequencies to mask the content of a radio message.While this is successful in military applications, the technology has not yet penetrated the commercial markets to a significant degree.

Product improvement is important for radio-based AMR manufacturers They will have to demonstrate their product's potential for broad application over time before they can capture the utility industry as a long-term AMR customer

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Dr. Stephen N Brown is Chief, Bureau of Energy Efficiency, Auditing, and Research Utilities Division, Iowa Department of Commerce This paper was presented at the New Mexico State University's Center for Public Utilities Current Issues Challenging the Regulatory Process held in Santa Fe, New Mexico March 11, 1992

Opinion

No Second Time Around for AMR

By Stephen Brown, AMRA Treasurer
Iowa Department of Commerce

David Gorton's editorial in AMRA's January newsletter ["Looking Back to See the Future," p. 2] conveyed the notion that AMR's problems are no different today than they were 30 years ago. To an extent, he is right. AMR's problems are perennial because the utility industry's retail business environment has been remarkably stable. But the time will come when the environment changes, allowing a permanent fix for the infirmities of the AMR market.

Utilities have a growing need for accurate and prompt measurement of consumption. This is not caused by a sense of righteous conversion to AMR. Cold, hard self-interest is the reason. The electric and gas utilities, in particular, are more interested in AMR today because they face the prospect of competition in all phases of their business. Competition implies uncertainty about profit margins and a need for detailed knowledge of the retail market. Good information acquired through AMR will make the difference between success and failure in a competitive market.

Standard and Poor's Corp., a major financial ratings firm, believes that competition is making the electric business very risky. Consequently, the firm set new financial standards that may reduce credit ratings for one-third of the nation's electric utilities. This has never happened before. The industry's new competitive environment may compel utilities to install AMR equipment that embodies rapid communication and sophisticated measurement. Thus, the recycling of AMR's familiar problems may truly come to a final end.

However, Gorton's editorial shows the same thought being voiced in 1967: "AMR has been a 'want' of the electric utilities for many years but now is rapidly becoming a 'must.'" That statement was wrong in 1967, but it's right today. If you want to know why, read an insightful article by AMRA member Roger Levy. He cowrote *Re-engineering DSM: Opportunities Through Information and Integration*, which appears in last November's issue of *The Electricity Journal*. Levy explains why the electric utility industry failed, in general, to implement automation procedures regarding measurement and communication in the retail market. The dominant reason, says Levy, is "most ... technical and procedural designs incorporate implicit and explicit compromises to make sure that programs cause little disruption and conform as closely as possible to the operating practices and features of existing utility company business management and information systems."

In short, AMR and all automation systems have the potential to create ripple effects throughout a company. If unwilling to live with these or take advantage of them, the company constrains the automation project, cutting it here and tweaking it there until the project is reduced to a shadow, drained of its promise and potential.

In Levy's words, "What starts out as a 'logical compromise' ... artificially limits how ... communication, measurement and control technologies might be used to modernize existing utility systems and practices."

In today's market, many industries depend on rapid information flow for marketing, cost cutting and competing, including: the overnight package delivery industry, the vending machine business, the liquid fuels business of propane and butane delivery, and all "just-in-time" production and inventory businesses. These enterprises have made every effort to automate because it's vital to their success.

In 1967, automation at the retail level didn't mean anything to the utility industry, and AMR was a nonevent. That era is over. The AMR industry should take advantage of the present, push on all fronts and think big.

The advice of Daniel Burnham is appropriate. He was a urban planner who, in 1900, redesigned the cities of Chicago and Washington, D C. He told the cities' leaders, "Make no small plans, they do not stir men's imagination."

AMR pilot projects have seen their day. The technology won't mature if it's forever limited to trials. Its true potential lies in full-scale, utilitywide projects, and now is the time to pursue them.

Stephen Brown works for the Iowa Department of Commerce, which is based in Des Moines. He also serves as the treasurer of AMRA.

Opinion

DOE Proposal Trivializes AMR

By Stephen Brown
Iowa Department of Commerce

Automatic meter reading (AMR) received much needed attention when Congress enacted the Telephone Disclosure and Dispute Resolution Act of 1992. It directed the U.S. Department of Energy (DOE) to consider a government demonstration project involving utility communications and AMR.

Last March, the DOE opened docket CE-NOI-93-001, an inquiry meant to implement Congress' directive. After consultation with the U.S. Commerce Department, the DOE released its final report, *Proposal for Demonstrating the Potential of Innovative Communications Equipment and Services for Utility Applications*, on Sept. 2. [See related article on page 3.] In it, the DOE recommends against a "use of federal funds" to develop an AMR or energy-management demonstration project because "it would duplicate demonstrations already planned by utilities."

Despite this reasonable conclusion, the final document is disappointing. It could have been a means for the DOE to show Congress that meter reading and utility communication are vital functions in the American economy. Instead, the DOE sent Congress a message that trivializes AMR.

The report accepts without question a cliched, moss-backed argument used for years to stifle innovation in metering, utility pricing and communication: "Presently the main limitation on automatic meter reading is cost. According to the Edison Electric Institute in their response, a survey of their members shows that it only costs between 30 cents and 60 cents per customer per month to read the meter manually for typical customers...". When Congress reads this, they will wonder why anyone would bother with AMR since manual reading is cheaper than a phone call.

The report is flawed because the agency's world view is confined to the Washington Beltway. Twenty-seven respondents filed comments on CE-NOI-93-001. The DOE apparently thinks only two had opinions that are worthy of Congress' attention. The DOE highlights the filings of the Edison Electric Institute and the Utility Telecommunications Council, two of the oldest guards in Washington. The report does not refer to the opinions of the other 25 respondents — vendors, phone companies, cable companies, utilities and consultants. A balanced report would have drawn from many respondents, not just two. It would have shown the fallacy of the "manual meter reading is cheap" argument.

Manual meter reading is cheap because it is an almost worthless service. It gives practically nothing to consumers and utilities. The inadequacy of meter reading and its failure to facilitate economic decision making by consumers is shown by the popularity of balanced-billing for gas, water and electric utilities.

In balanced-billing, a customer's annual bill is estimated and divided by 12. The result is the customer's monthly bill. At the end of one year, the difference between actual and estimated consumption is reconciled, the customer receives a credit or debit, and the cycle starts again. Millions of consumers use balanced-billing. In short, the payment for consumption of gas, water and electricity in the United States is little different from making a premium payment for insurance. The success of balanced-billing shows the only effective use of manual meter reading — reconciling the customer's estimated annual consumption against actual consumption once a year in order to balance a company's annual cash flow.

It is a mystery why the DOE gladly accepts the cheap meter-read argument and then passes it on to Congress as an unquestioned truth. Consumers need the opportunity and the tools to treat their energy and water purchases like any other commodity or service. AMR is the tool, and a time-sensitive utility price is the opportunity These will create new patterns of energy and water use, perhaps allowing the next generation of Americans to mitigate and avoid costs for such things as the safe disposal of nuclear fuel used in power plants, which is now estimated at $45 billion.

With AMR, the next generation will shop for the right time to buy energy, from the right source and at the right price — just like it shops for the right groceries and right times to travel. It's time for the utility industry's metering practices to measure up to the 1990s and the next century

The DOE's report could have sent these messages to Congress while still arriving at the same conclusions. Instead, Congress will now dismiss the issue as trivial.

Stephen Brown works for the Iowa Department of Commerce He also serves as the treasurer of AMRA

electric potential

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Bubble Memory Technology: Its Impact on Metering and Rate Structure

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Bubble memory will replace magnetic tape as the principal means of implementing product differentiation and rate structures within the electric utility industry for two reasons. first, research and commercial development of bubble memory technology is moving forward after the technology was abandoned by several U.S. producers. Advances in the technology will reduce the importance of silicon and increase the importance of ferrous magnetic substances by achieving very high density rates of bit storage which in turn will bring economies of scale and rapidly declining average costs for the storage of information. Second, bubble memory's performance already exceeds that of magnetic tape, and the difference between these levels of performance will become even greater.

The remainder of this discussion is divided into three parts: the first is a brief explanation of how product differentiation in the electric utility industry creates a need for efficient information storage; the second is a comparison of magnetic tape and bubble memories; and the third section explains why bubble memory technology is viable, marketable and dependable.

I

In the context of an electric utility, product differentiation means that electric power sales represent several different services that are distinguished from one another by such criteria as the time of the sale, the customer making the purchase, whether the sale is short-term, long-term, intermittent, or continuous, and any other criteria that would be relevant. Product differentiation naturally entails different prices for different commodities. For example, electric power subject to interruption is clearly a different commodity than power not subject to interruption; similarly, electric power sold at the time of the system's peak demand is different from power sold at another time.

A utility that charges for its product on a time-of-day basis has to know the moment-by-moment purchases of a customer; such information becomes voluminous in a matter of hours and must be processed, evaluated, and stored. Since charging for power sales on a time-of-day basis is now a regular feature of many utilities' rate structure, and since interruptable and standby power sales are becoming more common both to industrial customers and to other utilities, even more information (and storage) will be required. These needs will rapidly exceed the capabilities of magnetic tape as a sales recording device.

II

Bubble memory is a storage medium in solid state form, in which the presence or absence of a "bubble" in a submicroscopic magnetic domain on a chip represents respectively a 0 or a 1 so that data can be stored in binary form. Unlike other kinds of memory, bubble memory has no moving parts and is nonvolatile (i.e., not power-dependent); it retains recorded data even if the power supply is interrupted.[1] Although magnetic tape also retains data when the power supply is interrupted, measurement of consumption using magnetic tape entails a mechanical system installed and reset manually, the shortcomings of which make possible inaccurate measurement of consumption and concomitantly lower revenue. This is readily demonstrated by an examination of the steps required for magnetic tape to measure power consumption by an industrial customer on a time-of-day rate.

The tape of a magnetic tape meter is usually divided into two or more tracks: one track always records time pulses sent from an external clock, while the other tracks record data pulses that represent power consumption. The time pulses are recorded according to a predetermined interval length. Consumption within a time period is determined by adding up the number of data pulses recorded between two adjacent time pulses. Once an initial start time is determined, all time pulses will occur at those regular intervals that subdivide the billing period. For example, if the start time is 9:00 and the interval length is 15 minutes, the time pulses occur at 9:15, 9:30, 9:45, and so on.

While this may seem simple to implement theoretically, practically it poses several problems. Magnetic tape metering requires extensive training of the personnel that install, maintain and remove the tapes from the metering site. A tape metering system is essentially a mechanical system insofar as it relies on the tape drive gears to operate properly and move the tape at the required number of inches per second; otherwise the space between adjacent time pulses may not represent the time interval specified by the utility. Referring to the example above, the interval could represent 9:03 to 9:12, or 9:03 to 9:20 depending on the speed of the tape drive.

The metering tapes also have nonmagnetic leaders and trailers which record nothing,[2] so that when the tape begins, it must be positioned properly for the initial time and data pulses to fall on the magnetic portion. Otherwise there is a mismatch between tape start time and recorded information, causing a loss of information, and in metering situations, loss of information usually means loss of revenues

There is another possibility for error. The tape must be replaced before the magnetic trailer is reached, or billing information is lost at this stage, too. This means that the tape must be physically replaced; therefore, the utility must follow a precise schedule not only to read the tapes but to replace them as well.

There are other problems. The initial start time of the first interval on the tape must be set from an external clock, one that runs independently of the tape. The interval length can only be changed by changing the external clock. While this is not a problem for a single meter, it would be a very expensive problem, in terms of labor costs, where several hundred meters are involved. So once a utility selects an interval's starting point and its length, change is a problem.

All of these points underscore the importance of trained personnel in maintaining, setting, and reading the meters. But this also highlights the vulnerability of billing in the event of a labor strike.

Performance characteristics are particularly important in metering situations because the storage medium is subject to the extremes of weather: heat, cold, humidity, and dust. How does magnetic tape hold up compared with bubble memory under these conditions?

Magnetic tape expands with heat and contracts with cold, ages, wrinkles, and develops ripples. The recording head is subject to oxide buildup and must be regularly cleaned.[3] Any of these can cause data loss or data error so that the tape is incorrectly read and translated to a mainframe computer. Bubble memories produced by Intel Magnetics can operate within a range of 0 to 70 Celsius;[4] the limits of the range will expand to -20 and 85 Celsius in the very near future.[5] Bubble memory is minimally affected by dust, vapor, vibration,[6] and hard radiation,[7] even in very harsh environments; it maintains data integrity.

Furthermore, the reliability of bubble memory is a distinct advantage to a utility's metering capability. The failure rate for a 128K bubble memory device is 1 in 10 to the 15th power; this is about once in every 100 years of operation.[8] The mean repair time (i.e., for replacement) of a bubble memory unit is only a few minutes.[9] The reliability of a magnetic tape system is far less simply because it is a mechanical system;[10] a major portion of any magnetic tape storage system involves mechanically operated systems-control and -drive hardware.

Another point of comparison is storage capacity, and magnetic tape used in metering situations has a maximum capacity of 3 M bits/square inch.[11] In 1983, Intel Magnetics introduced a 4M bit chip measuring 1.46 x 1.35 centimeters with a storage capacity of slightly more than 2 M bits per square centimeter or 5 M bits per square inch.[12] On this basis, bubble memory has a 60capability of magnetic tape does not apply in metering situations because increasing data storage on tape at a metering site requires decreasing the speed at which the tape moves and because there is a limit to how slow a tape can be set to move.[13] For example, for data collected on a 15-minute interval basis, tapes used in metering situations have a practical storage limit of 90 days. Bubble memory, on the other hand, has no moving parts. Its full storage capacity can always be utilized as this capacity continues to increase with technological advances. Bubble memory already has a capacity in the range of 6 months for 15-minute intervals and 2 months for 5-minute intervals. Unlike magnetic tape, bubble memory technology offers the possibility of remote readings over telephone lines or other data transmission paths. Telephone interrogation of magnetic tapes is not practical. Remote data access and bubble memory technology also offer the possibility of automatic reprogramming from a central source of all interval lengths and start times for all meters simultaneously.

The foregoing clearly implies that the use of bubble memory would be substitution of capital for labor, thereby providing greater management control over the entire process. More important, however, is the flexibility (that does not now exist) in a utility's rate structure that bubble memory can provide. Consider the following as a case in point. For billing purposes, the practical minimum interval length on a magnetic tape is 15 minutes. This interval length cannot accurately measure power used in time periods that are shorter than the interval and that overlap interval boundaries.

For example, given the 15-minute interval beginning at 9:00, there is no way to measure the power flow from 9:07 to 9:22, and this is particularly important where large inductive loads operate intermittently and where the operation of these loads is timed to circumvent the real measure of the power flow: for example, if an electric drag line or an electric furnace is used between 9:07 and 9:22, the power flow measure on a magnetic tape meter with 15-minute intervals described above would only capture half the actual power flow. In this situation, the unmeasured power sales become system-demand losses to the utility. These losses usually range from 5 percent to 10 percent of a utility's net generation.

However, a bubble memory using a one-minute or five-minute interval would solve this problem by recording a higher sales volume, leading to lower system-demand losses and to either greater revenue for a given sales price or lower prices because of a given revenue requirement. This could have a substantial industry-wide effect by bringing in several hundred millions of dollars that are otherwise lost or by keeping electrical price levels lower. Furthermore, bubble memory's capability to record power usage accurately no matter how short the duration will also provide for more precise cost-of-service studies, enhance the utility's ability to sell interruptible-power and thereby more fully utilize spinning reserve. The last point of comparison to be made here between bubble memory and magnetic tape is data access. At one time, both magnetic tape and bubble memory entailed sequential access to data: the only way to access data in the middle of stored information was by accessing all information leading up to what was desired. Improvements in chip architecture for bubble memories now make data access time two to four times faster than either hard or floppy disk drive access times [14] Of course data access time on a magnetic tape cannot be improved by manipulating the medium, and this further demonstrates that bubble memory storage is superior to tape storage

III

Major factors in adopting any new technology are expected life and serviceability Bubble memory is not new but it is still a fairly recent development The driving force behind the discovery of magnetic bubbles was a group of scientists at Bell Laboratories, prominent among them A H Bobeck, U F Gianola R C Sherwood H E.D Scovil and W Shockley [15] Theoretical discoveries in the late 1960 s by the Bell group gave impetus to further research and attempts at commercial development throughout the 1970 s Research has been conducted along several lines of development materials analysis chip architecture and chip fabrication, to mention a few At one time in the late 1970 s, development programs were underway at Texas Instruments, National Semiconductor Rockwell International, Motorola, Intel, and Signetics. Bell Labs developed an experimental 11 5 M bit bubble device only 1 3 inches square, even Hewlett Packard developed applications in desktop calculators [16] All of this is sufficient indication that the bubble memory market was perceived as one that would grow and be viable In the late seventies there was a consensus that the annual sales volume in the United States would approach 1 billion dollars and that the technology would cost only 10 millicents per bit [17] but by 1981 Intel was the only domestic producer of bubble memory· all the others had abandoned the market

Far from being sidelined in terms of research and development bubble memory remains viable because it is ideally suited for portable applications and because of its radiation- hardness For example, in the mid-1970's it was considered for inclusion as a component for an on-board attitude control computer for spacecraft [18] Research on magnetic bubbles continues in Japan Britain France, West Germany and the Soviet Union From the standpoint of development in the United States Intel negotiated a "second source" agreement with Motorola in 1982 so that technological research product development and manufacture of bubble memory will be shared between the two firms [19] This is significant because bubble memory will have a full line of support electronics, the lack of which had previously hampered commercial development. Furthermore research done by IBM at San Jose determined that "magnetic bubble memories must have a capacity of at least 4 M bits to challenge RAM devices on the basis of cost." [20] It is no coincidence, therefore, that Intel introduced a 4 M bit chip in 1983. This is a clear signal that further commercial development of bubble memory is anticipated A 16 M bit device is the next logical step [21] and it could be available by the early 1990 s Research is under way at Hitachi, Fujitsu, Sagem [22] IBM and Bell Labs [23] It must not be forgotten that the original corporate developer of the bubble memory, Bell Labs and its parent AT&T were prevented from entering the computer technology market. But this has all changed with the recent divestiture of AT&T It is only logical to conclude that the founder of the technology would seek to commercialize and expand it now that legal restrictions are removed from commercial competition in the industry

Further development of the technology can be expected because of the tremendous potential for miniaturization and scale economies in bubble fabrication In fact scale economies are already occuring In 1979 Intel published a series of guaranteed prices for bubble devices purchased in quantities of 25 000 The

prices of devices were $1000 in 1980, $600 in 1981, and $300 in August of 1982 By January of 1983, the prices fell below $250 in lots of 10 000 [24] The price of the 4 M bit device is expected to approach $150 by 1986 [25] Achieving low-cost chips requires high device density and large chip capacity. The complementary technologies to achieve this are either in place or undergoing advancement themselves For example, the Intel 4 M chip referred to earlier in this essay was fabricated using x-ray lithography [26] this is the production tool that enabled the achievement of 4 M bit density but as time and research continue x-ray lithography can be expected to give way to electron beam lithography [27] the ultimate key to bubble miniaturization and scale economies.

The ongoing research and commercial development makes a myth of the notion that bubble memory is a dead technology The complexities of the utility industry are already outdistancing the capabilities of the magnetic tape and new avenues must be investigated. Bubble memory is a viable and superior option to develop for the long term

Conclusion

Some of the technological differences between magnetic tape and magnetic bubble memory have been discussed and policy implications briefly outlined The industry cannot ignore the technological changes that are coming in the 1980's and 1990 s. The limitations of magnetic tape necessitate a vigorous search for a suitable substitute, one that does not allow data error/loss in metering, one that can measure interruptible and standby power and insure against revenue erosion by means of interval adjustment, one that allows for remote monitoring using data communications technology, and one that makes for greater flexibility in the development of rate structures.

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ECONOMIC INCENTIVES FOR NUCLEAR PLANT PERFORMANCE: A STATE PERSPECTIVE

BY

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DELIVERED AT THE NRC'S STATE LIAISON OFFICERS' MEETING: REGION III
GLEN ELLYN, ILL., SEPTEMBER 29, 1988

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INTRODUCTION

I had the opportunity to listen to Nuclear Regulatory Commissioner Ken Rogers' presentation at the July 25th meeting of NARUC's subcommittee on nuclear issues. Commissioner Rogers clearly takes the position that capacity factors can be a disincentive to the safe operation of a nuclear power plant when they are used as a sole measure of the plant's overall economic performance. Of course, the Commissioner's stance accurately represents the Nuclear Regulatory Commission's (NRC's) basic opinion regarding target capacity factors and their role in the incentive programs established by state regulatory bodies.

I'm a senior staff member of a state regulatory body, the Iowa Utilities Division, a group that provides line and staff support to the Iowa Utilities Board, a body composed of three appointed officials, the decision-makers who set policy. **I do not speak for their policy views on incentive programs.** But I am in the position to describe why nuclear plant performance is becoming an issue in Iowa, to make my own professional assessment of the capacity factor issue, and to offer a compromise measure, one that may satisfy the concerns of the NRC and those of state regulatory agencies engaged in economic incentive programs.

NUCLEAR POWER IN IOWA

Nuclear power plants provide approximately 25% of the net electrical generation devoted to consumption in Iowa. The plants are: Cooper, wholely owned and operated by Nebraska Public Power, but one-half of the net output is committed to the Iowa Power & Light Company; Duane Arnold, operated by Iowa Electric Light & Power Company, but jointly owned with two rural electric organizations; and Quad Cities Units 1 and 2, operated by Commonwealth Edison, but jointly owned with Iowa-Illinois Gas & Electric Company.

Nuclear plants are normally operated at a nearly constant level of output during most on-line hours, the exception being those on-line hours either immediately prior to a planned shut-down or during coast-down at the end of the fuel cycle. But the Utilities Division Staff found that Cooper and Duane Arnold substantially deviated from this pattern; from 1983 through

1986 both plants appeared to swing with load rather than operating in the base-load fashion characteristic of most other nuclear plants in the country. Table 1 is a comparison of Duane Arnold and Cooper utilization to utilization of nuclear plants in states adjacent to Iowa. For all four years these two plants were consistently near the bottom of the scale. Table 2 is a similar comparison for nuclear plants in the Mid-Continent Area Power Pool (MAPP), and Cooper and Duane Arnold again fall to the bottom of the scale. Tables 3 and 4 are similar comparisons using all the nuclear plants.[1]

All of this descriptive information substantiates the idea that these two plants, unlike most others in the country, were not being extensively base loaded. This is significant because of the very low fuel costs involved: between 6 and 9 mills per kilowatt-hour at both plants in comparison to costs of 13 to 15 mills at the large coal-fired plants in the state. The very obvious question is: why not increase the output at the nuclear plants as a substitute for the more expensive coal output? This issue is even more puzzling because one of the state's base-load coal fired plants has greater utilization than either Cooper or Duane Arnold during the same time frame. The Iowa Utilities Board ordered an investigation into this issue; interrogatories were sent to the two Iowa companies involved, and responses are expected in mid-October.

This approach appears to be retrospective, but it should also be viewed as a planning consideration. Federal acid rain legislation could have a negative impact on eight major generating plants in Iowa. If and when such legislation becomes law, compliance would most likely require curtailed output at some or all of these plants. As a group, the plants provide 4,600 megawatt hours (MWH) of the state's net electrical output, about 21 percent of the total net output. In addition, the plants' average number of annual service hours exceed 7,000, and the average hourly output is 82 megawatts (MW). Improved performance at the nuclear plants will alleviate some of the negative consequences of compliance with the new legislation. This is a primary reason why nuclear power plant performance in Iowa will be more important in the future.

THE CAPACITY FACTOR ISSUE

Given the scenario just described, how should a regulatory body proceed with the development performance evaluation? A quick answer, but one that would disturb the NRC, would be to use capacity factors. As most of you know, a capacity factor is a composite measure of a plant's availability and output level. If availability falls or if output declines, the capacity factor drops. The NRC's objection to capacity factors is simple but cogent: use of the factor encourages a company to run a nuclear plant when it should be shut down for periodic and preventive maintenance. Therefore, capacity factors lead to incremental deterioration of the plant with a cumulative effect on safety. New York Attorney General Robert Abrams expressed this sentiment when criticizing the New York PSC's incentive program: "A company striving to meet a capacity-factor target would be tempted to ignore or downplay the seriousness of safety problems."

This argument is aimed at state regulatory agencies. These organizations have a direct and large effect on the financial well-being of the utilities involved with the nuclear plants. From a financial view, the state bodies have a much greater impact on the companies than does the NRC. For this reason, state agencies can have substantial influence on how the companies manage nuclear plants. In fact, several states have chosen to exercise their influence, and despite the concerns of the NRC, have adopted incentive programs that include capacity factors. These states include New York, New Jersey, Florida, Virginia, and North Carolina among others. The contention and fractiousness over economic incentives and regulation is quite visible.

For example, a July 1988 Electrical World article summarized a nuclear plant survey conducted by the Reliability Engineering Department of Westinghouse Electric:

> ...organizational and external factors have a far stronger effect on availability of US reactors than physical attributes, such as age, reactor type, or nuclear-steam-supply-system vendor...Economic regulation sometimes hinders preventive-maintenance initiatives and plant equipment upgrades, the report concluded. "On the state level, there appears to be a widespread lack of understanding by utility commissions of the importance of nuclear power..."

The other side of the coin is illustrated by a December 1985 article appearing in the New York Times:

> ...(S)tate regulators seem unimpressed with the NRC's concerns and suggestions. "This is a political process," said one state regulator, adding that the NRC's protestations about the deleterious effect of financial incentive programs on reactor safety are "a nice smokescreen."

There appears to be disagreement between many state regulatory authorities, the nuclear power industry, and the NRC over the use of incentive programs and capacity factors. The most important question here is not who's right, but is there an alternative, one that is tenable for all concerned parties?

I believe that the answer lies in a composite measure that incorporates three ideas: (1) the utilization ratio concept illustrated in Tables 1 through 4; (2) service hours; and (3) reactor trip rates, referred to more formally as Reactor Protection System Actuation Rates.

DEVELOPING A COMPOSITE MEASURE

The utilization ratios in Tables 1 through 4 exclude hours when the plant is not in service, and therefore provide a simple indication about the kind of loading that prevails at the nuclear plant. The ratios are useful because they indicate if an economic dispatch problem is present. An economic dispatch problem is clearly not a plant performance problem, but this distinction would be hidden by capacity factors. By mixing availability and output level, capacity factors fail to pinpoint and isolate system problems from plant problems.

However, utilization ratios shed no light on plant availability; they are useless in this regard. Plant availability should be synonymous with service hours; this method is simple, clear, and avoids any confusion that might be caused by using capacity factors as a surrogate measure for availability. But there is an important point here; if capacity factors should not be used in an economic incentive program, then how can the capacity factor concept be legitimately used by generation planners when they're assessing the economic feasibility of a new plant? The link between capacity factors used for planning and actual capacity factors is shown in a February 1987 decision by the New Jersey Board of Public Utilities. The following is taken from the decision and order in Docket ER85121163.

> Nuclear plants are constructed with the expectation that their high capital costs will be offset by their low operating costs, thereby providing an economical, year-round energy supply to ratepayers. At the time the decisions were made to construct each of the Company's five operating nuclear plants - Salem I, Salem II, Peach Bottom II, Peach Bottom III and Hope Creek I- they were projected to perform at approximately 80% capacity factors. These projections were subsequently revised downward at the time construction commenced and again at the time of initial commercial operation. Despite these projections, the plants (exclusive of Hope Creek) have not met performance expectations and have been plagued with prolonged outages. The Company reported that the lifetime cumulative capacity factor for Salem I is 51.3%, Salem II - 47.7%, Peach Bottom II - 53.8% and Peach Bottom III - 60%. Further, plant operations have been characterized by wide swings in performance as evidenced by Salem II's 8% capacity factor in 1983 and Salem I's 95% capacity factor in 1985. Thus, ratepayers have been saddled with the cost burden of the plants' high fixed costs in base rates and expensive replacement power costs incurred as a result of substandard nuclear performance ... It is this history of uneven and substandard nuclear performance, its attendant cost burden to ratepayers and the Company's increasing reliance on nuclear generation that gives rise to the need for nuclear performance standards.

Repudiating capacity factors in an economic incentive program also means repudiating them in the generation planning and economic feasibility stage. How is this contradiction resolved to create a workable incentive program, one that also addresses the concerns of the NRC and the criticism of capacity factors voiced by New York State Attorney General, Robert Abrams, mentioned earlier? I believe the answer lies in the use of reactor trip rates.

The concept is clearly explained in a well-documented paper authored by David Dietrich of Technical Analysis Corporation. He makes several points in his paper, and I'm going to highlight just two of them because they're useful in this forum. The author makes this statement:

> An "RPS actuation with control rod motion" -- the standard terminology meaning reactor scram or shutdown -- results in lower economic efficiency because the plant is taken off line. Such an RPS actuation also results in a lower level of safety because the event presents a challenge to safety systems and operating staff that must bring the reactor to a safe condition.

With this comment Mr. Dietrich is establishing a connection between a reactor trip and economic efficiency; the greater the number of trips the lower the overall efficiency. In the next statement the author points out how well reactor trip rates coincide with the NRC's policy goals.

> The NRC has had a formal program to reduce trip frequency since 1984 and every year has seen a gradual reduction in trip rates. The NRC has concluded that "a reduction in the frequency of challenges to plant safety systems should be a prime goal of each licensee." It also finds that large reductions in the risk of an anticipated transient without scram (ATWS) can be achieved by reducing the frequency of transients that call for RPS operation. A reduction in the RPS actuation rate, the goal of the proposed incentive program criterion, is not only consistent with formal NRC policy. It is formal NRC policy.

However, reactor trip rates are not complete substitutes for capacity factors; although the two items are inversely correlated with each other, the correlation is not perfect. David Dietrich points out that while low trip rates are accompanied by high capacity factors and vice-versa, there are also instances where high capacity factors and high trip rates accompany each other. Based on this observation, my conclusion is that reactor trip rates alone should not be the only criteria to evaluate the economic performance of a nuclear plant.

CONCLUSION

In my opinion an economic incentive program should explicitly include reactor trip rates because they are useful and prudent, as well as being responsive to the concerns of the NRC. But I continue to believe that utilization levels and the number of plant service hours should also be a part of an incentive program. The exact weight given to each component would be a matter for the policy makers. The conceptual framework provided here represents a middle road, one that does not rely on a single measure to evaluate performance. An incentive program focusing on reactor trip rates, utilization levels, and service hours provides a workable alternative to reliance on target capacity factors and is a solution to the problem I mentioned earlier: where a company or industry repudiates capacity factors as a method of economic evaluation even though generation planners used capacity factors to justify economic feasibility for the plants in question. Use of the composite measure put forth in this paper would certainly recognize the interests of the ratepayers, the companies, and the concerns for safety expressed by the NRC.

TABLE 1

Comparison of Cooper and Duane Arnold Utilization to Utilization of Nuclear Plants in States Adjacent to Iowa for 1983-1986.

Plant No.	Year	Plant Name	State	Total Plant Name Plate (A)	Maximum Dependable Capacity (Net MW) (B)	Total MWH Generation (C)	Service Hours (D)	Estimated Avg. MW Generated (E)=(C)/(D)	Percentage of Capacity Utilized (F)=(E)/(B)
1.	1983	Palisades	MI	812.00	635.00	3,769,958	5,283.60	713.52	112.37%
2.	1986	Kewaunee	WI	560.00	503.00	3,854,674	7,515.20	512.92	101.97%
3.	1985	Kewaunee	WI	560.00	503.00	3,699,176	7,214.70	512.73	101.93%
4.	1984	Kewaunee	WI	560.00	503.00	3,810,000	7,528.40	506.08	100.61%
5.	1984	Point Beach #1	WI	524.00	485.00	3,109,208	6,380.00	487.34	100.48%
6.	1983	Kewaunee	WI	560.00	503.00	3,706,928	7,335.80	505.32	100.46%
7.	1985	Point Beach #1	WI	524.00	485.00	3,354,176	6,919.30	484.76	99.95%
8.	1986	Point Beach #1	WI	524.00	485.00	3,770,070	7,787.60	484.11	99.82%
9.	1985	Point Beach #2	WI	524.00	485.00	3,603,081	7,491.30	480.97	99.17%
10.	1985	Palisades	MI	812.00	730.00	5,301,797	7,344.40	721.88	98.89%
11.	1986	Point Beach #2	WI	524.00	485.00	3,417,550	7,188.30	475.43	98.03%
12.	1984	Point Beach #2	WI	524.00	485.00	3,512,373	7,406.60	474.22	97.78%
13.	1983	Point Beach #2	WI	524.00	495.00	3,016,298	6,247.60	482.79	97.53%
14.	1984	Cook #2	MI	1,133.00	1,060.00	5,364,363	5,198.70	1,031.87	97.35%
15.	1983	Cook #2	MI	1,133.00	1,060.00	7,013,579	6,838.40	1,025.62	96.76%
16.	1986	Wolf Creek #1	KS	1,250.00	1,128.00	6,966,063	6,418.50	1,085.31	96.22%
17.	1986	Zion #2	IL	1,098.00	1,040.00	7,334,233	7,372.00	994.88	95.66%
18.	1984	Palisades	MI	812.00	635.00	811,549	1,336.30	607.31	95.64%
19.	1984	Callaway #1	MO	1,188.00	1,120.00	323,023	302.50	1,067.84	95.34%
20.	1986	Big Rock Pt. #1	MI	60.00	64.00	506,148	8,361.70	60.53	94.58%
21.	1985	Wolf Creek #1	KS	1,250.00	1,128.00	2,942,100	2,771.60	1,061.52	94.11%
22.	1984	La Crosse	WI	65.00	48.00	318,604	7,067.30	45.08	93.92%
23.	1984	Zion #2	IL	1,098.00	1,040.00	5,986,311	6,180.00	968.66	93.14%
24.	1983	Zion #2	IL	1,098.00	1,040.00	6,181,965	6,406.60	964.94	92.78%
25.	1984	Cook #1	MI	1,152.00	1,020.00	7,550,755	8,017.80	941.75	92.33%
26.	1983	Cook #1	MI	1,152.00	1,020.00	5,286,839	5,630.80	938.91	92.05%
27.	1985	Cook #2	MI	1,133.00	1,060.00	5,683,634	5,855.00	970.73	91.58%
28.	1985	Callaway #1	MO	1,236.00	1,120.00	8,045,764	7,884.90	1,020.40	91.11%
29.	1984	Zion #1	IL	1,098.00	1,040.00	5,692,090	6,030.40	943.90	90.76%
30.	1985	Zion #1	IL	1,098.00	1,040.00	4,813,949	5,107.40	942.54	90.63%
31.	1984	Dresden #2	IL	828.00	772.00	4,460,360	6,403.70	696.53	90.22%
32.	1986	Callaway #1	MO	1,236.00	1,120.00	7,199,113	7,124.50	1,010.47	90.22%
33.	1985	Lasalle #2	IL	1,078.00	1,036.00	3,430,898	3,699.90	927.29	89.51%
34.	1986	Dresden #2	IL	828.00	772.00	4,648,539	6,763.50	687.30	89.03%
35.	1985	La Crosse	WI	65.00	48.00	322,909	7,597.60	42.50	88.54%
36.	1983	Big Rock Pt. #1	MI	60.00	64.00	348,591	6,222.80	56.02	87.53%
37.	1984	Lasalle #2	IL	1,078.00	1,036.00	1,392,117	1,537.40	905.50	87.40%
38.	1986	Cook #1	MI	1,152.00	1,020.00	6,650,074	7,466.00	890.71	87.32%
39.	1986	Palisades	MI	812.00	730.00	841,244	1,324.40	635.19	87.01%
40.	1983	Dresden #2	IL	828.00	772.00	3,397,514	5,080.30	668.76	86.63%
41.	1986	Zion #1	IL	1,098.00	1,040.00	4,904,664	5,452.00	899.61	86.50%
42.	1984	Big Rock Pt. #1	MI	60.00	70.00	417,523	6,906.20	60.46	86.37%
43.	1985	Dresden #3	IL	828.00	773.00	4,390,064	6,621.30	663.02	85.77%
44.	1985	Dresden #2	IL	828.00	772.00	3,087,488	4,680.40	659.66	85.45%

TABLE 1 (Cont.)

Comparison of Cooper and Duane Arnold Utilization to Utilization of Nuclear Plants in States Adjacent to Iowa for 1983-1986.

Plant No.	Year	Plant Name	State	Total Plant Name Plate (A)	Maximum Dependable Capacity (Net MWe) (B)	Total MWH Generation (C)	Service Hours (D)	Estimated Avg. MW Generated (E)=(C)/(D)	Percentage of Capacity Utilized (F)=(E)/(B)
45.	1986	Lasalle #2	IL	1,078.00	1,036.00	5,717,014	6,534.50	874.90	84.45%
46.	1986	Bryon #1	IL	1,175.00	1,129.00	7,396,003	7,761.30	952.93	84.41%
47.	1983	Dresden #3	IL	828.00	773.00	4,147,939	6,403.10	647.80	83.80%
48.	1986	Lasalle #1	IL	1,078.00	1,036.00	2,018,117	2,331.90	865.44	83.54%
49.	1985	Zion #2	IL	1,098.00	1,040.00	5,114,186	5,901.30	866.62	83.33%
50.	1985	Cook #1	MI	1,152.00	1,020.00	2,116,062	2,491.10	849.45	83.28%
51.	1985	Lasalle #1	IL	1,078.00	1,036.00	4,809,395	5,584.90	861.14	83.12%
52.	1984	Lasalle #1	IL	1,078.00	1,036.00	5,206,209	6,055.00	859.82	82.99%
53.	1984	D.A.E.C.	*	597.15	515.00	2,717,563	6,405.00	424.29	82.39%
54.	1984	Dresden #3	IL	828.00	773.00	2,105,646	3,311.10	635.94	82.27%
55.	1983	D.A.E.C.	*	597.15	515.00	2,324,318	5,508.00	421.99	81.94%
56.	1986	La Crosse	WI	65.00	48.00	157,179	3,998.10	39.31	81.90%
57.	1985	Big Rock Pt. #1	MI	60.00	69.00	362,428	6,441.70	56.26	81.54%
58.	1986	D.A.E.C.	*	597.15	515.00	3,008,073	7,181.00	418.89	81.34%
59.	1986	Cooper	*	836.00	764.00	4,052,138	6,546.20	619.01	81.02%
60.	1983	La Crosse	WI	65.00	48.00	201,267	5,232.60	38.46	80.13%
61.	1985	D.A.E.C.	*	597.15	515.00	1,940,485	4,712.00	411.82	79.96%
62.	1983	Cooper	*	836.00	764.00	3,343,199	5,546.00	602.81	78.90%
63.	1984	Cooper	*	836.00	764.00	3,469,953	5,902.00	587.93	76.95%
64.	1986	Dresden #3	IL	828.00	773.00	1,456,025	2,457.10	592.58	76.66%
65.	1986	Cook #2	MI	1,133.00	1,060.00	4,335,567	5,389.70	804.42	75.89%
66.	1985	Bryon #1	IL	1,175.00	1,129.00	1,012,898	1,192.40	849.46	75.24%
67.	1985	Cooper	*	836.00	764.00	1,067,748	1,885.00	566.44	74.14%
68.	1983	Point Beach #1	WI	524.00	495.00	2,384,844	6,499.20	366.94	74.13%
69.	1983	Zion #1	IL	1,098.00	1,040.00	4,016,176	5,742.20	699.41	67.25%
70.	1983	Lasalle #1	IL	1,078.00	1,036.00	1,639,809	3,085.90	531.39	51.29%
71.	1986	Fermi #2	MI	1,215.00	1,093.00	-23,926	437.70	-54.66	-5.00%
72.	1983	Bryon #1	IL	--	--	--	--	--	--
73.	1984	Bryon #1	IL	--	--	--	--	--	--
74.	1983	Callaway #1	MO	--	--	--	--	--	--
75.	1983	Fermi #2	MI	--	--	--	--	--	--
76.	1984	Fermi #2	MI	--	--	--	--	--	--
77.	1985	Fermi #2	MI	--	--	--	--	--	--
78.	1983	Lasalle #2	IL	--	--	--	--	--	--
79.	1983	Wolf Creek #1	KS	--	--	--	--	--	--
80.	1984	Wolf Creek #1	KS	--	--	--	--	--	--

Note: Information taken from The Licensed Operating Reactors Status Summary Report from the USNRC.

TABLE 2

1983-1986 Est. Average MW Generation and Utilization of Nuclear Plants Participating in Mapp

No.	Year	Plant Name	Total Plant Name Plate (A)	Maximum Dependable Capacity (Net MW) (B)	Total MWH Generation (C)	Service Hours (D)	Estimated Avg. MW Generated (E)=(C)/(D)	Percentage of Capacity Utilized (F)=(E)/(B)
1.	1983	D.A.E.C.	597.15	515.00	2,324,318	5,508.00	421.99	81.94%
1.	1984	D.A.E.C.	597.15	515.00	2,717,563	6,405.00	424.29	82.39%
1.	1985	D.A.E.C.	597.15	515.00	1,940,485	4,712.00	411.82	79.96%
1.	1986	D.A.E.C.	597.15	515.00	3,008,073	7,181.00	418.89	81.34%
2.	1983	Quad Cities #1	828.30	769.00	5,776,352	8,261.00	699.23	90.93%
2.	1984	Quad Cities #1	828.30	769.00	3,349,735	4,687.00	714.69	92.94%
2.	1985	Quad Cities #1	828.30	769.00	6,072,319	8,244.00	736.57	95.78%
2.	1986	Quad Cities #1	828.30	769.00	4,420,669	5,880.00	751.81	97.77%
3.	1983	Quad Cities #2	828.30	769.00	3,151,307	5,622.00	560.53	72.89%
3.	1984	Quad Cities #2	828.30	769.00	4,983,925	6,840.00	728.64	94.75%
3.	1985	Quad Cities #2	828.30	769.00	4,556,866	6,248.00	729.33	94.84%
3.	1986	Quad Cities #2	828.30	769.00	4,722,778	6,401.50	737.76	95.94%
4.	1983	Cooper	836.00	764.00	3,343,199	5,546.00	602.81	78.90%
4.	1984	Cooper	836.00	764.00	3,469,953	5,902.00	587.93	76.95%
4.	1985	Cooper	836.00	764.00	1,067,748	1,885.00	566.44	74.14%
4.	1986	Cooper	836.00	764.00	4,052,138	6,546.20	619.01	81.02%
5.	1983	Monticello	569.00	525.00	4,147,725	8,439.00	491.49	93.62%
5.	1984	Monticello	569.00	525.00	263,119	808.80	325.32	61.97%
5.	1985	Monticello	569.00	536.00	4,286,986	8,030.60	533.83	99.60%
5.	1986	Monticello	569.00	536.00	3,375,350	6,927.10	487.27	90.91%
6.	1983	Prairie Island #1	593.00	503.00	3,888,853	7,624.20	510.07	101.40%
6.	1984	Prairie Island #1	593.00	503.00	4,159,389	8,286.80	501.93	99.79%
6.	1985	Prairie Island #1	593.00	503.00	3,677,016	7,334.60	501.32	99.67%
6.	1986	Prairie Island #1	593.00	503.00	3,819,563	7,871.30	485.25	96.47%
7.	1983	Prairie Island #2	593.00	500.00	3,716,220	7,578.10	490.39	98.08%
7.	1984	Prairie Island #2	593.00	500.00	3,905,956	7,831.10	498.77	99.75%
7.	1985	Prairie Island #2	593.00	500.00	3,608,478	7,378.20	489.07	97.81%
7.	1986	Prairie Island #2	593.00	500.00	3,860,117	7,932.30	486.63	97.33%
8.	1983	Fort Calhoun #1	502.00	438.00	2,749,832	6,405.00	429.33	98.02%
8.	1984	Fort Calhoun #1	502.00	478.00	2,331,771	5,264.90	442.89	92.65%
8.	1985	Fort Calhoun #1	502.00	478.00	3,066,254	6,455.50	474.98	99.37%
8.	1986	Fort Calhoun #1	502.00	478.00	3,605,563	8,264.20	436.29	91.27%
9.	1983	Total MAPP	5,346.75	4,783.00	29,097,806	54,983.30		
9.	1984	Total MAPP	5,346.75	4,823.00	25,181,411	46,025.60		
9.	1985	Total MAPP	5,346.75	4,834.00	28,276,152	50,287.90		
9.	1986	Total MAPP	5,346.75	4,834.00	30,864,251	57,003.60		

Note: Information taken from The Licensed Operating Reactors Status Summary Report from the USNRC. Northwest Power Cooperative has Genoa #2 listed as a nuclear plant in the 1986 MAPP Load and Capacity Report, but Genoa was not listed in the The Licensed Operating Reactors Status Summary Report for 1983-1986.

TABLE 3

1986 ESTIMATED AVERAGE MW GENERATION AND UTILIZATION OF NUCLEAR PLANTS - SORTED BY UTILIZATION PERCENTAGE

No.	Plant Name	State Location	Total Plant Name Plate (A)	Maximum Dependable Capacity (Net MWe) (B)	Total MWH Generation (C)	Service Hours (D)	Estimated Avg. MW Generated (E)=(C)/(D)	Percent of Capacity Utilized (F)=(E)/(B)
1.	Calvert Cliffs #1	Maryland	918.00	825.00	5,830,738	6,856.40	850.41	103.08%
2.	Robinson #2	South Carolina	769.00	665.00	4,798,026	7,030.10	682.50	102.63%
3.	Kewaunee	Wisconsin	560.00	503.00	3,854,674	7,515.20	512.92	101.97%
4.	Calvert Cliffs #2	Maryland	911.00	825.00	7,006,666	8,408.70	833.26	101.00%
5.	St. Lucie #2	Florida	850.00	839.00	6,146,561	7,255.50	847.16	100.97%
6.	St. Lucie #1	Florida	890.00	839.00	7,052,031	8,353.60	844.19	100.62%
7.	Ginna	New York	517.00	470.00	3,610,266	7,659.90	471.32	100.28%
8.	Yankee-Rowe #1	Massachusetts	185.00	167.00	1,392,716	8,322.30	167.35	100.21%
9.	Maine Yankee	Maine	864.00	810.00	6,241,756	7,694.80	811.17	100.14%
10.	Three Mile Island #1	Pennsylvania	871.00	776.00	4,818,263	6,212.30	775.60	99.95%
11.	Point Beach #1	Wisconsin	524.00	485.00	3,770,070	7,787.60	484.11	99.82%
12.	Turkey Point #3	Florida	760.00	666.00	4,513,059	6,820.50	661.69	99.35%
13.	Palo Verde #2	Arizona	1,403.00	1,221.00	2,654,603	2,195.00	1,209.39	99.05%
14.	Arkansas #2	Arkansas	943.00	858.00	5,305,213	6,276.00	845.32	98.52%
15.	Millstone #1	Connecticut	662.00	654.00	5,247,940	8,176.20	641.86	98.14%
16.	Waterford #3	Louisiana	1,153.00	1,075.00	7,301,595	6,924.80	1,054.41	98.08%
17.	Point Beach #2	Wisconsin	524.00	485.00	3,417,550	7,188.30	475.43	98.03%
18.	Limerick #1	Pennsylvania	1,138.00	1,055.00	6,848,850	6,636.00	1,032.08	97.83%
19.	Prairie Island #2	Minnesota	593.00	500.00	3,860,117	7,932.30	486.63	97.33%
20.	Farley #2	Alabama	860.00	824.00	5,959,872	7,458.30	799.09	96.98%
21.	Summer #1	South Carolina	900.00	885.00	7,160,639	8,350.90	857.47	96.89%
22.	Prairie Island #1	Minnesota	593.00	503.00	3,819,563	7,871.30	485.25	96.47%
23.	Mcguire #2	North Carolina	1,305.00	1,150.00	6,209,772	5,604.60	1,107.98	96.35%
24.	Wolf Creek #1	Kansas	1,250.00	1,128.00	6,966,063	6,418.50	1,085.31	96.22%
25.	Farley #1	Alabama	860.00	825.00	5,726,616	7,216.80	793.51	96.18%
26.	Palo Verde #1	Arizona	1,403.00	1,221.00	5,851,048	4,988.80	1,172.84	96.06%
27.	Quad Cities #2	Illinois	828.00	769.00	4,722,778	6,401.50	737.76	95.94%
28.	Millstone #3	Connecticut	1,253.00	1,142.00	5,861,760	5,355.90	1,094.45	95.84%
29.	Zion #2	Illinois	1,098.00	1,040.00	7,334,233	7,372.00	994.88	95.66%
30.	Surry #1	Virginia	848.00	781.00	4,488,628	6,015.80	746.14	95.54%
31.	Fitzpatrick	New York	883.00	794.00	6,015,605	7,932.20	758.38	95.51%
32.	Vermont Yankee #1	Vermont	563.00	504.00	2,058,426	4,281.20	480.81	95.40%
33.	Quad Cities #1	Illinois	828.00	769.00	4,420,669	6,037.10	732.25	95.22%
34.	Beaver Valley #1	Pennsylvania	923.00	810.00	4,778,500	6,196.50	771.16	95.21%
35.	San Onofre #2	California	1,127.00	1,070.00	6,361,900	6,267.70	1,015.03	94.86%
36.	Surry #2	Virginia	848.00	781.00	4,498,941	6,075.00	740.57	94.82%
37.	Millstone #2	Connecticut	910.00	857.00	5,160,945	6,354.20	812.21	94.77%
38.	Oconee #1	South Carolina	934.00	860.00	4,784,795	5,872.60	814.77	94.74%
39.	Oconee #2	South Carolina	934.00	860.00	5,801,065	7,124.50	814.24	94.68%
40.	Trojan	Oregon	1,216.00	1,075.00	7,090,231	6,985.30	1,015.02	94.42%
41.	Susquehanna #1	Pennsylvania	1,152.00	1,032.00	5,830,291	5,995.20	972.49	94.23%
42.	Hatch #1	Georgia	850.00	750.00	3,645,387	5,164.40	705.87	94.12%
43.	North Anna #1	Virginia	947.00	915.00	6,310,739	7,330.90	860.84	94.08%
44.	Brunswick #1	North Carolina	867.00	790.00	5,973,813	8,069.90	740.26	93.70%
45.	Peach Bottom #2	Pennsylvania	1,152.00	1,051.00	6,896,565	7,014.00	983.26	93.55%
46.	Pilgrim #1	Massachusetts	678.00	670.00	1,027,531	1,646.00	624.26	93.17%
47.	Turkey Point #4	Florida	760.00	666.00	1,721,504	2,792.10	616.56	92.58%
48.	Salem #1	New Jersey	1,170.00	1,106.00	7,079,276	6,923.80	1,022.46	92.45%
49.	Susquehanna #2	Pennsylvania	1,152.00	1,032.00	5,448,219	5,734.20	950.13	92.07%
50.	Brunswick #2	North Carolina	867.00	790.00	2,911,036	4,029.60	722.41	91.44%
51.	Mcguire #1	North Carolina	1,305.00	1,150.00	5,164,769	4,916.00	1,050.60	91.36%
52.	North Anna #2	Virginia	947.00	915.00	6,022,050	7,210.50	835.18	91.28%
53.	Fort Calhoun #1	Nebraska	502.00	478.00	3,605,563	8,264.20	436.29	91.27%
54.	Indian Point #2	New York	1,013.00	849.00	3,810,597	4,926.80	773.44	91.10%
55.	Monticello	Minnesota	569.00	536.00	3,375,350	6,927.10	487.27	90.91%
56.	Oyster Creek #1	New Jersey	674.00	620.00	1,301,476	2,310.90	563.19	90.84%
57.	Oconee #3	South Carolina	934.00	860.00	6,064,306	7,782.80	779.19	90.60%
58.	Callaway #1	Missouri	1,236.00	1,120.00	7,199,113	7,124.50	1,010.47	90.22%

Note: Information taken from The Licensed Operating Reactors Status Summary Report from USNRC.

TABLE 3 (Cont.)

1986 ESTIMATED AVERAGE MW GENERATION AND UTILIZATION OF NUCLEAR PLANTS – SORTED BY UTILIZATION PERCENTAGE

No.	Plant Name	State Location	Total Plant Name Plate (A)	Maximum Dependable Capacity (Net MWe) (B)	Total MWH Generation (C)	Service Hours (D)	Estimated Avg. MW Generated (E)=(C)/(D)	Percent of Capacity Utilized (F)=(E)/(B)
59.	Diablo Canyon #2	California	1,164.00	1,079.00	6,548,174	6,730.50	972.91	90.17%
60.	Nine Mile Point #1	New York	642.00	610.00	3,146,883	5,724.10	549.76	90.12%
61.	Dresden #2	Illinois	828.00	772.00	4,648,539	6,763.50	687.30	89.03%
62.	Salem #2	New Jersey	1,162.00	1,106.00	5,312,561	5,416.90	980.74	88.67%
63.	San Onofre #3	California	1,127.00	1,080.00	6,760,591	7,070.80	956.13	88.53%
64.	Crystal River #3	Florida	890.00	821.00	2,653,212	3,661.30	724.66	88.27%
65.	Catawba #1	South Carolina	1,305.00	1,145.00	5,182,492	5,155.00	1,005.33	87.80%
66.	Big Rock Point #1	Michigan	60.00	69.00	506,148	8,361.70	60.53	87.73%
67.	Cook #1	Michigan	1,152.00	1,020.00	6,650,074	7,466.00	890.71	87.32%
68.	Palisades	Michigan	812.00	730.00	841,244	1,324.40	635.19	87.01%
69.	Zion #1	Illinois	1,098.00	1,040.00	4,904,664	5,452.00	899.61	86.50%
70.	Indian Point #3	New York	1,013.00	1,000.00	5,525,581	6,432.40	859.02	85.90%
71.	Diablo Canyon #1	California	1,137.00	1,073.00	5,293,267	5,758.20	919.26	85.67%
72.	Catawba #2	South Carolina	1,305.00	1,145.00	1,297,202	1,325.80	978.43	85.45%
73.	Peach Bottom #3	Pennsylvania	1,152.00	1,035.00	4,849,352	5,545.30	874.50	84.49%
74.	Lasalle #2	Illinois	1,078.00	1,036.00	5,717,014	6,534.50	874.90	84.45%
75.	Bryon #1	Illinois	1,175.00	1,129.00	7,396,003	7,761.30	952.93	84.41%
76.	Lasalle #1	Illinois	1,078.00	1,036.00	2,018,117	2,331.90	865.44	83.54%
77.	La Crosse	Wisconsin	65.00	48.00	157,179	3,998.10	39.31	81.90%
78.	Duane Arnold	Iowa	597.00	515.00	3,008,073	7,181.10	418.89	81.34%
79.	Cooper Station	Nebraska	836.00	764.00	4,052,138	6,546.20	619.01	81.02%
80.	Haddam Neck	Connecticut	600.00	569.00	2,132,316	4,698.90	453.79	79.75%
81.	Arkansas #1	Arkansas	903.00	836.00	3,573,159	5,447.70	655.90	78.46%
82.	Washington Nuc. #2	Washington	1,201.00	1,095.00	5,183,198	6,134.40	844.94	77.16%
83.	Hatch #2	Georgia	850.00	761.00	3,618,712	6,172.70	586.24	77.04%
84.	Dresden #3	Illinois	828.00	773.00	1,456,025	2,457.10	592.58	76.66%
85.	Cook #2	Michigan	1,133.00	1,060.00	4,335,567	5,389.70	804.42	75.89%
86.	River Bend #1	Louisiana	990.00	936.00	2,995,439	4,225.70	708.86	75.73%
87.	San Onofre #1	California	450.00	436.00	874,187	2,731.50	320.04	73.40%
88.	Grand Gulf #1	Mississippi	1,373.00	1,142.00	4,098,054	5,330.50	768.79	67.32%
89.	Hope Creek #1	New Jersey	1,118.00	1,067.00	1,030,793	1,679.00	613.93	57.54%
90.	Fort St. Vrain	Colorado	343.00	330.00	52,007	1,087.10	47.84	14.50%
91.	Davis-Besse #1	Ohio	962.00	860.00	3,486	116.60	29.90	3.48%
92.	Browns Ferry #1	Alabama	1,152.00	1,065.00	-36,374	0.00	0.00	0.00%
93.	Browns Ferry #2	Alabama	1,152.00	1,065.00	-47,061	0.00	0.00	0.00%
94.	Browns Ferry #3	Alabama	1,152.00	1,065.00	-41,625	0.00	0.00	0.00%
95.	Fermi #2	Michigan	1,215.00	1,093.00	-23,916	437.70	0.00	0.00%
96.	Rancho Seco #1	California	963.00	873.00	-32,157	0.00	0.00	0.00%
97.	Sequoyah #1	Tennessee	1,220.00	1,148.00	-40,178	0.00	0.00	0.00%
98.	Sequoyah #2	Tennessee	1,220.00	1,148.00	-64,434	0.00	0.00	0.00%
	Total		90,675.00	83,271.00	407,666,034	538,038.70		

Note: Information taken from The Licensed Operating Reactors Status Summary Report from USNRC.

TABLE 4

1987 ESTIMATED AVERAGE MW GENERATION AND UTILIZATION OF NUCLEAR PLANTS – SORTED BY UTILIZATION PERCENTAGE

No	Plant Name	State Location	Total Plant Name Plate (A)	Maximum Dependable Capacity (Net MWe) (B)	Total MWH Generation (C)	Service Hours (D)	Estimated Avg. MW Generated (E)=(C)/(D)	Percent of Capacity Utilized (F)=(E)/(B)
1.	Calvert Cliffs #1	Maryland	918.00	825.00	5,268,477	6,237.00	844.71	102.39%
2.	Robinson #2	South Carolina	769.00	665.00	4,230,329	6,226.30	679.43	102.17%
3.	Three Mile Island #1	Pennsylvania	871.00	776.00	5,034,307	6,353.60	792.36	102.11%
4.	Kewaunee	Wisconsin	560.00	503.00	4,008,624	7,811.00	513.20	102.03%
5.	Prairie Island #2	Minnesota	593.00	500.00	4,429,989	8,760.00	505.71	101.14%
6.	Ginna	New York	517.00	470.00	3,797,701	7,994.00	475.07	101.08%
7.	Arkansas #2	Arkansas	943.00	858.00	6,605,168	7,681.70	859.86	100.22%
8.	Point Beach #1	Wisconsin	524.00	485.00	3,567,092	7,350.30	485.30	100.06%
9.	St. Lucie #1	Florida	890.00	839.00	5,715,344	6,814.10	838.75	99.97%
10.	Calvert Cliffs #2	Maryland	911.00	825.00	4,831,976	5,861.60	824.34	99.92%
11.	San Onofre #3	California	1,127.00	1,080.00	7,519,728	6,987.80	1,076.12	99.64%
12.	Point Beach #2	Wisconsin	524.00	485.00	3,606,145	7,481.10	482.03	99.39%
13.	Susquehanna #2	Pennsylvania	1,152.00	1,032.00	8,598,435	8,431.60	1,019.79	98.82%
14.	Prairie Island #1	Minnesota	593.00	503.00	3,590,268	7,234.20	496.29	98.67%
15.	St. Lucie #2	Florida	850.00	839.00	5,950,184	7,209.70	825.30	98.37%
16.	Millstone #2	Connecticut	910.00	857.00	6,892,531	8,180.10	842.60	98.32%
17.	Millstone #1	Connecticut	662.00	654.00	4,377,008	6,827.10	641.12	98.03%
18.	Fort Calhoun #1	Nebraska	502.00	478.00	3,060,620	6,531.70	468.58	98.03%
19.	Palo Verde #2	Arizona	1,403.00	1,221.00	8,190,044	6,858.20	1,194.20	97.80%
20.	Waterford #3	Louisiana	1,153.00	1,075.00	7,425,710	7,087.80	1,047.67	97.46%
21.	Oconee #3	South Carolina	934.00	860.00	5,084,967	6,069.90	837.73	97.41%
22.	Surry #1	Virginia	848.00	781.00	4,633,405	6,116.90	757.48	96.99%
23.	Vermont Yankee #1	Vermont	563.00	504.00	3,536,411	7,290.60	485.06	96.24%
24.	Hatch #1	Georgia	850.00	750.00	5,076,654	7,046.00	720.50	96.07%
25.	San Onofre #2	California	1,127.00	1,070.00	6,230,341	6,068.30	1,026.70	95.95%
26.	Wolf Creek #1	Kansas	1,250.00	1,128.00	6,504,145	6,013.00	1,081.68	95.89%
27.	Palo Verde #1	Arizona	1,403.00	1,221.00	5,268,268	4,504.50	1,169.56	95.79%
28.	Yankee-Rowe #1	Massachusetts	185.00	167.00	1,135,611	7,100.70	159.93	95.77%
29.	Indian Point #2	New York	1,013.00	849.00	5,146,333	6,333.00	812.62	95.72%
30.	Grand Gulf #1	Mississippi	1,373.00	1,142.00	7,726,991	7,100.00	1,088.31	95.30%
31.	Farley #1	Alabama	860.00	825.00	6,444,862	8,203.10	785.66	95.23%
32.	Mcguire #1	North Carolina	1,305.00	1,150.00	7,348,715	6,715.80	1,094.24	95.15%
33.	Surry #2	Virginia	848.00	781.00	4,790,953	6,457.90	741.87	94.99%
34.	Summer #1	South Carolina	900.00	885.00	5,151,897	6,136.90	839.50	94.86%
35.	Beaver Valley #1	Pennsylvania	923.00	810.00	5,620,890	7,322.90	767.58	94.76%
36.	Millstone #3	Connecticut	1,253.00	1,142.00	6,742,317	6,234.60	1,081.44	94.70%
37.	Mcguire #2	North Carolina	1,305.00	1,150.00	7,572,577	6,957.10	1,088.47	94.65%
38.	Haddam Neck	Connecticut	600.00	569.00	2,527,207	4,700.50	537.65	94.49%
39.	Quad Cities #1	Illinois	828.00	769.00	4,456,087	6,141.70	725.55	94.35%
40.	Quad Cities #2	Illinois	828.00	769.00	4,952,988	6,836.20	724.52	94.22%
41.	Catawba #1	South Carolina	1,305.00	1,145.00	6,377,839	5,928.60	1,075.77	93.95%
42.	Susquehanna #1	Pennsylvania	1,152.00	1,032.00	6,127,879	6,333.00	967.61	93.76%
43.	Monticello	Minnesota	569.00	536.00	3,533,357	7,052.90	500.98	93.47%
44.	Lasalle #2	Illinois	1,078.00	1,036.00	4,542,494	4,700.20	966.45	93.29%
45.	Nine Mile Point #1	New York	642.00	610.00	4,615,169	8,130.50	567.64	93.06%
46.	Farley #2	Alabama	860.00	824.00	4,902,626	6,397.80	766.30	93.00%
47.	Diablo Canyon #1	California	1,137.00	1,073.00	8,284,201	8,342.80	992.98	92.54%
48.	Oyster Creek #1	New Jersey	674.00	620.00	3,110,919	5,422.90	573.66	92.53%
49.	Vogtle #1	Georgia	1,157.00	1,084.00	3,921,520	3,920.40	1,000.29	92.28%
50.	Maine Yankee	Maine	864.00	810.00	4,042,901	5,415.40	746.56	92.17%
51.	Diablo Canyon #2	California	1,164.00	1,079.00	5,715,218	5,754.50	993.17	92.05%
52.	Callaway #1	Missouri	1,236.00	1,120.00	6,321,776	6,143.90	1,028.95	91.87%
53.	Turkey Point #4	Florida	760.00	666.00	2,636,070	4,318.90	610.36	91.65%
54.	Hope Creek #1	New Jersey	1,118.00	1,067.00	7,277,090	7,457.10	975.86	91.46%
55.	Zion #2	Illinois	1,098.00	1,040.00	5,114,145	5,384.50	949.79	91.33%
56.	North Anna #2	Virginia	947.00	915.00	5,653,448	6,785.50	833.17	91.06%
57.	Harris #1	North Carolina	950.00	860.00	3,378,829	4,323.60	781.49	90.87%
58.	River Bend #1	Louisiana	990.00	936.00	4,964,440	5,837.70	850.41	90.86%
59.	Brunswick #1	North Carolina	867.00	790.00	4,046,631	5,652.30	715.93	90.62%

Note: Information taken from The Licensed Operating Reactors Status Summary Report from USNRC.

TABLE 4 (Cont.)

1987 ESTIMATED AVERAGE MW GENERATION AND UTILIZATION OF NUCLEAR PLANTS – SORTED BY UTILIZATION PERCENTAGE

No.	Plant Name	State Location	Total Plant Name Plate (A)	Maximum Dependable Capacity (Net MWe) (B)	Total MWH Generation (C)	Service Hours (D)	Estimated Avg. MW Generated (E)=(C)/(D)	Percent of Capacity Utilized (F)=(E)/(B)
60.	Palisades	Michigan	812.00	730.00	2,634,430	3,983.10	661.40	90.60%
61.	Hatch #2	Georgia	850.00	761.00	5,755,607	8,390.40	685.98	90.14%
62.	Zion #1	Illinois	1,098.00	1,040.00	6,058,385	6,482.40	934.59	89.86%
63.	Indian Point #3	New York	1,013.00	1,000.00	4,850,586	5,399.90	898.27	89.83%
64.	Fitzpatrick	New York	883 00	794.00	4,198,340	5,894.80	712.21	89.70%
65.	Duane Arnold	Iowa	597.00	515 00	2,540,837	5,514.80	460.73	89.46%
66.	Catawba #2	South Carolina	1,305.00	1,145 00	7,169,495	7,019.00	1,021.44	89.21%
67.	Perry #1	Ohio	1,250.00	1,205.00	828,484	773.40	1,071.22	88.90%
68.	Big Rock Point #1	Michigan	60.00	69.00	374,931	6,132.20	61.14	88.61%
69.	Salem #1	New Jersey	1,170.00	1,106.00	6,211,441	6,363.20	976.15	88.26%
70.	Salem #2	New Jersey	1,162.00	1,106.00	6,172,052	6,343.40	972.99	87.97%
71.	Brunswick #2	North Carolina	867.00	790.00	5,694,104	8,205.80	693.91	87.84%
72.	Beaver Valley #2	Pennsylvania	923.00	885.00	738,104	949.80	777.12	87.81%
73.	Oconee #1	South Carolina	934.00	860.00	5,028,061	6,694.70	751.05	87.33%
74.	Trojan	Oregon	1,216.00	1,075.00	4,347,772	4,631.60	938.72	87.32%
75.	Cooper Station	Nebraska	836.00	764.00	5,522,126	8,292.40	665.93	87.16%
76.	Dresden #3	Illinois	828.00	773.00	4,395,502	6,595.70	666.42	86.21%
77.	North Anna #1	Virginia	947.00	915.00	3,568,907	4,525.50	788.62	86.19%
78.	Peach Bottom #2	Pennsylvania	1,152.00	1,051.00	1,552,256	1,724.00	900.38	85.67%
79.	Limerick #1	Pennsylvania	1,138.00	1,055.00	5,318,987	5,926.70	897.46	85.07%
80.	Peach Bottom #3	Pennsylvania	1,152.00	1,035.00	1,460,062	1,659.60	879.77	85.00%
81.	San Onofre #1	California	450.00	436 00	2,708,001	7,323.40	369.77	84.81%
82.	Oconee #2	South Carolina	934.00	860 00	6,228,692	8,567.10	727.05	84.54%
83.	Crystal River #3	Florida	890.00	821 00	3,620,784	5,263.80	687.87	83.78%
84.	Cook #1	Michigan	1,152.00	1,020.00	5,033,767	5,918.80	850.47	83.38%
85.	Washington Nuc. #2	Washington	1,201.00	1,095.00	5,397,981	5,981.00	902.52	82.42%
86.	Turkey Point #3	Florida	760.00	666.00	856,146	1,567.70	546.12	82.00%
87.	Clinton #1	Illinois	NA	933.00	684,103	898 30	761.55	81.62%
88.	Dresden #2	Illinois	828.00	772.00	3,342,347	5,345.30	625.29	81.00%
89.	Davis-Besse #1	Ohio	962.00	860.00	5,063,984	7,312.40	692.52	80.53%
90.	Bryon #1	Illinois	1,175.00	1,129 00	5,330,576	6,007.30	887.35	78.60%
91.	Bryon #2	Illinois	1,175.00	1,120.00	1,970,901	2,280.40	864.28	77.17%
92.	Cook #2	Michigan	1,133.00	1,060.00	5,026,564	6,251.60	804.04	75.85%
93.	Arkansas #1	Arkansas	903.00	836.00	4,763,342	7,723.10	616.77	73.78%
94.	Lasalle #1	Illinois	1,078.00	1,036.00	4,073,067	5,456.80	746.42	72.05%
95.	Braidwood #1	Illinois	NA	1,120.00	1,456,651	2,610.70	557.95	49.82%
96.	Palo Verde #3	Arizona	1,403.00	1,221.00	319,661	620.70	515.00	42.18%
97.	Fermi #2	Michigan	1,215.00	1,093.00	1,392,801	4,084.20	341.02	31.20%
98.	Fort St. Vrain	Colorado	343.00	330.00	180,922	2,030.40	89.11	27.00%
99.	Nine Mile Point #2	New York	1,214.00	1,080.00	260,995	1,059.00	246.45	22.82%
100.	Browns Ferry #1	Alabama	1,152.00	1,065.00	-12,718	0.00	0.00	0.00%
101.	Browns Ferry #2	Alabama	1,152.00	1,065.00	-34,470	0.00	0.00	0.00%
102.	Browns Ferry #3	Alabama	1,152.00	1,065.00	-50,980	0.00	0.00	0.00%
103.	Pilgrim #1	Massachusetts	678.00	670.00	0	0.00	0.00	0 00%
104.	Rancho Seco #1	California	963.00	873.00	-56,759	0.00	0.00	0.00%
105.	Sequoyah #1	Tennessee	1,220.00	1,148.00	-48,236	0.00	0.00	0 00%
106.	Sequoyah #2	Tennessee	1,220 00	1,148 00	-59,378	0 00	0.00	0.00%
	Total		98,682.00	92,731 00	449,087,064	584,375 40		

Note: Information taken from The Licensed Operating Reactors Status Summary Report from USNRC.

END NOTES

1 Tables 1 and 2 are drawn from a report authored by Shari Cameron of Utilities Division, Department of Commerce, State of Iowa. A full reference appears in the Bibliography. Tables 3 and 4 were prepared by Leighann O'Tool of the Utilities Division, Department of Commerce, State of Iowa.

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