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June 27, 2002

IN REPLY REFER TO:

Ansley Watson, Jr.
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BY HAND DELIVERY

Blanca S. Bayo, Director
Division of Commission Clerk & Administrative Services
Florida Public Service Commission
Capital Circle Office Center
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399-0850

Re: Docket No. 020384-GU -- Application for a rate increase by Tampa Electric Company d/b/a PEOPLES GAS SYSTEM

Dear Ms. Bayo:

Enclosed herewith for filing in the above docket on behalf of Peoples Gas System, please find:

1. The original and 20 copies of Peoples' Petition for Authority to Increase its Rates and Charges. 06616-02

2. 20 copies of new rate schedules (and other tariff modifications), pursuant to Section 366.06(4), *Florida Statutes*. 06617-02

3. The original and 20 copies of Peoples' Petition for Interim Rate Relief under Section 366.071, *Florida Statutes*. 06618-02

4. 20 copies of the natural gas utility Minimum Filing Requirements ("MFRs") required by the Commission's Rule 25-7.039, each set consisting of two volumes. One of the volumes contains the proposed new tariff sheets in legislative form, and the other contains the remainder of the MFRs.

06619-02
06620-02

AUS Vandiver
CAF
CMP
COM 3 + orig. transmittal
CTR
ECR
GCL 2
OPC 1
MMS
SEC 1
OTH

RECEIVED & FILED
KKM
FPSC-BUREAU OF RECORDS

5. 20 copies of books containing the direct testimony and exhibit(s) of Francis J. Sivard, Bruce Narzissenfeld, J. Paul Higgins, Roger H. Morin, Ph.D., and Wraye J. Grimard, on behalf of the Company. 06621-02

6. A computer diskette containing the Petitions referenced in paragraphs 1 (minus Exhibit B thereto) and 3 above in Microsoft Word format.

Please acknowledge your receipt and the date of filing of the items referenced above on the duplicate copy of this letter, and return the same to Mrs. Wraye Grimard of Peoples Gas System, who will be delivering this letter and the enclosures to you for filing.

Thank you for your usual assistance.

Sincerely,

Ansley Watson, Jr.

ANSLEY WATSON, JR.

AWjr/a
Enclosures

cc: Ms. Angela Llewellyn
Matthew R. Costa, Esquire

PEOPLES GAS SYSTEM

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

Docket No. 020384-GU

In Re: Petition of Peoples Gas System, For Authority to Increase Its Rates and Charges

Submitted for Filing:
6/27/2002

DIRECT TESTIMONY AND EXHIBIT OF:

FRANCIS J. SIVARD
On Behalf of Peoples Gas System

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Francis J. Sivard and my business address is 702 N. Franklin Street, Tampa, Florida 33602.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by Peoples Gas System ("Peoples" or the "Company") as Vice President, Accounting and Regulatory.

Q. HOW LONG HAVE YOU BEEN EMPLOYED BY PEOPLES?

A. I have been employed by Peoples since May 1973. At that time the name of the company was Peoples Gas System, Inc. I served as a staff accountant until 1975 when I was appointed Manager, Corporate Accounting. In June 1982, I was elected Controller, and served in that capacity until March 1985, when I was elected Vice President, Accounting. I retained that position after the merger of Peoples Gas System, Inc. into Tampa Electric Company in mid-June 1997, at which time Peoples became a division of Tampa Electric Company. I assumed the added duties associated with regulatory affairs in 2001.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to explain generally why the Company is seeking an increase in base rates at this time. I will describe some of the more significant factors that have contributed to the Company's decision to seek rate relief, as well as some of the specific actions the Company has taken to avoid having to do so. I will also identify the individuals who are providing detailed support for the rate relief requested.

Q. HAVE YOU PREPARED OR CAUSED TO BE PREPARED AN EXHIBIT TO BE INTRODUCED IN THIS PROCEEDING?

A. Yes. Exhibit FJS-1, which is attached to this testimony, was prepared under my supervision.

Q. PLEASE DESCRIBE THE COMPANY, ITS ORGANIZATIONAL STRUCTURE, AND THE TERRITORY IT SERVES.

A. Peoples provides natural gas service to residential, commercial and industrial users through distribution systems located in 15 separate geographical areas within the State of Florida. These geographic areas are divided into four "Regions" that serve franchised areas, as well as adjacent non-franchised areas, through delivery facilities common to both. The Regions are currently structured as follows:

South Region consisting primarily of North Miami, Miami, Palm Beach, and Southwest Florida.

Tampa Bay Region consisting primarily of Tampa, St. Petersburg, and Sarasota.

Central Region consisting primarily of Orlando, Eustis, Lakeland, Daytona, and Avon Park.

North Region consisting primarily of Jacksonville, Panama City and Ocala.

Each of these Regions is under the administration of a General Manager who is responsible for all operations within the Region. Company headquarters, located in Tampa, includes corporate offices and staff, as well as support services for the Regions.

As the Florida Public Service Commission (the "Commission") is aware, effective June 30, 1997, Peoples acquired, via merger, the former West Florida Natural Gas Company ("West Florida"). The transaction was accounted for as a pooling of interests. The natural gas distribution operations of West Florida were located in the Panama City and Ocala areas. Upon the acquisition of the West Florida properties, Peoples' area of operations expanded to include all of that territory. Pursuant to the Commission's rules, the service rates applicable in the areas served by the distribution properties acquired from West Florida remained unchanged. Thus, at present, customers in Peoples' "old" service area are served under Peoples' rates which were established in Peoples' last rate case. Customers in the areas formerly served by West Florida currently receive gas service under service rates established in West Florida's last rate proceeding. The Company seeks in this proceeding to make uniform the rates applicable to service in all of the areas in which it provides service.

Peoples currently operates the largest natural gas distribution system in the State of Florida, serving customers at approximately 273,000 locations as of December 2001. Of this total, approximately 245,000 are residential and 28,000 are commercial or industrial customers. During the year ended December 31, 2001, Peoples sold 58,843,000 therms to residential customers, and sold or transported 1,058,817,000 therms to commercial and industrial customers, for a total system throughput of 1,117,660,000 therms.

Q. PLEASE DESCRIBE WHAT CHANGES HAVE OCCURRED AS A RESULT OF PEOPLES' MERGER WITH TAMPA ELECTRIC COMPANY.

A. Operationally very few changes have occurred as a result of Peoples' merger with Tampa Electric. The ownership of the Company changed, but

Peoples continues to operate as a stand-alone company, separate and apart from Tampa Electric. Tampa Electric operates only in the Tampa Bay area, whereas Peoples operates throughout the State, making consolidation of field operations impractical. The Company has taken advantage of synergies in areas where service territories overlap, such as contracting with Tampa Electric for meter reading services in the Tampa Bay area. More synergies were realized in the area of corporate overhead services where we share services with Tampa Electric (as well as TECO Energy) in areas such as information technology, tax, insurance, and cash management. Many of these synergies are reflected in various schedules of the Minimum Filing Requirements ("MFRs") and in the testimony of other witnesses.

Q. HOW MANY AND WHAT TYPES OF CUSTOMERS WERE ADDED TO PEOPLES' SYTEM DURING 2001?

A. During this period we added a total of 20,107 new customers of which 18,207 were residential and 1,900 were commercial and industrial.

Q. WAS PEOPLES REQUIRED TO MAKE ANY CAPITAL EXPENDITURES TO ADD THESE CUSTOMERS?

A. Yes. Capital expenditures for 2001 were $73 million, of which approximately $54 million was spent to construct revenue producing facilities to serve new customers or to accommodate increased uses by existing customers. This included construction of mains and services, together with installation of metering and pressure regulation stations, control equipment, corrosion prevention systems, and other appurtenances. Another $10 million of the total capital expenditures during 2001 was invested in replacement of mains and services for improvement of the distribution systems, including relocations and replacements to accommodate municipal, state and federal road construction. Capital expenditures of this nature are required annually to assure adequate and efficient service for Peoples' customers and to assure compliance with this Commission's rules.

The remaining funds, $9 million were required for replacement of vehicles and transportation equipment, improvements to structures, new computer systems, and communication, office, shop and garage equipment.

Q. WILL SIMILAR CAPITAL EXPENDITURES BE REQUIRED IN FUTURE YEARS?

A. Most definitely. Our continuing efforts to market more high priority gas throughout our system, as well as to add additional industrial volume, will necessitate that Peoples expand, maintain and upgrade its facilities to assure that it continues to provide reasonably adequate and efficient service for customers.

Q. WHAT ARE THE COMPANY'S PROJECTED CAPITAL EXPENDITURES FOR 2002?

A. Our capital expenditure budget for 2002 totals $62.4 million and includes $43.2 million for revenue producing facilities, $10.3 million for replacement of mains and services and improvement of the distribution system, and $8.9 million for replacement of vehicles and equipment and replacement of or improvements to structures.

Q. PLEASE QUANTIFY THE COMPANY'S PROJECTED CAPITAL

EXPENDITURES FOR 2003.

A. Our plans for 2003 total $61.9 million of which $43.0 million is for facilities to serve new customers or accommodate increased uses by existing customers. In addition, we plan to spend $10.7 million for replacement of mains and services and improvement of the distribution systems, and another $8.2 million for replacement vehicles and equipment and for replacement of or improvements to structures, and communication, office, shop and garage equipment.

Q. WHY IS IT NECESSARY FOR PEOPLES TO SEEK RATE RELIEF AT THIS TIME?

A. Peoples' last rate case (Docket No. 911150-GU) was filed in January 1992. The final order (Commission Order No. PSC-92-0924-FOF-GU) was issued on September 3, 1992. In that docket, the Commission authorized the Company to revise its rates and charges so as to produce an overall return on equity within the range of 11% to 13%, with a midpoint of 12%. Subsequent to this order, the Company and the Commission reached an agreement to reduce the authorized return on equity to a range of 10.25% to 12.25%, with a midpoint of 11.25%, to be "...more reflective of current market conditions" (Docket No. 931101-GU). The Company is currently earning a return on equity which is deteriorating monthly. The Company's adjusted return on equity as of December 31, 2001 was 9.51%. Based on the Company's projections, the return on equity is expected to drop to approximately 7.74% by December 31, 2002. Without rate relief, the adjusted return on equity for 2003 is expected to drop further to 6.72%.

In the 10 years since Peoples' last rate case, a number of factors have contributed to the necessity for the Company to now seek rate relief. The Consumer Price Index during this period has increased more than 30%, which has not only required that the Company pay more for the goods and services it purchases, but has also contributed to a steady increase in the level of the Company's direct and indirect payroll costs. Additionally, health care costs continue to escalate at a rate significantly higher than that of inflation. During this 10-year period, there have also been major changes in accounting regulations. For example, the implementation of FAS 106, Employers' Accounting for Postretirement Benefits Other Than Pensions, has resulted in an increase in Peoples' cost of service of approximately $1 million. Additionally, there have been increases in various taxes, all of which have contributed to the increase in the cost to provide service to our customers.

In spite of increased costs, the Company has been able to continue to expand its pipeline distribution system in order to make natural gas available as an energy choice to more customers. Since its last rate case, the Company, through growth and acquisition, has expanded its pipeline system from approximately 5,000 miles to approximately 9,000 miles and has added more than 100,000 customers.

At the same time, the Company has strived to improve the efficiency and economy of its operations without compromising the level of service rendered to its customers.

Q. WHAT EFFORTS HAS PEOPLES UNDERTAKEN SINCE ITS LAST RATE CASE TO CONTROL OPERATING EXPENSES?

A. Over the last 10 years, Peoples has made substantial efforts to control expense levels and avoid the need for additional rate relief. A restructuring of the Company's field operations combined 15 divisional operating units into four regional operating units. This resulted in consolidation of both customer service operations and management oversight. Through the restructuring, Peoples was able to reduce its work force by over 200 people, a reduction of more than 15%, without negatively impacting service levels to the customers.

In addition, Peoples has been successful in managing the cost of materials and supplies through the development of strategic alliances with vendors. A strategic alliance is a partnership with a vendor where, in exchange for a commitment to procure certain quantities of materials and supplies and adopt agreed upon best practices, favorable pricing is received by the Company. These alliances cover such things as pipe, valves, fittings, meters, regulators, and office supplies. Peoples makes annual purchases of approximately $100 million for materials and supplies and, of this amount, approximately $15 million consists of purchases through strategic alliance partners.

The last 10 years have been marked by significant growth in the number of customers served by the Company, the size of its service territory, and ever increasing reporting complexities. The Company has been able to manage through this by prudent leveraging of proven technologies. Peoples has implemented computer applications which assist in managing costs while continuing to provide a high level of customer service. Some of the more significant changes the Company has implemented are:

- A work management system which automatically dispatches service orders based on a technician's skill level, geographic area, and availability.
- A system which allows for electronic placement of orders and electronic funds settlement, making purchasing and bill payment transactions more efficient.
- Systems which provide on-line financial reporting capabilities, which significantly reduce the need for paper reports.
- A fixed asset system which enables electronic project approval and provides on-line features to better track and manage capital projects.
- Systems to provide customers with budget billing and auto-pay options to provide better customer service and reduce customer calls.

Overall, Peoples' goal is to follow as closely as possible this Commission's objective, which is to keep the growth rate for controllable operating and maintenance expenses in total to a level no greater than the inflation rate plus customer growth.

Q. HAS THE COMPANY BEEN ABLE TO JUSTIFY THE INCREASE IN OPERATING AND MAINTENANCE EXPENSES IN THE HISTORIC BASE YEAR ENDED DECEMBER 31, 2001 OVER THE BENCHMARK OF THE FISCAL YEAR 1991, INCREASED BY THE CHANGE IN THE CONSUMER PRICE INDEX PLUS CUSTOMER GROWTH?

A. Yes. Schedule C-34 of the MFRs shows that O&M expenses for the historic base year necessary to the provision of adequate, sufficient and efficient service to our customers were $52.3 million compared to the benchmark of $79.0 million. The Company was below the benchmark by more than $26 million or 34%.

Q. IN ADDITION TO CONTROLLING OPERATING EXPENSES, WHAT HAS THE COMPANY DONE TO FURTHER THE SALE AND TRANSPORTATION OF NATURAL GAS AND THUS IMPROVE REVENUES?

A. Peoples has placed additional emphasis on an aggressive marketing program aimed at acquiring new natural gas customers in the Company's market areas. During the period from 1991 to 1995 our average annual customer growth rate was 2.5%. During the period from 1997 through 2001 the growth rate grew to 3.4%. This growth was accomplished by, among other things, developing programs specifically targeted at builders and developers as well as architects and engineers – in short, the decision makers as to whether or not natural gas is used in a facility. In addition, the Company has created alliances with a significant number of appliance sales and service companies that now promote and market natural gas and natural gas appliances to their customers.

In 2001, Peoples completely outsourced its sales and marketing function. There were several reasons for this action. First, the outsource provider is dedicated to offering natural gas and other energy related products and services, which provides People's customers with "one-stop" shopping and increases customer satisfaction. Second, the contract with the sales and marketing provider is a performance-based contract. If the provider doesn't achieve targeted sales levels, fees paid are proportionately reduced. Third, the Company feels that a dedicated sales and marketing company will be able to take advantage of synergies that will result in lower costs to Peoples. As a result of this outsourcing, Peoples has forecasted a 3% reduction in the contract amount for sales and marketing services in both 2002 and the projected test year of 2003, while at the same time forecasting increases in customer growth of 4.5% in 2002 and 4.9% in 2003.

Q. HAVE YOU HAD A SCHEDULE PREPARED UNDER YOUR SUPERVISION SHOWING THE CAPITAL STRUCTURE OF THE COMPANY FOR THE HISTORIC BASE YEAR ENDED DECEMBER 31, 2001?

A. Yes. Schedule D-1 of the MFRs shows the 13-month average capital structure of the Company at December 31, 2001, with the ratio of each class of capital to total capital, the cost rate for each class, the weighted component for each class and the return required. This schedule shows that the embedded cost of long-term debt is 7.52%; the cost of short-term debt is 4.08%; and the costs of residential and commercial customer deposits are 6.00% and 7.00% respectively. Deferred taxes and tax credits are shown at zero cost. Equity is shown at a cost of 11.25%, which is the midpoint of the Company's currently authorized range.

Q. WHAT IS SHOWN BY EXHIBIT FJS-1?

A. MFR Schedule G-1, Page 1, shows that the Company's existing rates would produce a 6.66% adjusted overall rate of return on the average rate base for the projected test year ending December 31, 2003. Exhibit FJS-1 shows that the 6.66% rate of return equates to a return on equity of 6.72%. This return on equity of 6.72% can be compared to an 11.25% rate of return on equity currently authorized by the Commission, and is not adequate to maintain the financial integrity of the Company.

Q. WHY WON'T THE SERVICE RATES AUTHORIZED IN THE COMPANY'S LAST RATE PROCEEDING PRODUCE THE AUTHORIZED RATE OF RETURN?

A. The Company's authorized rates are currently inadequate primarily because of the effects of inflation and the passage of time. The service rates authorized in the Company's last rate proceeding were based on the costs which the Company was projected to incur in its fiscal year ended September 30, 1993. Peoples is seeking approval in this proceeding for rates necessary to recover its cost of service for the 2003 projected test year. Although the Company has been successful in increasing its sales, the passage of time, continuing increases in costs, and the effects of continuing inflation on the Company's operating and construction costs generally, as well as the continued expansion and improvement of the Company's distribution system, have combined to render the previously authorized rates inadequate for recovery by the Company of its cost of service. Such rates will not produce, under the economic conditions existing in the projected test year, a fair rate of return on the property of the Company used and useful in providing public service.

Q. WHAT IS THE AMOUNT OF THE RATE INCREASE FOR WHICH PEOPLES SEEKS APPROVAL IN THIS CASE?

A. Based on the 2003 projected test year, the Company requires a rate increase of $22,615,228 in order to earn a fair return on investment.

Q. WOULD YOU PLEASE IDENTIFY THE OTHER WITNESSES WHO WILL TESTIFY FOR PEOPLES IN THIS PROCEEDING, AND THE SUBECTS UPON WHICH THEY WILL TESTIFY?

A. Bruce Narzissenfeld, Controller, will testify on the historical financial data from the books and records of the Company. J. Paul Higgins, Director – Finance & Budget, will testify on the projected test year data and the increased amount of revenue needed to cover cost of service. Dr. Roger A. Morin will testify on rate of return, cost of capital and related matters. Wraye J. Grimard, Manager – Regulatory Planning, will testify on marketing, rate matters, cost of service and rate design.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

PEOPLES GAS SYSTEM
CALCULATED AVERAGE RETURN ON CAPITAL
DECEMBER 31, 2003

DECSRIPTION	$(000) AMOUNT	RATIO	COST RATE	WEIGHTED COST
Common Equity	$ 273,218	52.30%	6.72%	3.51%
Long-Term Debt	167,399	32.04%	7.81%	2.50%
Short-Term Debt	34,975	6.70%	4.00%	0.27%
Residential Customer Deposits	5,528	1.06%	6.00%	0.06%
Commercial Customer Deposits	23,250	4.45%	7.00%	0.31%
Inactive Deposits	164	0.03%		
Deferred Taxes	17,123	3.28%		
Tax Credits	735	0.14%		
TOTAL	$ 522,393	100.00%		6.66%

Note: Amounts and ratios are per MFR Schedule G-3 (page 2). Cost rates for all components except Common Equity are per MFR Schedule G-3 (page 2).

PEOPLES GAS SYSTEM

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

Docket No. 020384-GU

In Re: Application for a rate increase by Tampa Electric Company d/b/a Peoples Gas System

Submitted for Filing: 6/27/2002

DIRECT TESTIMONY AND EXHIBIT OF:

BRUCE NARZISSENFELD
On Behalf of Peoples Gas System

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Bruce Narzissenfeld and my business address is 702 N. Franklin Street, Tampa, Florida 33602.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by Peoples Gas System ("Peoples" or the "Company") as Controller.

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I graduated from the University of Florida in 1979 with a Bachelor of Science degree in Accounting. Upon graduation I was employed by Arthur Andersen, where I worked for four years in the auditing group. On leaving Arthur Andersen, I joined Florida Power & Light Company where I worked in Finance from 1984 to 1985. I have been with the TECO Energy family of companies since 1985, and have been employed by Peoples since March 1998. I served Peoples as Assistant Controller until January 2000 when I was appointed Controller. I have been a Certified Public Accountant since 1980 and additionally earned a Masters in Business Administration from the University of Tampa in 1988.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to sponsor those sections of the Minimum Filing Requirements ("MFRs") required by Commission Rule 25-7.039, which pertain to the historic base year. Those sections are identified in Exhibit BNN-1, which is attached to this testimony.

Q. WHAT IS THE HISTORIC BASE YEAR THAT PEOPLES IS USING IN THIS PROCEEDING?

A. The Company is using as its historic base year the 12 months ended December 31, 2001. All data related to the base year is historical data taken from the books and records of the Company, which are kept in accordance with recognized accounting practices and provisions of the Uniform System of Accounts prescribed by this Commission.

Q. **WHAT IS THE AMOUNT OF THE RATE BASE FOR THE HISTORIC BASE YEAR ENDED DECEMBER 31, 2001?**

A. The calculation of the 13-month average rate base for the historic base year is contained on MFR Schedule B-2. As adjusted, Peoples' average rate base as of December 31, 2001 was $461,554,070. This compares to the average rate base for the historic base year in the 1991 case of $192,267,000, an increase of 140%.

Q. **WHAT ARE SOME OF THE FACTORS THAT HAVE CONTRIBUTED TO THIS GROWTH IN RATE BASE OVER THIS 10 YEAR PERIOD?**

A. There are several factors that have contributed to growth in rate base over this 10 year period. First, 30,000 customers were added as a result of Peoples' June 1997 acquisition of the former West Florida Natural Gas Company via a merger. Additionally, from a combination of the investments in rate base required to serve normal customer growth and the expansion of Peoples' pipelines into new geographical areas not previously served, the Company has added more than 100,000 customers since the 1991 rate relief filing.

Q. **WHAT WERE THE BENEFITS OF PEOPLES' EXPANSION INTO NEW GEOGRAPHIC AREAS?**

A. By bringing natural gas to areas not previously served, customers were provided an additional energy option and increased competition was introduced into the marketplace in these areas. Areas in which this expansion has occurred are Charlotte, Clay, Collier, Hernando, Lee, Pasco and St. Johns Counties.

Q. PLEASE EXPLAIN THE ADJUSTMENTS THAT HAVE BEEN MADE TO THE HISTORIC RATE BASE.

A. Adjustments to the rate base for the historic base year were made to remove non-utility and non-jurisdictional items from the average per books rate base. In addition, the Company removed items that are recovered through other cost recovery mechanisms such as fuel and conservation. Further details describing these adjustments are contained on MFR Schedules B-3 and B-13.

Q. HOW WERE THESE ADJUSTMENTS DETERMINED?

A. Allocation of land and structures was determined based on a physical inspection of all facilities by Company personnel. Facilities were measured to arrive at the square footage of space utilized. Portions not used in providing utility services have been removed. In the case of computer equipment, each application was allocated to non-utility operations based on a combination of customer count, checks processed, number of bills and number of computer users. These plant allocations are contained on MFR Schedule B-5.

Q. HAS PEOPLES EXPERIENCED ANY MAJOR CHANGE IN ALLOCATIONS MADE TO NON-UTILITY OPERATIONS?

A. Yes. The amount of plant allocated to non-utility operations has been significantly reduced as a result of increased growth and focus on utility operations, the elimination of propane and sales and service businesses, and outsourcing of sales and marketing functions.

Q. WHAT IS THE AMOUNT OF NET OPERATING INCOME ("NOI") FOR THE HISTORIC BASE YEAR?

A. The calculation of the historic base year NOI is contained on MFR ScheduleC-1. Certain adjustments were made to the base year data to arrive at an adjusted NOI of $35,166,237.

Q. PLEASE DESCRIBE THE ADJUSTMENTS THAT WERE MADE TO THE HISTORIC BASE YEAR NOI.

A. Items that are recoverable through cost recovery mechanisms, as opposed to through base rates, have been removed from the calculation of NOI; that is, all fuel revenue and expenses and energy conservation revenue and expenses have been removed. Off-system sales have been removed from the calculation of NOI as they are sporadic, opportunistic transactions for the Company that are highly dependent on market conditions and are not reflective of on-going utility operations. In addition, depreciation and amortization expense was adjusted for the effect of the rate base adjustments referred to earlier.

Q. HAS A COMPARISION BEEN MADE OF OPERATIONS AND MAINTENANCE ("O&M") EXPENSES FOR THE 2001 HISTORIC BASE YEAR VERSUS THE BENCHMARK OF THE O&M EXPENSES IN THE HISTORIC BASE YEAR IN PEOPLES' LAST RATE CASE?

A. Yes. O&M expense for the historic base year in the current case is

$52,282,684 compared to a $79,048,008 benchmark calculated using the Commission objective of allowing controllable O&M expenses to increase no greater than the inflation rate plus customer growth. Thus, the historic base year's O&M expense is lower than the benchmark by $26,765,324 or 34%. These amounts are detailed by function on MFR Schedule C-34.

Q. ARE ALL FUNCTIONAL AREAS OF THE O&M BENCHMARK CALCULATED USING IDENTICAL COMPOUND MULTIPLIERS?

A. No. The compound multiplier for Sales Expense was based on gross customer additions, excluding additions resulting from acquisitions. Since the emphasis of sales and marketing activities is customer additions, it is more appropriate when looking at these activities to use gross customer growth rather than using net customer growth, which was used in the computation of the other functions' compound multiplier.

Q. WHAT ARE THE VARIOUS FUNCTIONS COMPRISING O&M?

A. The functions comprising O&M are Distribution, Customer Accounts, General and Administrative ("G&A"), and Sales Expense.

Q. HOW DOES DISTRIBUTION EXPENSE FOR THE 2001 HISTORIC BASE YEAR COMPARE TO THE BENCHMARK FOR DISTRIBUTION EXPENSE IN THE HISTORIC BASE YEAR IN PEOPLES' LAST RATE CASE?

A. Distribution Expense for the 2001 historic base year is $13,245,500 less than the benchmark. This amount is calculated on MFR Schedule C-34. Among the reasons for this better-than-benchmark result is the Company's decision to move from a divisional to a regional structure. This organizational change has allowed Peoples to significantly reduce its workforce resulting in lower distribution expense. In addition, economies and efficiencies have been realized from the cross training of remaining employees and the outsourcing of various other functions. Another reason for this better-than-benchmark performance is the adoption of a meter change-out program in which removed meters are retired as opposed to Peoples' incurring the expenses associated with testing and repair. The adoption of this procedure also allowed Peoples to realize savings associated with the outsourcing of its meter shop. Peoples also has realized savings in distribution expense though its implementation of a Commission-approved statistical sampling plan for the purposes of periodic testing of residential meters. Additionally contributing to the better-than-benchmark performance are savings associated with the establishment of alliances with a dealer network which performs service work previously done by Peoples.

Q. HOW DOES CUSTOMER ACCOUNTS EXPENSE FOR THE 2001 HISTORIC BASE YEAR COMPARE TO THE BENCHMARK FOR CUSTOMER ACCOUNTS EXPENSE IN THE HISTORIC BASE YEAR IN PEOPLES' LAST RATE CASE?

A. Customer Account Expense for the 2001 historic base year is $8,623,822 less than the benchmark. This amount is calculated on MFR Schedule C-34. The primary reason for this better-than-benchmark performance is Peoples' restructuring of the Company's customer service function from 15 divisional operations into four regional operating units. This resulted in a reduction in work force through the consolidation of both operations personnel and management oversight.

Q. HOW DOES G&A EXPENSE FOR THE 2001 HISTORIC BASE YEAR COMPARE TO THE BENCHMARK FOR G&A EXPENSE IN THE HISTORIC BASE YEAR IN PEOPLES' LAST RATE CASE?

A. G&A for the 2001 historic base year is $8,263,818 less than the benchmark. This amount is calculated on MFR Schedule C-34. One primary reason for this better-than-benchmark performance is related to insurance premiums and deductibles. When Peoples filed for rate relief in 1991, it held insurance policies with $250,000 deductibles. Following the merger with Tampa Electric, it implemented a practice of maintaining $1 million deductibles. This change in deductible combined with the Company's excellent safety record has contributed to G&A savings in the form of lower premium expenses. Additionally, G&A savings have resulted from lower pension costs as a result of the reductions in work force which have occurred since Peoples' 1991 rate case. Lastly, significant G&A savings in the information technology area have also been realized. These savings reflect both a leveraging of proven technologies and the realization of economies and efficiencies of scale related to the June 1997 merger with Tampa Electric.

Q. HOW DOES SALES EXPENSE FOR THE 2001 HISTORIC BASE YEAR COMPARE TO THE BENCHMARK FOR SALES EXPENSE IN THE HISTORIC BASE YEAR IN PEOPLES' LAST RATE CASE?

A. Sales Expense in 2001 exceeded the benchmark by $3,367,817. This amount is calculated on MFR Schedule C-34. However, a more accurate comparison of Sales Expense requires that consideration be given to the agreement entered into by Peoples to outsource its sales and marketing activities. This agreement is a performance-based contract under which payments by Peoples are contingent upon specific sales targets being achieved. As a result of this agreement, expenses previously paid by Peoples in support of sales activities, but not previously charged directly to Sales Expense (FERC Accounts 911 – 916), are now included in FERC Account 912 as Sales Expense. These expenses are detailed in MFR Schedule C-38 Page 5. Including these items as Sales Expense for purposes of determining the benchmark variance puts the current historical base year Sales Expense $159,421 under the benchmark.

Q. **HAS AN ADJUSTMENT BEEN MADE TO ALLOCATE PEOPLES' GENERAL AND ADMINISTRATIVE ("G&A") EXPENSES BETWEEN THE UTILITY AND ITS NON-UTILITY AFFILIATES?**

A. Yes. Peoples goes through a process whereby all applicable corporate G&A expenses are allocated between the Company and its non-utility affiliates. This allocation is recorded on the books based on budgeted expenses for the year. Since this allocation is included in the actual per books expenses, no further adjustment is needed. MFR Schedule C-6 shows the amount of G&A expenses (as well as other expenses) that have been allocated.

Q. **DOES PEOPLES' HISTORIC BASE YEAR NOI INCLUDE CHARGES FROM TAMPA ELECTRIC COMPANY?**

A. Yes. The historic base year includes charges for various goods and services received from Tampa Electric Company. The goods and services received are primarily corporate overhead items consisting of information technology, telecommunication, payroll processing, human resources, mail room services (including postage), bank charges and rent. The Company also contracts with Tampa Electric Company for meter reading services in areas where there is overlapping service territory. Expenses are determined based on a direct charging of services received or resources consumed. Corporate overhead items are charged to Peoples at cost, while service agreements exist for meter reading work performed.

Q. DOES PEOPLES' HISTORIC BASE YEAR NOI INCLUDE CHARGES FROM TECO ENERGY?

A. Yes. The historic base year includes charges for various services received from TECO Energy. The services received consist primarily of corporate governance, treasury, regulatory, general accounting, tax support, legal services, and risk management. Expenses are based on a direct charging for services received and also an allocation of overhead expense. Both direct and allocated expenses are charged to Peoples at cost. Charges are allocated utilizing an operating methodology based on the Modified Massachusetts Formula. This allocation methodology consists of developing weighted average allocation percentages based on operating revenues, operating income and operating assets.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

MFR SCHEDULES SPONSORED BY:

Bruce Narzissenfeld

Schedule	Title	Schedule Number
"A" Schedules	Executive Summary	A-1 through A-6
"B" Schedules	Rate Base Schedules	B-1 through B-18
"C" Schedules	Net Operating Income Schedules	C-1 through C-38
"D" Schedules	Rate of Return Schedules	D-1 through D-12
"F" Schedules	Interim Rate Relief Schedules	F-1 through F-10
"I" Schedules	Engineering Schedules	I-1 through I-4

PEOPLES GAS SYSTEM

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

Docket No. 020384-GU

In Re: Application for a rate
increase by Tampa Electric Company
d/b/a Peoples Gas System.

Submitted for Filing:
6/27/2002

DIRECT TESTIMONY
AND EXHIBIT OF:

J. PAUL HIGGINS
On Behalf of Peoples Gas System

Q. **PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

A. My name is J. Paul Higgins and my business address is 702 N. Franklin Street, Tampa, Florida 33602.

Q. **BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?**

A. I am employed by Peoples Gas System ("Peoples" or the "Company"), as Director, Finance & Budget.

Q. **HOW LONG HAVE YOU BEEN EMPLOYED BY PEOPLES GAS SYSTEM?**

A. I have been employed by Peoples since July 1993. I served as a budget analyst until 1998 when I was appointed Manager, Finance & Budget. In September 2000, I was promoted to Director, Finance & Budget.

Q. **WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

A. The purpose of my testimony is to sponsor the portions of the Minimum Filing Requirements ("MFRs") related to the Projected Test Year. These schedules are identified on Exhibit JPH-1.

Q. **WHAT IS THE PROJECTED TEST YEAR THAT PEOPLES IS USING IN THIS PROCEEDING?**

A. The Company is using as its projected test year the 12 months ending December 31, 2003. The Commission has acknowledged the use of this projected test year and that year, as adjusted, is representative of the operations of the Company.

Q. **PLEASE DESCRIBE HOW YOU ARRIVED AT THE AMOUNT OF PROJECTED TEST YEAR RATE BASE.**

A. Rate base was projected using a combination of trending based on historical data as well as specific adjustments based on known or reasonably foreseeable events that are expected to occur during the projected test year.

The main item that affects the rate base calculation is the projected capital expenditures that are incorporated in plant in service. Historical capital expenditures are broken down into two categories: normal expenditures and special projects. Normal expenditures are those routine costs necessary to provide service to new customers as well as routine costs associated with the replacement and/or relocation of existing facilities and equipment. Special projects generally represent a major expansion of plant or equipment with costs in excess of $500,000.

In order to develop plant in service for the projected test year, capital expenditures had to be estimated for both 2002 and 2003. For 2002, the Company's capital budget was used as the basis for capital expenditures. In developing 2003 expenditures, a combination of trend analysis and specific identification of special projects was employed. For most categories, a five-year analysis of historical expenditures was used as a basis for 2003 estimates, accounting for adjustments for large, non-recurring expenditures in the historical data. Additionally, special projects were determined by surveying each of our regional offices for major projects which are currently in the planning stage and that are expected to occur during fiscal year 2003. Only one such project, approximately $3 million for main extensions related to the new Gulfstream pipeline, was included in our 2003 estimated capital expenditures. Plant retirements were also projected based on actual historical trends.

The other major component of rate base is working capital.

Working capital was developed using the balance sheet method as prescribed by this Commission. The individual components that make up working capital were projected using a variety of different methodologies. These are described in MFR Schedule G-6, pages 2 and 3.

Q. PLEASE EXPLAIN THE ADJUSTMENTS THAT HAVE BEEN MADE TO RATE BASE.

A. The adjustments that have been made to rate base are for the purpose of removing non-utility and non-jurisdictional items. Further details describing these adjustments are contained on MFR Schedule G-1, page 4.

Q. WHAT IS THE APPROPRIATE ADJUSTED RATE BASE FOR THE PROJECTED TEST YEAR ENDING DECEMBER 31, 2003?

A. Taking the test year projections and making the adjustments referenced on MFR Schedule G-1, page 4, the appropriate adjusted rate base for the projected test year is $522,393,278.

Q. WAS A SIMILAR METHODOLOGY USED TO DEVELOP THE PROJECTED NET OPERATING INCOME ("NOI") AS WAS USED TO DEVELOP RATE BASE?

A. Yes, that is correct. Revenues were developed based on projected throughput and customer growth data that was prepared based on estimated customer additions and losses. This analysis was prepared at the local division office level. The current rate structure was applied to these projections to arrive at projected revenue.

Operation and maintenance ("O&M") expenses were developed using the trending methodology currently prescribed by the Commission Staff. Certain items were identified as not following normal trending patterns and, as such, were projected based on known or anticipated costs. A list of these items is contained on MFR Schedule G-6, page 8.

Two O&M expense accounts are worthy of special mention here. Specifically, those are accounts 916 (Miscellaneous Sales Expense) and account 930 (Miscellaneous General Expenses). In account 916, the Company has included $250,000 for a new customer retention program that aims to increase gas appliance penetration to existing customers who have only one gas appliance. The program was developed to reduce the loss of this type of customer. Loss of these customers would ultimately harm remaining ratepayers as a result of both reduced gas revenues and an increase in rate base resulting from the cost of cutting and capping the lost customers' service lines. In account 930, Peoples has included $500,000 for payments to industry organizations for research that were formerly included and recovered from ratepayers as part of the Company's Purchased Gas Adjustment. Pursuant to Commission Order No. PSC-01-2370-FOF-GU, the Company now records this expense in non-fuel O&M expense.

Depreciation expense was calculated based on projected plant in service and using depreciation rates as proposed by the Company in Docket No. 010383-GU in its application for approval of new depreciation rates. The depreciation rates for which Peoples has sought approval are the result of a study performed by the Company as required by Commission Rule 25-7.045. Because there has been no final order in the referenced docket, the Company will make adjustments to the depreciation expense reflected on the MFR schedules as filed if the new depreciation rates are different from the ones used to develop the MFR schedules filed by the Company with its petition for rate relief.

A complete description of the NOI projection methodology is contained in MFR Schedule G-6, pages 4 through 9.

Q. WHAT IS THE APPROPRIATE NET OPERATING INCOME FOR THE PROJECTED TEST YEAR?

A. The appropriate NOI for the projected test year, after making the adjustments on MFR Schedule G-2, pages 2 and 3, is $34,774,838.

Q. WHAT IS THE AMOUNT OF REVENUE RELIEF THAT THE COMPANY IS SEEKING IN THIS PROCEEDING?

A. The Company is seeking to adjust its rates in order to recover an overall cost of service of $170,796,957. This, when compared to the projected test year cost of service at present rates of $148,181,729, results in a requested revenue increase of $22,615,228.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

Exhibit No._________
Docket No. 020384-GU
Peoples Gas System
(JPH-1)
Page 1 of 1

MFR SCHEDULES SPONSORED BY:

J. Paul Higgins

Schedule	Title	Schedule Number
"G" Schedules	Projected Test Year Calculations	G-1 through G-6

PEOPLES GAS SYSTEM

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

Docket No. 020384-GU

In Re: Petition of Peoples Gas System, For Authority to Increase Its Rates and Charges

Submitted for Filing: 6/27/2002

DIRECT TESTIMONY AND EXHIBIT OF:

DR. ROGER A. MORIN
On Behalf of Peoples Gas System

Q. PLEASE STATE YOUR NAME, ADDRESS, AND OCCUPATION.

A. My name is Dr. Roger A. Morin. My business address is Georgia State University, Robinson College of Business, University Plaza, Atlanta, Georgia, 30303. I am Professor of Finance at the College of Business, Georgia State University and Professor of Finance for Regulated Industry at the Center for the Study of Regulated Industry at Georgia State University. I am also a principal in Utility Research International, an enterprise engaged in regulatory finance and economics consulting to business and government.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND.

A. I hold a Bachelor of Engineering degree and an MBA in Finance from McGill University, Montreal, Canada. I received my Ph.D. in Finance and Econometrics at the Wharton School of Finance, University of Pennsylvania.

Q. PLEASE SUMMARIZE YOUR ACADEMIC AND BUSINESS CAREER.

A. I have taught at the Wharton School of Finance, University of Pennsylvania, Amos Tuck School of Business at Dartmouth College, Drexel University, University of Montreal, McGill University, and Georgia State University. I was a faculty member of Advanced Management Research International, and I am currently a faculty member of The Management Exchange Inc. and Exnet where I conduct frequent national executive-level education seminars throughout the United States and Canada. In the last twenty years, I have conducted numerous national seminars on such topics as "Utility Finance", "Utility Cost of Capital", "Alternative Regulatory Frameworks," and on "Utility Capital Allocation" which I have developed on behalf of The Management Exchange Inc. in conjunction with Public Utilities Reports, Inc.

I have authored or co-authored several books, monographs, and articles in academic scientific journals on the subject of finance. They have appeared in a variety of journals, including The Journal of Finance, The Journal of Business Administration, International Management Review, and Public Utility Fortnightly. I published a widely-used treatise on regulatory finance, Utilities' Cost of Capital, Public Utilities Reports Inc., Arlington, Va. 1984. My more recent book, Regulatory Finance, a voluminous text on the application of finance to regulated utilities, was released by the same publisher in late 1994. I have engaged in extensive consulting activities on behalf of numerous corporations and legal firms in matters of financial management and corporate litigation. Exhibit RAM-1 describes my professional credentials in more detail.

Q. HAVE YOU TESTIFIED ON COST OF CAPITAL BEFORE?

A. Yes, I have been a cost of capital witness before more than 40 regulatory boards in North America, including the Florida Public Service Commission ("FPSC" or the "Commission"), the Federal Energy Regulatory Commission ("FERC"), and the Federal Communications Commission. I have appeared before the following state and provincial commissions:

Alabama	Indiana	New Brunswick	Pennsylvania
Alaska	Iowa	New Jersey	Quebec
Alberta	Kentucky	New York	South Carolina
Arizona	Louisiana	Newfoundland	South Dakota
British Columbia	Manitoba	North Carolina	Tennessee
California	Michigan	North Dakota	Texas
Colorado	Minnesota	Ohio	Utah
Florida	Mississippi	Oklahoma	Vermont
Georgia	Missouri	Ontario	Washington
Hawaii	Montana	Oregon	West Virginia
Illinois	Nevada		

The details of my participation in regulatory proceedings are provided in Exhibit RAM-1.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to present an independent appraisal of the fair and reasonable rate of return on the gas distribution business of Peoples Gas System ("Peoples Gas" or the "Company"), which is an operating division of Tampa Electric Company, a subsidiary of TECO Energy Inc. ("TECO Energy"), with particular emphasis on the fair return on the Company's common equity capital committed to that business. Based upon this appraisal, I have formed my professional judgment as to a return on such capital which will (1) be fair to the ratepayer, (2) allow the Company to attract capital on reasonable terms, (3) maintain its financial integrity, and (4) be comparable to returns offered on comparable risk investments; and to testify in these proceedings as to that opinion.

Q. WOULD YOU PLEASE BRIEFLY IDENTIFY THE EXHIBITS AND APPENDICES WHICH ACCOMPANY YOUR TESTIMONY?

A. Yes. I have attached to my testimony Exhibits RAM-1 through RAM-5 and Appendix A. These Exhibits and Appendix relate directly to points in my testimony, and are described in further detail in connection with those points.

Q. PLEASE SUMMARIZE YOUR FINDINGS.

A. I recommend the adoption of a return on common equity of 11.75%. My recommendation is derived from studies I performed using the Capital Asset Pricing Model ("CAPM"), Risk Premium, and Discounted Cash Flow ("DCF") methodologies. I performed two CAPM analyses, one using the plain vanilla CAPM and another using an empirical approximation of the CAPM ("ECAPM"). I performed two risk premium analyses: a historical risk premium analysis on the gas distribution industry and a study of the risk premiums allowed in the gas distribution industry. I also performed DCF analyses on two surrogates for the Company's gas distribution business. They are: a group of comparable natural gas distribution utilities and a group of combination gas and electric utilities. My recommended rate of return reflects the application of my professional judgment to the results in light of the indicated returns from my Risk Premium, CAPM, and DCF analyses.

Q. PLEASE DESCRIBE HOW YOUR TESTIMONY IS ORGANIZED.

A. My testimony is organized in three (3) broad sections:

I. Regulatory Framework and Rate of Return

II. Cost of Equity Estimates

III. Summary and Recommendation

The first section discusses the rudiments of rate of return regulation and the basic notions underlying rate of return. The second section contains the application of CAPM, Risk Premium, and DCF tests. In the third section, the results from the various approaches used in determining a fair return are summarized.

I. REGULATORY FRAMEWORK AND RATE OF RETURN

Q. WHAT ECONOMIC AND FINANCIAL CONCEPTS HAVE GUIDED YOUR ASSESSMENT OF PEOPLES GAS' COST OF COMMON EQUITY?

A. Two fundamental economic principles underlie the appraisal of Peoples Gas' cost of equity, one relating to the supply side of capital markets, the other to the demand side. According to the first principle, a rational investor is maximizing the performance of his portfolio only if he expects the returns earned on investments of comparable risk to be the same. If not, the rational investor will switch out of those investments yielding lower returns at a given risk level in favor of those investment activities offering higher returns for the same degree of risk. This principle implies that a company will be unable to attract the capital funds it needs to meet its service demands and to maintain financial integrity unless it can offer returns to capital suppliers which are comparable to those achieved on alternate competing investments of similar risk. On the demand side, the second principle asserts that a company will continue to invest in real physical assets if the return on these investments exceeds or equals the company's cost of capital. This concept suggests that a regulatory commission should set rates at a level sufficient to create equality between the return on physical asset investments and the company's cost of capital.

Q. HOW DOES PEOPLES GAS' COST OF CAPITAL RELATE TO THAT OF TECO ENERGY?

A. I am treating Peoples Gas as a separate stand-alone entity, distinct from Tampa Electric Company and from TECO Energy because it is the cost of capital for Peoples Gas that we are attempting to measure and not the cost of capital for TECO Energy's consolidated overall activities. Financial theory clearly establishes that the cost of equity is the risk-adjusted opportunity cost to the investor, in this case, TECO Energy. The true cost of capital depends on the use to which the capital is put, in this case TECO Energy's natural gas distribution operations in the State of Florida. The specific source of funding an investment and the cost of funds to the investor are irrelevant considerations.

For example, if an individual investor borrows money at the bank at an after-tax cost of 8% and invests the funds in a speculative oil extraction venture, the required return on the investment is not the 8% cost but rather the return foregone in speculative projects of similar risk, say 20%. Similarly, the required return on Peoples Gas is the return foregone in comparable risk gas operations, and is unrelated to the parent's cost of capital. The cost of capital is governed by the risk to which the capital is exposed and not by the source of funds. The identity of the shareholders has no bearing on the cost of equity.

Just as individual investors require different returns from different assets in managing their personal affairs, corporations should behave in the same manner. A parent company normally invests money in many operating companies of varying sizes and varying risks. These operating subsidiaries pay different rates for the use of investor capital, such as long-term debt capital, because investors recognize the differences in capital structure, risk, and prospects between subsidiaries. Therefore, the cost of investing funds in an operating utility division such as Peoples Gas is the return foregone on investments of similar risk and is unrelated to the identity of the investor.

Q. PLEASE EXPLAIN HOW A REGULATED COMPANY'S RATES SHOULD BE SET UNDER TRADITIONAL COST OF SERVICE REGULATION.

A. Under the traditional regulatory process, a regulated company's rates should be set so that the company covers its costs, including taxes and depreciation, plus a fair and reasonable return on its invested capital. The allowed rate of return must necessarily reflect the cost of the funds obtained, that is, investors' return requirements. In determining a company's rate of return, the starting point is investors' return requirements in financial markets. A rate of return can then be set at a level sufficient to enable the company to earn a return commensurate with the cost of those funds.

Funds can be obtained in two general forms, debt capital and equity capital. The cost of debt funds can be easily ascertained from an examination of the contractual interest payments. The cost of common equity funds, that is, investors' required rate of return, is more difficult to estimate. It is the purpose of this testimony to estimate a fair and reasonable return on the common equity capital of Peoples Gas.

Q. WHAT MUST BE CONSIDERED IN ESTIMATING A FAIR RETURN ON EQUITY?

A. As discussed in the next section, the basic premise is that the allowable return on equity should be commensurate with returns on investments in other firms having corresponding risks. The allowed return should be sufficient to assure confidence in the financial integrity of the firm, in order to maintain creditworthiness and ability to attract capital on reasonable terms. The attraction of capital standard focuses on investors' return requirements which are generally determined using market value methods, such as the Risk Premium, CAPM, or the DCF methods. These market value tests define fair return as the return investors anticipate when they purchase equity shares of comparable risk in the financial marketplace. This is a market rate of return, defined in terms of anticipated dividends and capital gains as determined by expected changes in stock prices, and reflects the opportunity cost of capital. The economic basis for market value tests is that new capital will be attracted to a firm only if the return expected by the suppliers of funds is commensurate with that available from alternatives of comparable risk.

Q. HOW IS A UTILITY'S RATE OF RETURN DERIVED?

A. The required return in dollars is obtained by multiplying the established rate of return set by the regulator by the "rate base". The rate base is essentially the net book value of the utility's plant considered used and useful in dispensing service.

Q. WHAT FUNDAMENTAL PRINCIPLES ARE APPLICABLE IN DETERMINING A RATE OF RETURN THAT IS FAIR AND REASONABLE?

A. The heart of utility regulation is the setting of just and reasonable rates by way of a fair and reasonable return. There are two landmark United States Supreme Court cases which define the legal principles underlying the regulation of a public utility's rate of return and provide the foundations for the notion of a fair return:

1. Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia, 262 U.S. 679 (1923).
2. Federal Power Commission v. Hope Natural Gas Company, 320 U.S. 391 (1944).

The Bluefield case set the standard against which just and reasonable rates of return are measured:

"A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties ... The return should be reasonable, sufficient to assure confidence in the financial soundness of the utility, and should be adequate, under efficient

and economical management, to maintain and support its credit and enable it to raise money necessary for the proper discharge of its public duties." (emphasis added)

The Hope case expanded on the guidelines to be used to assess the reasonableness of the allowed return. The Court reemphasized its statements in the Bluefield case and recognized that revenues must cover "capital costs". The Court stated:

"From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock ... By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and attract capital." (emphasis added)

The United States Supreme Court reiterated the criteria set forth in Hope in Federal Power Commission v. Memphis Light, Gas & Water Division, 411 U.S. 458 (1973), in Permian Basin Rate Cases, 390 U.S. 747 (1968), and most recently in Duquesne Light Co. vs. Barasch, 488 U.S. 299 (1989). In the Permian cases, the Supreme Court stressed that a regulatory agency's rate of return order should:

"...reasonably be expected to maintain financial integrity, attract necessary capital, and fairly compensate investors for the risks they have assumed..."

Therefore, the "end result" of this Commission's decision should be to allow Peoples Gas to earn a return on equity that is: (1) commensurate with returns on investments in other firms having corresponding risks, (2) sufficient to assure confidence in Peoples Gas' financial integrity, and

(3) sufficient to maintain Peoples Gas' creditworthiness and ability to attract capital on reasonable terms.

Q. HOW IS THE FAIR RATE OF RETURN DETERMINED?

A. The aggregate return required by investors is called "cost of capital". The cost of capital is the opportunity cost, expressed in percentage terms, of the total pool of capital employed by Peoples Gas. It is the composite weighted cost of the various classes of capital (bonds, preferred stock, common stock) used by the utility, with the weights reflecting the proportions of the total which each class of capital represents.

While utilities like Peoples Gas enjoy varying (and declining) degrees of monopoly in the sale of public utility services, they must compete with everyone else in the free, open market for the input factors of production, whether it be labor, materials, machines, or capital. The prices of these inputs are set in the competitive marketplace by supply and demand, and it is these input prices which are incorporated in the cost of service computation. This is just as true for capital as for any other factor of production. Since utilities and other investor-owned businesses must go to the open capital market and sell their securities in competition with every other issuer, there is obviously a market price to pay for the capital they require, for example, the interest on debt capital, or the expected return on equity.

Q. HOW DOES THE CONCEPT OF A FAIR RETURN RELATE TO THE CONCEPT OF OPPORTUNITY COST?

A. The concept of a fair return is intimately related to the concept of opportunity costs. When investors supply funds to a utility by buying its stocks or bonds, they are not only postponing consumption, giving up the alternative of spending their dollars in some other way, they are also exposing their funds to risk. Investors are willing to incur this double penalty only if they are adequately compensated. The compensation they require is the price of capital. If there are differences in the risk of the investments, competition among firms for a limited supply of capital will bring different prices. These differences in risk are translated by the capital markets into price differences in much the same way that differences in the characteristics of commodities are reflected in different prices.

The important point is that the prices of debt capital and equity capital are set by supply and demand, and both are influenced by the relationship between the risk and return expected for those securities and the risks expected from the overall menu of available securities.

Q. HOW DOES PEOPLES GAS OBTAIN ITS CAPITAL?

A. The funds employed by Peoples Gas will be obtained from TECO Energy in two general forms, debt capital and common equity capital. The cost of debt funds can be easily ascertained from an examination of the contractual interest payments. The cost of common equity funds, that is, equity investors' required rate of return, is more difficult to estimate because the dividend payments received from common stock are not contractual or guaranteed in nature. They are uneven and risky, unlike interest payments. The return on common equity estimate can then be easily combined with the embedded cost of debt together with the capital structure, in order to arrive at the overall cost of capital.

Q. WHAT IS THE MARKET REQUIRED RATE OF RETURN ON EQUITY CAPITAL?

A. The market required rate of return on common equity, or cost of equity, is the return demanded by the equity investor. Investors determine the price for equity capital through their buying and selling decisions in capital markets. Investors set return requirements according to their perception of the risks inherent in the firm, recognizing the opportunity cost of foregone investments in other firms, and the returns available from other investments of comparable risk.

II. COST OF EQUITY ESTIMATES

Q. DR. MORIN, HOW DID YOU ESTIMATE THE FAIR RETURN ON EQUITY FOR PEOPLES GAS?

A. I employed three methodologies: (1) the CAPM, (2) the Risk Premium, and (3) the DCF methodologies. All three are market-based methods and are designed to estimate the return required by investors on equity capital committed to Peoples Gas.

Q. WHY DID YOU USE MORE THAN ONE APPROACH FOR ESTIMATING THE COST OF EQUITY?

A. No one individual method provides the necessary level of precision for determining a fair return, but each method provides useful evidence so as to facilitate the exercise of an informed judgment. Reliance on any single method or preset formula is inappropriate when dealing with investor expectations because of possible measurement errors and vagaries in individual companies' market data. The advantage of using several different approaches is that the results of each one can be used to check the others.

As a general proposition, it is extremely dangerous to rely on only one generic methodology to estimate equity costs. The difficulty is compounded when only one variant of that methodology is employed. It is compounded even further when that one methodology is applied to a single company. Hence, several methodologies applied to several comparable risk companies should be employed to estimate the cost of capital.

A. RISK PREMIUM ESTIMATES

Q. PLEASE DESCRIBE THE RISK PREMIUM METHOD FOR DETERMINING THE COST OF COMMON EQUITY.

A. The Risk Premium method of determining the cost of equity recognizes the fundamental principle that common equity capital is more risky than debt from an investor's standpoint, and that investors require higher returns on stocks than on bonds to compensate for the additional risk. The general approach is relatively straightforward. First, determine the historical spread between the return on debt and the return on equity. Second, this spread must be added to the current debt yield to derive an estimate of current equity return requirements.

The magnitude of the relative risk premiums is determined by shifts in demand and supply in each capital market segment, which are in turn driven by investors' attitudes towards risk, and by the relative risk differentials perceived by investors between each type of security.

The risk premium approach to estimating the cost of equity derives its merits and its usefulness from the simple fact that while equity returns cannot be readily quantified at a given point in time, the returns on bonds can be assessed on a regular basis. If the magnitude of the risk premium between stocks and bonds is known, then this information can be utilized to determine the cost of common equity.

Q. HOW DID YOU APPLY THE RISK PREMIUM METHOD TO PEOPLES GAS?

A. In order to quantify the risk premium for Peoples Gas, I have performed four risk premium studies. The first two CAPM-driven studies deal with aggregate stock market risk premium evidence and the other two empirical studies deal directly with the natural gas distribution utility industry.

1. CAPM ESTIMATES

Q. PLEASE DESCRIBE YOUR APPLICATION OF THE CAPM RISK PREMIUM APPROACH.

A. I developed two risk premium estimates based respectively on the CAPM and on an empirical approximation to the CAPM ("ECAPM"). The CAPM is a fundamental paradigm of finance. The fundamental idea underlying the CAPM is that risk-averse investors demand higher returns for assuming additional risk, and higher-risk securities are priced to yield higher expected returns than lower-risk securities. The CAPM quantifies the additional return, or risk premium, required for bearing incremental risk. It provides a formal risk-return relationship anchored on the basic idea that only market risk matters, as measured by beta. According to the CAPM, securities are priced such that:

EXPECTED RETURN = RISK-FREE RATE + RISK PREMIUM

Denoting the risk-free rate by R_F and the return on the market as a whole by R_M, the CAPM is stated as follows:

$$K = R_F + \beta(R_M - R_F)$$

This is the seminal CAPM expression, which states that the return required by investors is made up of a risk-free component, R_F, plus a risk premium given by $\beta(R_M - R_F)$. To derive the CAPM risk premium estimate, three quantities are required: the risk-free rate (R_F), beta (β), and the market risk premium, ($R_M - R_F$). For the risk-free rate, I used 5.7%. For beta, I used 0.64, and for the market risk premium, I used 7.5%. These inputs to the CAPM are explained below.

Q. WHAT RISK-FREE RATE DID YOU USE IN YOUR RISK PREMIUM ANALYSES?

A. To implement the Risk Premium method, an estimate of the risk-free return is required as a benchmark. As a proxy for the risk-free rate, I have relied on the actual yields on long-term Treasury bonds. Long-term rates are the relevant benchmarks when determining the cost of common equity, rather than short-term interest rates. Short-term rates are volatile, fluctuate widely, and are subject to more random disturbances than are long-term rates. For example, Treasury bills are used by the Federal Reserve as a policy vehicle to stimulate the economy and to control the money supply, and are also used by foreign governments, firms, and individuals as a temporary safe-house for money. Short-term rates are largely administered rates.

As a practical matter, it is inappropriate to relate the return on common stock to the yield on short-term instruments. This is because short-term rates, such as the yield on 90-day Treasury Bills, fluctuate widely leading to volatile and unreliable equity return estimates. Moreover, yields on 90-day Treasury Bills typically do not match the equity investor's planning horizon. Equity investors generally have an investment horizon far in excess of 90 days.

As a conceptual matter, short-term Treasury Bill yields reflect the impact of factors different from those influencing long-term securities such as common stock. For example, the premium for expected inflation embedded into 90-day Treasury Bills is likely to be far different than the inflationary premium embedded into long-term securities yields. On grounds of stability and consistency, the yields on long-term Treasury bonds match more closely with common stock returns.

The level of U.S. Treasury long-term bond yields prevailing in May 2002 was 5.7% (www.bondsonline.com, June 12, 2002).

Q. HOW DID YOU SELECT THE BETA FOR YOUR CAPM ANALYSIS?

A. A major thrust of modern financial theory as embodied in the CAPM is that perfectly diversified investors can eliminate the company-specific component of risk, and that only market risk remains. The latter is technically known as "beta", or "systematic risk". The beta coefficient measures change in a security's return relative to that of the market. The beta coefficient states the extent and direction of movement of the rates of return to a stock with those of the market as a whole. Therefore, it indicates the change in the rate of return on a stock associated with a one percentage point change in the rate of return on the market. The beta coefficient thus measures the degree to which a particular stock shares the risk of the market as a whole. Modern financial theory has established that beta incorporates several economic characteristics of a corporation which are reflected in investors' return requirements.

Technically, the beta of a stock is a measure of the covariance of the return on the stock with the return on the market as a whole. Accordingly, it measures dispersion in a stock's return which cannot be reduced through diversification. In abstract theory for a large diversified portfolio, dispersion in the rate of return on the entire portfolio is the weighted sum of the beta coefficients of its constituent stocks.

Of course, Peoples Gas is not publicly traded, and therefore, proxies must be used. It is reasonable to postulate that Peoples Gas possesses an investment risk profile similar to publicly-traded natural gas distribution utility businesses. As a proxy for the Company's beta, I have therefore examined the betas of a sample of publicly-traded natural gas distribution utilities contained in the Value Line Investment Survey for Windows ("VLIS") of May 2002. In order to minimize the well-known thin trading bias in measuring beta, only those companies whose market capitalization exceeded $500 million were considered. The group of fifteen companies is shown on Exhibit RAM-2. The average beta for the group is 0.64.

Q. WHAT MARKET RISK PREMIUM ESTIMATE DID YOU USE IN YOUR CAPM ANALYSIS?

A. For the market risk premium, I used 7.5%. This estimate was based on the results of both forward-looking and historical studies of long-term risk premiums. Two studies guided the assumed range. First, the Ibbotson Associates study of historical returns from 1926 to 2000 (Ibbotson Associates, *Stocks, Bonds, Bills and Inflation: 2001 Yearbook*, Valuation Edition) shows that a broad market sample of common stocks outperformed long-term Treasury bonds by 7.3%. The historical market risk premium over the income component of long-term Treasury bonds rather than over the total return is 7.8%. Ibbotson Associates recommends the use of the latter as a more reliable estimate of the historical market risk premium. Second, a DCF analysis applied to the aggregate equity market indicates a prospective market risk premium of 6.5%, while Value Line's expected equity return for the overall market is 7.8%. The average of the various historical and prospective estimates is approximately 7.5%.

Q. WHY DID YOU USE LONG HISTORICAL TIME PERIODS IN ARRIVING AT YOUR MARKET RISK PREMIUM ESTIMATE?

A. It is important to employ returns realized over long time periods rather than returns realized over more recent time periods when estimating the market risk premium with historical returns. This is because realized returns can be substantially different from prospective returns anticipated by investors, especially when measured over short time periods. Therefore, a risk premium study should consider the longest possible period for which data are available. Short-run periods during which investors earned a lower risk premium than they expected are offset by short-run periods during which investors earned a higher risk premium than they expected. Only over long time periods will investor return expectations and realizations converge.

I have therefore ignored realized risk premiums measured over short time periods, since they are heavily dependent on short-term market movements. Instead, I relied on results over periods of enough length to smooth out short-term aberrations, and to encompass several business and interest rate cycles. The use of the entire study period in estimating the appropriate market risk premium minimizes subjective judgment and encompasses many diverse regimes of inflation, interest rate cycles, and economic cycles.

To the extent that the historical equity risk premium estimated follows what is known in statistics as a random walk, one should expect the equity risk premium to remain at its historical mean. The best estimate of the future risk premium is the historical mean. Since I found no evidence that the market price of risk or the amount of risk in common stocks has changed over time, that is, there is no significant serial correlation in the aforementioned Ibbotson study of historical market risk premiums, it is reasonable to assume that these quantities will remain stable in the future.

Q. PLEASE DESCRIBE YOUR PROSPECTIVE APPROACH IN DERIVING THE MARKET RISK PREMIUM IN THE CAPM ANALYSIS.

A. In order to determine a prospective market risk premium in the CAPM analysis, I applied a DCF analysis to the aggregate equity market using Value Line's VLIS software. The dividend yield on the aggregate market is currently 2.2% (VLIS 05/2002 edition), and the projected growth for the nearly 5,000 dividend-paying stocks covered by Value Line is in the range of 5.3% to 13.8% with a midpoint of 9.6%. Adding the dividend yield to the midpoint growth rate produces an expected return on the aggregate equity market of 11.8%. Following the tenets of the DCF model, the spot dividend yield must be converted into an expected dividend yield by multiplying it by one plus the growth rate. This brings the expected return on the aggregate equity market to 12.0%. Recognition of the quarterly timing of dividend payments rather than the annual timing of dividends assumed in the annual DCF model brings this estimate to approximately 12.2%. The implied risk premium is therefore 6.5% over long-term U.S. Treasury bonds that are currently yielding 5.7%.

Value Line forecasts a price appreciation of 60% over the next four years for the companies that make up the Value Line Composite Index, implying an annual appreciation of 12.5%. Coupled with the forecast dividend yield of 1.6%, the implied market return is 14.1%. The implied risk premium is therefore 8.4% over long-term U.S. Treasury bonds that are currently yielding 5.7%.

The average market risk premium result from the various historical and prospective estimates is 7.5%, which is my estimate of the market risk premium.

Q. WHAT IS YOUR RISK PREMIUM ESTIMATE USING THE CAPM APPROACH?

A. Inserting those input values in the CAPM equation, namely a risk-free rate of 5.7%, a beta of 0.64, and a market risk premium of 7.5%, the CAPM estimate of the Company's return on equity is: 5.7% + 0.64 x 7.5% = 10.5%. This estimate becomes 10.8% with flotation costs, discussed later in my testimony.

Q. WHAT IS YOUR RISK PREMIUM ESTIMATE USING THE EMPIRICAL VERSION OF THE CAPM?

A. It is well established in the academic finance literature that the CAPM produces a downward-biased estimate of equity cost for companies with a beta of less than 1.00. Expanded CAPMs have been developed which relax some of the more restrictive assumptions underlying the traditional CAPM responsible for this bias, and thereby enrich its conceptual validity. These expanded CAPMs typically produce a risk-return relationship that is "flatter" than the traditional CAPM's prediction, consistent with the empirical findings of the finance literature. The following equation provides a viable approximation to the observed relationship between risk and return, and provides the following cost of equity capital estimate:

$$K = R_F + 0.25\,(R_M - R_F) + 0.75\,\beta(R_M - R_F)$$

Inserting 5.7% for R_F, a market risk premium of 7.5% for $R_M - R_F$ and a beta of 0.64 in the above equation, the return on common equity is 11.2% without flotation cost and 11.5% with flotation costs.

Q. DID YOU ADJUST YOUR RISK PREMIUM RESULTS TO ACCOUNT FOR THE FACT THAT THE COMPANY'S RISKS MAY BE DIFFERENT FROM THOSE OF THE AVERAGE NATURAL GAS DISTRIBUTION UTILITY ?

A. No, I did not. The estimates obtained from the CAPM analyses and from the historical risk premium analysis of the Moody's group reflect the risk of the average natural gas utility. Therefore, there is no need to adjust these results for any risk differential as between the Company and the industry average. As I show below, the Company's investment risks are comparable to those of the industry.

PEOPLES GAS'S RISK ENVIRONMENT

Q. PLEASE DESCRIBE HOW YOU ASSESSED PEOPLES GAS'S CURRENT RISK ENVIRONMENT.

A. It is convenient to disaggregate a company's risk into two broad components: business risk and financial risk.

TOTAL RISK = BUSINESS RISK + FINANCIAL RISK

Business risk refers to the relative variability of operating profits induced by the external forces of demand for and supply of the firm's products (demand and supply risk), by the presence of fixed costs (operating leverage), by the extent of diversification or lack thereof of services, and by the character of regulation (regulatory risk):

BUSINESS RISK = DEMAND RISK + SUPPLY RISK + REGULATORY RISK

A further distinction is frequently made between short-term and long-term business risks. Financial risk refers to the additional variability of earnings induced by the employment of fixed cost financing, that is, debt and preferred stock capital.

Relative to other local gas distribution companies ("LDCs"), Peoples Gas possesses above average demand risk, average supply and financial risks, and below average regulatory risks. The net result, in my judgment, is that Peoples Gas's overall risk is comparable relative to other LDCs. These risks are addressed below.

BUSINESS RISK

Q. PLEASE DESCRIBE THE BUSINESS RISKS FACED BY THE GAS DISTRIBUTION INDUSTRY IN RECENT YEARS.

A. Yes. The traditional role of LDCs, as intermediaries between pipelines and end-users has changed drastically in the past several years. Because of policy initiatives enacted by regulators at both the federal and state levels, the business risk environment has changed significantly and the level of risk has increased. Competition in the natural gas industry has increased from both the input and output ends of the intermediation process.

On the one hand, customers have alternative means of filling their energy needs (demand risk). On the other hand, supplies of gas have become riskier due to price and regulatory uncertainty and the gradual removal of barriers to competition by federal policy (supply risk). The LDC is caught in the middle. It has become more difficult to forecast demand, market behavior, financing requirements, earnings, and cash flows.

DEMAND RISK

Q. PLEASE EXPLAIN WHY THE DEMAND RISKS FACED BY THE GAS DISTRIBUTION INDUSTRY HAVE INCREASED IN RECENT YEARS.

A. On the output end, competition prevails from alternative energy sources in the gas companies' important markets, especially in the industrial user market. Given this increasingly competitive environment, the existing fuel alternatives, and a fragile rate structure, there is a potential incentive for these large volume users to leave the gas distributor's network and seek alternative energy sources. When these large volume industrial users represent an important proportion of total revenues, and/or the interruptible demand component from these industrial users is large, the loss of any or all of these customers has serious financial consequences for gas distributors. Competition from fossil fuel remains high, and oil prices continue to be volatile.

Investors are uncertain as to the final impact of competitive forces which have penetrated the industry and as to the final regulatory reaction to these developments. Uncertainty regarding the impact of more competition in traditionally monopolistic markets increases long-term business risks of the regulated firm in these markets.

Investors and bond rating agencies are aware that the LDC industry is riskier and more vulnerable, especially for those LDCs with a high dependence on a high-volume industrial customer base, such as Peoples Gas. For the shorter-term, the LDC industry's vulnerability is considerably enhanced by the current economic slowdown, and by the uncertain timing and magnitude of economic recovery.

Q. ARE THE DEMAND RISKS FACED BY PEOPLES GAS SIMILAR TO THOSE OF OTHER GAS DISTRIBUTION UTILITIES?

A. Yes. While, unlike several LDCs, Peoples Gas does not have overlapping service territories with other LDCs, the Company does face competition from electricity, oil, steam, coal, and propane. Some of its competitors are unregulated, with no obligation to serve.

Peoples Gas faces stiff competition in the industrial market, which represented some 60% of its throughput in 2001. For example, in 2001 there was a significant quantity (Bcf) of highly competitive load exposed on the Peoples Gas system. The industrial market is highly concentrated, and thus, vulnerable to competition, with a handful of customers accounting for 50% of the volume. This heightened competitive threat to the Company's revenue stream can trigger a dangerous and sometimes irreversible spiral effect: any erosion of sales to high-volume users results in squeezed profit and possibly higher rates for residential users, which in turn leads to accelerated switching to alternative energy forms. Losing industrial customers would have a damaging effect on Peoples Gas's cash flow and financial ratios.

The risks of physical bypass have intensified since the implementation of FERC Order 636 and with the expansion of new interstate pipelines into the state. For the shorter-term, Peoples Gas's vulnerability is enhanced by the current economic slowdown, while the timing and magnitude of economic recovery remains uncertain. In short, the Company's demand risks have increased markedly in recent years, and are greater than the industry average.

SUPPLY RISK

Q. PLEASE EXPLAIN WHY THE SUPPLY RISKS FACED BY THE GAS DISTRIBUTION INDUSTRY HAVE INCREASED IN RECENT YEARS.

A. On the input end, the traditional buy-and-sell historical relationship between the regulated LDC and the pipeline supplier has ended, and a dramatic fundamental restructuring of this historical relationship has occurred.

Prior to 1975, long-term gas purchase contracts contained largely fixed prices with specific escalator indices set for the entire term of the contracts. From 1975 to 1986, government involvement in the natural gas industry led to government administered prices. Prior to 1986, uniform pricing did not permit differentiation of delivery conditions in gas purchase contracts. LDCs therefore had little price or contracting risk nor were they required to make choices as to the composition of gas supply portfolios.

Since deregulation, natural gas prices and delivery conditions are subject to market forces, and LDCs are now responsible for making decisions regarding prices, contract differentiation, and supply portfolio composition. The provision of gas supplies to its customers is therefore subject to greater risk of approval of these activities by the regulators. This risk is currently acute for two reasons. First, in general, regulators have limited experience in understanding the day-to-day dynamics of the open natural gas market. The continued evolving roles of LDCs in providing gas supplies to various customer groups who have several supply alternatives in a deregulated market complicate the decision process. Whether a LDC intends to be a competitive supplier or is required by regulation to be a supplier of last resort implies a very different set of prices, contract provisions, and portfolio choices.

Second, the rules of the game remain uncertain. This creates the risk that the decisions made by the LDC may not be acceptable to the regulators in hindsight.

Moreover, deregulation brings with it the ability for producers and other natural gas marketers to sell within the service area of Peoples Gas and other LDCs creating great uncertainty as to the size of market to be supplied. This risk and the reliance upon other parties for the security of supply and supply planning create a radically different supply risk for LDCs under deregulation.

Broad policy initiatives mandated by the FERC, which addressed open access and take-or-pay (TOP) resolution and were instituted under

Order Nos. 436 and 500, and the comparability of service in Orders 636 and 637, have increased and will continue to increase the level of risk associated with Peoples Gas's gas supply acquisition function. Peoples Gas used to experience this increased risk indirectly through Florida Gas Transmission Company ("FGT"), its main pipeline supplier, but now contends with this risk directly as a result of FGT's divestiture of its merchant function and the permanent assignment of upstream capacity, which would expand Peoples Gas' options for obtaining upstream capacity and supply and has enabled the Company to become a direct customer of other pipelines.

All aspects of the Company's business risks have been affected radically as a result of these various policy initiatives, and will continue to be affected. Supply-related risks have been particularly enhanced. The risks of gas procurement and reliable supply, transportation from production areas to the market, contract negotiations, take-or-pay liability, accounting, storage, measurement, and FERC-imposed surcharges have shifted from the merchant pipeline or others to the LDC. As a result, new competitive risks have appeared. For example, LDCs' customers have the opportunity to connect directly to the pipeline and convert their requirements to transportation service. The same business conditions that have the potential to cause this bypass risk can also cause end-users to shift to alternative fuels when the price of gas is driven upward. In essence, the producers and the pipeline affiliates see the LDC's historical customers as fair game and are aggressively pursuing gas sales or transportation agreements with large commercial customers and major industrial facilities.

Under the terms of the FERC's open-access ruling following FGT's application for unbundling, FGT obtained a blanket certificate to provide transportation and to provide interruptible gas sales both on and off the FGT system. The net result of this restructuring was to transpose the business risks previously borne by the pipeline onto the LDC. The risks of gas supply, transportation from production areas, contract uncertainties, take-or-pay liabilities, and storage previously assumed by the pipeline have become significant risks for the LDC such as PGS.

This fundamental restructuring reached its climax with the implementation of FERC Order 636, which fundamentally altered the natural gas industry by mandating total unbundling of transmission from sales, shifting risk to the LDC segment of the gas business.

In my judgment, Peoples Gas's supply risks are comparable to those of other gas distribution utilities, while its demand risks are slightly higher. The net result is that the Company's business risks slightly exceed the average risk of the industry.

REGULATORY and FINANCIAL RISKS

Q. PLEASE COMMENT ON THE REGULATORY AND FINANCIAL RISKS FACED BY PEOPLES GAS AT THIS TIME.

A. Regulatory risks have remained unchanged, and are lower relative to other LDCs. Take-or-pay ("TOP") exposure is limited. The FPSC has allowed full passthrough of TOP. With regard to bypass, the FPSC has approved special tariffs for large industrial customers with alternative competitive energy sources. Allowed returns have generally proved fair and reasonable.

With respect to Peoples Gas's financial risks, as manifested by its common equity ratio, they have essentially remained unchanged in recent years. Relative to the industry, the Company has a slightly higher common equity ratio. But in my judgment, its financial risks are equivalent to those of the industry. The company has no formal bond rating from the investment community for its debt securities, and is not a stand-alone capital market participant with a proven track record in the public securities markets. Its securities lack liquidity and trading volume.

In conclusion, Peoples Gas's total investment risk is comparable to that of the average LDC at this time, to the extent that its slightly above average business risks are offset by lower than average regulatory risks.

2. HISTORICAL RISK PREMIUM ESTIMATES

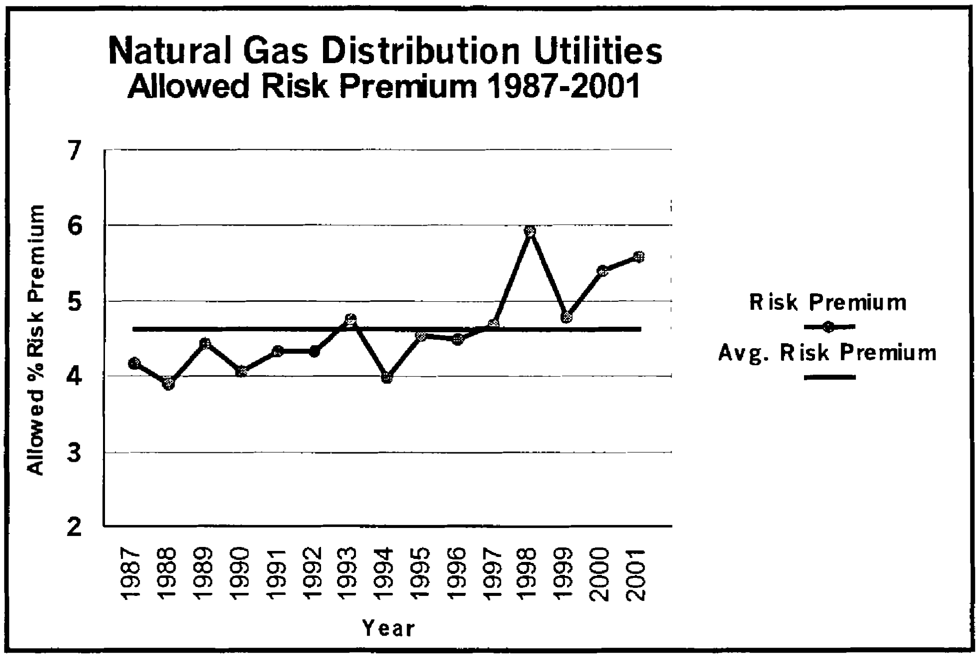
Q. PLEASE DESCRIBE YOUR HISTORICAL RISK PREMIUM ANALYSIS OF THE NATURAL GAS DISTRIBUTION INDUSTRY.

A. An historical risk premium for the Company was estimated with an annual time series analysis from 1955 to 2000 applied on the natural gas distribution industry as a whole, using Moody's Natural Gas Distribution Index as an industry proxy. Data for this particular index was unavailable prior to 1955. The analysis is depicted on Exhibit RAM-3. The risk premium was estimated by computing the actual return on equity capital for Moody's Index for each year from 1955 to 2000 using the actual stock prices and dividends of the index, and then subtracting the long-term government bond return for that year. The average risk premium over the period was 6.1% over long-term Treasury bonds. Given that long-term Treasury bonds are currently yielding 5.7%, the implied cost of equity for the average gas distribution utility from this particular method is 5.7% + 6.1% = 11.8%.

3. ALLOWED RISK PREMIUM

Q. PLEASE DESCRIBE YOUR ANALYSIS OF ALLOWED RISK PREMIUMS IN THE GAS DISTRIBUTION UTILITY INDUSTRY.

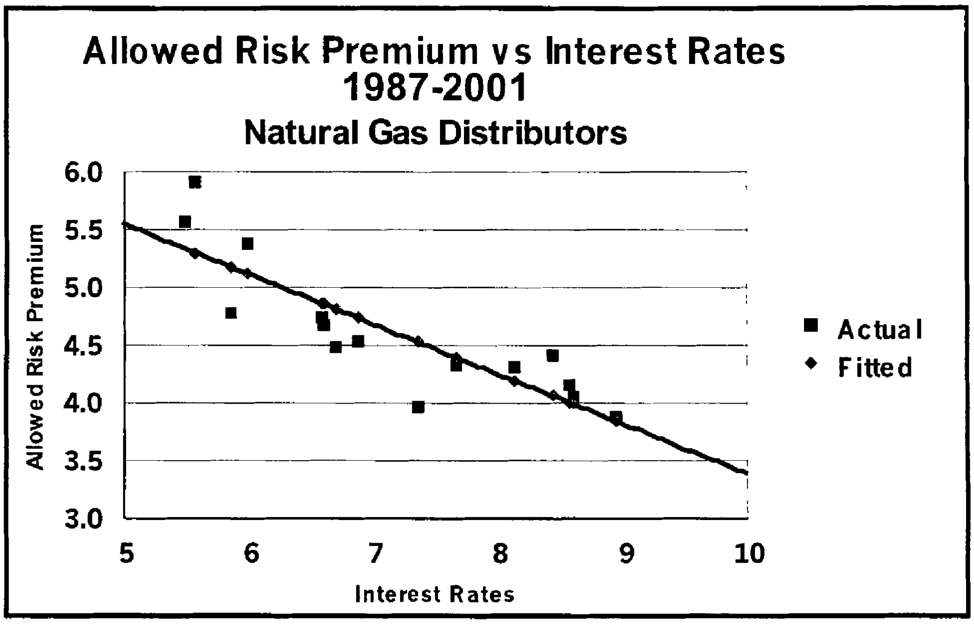
A. To estimate the Company's cost of common equity, I examined the historical risk premiums implied in the returns on equity ("ROEs") allowed by regulatory commissions in hundreds of natural gas utility ROE decisions over the period 1987-2001 relative to the contemporaneous level of the long-term Treasury bond yield. The average ROE spread over long-term Treasury yields was 4.6% for the 1987-2001 period as shown by the horizontal line in the graph below. The graph also shows the year-by-year allowed risk premium. The rising trend of the risk premium in response to rising competition and restructuring is noteworthy.



A more careful review of these ROE decisions relative to interest rates reveals a narrowing of the risk premium in times of rising interest rates, and a widening of the premium as interest rates fall. The following statistical relationship between the risk premium (RP) and interest rates (YIELD) emerges over the 1987-2000 period:

$$RP = 0.0772 - \underset{(t = 5.9)}{0.4317}\ YIELD \qquad R^2 = 0.73$$

The relationship is statistically significant as indicated by the high R^2 and statistically significant t-value of the slope coefficient. The figure below shows the inverse relationship between the allowed risk premium and interest rates as revealed in past ROE decisions.



Inserting the current long-term Treasury bond yield of 5.7% in the above equation suggests a risk premium estimate of 5.3% that would be allowed. This in turn implies an allowed ROE of 11.0%.

Q. PLEASE SUMMARIZE YOUR RISK PREMIUM ESTIMATES.

A. The table below summarizes the ROE estimates obtained from the various risk premium studies.

RISK PREMIUM STUDY	ROE
CAPM	10.8%
ECAPM	11.5%
Historical Risk Premium Gas Distribution	11.8%
Allowed Risk Premium Natural Gas Utilities	11.0%

B. DCF ESTIMATES

Q. PLEASE DESCRIBE THE DCF APPROACH TO ESTIMATING THE COST OF EQUITY CAPITAL.

A. According to DCF theory, the value of any security to an investor is the expected discounted value of the future stream of dividends or other benefits. One widely used method to measure these anticipated benefits in the case of a non-static company is to examine the current dividend plus the increases in future dividend payments expected by investors. This valuation process can be represented by the following formula, which is the traditional DCF model:

$$K_e = D_1/P_o + g$$

where: K_e = investors' expected return on equity

D_1 = expected dividend during the coming year

P_o = current stock price

g = expected growth rate of future dividends

The traditional DCF formula states that under certain assumptions, which are described in the next paragraph, the equity investor's expected return, K_e, can be viewed as the sum of an expected dividend yield, D_1/P_o, plus the expected growth rate of future dividends and stock price, g. The returns anticipated at a given market price are not directly observable and must be estimated from statistical market information. The idea of the market value approach is to infer 'K_e' from the observed share price and from an estimate of investors' expected future growth.

The assumptions underlying this valuation formulation are well known. The assumptions are discussed in detail in Chapter 4 of my book, Regulatory Finance. The traditional DCF model requires the following main assumptions: a constant average growth trend for both dividends and earnings, a stable dividend payout policy, a discount rate in excess of the expected growth rate, and a constant price-earnings multiple, which implies that growth in price is synonymous with growth in earnings and dividends. The traditional DCF model also assumes that dividends are paid annually when in fact dividend payments are normally made on a quarterly basis.

Q. HOW DID YOU ESTIMATE PEOPLES GAS' COST OF EQUITY WITH THE DCF MODEL?

A. I applied the DCF model to two proxies for the Company's gas distribution operations: a group consisting of widely-traded dividend-paying gas distribution companies drawn from the Value Line Gas Distribution Group and a group consisting of investment-grade combination gas and electric utilities whose revenues are predominantly from energy delivery utility operations.

To apply the DCF model, two components are required: the expected dividend yield (D_1/P_0) and the expected long-term growth (g). The expected dividend (D_1) in the annual DCF model can be obtained by multiplying the current indicated annual dividend rate by the growth factor (1 + g).

From a conceptual viewpoint, the stock price to employ is the current price of the security at the time of estimating the cost of equity. The reason is that current stock prices provide a better indication of expected future prices than any other price in an efficient market. An efficient market implies that prices adjust rapidly to the arrival of new information. Therefore, current prices reflect the fundamental economic value of a security. A considerable body of empirical evidence indicates that capital markets are efficient with respect to a broad set of information. This implies that observed current prices represent the fundamental value of a security, and that a cost of capital estimate should be based on current prices.

In implementing the DCF model, I have used the spot dividend yields reported in the May 2002 edition of the VLIS. I note that the vagaries of individual company stock prices are attenuated when using a large group of companies.

Q. HOW DID YOU ESTIMATE THE GROWTH COMPONENT OF THE DCF MODEL?

A. The principal difficulty in calculating the required return by the DCF approach is in ascertaining the growth rate that investors currently expect. Since no explicit estimate of expected growth is observable, proxies must be employed. As proxy for expected growth, I examined growth estimates developed by professional analysts employed by large investment brokerage institutions. Projected long-term growth rates actually used by institutional investors to determine the desirability of investing in different securities influence investors' growth anticipations. These forecasts are made by large reputable organizations, and the data are readily available to investors and are representative of the consensus view of investors. Because of the dominance of institutional investors in investment management and security selection, and their influence on individual investment decisions, analysts' growth forecasts influence investor growth expectations and provide a sound basis for estimating the cost of equity with the DCF model. Growth rate forecasts of several analysts are available from published investment newsletters and from systematic compilations of analysts' forecasts, such as those tabulated in Zacks Investment Research or Multex Investor Web sites. I have used analysts' long-term growth forecasts contained in Zacks as proxies for investors' growth expectations in applying the DCF model. I have also used Value Line's growth forecast as an additional proxy.

Q. WHAT DCF RESULTS DID YOU OBTAIN USING ANALYSTS' GROWTH FORECASTS FOR THE NATURAL GAS DISTRIBUTION UTILITY GROUP?

A. The initial group was described earlier in connection with beta estimates, and was displayed on Exhibit RAM-2. The same group was retained for the DCF analysis. However, for purposes of implementing the DCF model, non-dividend paying companies (AmeriGas Partners and Southern Union) were eliminated.

As shown on Column 4 of page 1 of Exhibit RAM-4, the average long-term earnings growth forecast from analysts obtained from the Zacks Web site is 7.1% for the natural gas distribution group. Adding this growth rate to the average expected dividend yield of 4.5% shown in Column 5 produces an estimate of equity costs of 11.6% for the gas distribution group, unadjusted for flotation costs. Allowance for flotation costs to the results of Column 6 brings the cost of equity estimate to 11.8%, shown in Column 7.

Repeating the exact same procedure on page 2 of Exhibit RAM-4, only this time using Value Line's long-term growth forecast of 9.2% instead of the Zacks consensus growth forecast, the cost of equity for the natural gas distribution group is 14.0%, unadjusted for flotation costs. Allowance for flotation costs brings the cost of equity estimate to 14.2%. Removing the outlying high estimate from Keyspan and the low estimate from Energen, the cost of equity estimate is 13.2%.

Q. WHAT DCF RESULTS DID YOU OBTAIN FOR THE COMBINATION GAS AND ELECTRIC UTILITIES?

A. Exhibit RAM-5 displays a group of 36 investment-grade dividend-paying combination gas and electric utilities. It is reasonable to postulate that the Company's natural gas distribution business possesses an investment risk profile similar to the activities of combination gas and electric utilities. These combination gas and electric companies possess economic characteristics similar to those of natural gas distribution utilities. They are both involved in the distribution of energy services products at regulated rates in a cyclical and weather-sensitive market. They both employ a capital-intensive network with similar physical characteristics. They are both subject to rate of return regulation.

As shown on Column 2 of page 1 of Exhibit RAM-5, the average long-term growth forecast obtained from Zacks is 6.5% for this group. Adding this growth rate to the average expected dividend yield of 4.8%

shown in Column 3 produces an estimate of equity costs of 11.3% for the group, unadjusted for flotation costs. Adding an allowance for flotation costs to the results of Column 4 brings the cost of equity estimate to 11.6%, shown in Column 5.

Using Value Line's long-term earnings growth forecast of 6.8% instead of the Zacks consensus forecast, the cost of equity for the combination gas and electric group is 11.7%, unadjusted for flotation costs. Allowance for flotation costs brings the cost of equity estimate to 11.9%. This analysis is displayed on page 2 of Exhibit RAM-5.

Q. PLEASE SUMMARIZE YOUR DCF ESTIMATES.

A. The table below summarizes the DCF estimates for the Company:

DCF STUDY	ROE
Natural Gas Distribution Zacks Growth	11.8%
Natural Gas Distribution Value Line Growth	13.2%
Combination Gas & Elec Zacks Growth	11.6%
Combination Gas & Elec Value Line Growth	11.9%

Q. PLEASE DESCRIBE THE NEED FOR A FLOTATION COST ALLOWANCE.

A. All the market-based estimates (CAPM, Risk Premium, DCF) reported above include an adjustment for flotation cost. The simple fact of the matter is that common equity capital is not free. Flotation costs associated with stock issues are exactly like the flotation costs associated with bonds and preferred stocks. Flotation costs are incurred, they are not expensed at the time of issue, and therefore must be recovered via a rate of return adjustment. This is routinely done for bond and preferred stock issues by most regulatory commissions. Clearly, the common equity capital accumulated by the Company through its parent TECO Energy was not cost-free. The flotation cost allowance to the cost of common equity capital is regularly discussed and applied in most corporate finance textbooks.

Flotation costs are very similar to the closing costs on a home mortgage. In the case of issues of new equity, flotation costs represent the discounts that must be provided to place the new securities. Flotation costs have a direct and an indirect component. The direct component is the compensation to the security underwriter for his marketing/consulting services, for the risks involved in distributing the issue, and for any operating expenses associated with the issue (printing, legal, prospectus, etc.). The indirect component represents the downward pressure on the stock price as a result of the increased supply of stock from the new issue. The latter component is frequently referred to as "market pressure".

Investors must be compensated for flotation costs on an ongoing basis to the extent that such costs are not expensed in the past, and therefore the adjustment must continue for the entire time that these initial funds are retained in the firm. Appendix A to my testimony discusses flotation costs in detail, and shows: 1) why it is necessary to apply an allowance of 5% to the dividend yield component of equity cost by dividing that yield by 0.95 (100% - 5%) to obtain the fair return on equity capital, 2) why the flotation adjustment is permanently required to avoid confiscation even if no further stock issues are contemplated, and 3) that flotation costs are only recovered if the rate of return is applied to total equity, including retained earnings, in all future years.

By analogy, in the case of a bond issue, flotation costs are not expensed but are amortized over the life of the bond, and the annual amortization charge is embedded in the cost of service. The flotation adjustment is also analogous to the process of depreciation, which allows the recovery of funds invested in utility plant. The recovery of bond flotation expense continues year after year, irrespective of whether the company issues new debt capital in the future, until recovery is complete, in the same way that the recovery of past investments in plant and equipment through depreciation allowances continues in the future even if no new construction is contemplated. In the case of common stock which has no finite life, flotation costs are not amortized. Thus, the recovery of flotation cost requires an upward adjustment to the allowed return on equity.

A simple example will illustrate the concept. A stock is sold for \$100, and investors require a 10% return, that is, \$10 of earnings. But if flotation costs are 5%, the company nets \$95 from the issue, and its common equity account is credited by \$95. In order to generate the same \$10 of earnings to the shareholders, from a reduced equity base, it is clear that a return in excess of 10% must be allowed on this reduced equity base, here 10.52%.

According to the empirical finance literature discussed in Appendix A, total flotation costs amount to 5% of gross proceeds. This in turn amounts to approximately 30 basis points. That is, dividing the average expected dividend yield of 6.0% for electric utility stocks by 0.95 yields 6.3%, which is 30 basis points higher.

Sometimes, the argument is made that flotation costs are real and should be recognized in calculating the fair return on equity, but only at the time when the expenses are incurred. In other words, the flotation cost allowance should not continue indefinitely, but should be made in the year in which the sale of securities occurs, with no need for continuing compensation in future years. This argument is valid only if the company has already been compensated for these costs. If not, the argument is without merit. My own recommendation is that investors be compensated for flotation costs on an on-going basis rather than through expensing, and that the flotation cost adjustment continue for the entire time that these initial funds are retained in the firm.

There are several sources of equity capital available to a firm including: common equity issues, conversions of convertible preferred stock, dividend reinvestment plans, employees' savings plans, warrants, and stock dividend programs. Each carries its own set of administrative costs and flotation cost components, including discounts, commissions, corporate expenses, offering spread, and market pressure. The flotation cost allowance is a composite factor which reflects the historical mix of sources of equity. The allowance factor is a build-up of historical flotation cost adjustments associated with and traceable to each component of equity at its source. It is impractical and prohibitively costly to start from the inception of a company and determine the source of all present equity. A practical solution is to identify general categories and assign one factor to each category. My recommended flotation cost allowance is a weighted average cost factor designed to capture the average cost of various equity vintages and types of equity capital raised by the Company.

III. SUMMARY & RECOMMENDATION

Q. PLEASE SUMMARIZE YOUR RESULTS AND RECOMMENDATION.

A. To arrive at my final recommendation, I performed four risk premium analyses. For the first two risk premium studies, I applied the CAPM and an empirical approximation of the CAPM using current market data. The other two risk premium analyses were performed on historical and allowed risk premium data from the natural gas distribution industry aggregate data. I also performed DCF analyses on two surrogates for Peoples Gas System's natural gas distribution business: a group consisting of investment-grade dividend-paying natural gas distribution utilities and a group of investment-grade combination gas and electric utilities. The results are summarized in the table below:

STUDY	COST OF EQUITY
CAPM	10.8%
ECAPM	11.5%
Historical Risk Premium Gas Distribution	11.8%
Allowed Risk Premium Gas Distribution	11.0%
DCF Comb Gas & Electrics Zacks Growth	11.6%
DCF Comb Gas & Electrics Value Line Growth	11.8%
DCF Natural Gas Zacks Growth	11.8%
DCF Natural Gas Value Line	13.2%

Both the average and median results from the various methodologies are 11.7%, or 11.75% to the nearest 25 basis points quartile.

Q. WHAT RATE OF RETURN DO YOU RECOMMEND AS PEOPLES GAS' COST OF EQUITY?

A. Based on the results of all my analyses and the application of my professional judgment, it is my opinion that a just and reasonable return on the common equity capital of Peoples Gas System's natural gas distribution operations at this time is 11.75%. Although a slightly higher return is warranted for the Company in view of its relatively small size, this risk is largely offset by the Company's sound capital structure and fair and reasonable regulatory climate.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

APPENDIX A

FLOTATION COST ALLOWANCE

To obtain the final cost of equity financing from the investors' expected rate of return, it is necessary to make allowance for underpricing, which is the sum of market pressure, costs of flotation, and underwriting fees associated with new issues. Allowance for market pressure should be made because large blocks of new stock may cause significant pressure on market prices even in stable markets. Allowance must also be made for company costs of flotation (including such items as printing, legal and accounting expenses) and for underwriting fees.

1. MAGNITUDE OF FLOTATION COSTS

According to empirical studies, underwriting costs and expenses average at least 4% of gross proceeds for utility stock offerings in the U.S. (See Logue & Jarrow: "Negotiations vs. Competitive Bidding in the Sale of Securities by Public Utilities", Financial Management, Fall 1978.) A study of 641 common stock issues by 95 electric utilities identified a flotation cost allowance of 5.0%. (See Borum & Malley: "Total Flotation Cost for Electric Company Equity Issues", Public Utilities Fortnightly, Feb. 20, 1986.)

Empirical studies suggest an allowance of 1% for market pressure in U.S. studies. Logue and Jarrow found that the absolute magnitude of the relative price decline due to market pressure was less than 1.5%. Bowyer and Yawitz examined 278 public utility stock issues and found an average market pressure of 0.72%. (See Bowyer & Yawitz, "The Effect of New Equity Issues on Utility Stock Prices", Public Utilities Fortnightly, May 22, 1980.)

Eckbo & Masulis ("Rights vs. Underwritten Stock Offerings: An Empirical Analysis", University of British Columbia, Working Paper No. 1208, Sept., 1987) found an average flotation cost of 4.175% for utility common stock offerings. Moreover, flotation costs increased progressively for smaller size issues. They also found that the relative price decline due to market pressure in the days surrounding the announcement amounted to slightly more than 1.5%. In a classic and monumental study published in the prestigious Journal of Financial Economics by a prominent scholar, a market pressure effect of 3.14% for industrial stock issues and 0.75% for utility common stock issues was found (see Smith, C.W., "Investment Banking and the Capital Acquisition Process," Journal of Financial Economics 15, 1986). Other studies of market pressure are reported in Logue ("On the Pricing of Unseasoned Equity Offerings, Journal of Financial and Quantitative Analysis, Jan. 1973), Pettway ("The Effects of New Equity Sales Upon Utility Share Prices," Public Utilities Fortnightly, May 10 1984), and Reilly and Hatfield ("Investor Experience with New Stock Issues," Financial Analysts' Journal, Sept.- Oct. 1969). In the Pettway study, the market pressure effect for a sample of 368 public utility equity sales was in the range of 2% to 3%. Adding the direct and indirect effects of utility common stock issues, the indicated total flotation cost allowance is above 5.0%, corroborating the results of earlier studies.

Therefore, based on empirical studies, total flotation costs including market pressure amount to approximately 5% of gross proceeds. I have therefore assumed a 5% gross total flotation cost allowance in my cost of capital analyses.

2. APPLICATION OF THE FLOTATION COST ADJUSTMENT

The section below shows: 1) why it is necessary to apply an allowance of 5% to the dividend yield component of equity cost by dividing that yield by 0.95 (100% - 5%) to obtain the fair return on equity capital, and 2) why the flotation adjustment is permanently required to avoid confiscation even if no further stock issues are contemplated. Flotation costs are only recovered if the rate of return is applied to total equity, including retained earnings, in all future years.

Flotation costs are just as real as costs incurred to build utility plant. Fair regulatory treatment absolutely must permit the recovery of these costs. An analogy with bond issues is useful to understand the treatment of flotation costs in the case of common stocks.

In the case of a bond issue, flotation costs are not expensed but are rather amortized over the life of the bond, and the annual amortization charge is embedded in the cost of service. This is analogous to the process of depreciation, which allows the recovery of funds invested in utility plant. The recovery of bond flotation expense continues year after year, irrespective of whether the company issues new debt capital in the future, until recovery is complete. In the case of common stock that has no finite life, flotation costs are not amortized. Therefore, the recovery of flotation cost requires an upward adjustment to the allowed return on equity. Roger A. Morin, Regulatory Finance, Public Utilities Reports Inc., Arlington, Va., 1994, provides numerical illustrations that show that even if a utility does not contemplate any additional common stock issues, a flotation cost adjustment is still permanently required. Examples there also demonstrate that the allowance applies to retained earnings as well as to the original capital.

From the standard DCF model, the investor's required return on equity capital is expressed as:

$$K = D_1/P_o + g$$

If P_o is regarded as the proceeds per share actually received by the company from which dividends and earnings will be generated, that is, P_o equals B_o, the book value per share, then the company's required return is:

$$r = D_1/B_o + g$$

Denoting the percentage flotation costs 'f', proceeds per share B_o are related to market price P_o as follows:

$$P - fP = B_o$$

$$P(1 - f) = B_o$$

Substituting the latter equation into the above expression for return on equity, we obtain:

$$r = D_1/P(1\text{-}f) + g$$

that is, the utility's required return adjusted for underpricing. For flotation costs of 5%, dividing the expected dividend yield by 0.95 will produce the adjusted cost of equity capital. For a dividend yield of 6% for example, the magnitude of the adjustment is 32 basis points: .06/.95 = .0632.

In deriving my DCF estimates of fair return on equity, it was therefore necessary to apply a conservative after-tax allowance of 5% to the dividend yield component of equity cost.

Even if no further stock issues are contemplated, the flotation adjustment is still permanently required to keep shareholders whole. Flotation costs are only recovered if the rate of return is applied to total equity, including retained earnings, in all future years, even if no future financing is contemplated. This is demonstrated by the numerical example contained in pages 6-8 of this Appendix. Moreover, even if the stock price, hence the DCF estimate of equity return, fully reflected the lack of permanent allowance, the company always nets less than the market price. Only the net proceeds from an equity issue are used to add to the rate base on which the investor earns. A permanent allowance for flotation costs must be authorized in order to insure that in each year the investor earns the required return on the total amount of capital actually supplied.

The example shown on pages 6-8 shows the flotation cost adjustment process using illustrative, yet realistic, market data. The assumptions used in the computation are shown on page 6. The stock is selling in the market for \$25, investors expect the firm to pay a dividend of \$2.25 that will grow at a rate of 5% thereafter. The traditional DCF cost of equity is thus $k = D/P + g = 2.25/25 + .05 = 14\%$. The firm sells one share stock, incurring a flotation cost of 5%. The traditional DCF cost of equity adjusted for flotation cost is thus $ROE = D/P(1\text{-}f) + g = .09/.95 + .05 = 14.47\%$.

The initial book value (rate base) is the net proceeds from the stock issue, which are $23.75, that is, the market price less the 5% flotation costs. The example demonstrates that only if the company is allowed to earn 14.47% on rate base will investors earn their cost of equity of 14%. On page 7, Column 1 shows the initial common stock account, Column 2 the cumulative retained earnings balance, starting at zero, and steadily increasing from the retention of earnings. Total equity in Column 3 is the sum of common stock capital and retained earnings. The stock price in Column 4 is obtained from the seminal DCF formula: $D_1/(k - g)$. Earnings per share in Column 6 are simply the allowed return of 14.47% times the total common equity base. Dividends start at $2.25 and grow at 5% thereafter, which they must do if investors are to earn a 14% return. The dividend payout ratio remains constant, as per the assumption of the DCF model. All quantities, stock price, book value, earnings, and dividends grow at a 5% rate, as shown at the bottom of the relevant columns. Only if the company is allowed to earn 14.47% on equity do investors earn 14%. For example, if the company is allowed only 14%, the stock price drops from $26.25 to $26.13 in the second year, inflicting a loss on shareholders. This is shown on page 8. The growth rate drops from 5% to 4.53%. Thus, investors only earn 9% + 4.53% = 13.53% on their investment. It is noteworthy that the adjustment is always required each and every year, whether or not new stock issues are sold in the future, and that the allowed return on equity must be earned on total equity, including retained earnings, for investors to earn the cost of equity.

ASSUMPTIONS:

ISSUE PRICE =	$25.00
FLOTATION COST =	5.00%
DIVIDEND YIELD =	9.00%
GROWTH =	5.00%
EQUITY RETURN = (D/P + g)	**14.00%**
ALLOWED RETURN ON EQUITY = (D/P(1-f) + g)	**14.47%**

COMPANY EARNS FLOTATION-ADJUSTED COST OF EQUITY
APPLIED ON ALL COMMON EQUITY
BEGINNING OF YEAR

YEAR	COMMON STOCK (1)	RETAINED EARNINGS (2)	TOTAL EQUITY (3)	STOCK PRICE (4)	MARKET/ BOOK RATIO (5)	EPS (6)	DPS (7)	PAYOUT (8)	CHANGE EARNINGS RETAINED (9)
1	$23.75	$0.000	$23.750	$25.000	1.0526	$3.438	$2.250	65.45%	$1.188
2	$23.75	$1.188	$24.938	$26.250	1.0526	$3.609	$2.363	65.45%	$1.247
3	$23.75	$2.434	$26.184	$27.563	1.0526	$3.790	$2.481	65.45%	$1.309
4	$23.75	$3.744	$27.494	$28.941	1.0526	$3.979	$2.605	65.45%	$1.375
5	$23.75	$5.118	$28.868	$30.388	1.0526	$4.178	$2.735	65.45%	$1.443
6	$23.75	$6.562	$30.312	$31.907	1.0526	$4.387	$2.872	65.45%	$1.516
7	$23.75	$8.077	$31.827	$33.502	1.0526	$4.607	$3.015	65.45%	$1.591
8	$23.75	$9.669	$33.419	$35.178	1.0526	$4.837	$3.166	65.45%	$1.671
9	$23.75	$11.340	$35.090	$36.936	1.0526	$5.079	$3.324	65.45%	$1.754
10	$23.75	$13.094	$36.844	$38.783	1.0526	$5.333	$3.490	65.45%	$1.842
			5.00%	5.00%		5.00%	5.00%		5.00%

COMPANY DOES NOT EARN THE FLOTATION-ADJUSTED COST OF EQUITY

YEAR	COMMON STOCK (1)	RETAINED EARNINGS (2)	TOTAL EQUITY (3)	STOCK PRICE (4)	MARKET/ BOOK RATIO (5)	EPS (6)	DPS (7)	PAYOUT (8)
1	$23.75	$0.000	$23.750	$25.000	1.0526	$3.325	$2.250	67.67%
2	$23.75	$1.075	$24.825	$26.132	1.0526	$3.476	$2.352	67.67%
3	$23.75	$2.199	$25.949	$27.314	1.0526	$3.633	$2.458	67.67%
4	$23.75	$3.373	$27.123	$28.551	1.0526	$3.797	$2.570	67.67%
5	$23.75	$4.601	$28.351	$29.843	1.0526	$3.969	$2.686	67.67%
6	$23.75	$5.884	$29.634	$31.194	1.0526	$4.149	$2.807	67.67%
7	$23.75	$7.225	$30.975	$32.606	1.0526	$4.337	$2.935	67.67%
8	$23.75	$8.627	$32.377	$34.082	1.0526	$4.533	$3.067	67.67%
9	$23.75	$10.093	$33.843	$35.624	1.0526	$4.738	$3.206	67.67%
10	$23.75	$11.625	$35.375	$37.237	1.0526	$4.952	$3.351	67.67%
			4.53%	4.53%		4.53%	4.53%	

RESUME OF ROGER A. MORIN

(Spring 2002)

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PRESENT EMPLOYER: Georgia State University
Robinson College of Business
Atlanta, GA 30303

RANK: Professor of Finance

HONORS: Professor of Finance for Regulated Industry & Director Center for the Study of Regulated Industry, College of Business, Georgia State University.

EDUCATIONAL HISTORY

- Bachelor of Electrical Engineering, McGill University, Montreal, Canada, 1967.
- Master of Business Administration, McGill University, Montreal, Canada, 1969.
- PhD in Finance & Econometrics, Wharton School of Finance, University of Pennsylvania, 1976.

EMPLOYMENT HISTORY

- Lecturer, Wharton School of Finance, Univ. of Pa., 1972-3
- Assistant Professor, University of Montreal School of Business, 1973-1976.
- Associate Professor, University of Montreal School of Business, 1976-1979.
- Professor of Finance, Georgia State University, 1979-2002
- Professor of Finance for Regulated Industry and Director, Center for the Study of Regulated Industry, College of Business, Georgia State University, 1985-2002
- Visiting Professor of Finance, Amos Tuck School of Business, Dartmouth College, Hanover, N.H., 1986

OTHER BUSINESS ASSOCIATIONS

- Communications Engineer, Bell Canada, 1962-1967.
- Member of the Board of Directors, Financial Research Institute of Canada, 1974-1980.
- Co-founder and Director Canadian Finance Research Foundation, 1977.
- Vice-President of Research, Garmaise-Thomson & Associates, Investment Management Consultants, 1980-1981.
- Executive Visions Inc., Board of Directors, Member
- Board of External Advisors, College of Business, Georgia State University, Member 1987-1991

PROFESSIONAL CLIENTS

AT & T Communications

Alagasco - Energen

Alaska Anchorage Municipal Light & Power

Alberta Power Ltd.

Ameren

American Water Works Company

Ameritech

Baltimore Gas & Electric

B.C. Telephone

B C GAS

Bell Canada

Bellcore

Bell South Corp.

Bruncor (New Brunswick Telephone)

Burlington-Northern

C & S Bank

Cajun Electric

Canadian Radio-Television & Telecomm. Commission

Canadian Utilities

Canadian Western Natural Gas

Centel

Centra Gas

Central Illinois Light & Power Co

Central Telephone

Central South West Corp.

Cincinnatti Gas & Electric

CONSULTING CLIENTS (CONT'D)

Cinergy Corp

Citizens Utilities

City Gas of Florida

CN-CP Telecommunications

Commonwealth Telephone Co.

Columbia Gas System

Consolidated Natural Gas

Constellation Energy

Deerpath Group

Edison International

Edmonton Power Company

Energen

Engraph Corporation

Entergy Corp.

Entergy Arkansas Inc.

Entergy Gulf States Utilities, Inc.

Entergy Louisiana, Inc.

Entergy New Orleans, Inc.

Florida Water Association

Fortis

Garmaise-Thomson & Assoc., Investment Consultants

Gaz Metropolitain

General Public Utilities

Georgia Broadcasting Corp.

Georgia Power Company

GTE California

CONSULTING CLIENTS (CONT'D)

GTE Northwest Inc

GTE Service Corp.

GTE Southwest Incorporated

Gulf Power Company

Havasu Water Inc.

Hope Gas Inc.

Hydro-Quebec

ICG Utilities

Illinois Commerce Commission

Island Telephone

Jersey Central Power & Light

Kansas Power & Light

Manitoba Hydro

Maritime Telephone

Metropolitan Edison Co.

Minister of Natural Resources Province of Quebec

Minnesota Power & Light

Mississippi Power Company

Mountain Bell

Nevada Power Company

Newfoundland Board of Public Utilities

Newfoundland Light & Power - Fortis Inc.

New Tel Enterprises Ltd.

New York Telephone Co.

Nova Scotia Utility and Review Board

Northern Telephone Ltd.

CONSULTING CLIENTS (CONT'D)

Northwestern Bell

Northwestern Utilities Ltd.

NUI Corp

NYNEX

OG&E

Oklahoma G & E

Ontario Telephone Service Commission

Orange & Rockland

Pacific Northwest Bell

People's Gas System Inc.

People's Natural Gas

Pennsylvania Electric Co.

Price Waterhouse

PSI Energy

Public Service Elec & Gas

Quebec Telephone

Regie de l'Energie du Quebec

Rochester Telephone

SaskPower

Sierra Pacific Power Company

Sierra Pacific Resources

Southern Bell

Southern States Utilities

South Central Bell

Sun City Water Company

TECO Energy

CONSULTING CLIENTS (CONT'D)

The Southern Company

Touche Ross and Company

Trans-Quebec & Maritimes Pipeline

US WEST Communications

Union Heat Light & Power

Utah Power & Light

Vermont Gas Systems Inc.

MANAGEMENT DEVELOPMENT AND PROFESSIONAL EXECUTIVE EDUCATION

- Canadian Institute of Marketing, Corporate Finance, 1971-73
- Hydro-Quebec, "Capital Budgeting Under Uncertainty, 1974-75
- Institute of Certified Public Accountants, Mergers & Acquisitions, 1975-78
- Investment Dealers Association of Canada, 1977-78
- Financial Research Foundation, bi-annual seminar, 1975-79
- Advanced Management Research (AMR), faculty member, 1977-80
- Financial Analysts Federation, Educational chapter: "Financial Futures Contracts" seminar
- Exnet Inc. a.k.a. The Management Exchange Inc., faculty member, 1981-2002, National Seminars:

  Risk and Return on Capital Projects

  Cost of Capital for Regulated Utilities

  Capital Allocation for Utilities

  Alternative Regulatory Frameworks

  Utility Directors' Workshop

  Shareholder Value Creation for Utilities

  Real Options in Utility Capital Investments

Fundamentals of Utility Finance in a Restructured Environment

- Georgia State University College of Business, Management Development Program, faculty member, 1981-1994

EXPERT TESTIMONY & UTILITY CONSULTING AREAS OF EXPERTISE

Rate of Return

Capital Structure

Generic Cost of Capital

Phase-in Plans

Costing Methodology

Depreciation

Flow-Through vs Normalization

Revenue Requirements Methodology

Utility Capital Expenditures Analysis

Risk Analysis

Capital Allocation

Divisional Cost of Capital, Unbundling

Publicly-owned Municipals

Telecommunications, CATV, Energy, Pipeline, Water

Incentive Regulation & Alternative Regulatory Plans

Shareholder Value Creation

Value-Based Management

REGULATORY BODIES:

Federal Communications Commission

Federal Energy Regulatory Commission

Georgia Public Service Commission

South Carolina Public Service Commission

North Carolina Utilities Commission

Pennsylvania Public Service Commission

Ontario Telephone Service Commission

Quebec Telephone Service Commission

Newfoundland Board of Commissioners of Public Utilities

Georgia Senate Committee on Regulated Industries

Alberta Public Service Board

Tennessee Public Service Commission

Oklahoma State Board of Equalization

Mississippi Public Service Commission

Minnesota Public Utilities Commission

Canadian Radio-Television & Telecommunications Comm.

New Brunswick Board of Public Commissioners

Alaska Public Utility Commission

National Energy Board of Canada

Florida Public Service Commission

Montana Public Service Commission

Arizona Corporation Commission

Quebec Natural Gas Board

Quebec Regie de l'Energie

New York Public Service Commission

Washington Utilities & Transportation Commission

Manitoba Board of Public Utilities

New Jersey Board of Public Utilities

Alabama Public Service Commission

Utah Public Service Commission

Nevada Public Service Commission

Louisiana Public Service Commission

Colorado Public Utilities Board

West Virginia Public Service Commission

Ohio Public Utilities Commission

California Public Service Commission

Hawaii Public Service Commission

Illinois Commerce Commission

British Columbia Board of Public Utilities

Indiana Utility Regulatory Commission

Minnesota Public Utilities Commission

Texas Public Service Commission

Michigan Public Service Commission

Iowa Board of Public Utilities

SERVICE AS EXPERT WITNESS

Southern Bell, So. Carolina PSC, Docket #81-201C

Southern Bell, So. Carolina PSC, Docket #82-294C

Southern Bell, North Carolina PSC, Docket #P-55-816

Metropolitan Edison, Pennsylvania PUC, Docket #R-822249

Pennsylvania Electric, Pennsylvania PUC,Docket#R-822250

Georgia Power, Georgia PSC, Docket # 3270-U, 1981

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Georgia Power, F.E.R.C., Docket # ER 80-326, 80-327

Georgia Power, F.E.R.C., Docket # ER 81-730, 80-731

Georgia Power, F.E.R.C., Docket # ER 85-730, 85-731

Bell Canada, CRTC 1987

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GTE-Quebec Telephone, Quebec PSC, Docket 84-052B

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Quebec Northern Telephone, Quebec PSC

Edmonton Power Company, Alberta Public Service Board

Kansas Power & Light, F.E.R.C., Docket # ER 83-418

NYNEX, FCC generic cost of capital Docket #84-800

Bell South, FCC generic cost of capital Docket #84-800

American Water Works - Tennessee, Docket #7226

Burlington-Northern - Oklahoma State Board of Taxes

Georgia Power, Georgia PSC, Docket # 3549-U

GTE Service Corp., FCC Docket #84-200

Mississippi Power Co., Miss. PSC, Docket U-4761

Citizens Utilities, Ariz. Corp. Comm., D # U2334-86020

Quebec Telephone, Quebec PSC, 1986, 1987, 1992

Newfoundland L & P, Nfld. Brd. Publ Comm. 1987, 1991

Northwestern Bell, Minnesota PSC, #P-421/CI-86-354

GTE Service Corp., FCC Docket #87-463

Anchorage Municipal Power & Light, Alaska PUC, 1988

New Brunswick Telephone, N.B. PUC, 1988

Trans-Quebec Maritime, Nat'l Energy Brd. of Cda, '88-92

Gulf Power Co., Florida PSC, Docket #88-1167-EI

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Mountain States Bell, Arizona CC, #E-1051-88-146

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Rochester Telephone, New York PSC, Docket # 89-C-022

Noverco - Gaz Metro, Quebec Natural Gas PSC, #R-3164-89

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Trans-Quebec Maritime Pipeline, Cdn. Nat'l Energy Board

Mountain Bell, Utah PSC,

Mountain Bell, Colorado PUB

South Central Bell, Louisiana PS

Hope Gas, West Virginia PSC

Vermont Gas Systems, Vermont PSC

Alberta Power Ltd., Alberta PUB

Ohio Utilities Company, Ohio PSC

Georgia Power Company, Georgia PSC

Sun City Water Company

Havasu Water Inc.

Centra Gas (Manitoba) Co.

Central Telephone Co. Nevada

AGT Ltd., CRTC 1992

BC GAS, BCPUB 1992

California Water Association, California PUC 1992

Maritime Telephone 1993

BCE Enterprises, Bell Canada, 1993

Citizens Utilities Arizona gas division 1993

PSI Resources 1993-5

CILCORP gas division 1994

GTE Northwest Oregon 1993

Stentor Group 1994-5

Bell Canada 1994-1995

PSI Energy 1993, 1994, 1995, 1999

Cincinnati Gas & Electric 1994, 1996, 1999

Southern States Utilities, 1995

CILCO 1995, 1999

Commonwealth Telephone 1996

Edison International 1996, 1998

Citizens Utilities 1997

Stentor Companies 1997

Hydro-Quebec 1998

Entergy Gulf States Louisiana 1998

Detroit Edison, 1999

Entergy Gulf States, Texas, 2000

Hydro Quebec TransEnergie, 2001

Sierra Pacific Company, 2000, 2001, 2002

Nevada Power Company, 2001

Mid American Energy, 2001, 2002

Entergy Louisiana Inc. 2001, 2002

Mississippi Power Company, 2001, 2002

Entergy Gulf States, Louisiana, 2001, 2002

Oklahoma Gas & Electric Company, 2002

Public Service Electric & Gas, 2001, 2002

NUI Corp (Elizabethtown Gas Company), 2002

Jersey Central Power & Light, 2002

PROFESSIONAL AND LEARNED SOCIETIES

- Engineering Institute of Canada, 1967-1972
- Canada Council Award, recipient 1971 and 1972
- Canadian Association Administrative Sciences, 1973-80
- American Association of Decision Sciences, 1974-1978
- American Finance Association, 1975-2002
- Financial Management Association, 1978-2002

ACTIVITIES IN PROFESSIONAL ASSOCIATIONS AND MEETINGS

- Chairman of meeting on "New Developments in Utility Cost of Capital", Southern Finance Association, Atlanta, Nov. 1982
- Chairman of meeting on "Public Utility Rate of Return", Southeastern Public Utility Conference, Atlanta, Oct. 1982
- Chairman of meeting on "Current Issues in Regulatory Finance", Financial Management Association, Atlanta, Oct. 1983
- Chairman of meeting on "Utility Cost of Capital", Financial Management Association, Toronto, Canada, Oct. 1984.
- Committee on New Product Development, FMA, 1985
- Discussant, "Tobin's Q Ratio", paper presented at Financial Management Association, New York, N.Y., Oct. 1986
- Guest speaker, "Utility Capital Structure: New

Developments", National Society of Rate of Return Analysts 18th Financial Forum, Wash., D.C. Oct. 1986

- Opening address, "Capital Expenditures Analysis: Methodology vs Mythology," Bellcore Economic Analysis Conference, Naples Fla., 1988.

PAPERS PRESENTED:

"An Empirical Study of Multiperiod Asset Pricing," annual meeting of Financial Management Assoc., Las Vegas Nevada, 1987.

"Utility Capital Expenditures Analysis: Net Present Value vs Revenue Requirements", annual meeting of Financial Management Assoc., Denver, Colorado, October 1985.

"Intervention Analysis and the Dynamics of Market Efficiency", annual meeting of Financial Management Assoc., San Francisco, Oct. 1982

"Intertemporal Market-Line Theory: An Empirical Study," annual meeting of Eastern Finance Assoc., Newport, R.I. 1981

"Option Writing for Financial Institutions: A Cost-Benefit Analysis", 1979 annual meeting Financial Research Foundation
"Free-lunch on the Toronto Stock Exchange", annual meeting of Financial Research Foundation of Canada, 1978.

"Simulation System Computer Software SIMFIN", HP International Business Computer Users Group, London, 1975.

"Inflation Accounting: Implications for Financial Analysis." Institute of Certified Public Accountants Symposium, 1979.

OFFICES IN PROFESSIONAL ASSOCIATIONS

- President, International Hewlett-Packard Business Computers Users Group, 1977

- Chairman Program Committee, International HP Business Computers Users Group, London, England, 1975

- Program Coordinator, Canadian Assoc. of Administrative Sciences, 1976

- Member, New Product Development Committee, Financial Management Association, 1985-1986

- Reviewer: Journal of Financial Research

  Financial Management

  Financial Review

  Journal of Finance

PUBLICATIONS

"Risk Aversion Revisited", Journal of Finance, Sept. 1983

"Hedging Regulatory Lag with Financial Futures," Journal of Finance, May 1983. (with G. Gay, R. Kolb)

"The Effect of CWIP on Cost of Capital," Public Utilities Fortnightly, July 1986.

"The Effect of CWIP on Revenue Requirements" Public Utilities Fortnightly, August 1986.

"Intervention Analysis and the Dynamics of Market Efficiency," Time-Series Applications, (New York: North Holland, 1983. (with K. El-Sheshai)

"Market-Line Theory and the Canadian Equity Market," Journal of Business Administration, Jan. 1982, M. Brennan, editor

"Efficiency of Canadian Equity Markets," International Management Review, Feb. 1978

"Intertemporal Market-Line Theory: An Empirical Test," Financial Review, Proceedings of the Eastern Finance Association, 1981

BOOKS

Utilities' Cost of Capital, Public Utilities Reports Inc., Arlington, Va., 1984.

Regulatory Finance, Public Utilities Reports Inc., Arlington, Va., 1994

Driving Shareholder Value, McGraw-Hill, January 2001

MONOGRAPHS

Determining Cost of Capital for Regulated Industries, Public Utilities Reports, Inc., and The Management Exchange Inc., 1982 - 1993. (with V.L. Andrews)

Alternative Regulatory Frameworks, Public Utilities Reports, Inc., and The Management Exchange Inc., 1993. (with V.L. Andrews)

Risk and Return in Capital Projects, The Management Exchange Inc., 1980, (with B. Deschamps)

Utility Capital Expenditure Analysis, The Management Exchange Inc., 1983.

Regulation of Cable Television: An Econometric Planning Model, Quebec Department of Communications, 1978.

''An Economic & Financial Profile of the Canadian Cablevision Industry''. Canadian Radio-Television & Telecommunication Commission (CRTC), 1978

Computer Users' Manual: Finance and Investment Programs, University of Montreal Press, 1974, revised 1978.

Fiber Optics Communications: Economic Characteristics, Quebec Department of Communications, 1978.

"Canadian Equity Market Inefficiencies", Capital Market Research Memorandum, Garmaise & Thomson Investment Consultants, 1979.

MISCELLANEOUS CONSULTING REPORTS

''Operational Risk Analysis: California Water Utilities, Calif. Water Association, 1993.

"Cost of Capital Methodologies for Independent Telephone Systems", Ontario Telephone Service Commission, March 1989.

"The Effect of CWIP on Cost of Capital and Revenue Requirements", Georgia Power Company,1985.

"Costing Methodology and the Effect of Alternate Depreciation and Costing Methods on Revenue Requirements and Utility Finances", Gaz Metropolitan Inc., 1985.

"Simulated Capital Structure of CN-CP Telecommunications: A Critique", CRTC, 1977.

"Telecommunications Cost Inquiry: Critique",CRTC,1977.

"Social Rate of Discount in the Public Sector", CRTC Policy Statement 1974.

"Technical Problems in Capital Projects Analysis", CRTC Policy Statement, 1974.

RESEARCH GRANTS

"Econometric Planning Model of the Cablevision Industry", International Institute of Quantitative Economics, CRTC

"Application of the Averch-Johnson Model to Telecommunications Utilities", Canadian Radio-Television Commission (CRTC)

"Economics of the Fiber Optics Industry", Quebec Dept. of Communications

"Intervention Analysis and the Dynamics of Market Efficiency", Georgia State Univ. College of Business, 1981

"Firm Size and Beta Stability", Georgia State University College of Business, 1982

"Risk Aversion and the Demand for Risky Assets", Georgia State University College of Business, 1981.

Chase Econometrics, Interactive Data Corp., Research Grant, $50,000 per annum, 1986-1989.

UNIVERSITY SERVICE

- University Senate, elected departmental senator 1987-1989, 1998-2002
- Faculty Affairs Committee, elected departmental representative
- Professional Continuing Education Committee member
- Director Master in Science (Finance) Program
- Course Coordinator, Corporate Finance, MBA program
- Chairman, Corporate Finance Curriculum Committee
- Executive Education: Departmental Coordinator 2000
- University Senate Committee on Commencement
- University Senate Committee on Student Discipline

NATURAL GAS DISTRIBUTION UTILITIES
BETA RISK MEASURES

	Company	Industry (1)	Beta (2)
1	AGL Resources	GASDISTR	0.60
2	AmeriGas Partners	GASDISTR	0.55
3	Atmos Energy	GASDISTR	0.55
4	Energen Corp.	GASDISTR	0.75
5	KeySpan Corp.	GASDISTR	0.55
6	NICOR Inc.	GASDISTR	0.60
7	New Jersey Resources	GASDISTR	0.60
8	Northwest Nat. Gas	GASDISTR	0.60
9	ONEOK Inc.	GASDISTR	0.80
10	Peoples Energy	GASDISTR	0.70
11	Piedmont Natural Gas	GASDISTR	0.60
12	Southern Union	GASDISTR	0.80
13	Southwest Gas	GASDISTR	0.65
14	UGI Corp.	GASDISTR	0.70
15	WGL Holdings Inc.	GASDISTR	0.60
	AVERAGE		**0.64**

Source: Value Line Investment Survey for Windows, 05/2002

MOODY'S NATURAL GAS DISTRIBUTION COMMON STOCKS
OVER LONG-TERM TREASURY BONDS
ANNUAL LONG-TERM RISK PREMIUM ANALYSIS

Year	Long-Term Government Bond Yield (1)	20 year Maturity Bond Value (2)	Gain/Loss (3)	Interest (4)	Bond Total Return (5)	Moody's Natural Gas Distribution Stock Index (6)	Dividend (7)	Capital Gain/(Loss) % Growth (8)	Yield (9)	Stock Total Return (10)	Equity Risk Premium (11)
1954	2.72%	1,000.00				26.47					
1955	2.95%	965.44	(34.56)	27.20	-0.74%	28.10	1.38	6.16%	5.21%	11.37%	12.11%
1956	3.45%	928.19	(71.81)	29.50	-4.23%	28.23	1.48	0.46%	5.27%	5.73%	9.96%
1957	3.23%	1,032.23	32.23	34.50	6.67%	25.78	1.49	-8.68%	5.28%	-3.40%	-10.07%
1958	3.82%	918.01	(81.99)	32.30	-4.97%	38.71	1.57	50.16%	6.09%	56.25%	61.21%
1959	4.47%	914.65	(85.35)	38.20	-4.71%	39.59	1.66	2.27%	4.29%	6.56%	11.28%
1960	3.80%	1,093.27	93.27	44.70	13.80%	48.21	1.84	21.77%	4.65%	26.42%	12.62%
1961	4.15%	952.75	(47.25)	38.00	-0.92%	64.96	1.94	34.74%	4.02%	38.77%	39.69%
1962	3.95%	1,027.48	27.48	41.50	6.90%	59.73	2.02	-8.05%	3.11%	-4.94%	-11.84%
1963	4.17%	970.35	(29.65)	39.50	0.99%	64.62	2.18	8.19%	3.65%	11.84%	10.85%
1964	4.23%	991.96	(8.04)	41.70	3.37%	68.24	2.30	5.60%	3.56%	9.16%	5.80%
1965	4.50%	964.64	(35.36)	42.30	0.69%	64.31	2.48	-5.76%	3.63%	-2.12%	-2.82%
1966	4.55%	993.48	(6.52)	45.00	3.85%	53.50	2.61	-16.81%	4.06%	-12.75%	-16.60%
1967	5.56%	879.01	(120.99)	45.50	-7.55%	50.49	2.74	-5.63%	5.12%	-0.50%	7.04%
1968	5.98%	951.38	(48.62)	55.60	0.70%	53.80	2.81	6.56%	5.57%	12.12%	11.42%
1969	6.87%	904.00	(96.00)	59.80	-3.62%	43.88	2.93	-18.44%	5.45%	-12.99%	-9.37%
1970	6.48%	1,043.38	43.38	68.70	11.21%	52.33	3.01	19.26%	6.86%	26.12%	14.91%
1971	5.97%	1,059.09	59.09	64.80	12.39%	47.86	3.07	-8.54%	5.87%	-2.68%	-15.06%
1972	5.99%	997.69	(2.31)	59.70	5.74%	53.54	3.12	11.87%	6.52%	18.39%	12.65%
1973	7.26%	867.09	(132.91)	59.90	-7.30%	43.43	3.28	-18.88%	6.13%	-12.76%	-5.46%
1974	7.60%	965.33	(34.67)	72.60	3.79%	29.71	3.34	-31.59%	7.69%	-23.90%	-27.69%
1975	8.05%	955.63	(44.37)	76.00	3.16%	38.29	3.48	28.88%	11.71%	40.59%	37.43%
1976	7.21%	1,088.25	88.25	80.50	16.87%	51.80	3.70	35.28%	9.66%	44.95%	28.07%
1977	8.03%	919.03	(80.97)	72.10	-0.89%	50.88	3.93	-1.78%	7.59%	5.81%	6.70%
1978	8.98%	912.47	(87.53)	80.30	-0.72%	45.97	4.18	-9.65%	8.22%	-1.43%	-0.71%
1979	10.12%	902.99	(97.01)	89.80	-0.72%	53.50	4.44	16.38%	9.66%	26.04%	26.76%
1980	11.99%	859.23	(140.77)	101.20	-3.96%	56.61	4.68	5.81%	8.75%	14.56%	18.52%
1981	13.34%	906.45	(93.55)	119.90	2.63%	53.50	5.12	-5.49%	9.04%	3.55%	0.92%
1982	10.95%	1,192.38	192.38	133.40	32.58%	50.62	5.39	-5.38%	10.07%	4.69%	-27.89%
1983	11.97%	923.12	(76.88)	109.50	3.26%	55.79	5.55	10.21%	10.96%	21.18%	17.92%
1984	11.70%	1,020.70	20.70	119.70	14.04%	69.70	5.88	24.93%	10.54%	35.47%	21.43%
1985	9.56%	1,189.27	189.27	117.00	30.63%	76.58	6.22	9.87%	8.92%	18.79%	-11.83%
1986	7.89%	1,166.63	166.63	95.60	26.22%	90.89	5.71	18.69%	7.46%	26.14%	-0.08%
1987	9.20%	881.17	(118.83)	78.90	-3.99%	77.25	6.02	-15.01%	6.62%	-8.38%	-4.39%
1988	9.18%	1,001.82	1.82	92.00	9.38%	86.76	6.30	12.31%	8.16%	20.47%	11.08%
1989	8.16%	1,099.75	99.75	91.80	19.16%	117.05	6.58	34.91%	7.58%	42.50%	23.34%
1990	8.44%	973.17	(26.83)	81.60	5.48%	108.86	6.84	-7.00%	5.84%	-1.15%	-6.63%
1991	7.30%	1,118.94	118.94	84.40	20.33%	124.32	6.99	14.20%	6.42%	20.62%	0.29%
1992	7.26%	1,004.19	4.19	73.00	7.72%	138.79	7.14	11.64%	5.74%	17.38%	9.66%
1993	6.54%	1,079.70	79.70	72.60	15.23%	154.06	7.30	11.00%	5.26%	16.26%	1.03%
1994	7.99%	856.40	(143.60)	65.40	-7.82%	126.96	7.44	-17.59%	4.83%	-12.76%	-4.94%
1995	6.03%	1,225.98	225.98	79.90	30.59%	155.94	7.56	22.83%	5.95%	28.78%	-1.81%
1996	6.73%	923.67	(76.33)	60.30	-1.60%	166.64	7.91	6.86%	5.07%	11.93%	13.54%
1997	6.02%	1,081.92	81.92	67.30	14.92%	191.04	8.02	14.64%	4.81%	19.46%	4.53%
1998	5.42%	1,072.71	72.71	60.20	13.29%	177.24	8.13	-7.22%	4.26%	-2.97%	-16.26%
1999	6.82%	848.41	(151.59)	54.20	-9.74%	178.02	8.22	0.44%	4.64%	5.08%	14.82%
2000	5.58%	1,148.30	148.30	68.20	21.65%	219.86	8.22	23.50%	4.62%	28.12%	6.47%
MEAN					**6.39%**					**12.44%**	**6.06%**

Source. Moody's Public Utility Manual 2001 December stock prices and dividends
Bond yields from Ibbotson Associates 2001 Yearbook Table B-9 Long-Term Government Bonds Yields December each year.

NATURAL GAS DISTRIBUTION UTILITIES
DCF ANALYSIS: ANALYSTS' GROWTH FORECASTS

	Company	Industry (1)	Beta (2)	% Current Divid Yield (3)	Analysts Growth Forecast (4)	Expected Divid Yield (5)	Cost of Equity (6)	ROE (7)
1	AGL Resources	GASDISTR	0.60	4.57	12.02	5.1	17.1	17.4
2	AmeriGas Partners	GASDISTR	0.55					
3	Atmos Energy	GASDISTR	0.55	4.95	6.36	5.3	11.6	11.9
4	Energen Corp.	GASDISTR	0.75	2.47	7.25	2.6	9.9	10.0
5	KeySpan Corp.	GASDISTR	0.55	4.95	7.86	5.3	13.2	13.5
6	NICOR Inc.	GASDISTR	0.60	3.91	6.60	4.2	10.8	11.0
7	New Jersey Resources	GASDISTR	0.60	3.72	8.05	4.0	12.1	12.3
8	Northwest Nat. Gas	GASDISTR	0.60	4.24	6.42	4.5	10.9	11.2
9	ONEOK Inc.	GASDISTR	0.80	2.75	9.40	3.0	12.4	12.6
10	Peoples Energy	GASDISTR	0.70	5.30	7.00	5.7	12.7	13.0
11	Piedmont Natural Gas	GASDISTR	0.60	4.24	6.15	4.5	10.7	10.9
12	Southern Union	GASDISTR	0.80					
13	Southwest Gas	GASDISTR	0.65	3.31	5.87	3.5	9.4	9.6
14	UGI Corp.	GASDISTR	0.70	5.08	5.88	5.4	11.3	11.5
15	WGL Holdings Inc.	GASDISTR	0.60	4.79	3.72	5.0	8.7	8.9
	AVERAGE		**0.64**	**4.2**	**7.1**	**4.5**	**11.6**	**11.8**

Notes:
Column 1, 2, 3: Value Line Investment Survey for Windows, 05/2002
Column 4: Zacks long-term earnings growth forecast, 06/2002
Column 5 = Column 3 times (1 + Column 4/100)
Column 6 = Column 5 + Column 4
Column 7 = (Column 5 /0.95) + Column 4
Non-dividend paying American Gas Partners and Southern Union excluded.

NATURAL GAS DISTRIBUTION UTILITIES
DCF ANALYSIS:VALUE LINE GROWTH PROJECTIONS

	Company	Industry (1)	% Current Divid Yield (2)	Value Line Proj Growth (3)	Expected Divid Yield (4)	Cost of Equity (5)	ROE (6)
1	AGL Resources	GASDISTR	4.57	9.5	5.0	14.5	14.8
2	AmeriGas Partners	GASDISTR		6.5			
3	Atmos Energy	GASDISTR	4.95	12.0	5.5	17.5	17.8
4	Energen Corp.	GASDISTR	2.47	5.5	2.6	8.1	8.2
5	KeySpan Corp.	GASDISTR	4.95	25.0	6.2	31.2	31.5
6	NICOR Inc.	GASDISTR	3.91	8.0	4.2	12.2	12.4
7	New Jersey Resources	GASDISTR	3.72	9.5	4.1	13.6	13.8
8	Northwest Nat. Gas	GASDISTR	4.24	7.5	4.6	12.1	12.3
9	ONEOK Inc.	GASDISTR	2.75	7.0	2.9	9.9	10.1
10	Peoples Energy	GASDISTR	5.30	7.5	5.7	13.2	13.5
11	Piedmont Natural Gas	GASDISTR	4.24	6.5	4.5	11.0	11.3
12	Southern Union	GASDISTR					
13	Southwest Gas	GASDISTR	3.31	5.0	3.5	8.5	8.7
14	UGI Corp.	GASDISTR	5.08	11.5	5.7	17.2	17.5
15	WGL Holdings Inc.	GASDISTR	4.79	7.5	5.1	12.6	12.9
	AVERAGE		**4.2**	**9.2**	**4.6**	**14.0**	**14.2**
	TRUNCATED AVERAGE						**13.2**

Notes:
Column 1, 2, 3: Value Line Investment Survey for Windows, 05/2002
Column 4 = Column 2 times (1 + Column 3/100)
Column 5 = Column 4 + Column 3
Column 6 = (Column 4 /0.95) + Column 3
Note: AmeriGas and Southern Union eliminated because they do not pay dividends

INVESTMENT GRADE COMBINATION GAS & ELEC UTILITIES
DCF ANALYSIS:ANALYSTS' GROWTH FORECASTS

	Company	% Current Divid Yield (1)	Analysts' Growth Forecast (2)	% Expected Divid Yield (3)	Cost of Equity (4)	ROE (5)
1	Allegheny Energy	4.7	7.4	5.1	12.5	12.7
2	Alliant Energy	7.1	5.3	7.5	12.8	13.1
3	Ameren Corp.	5.9	4.3	6.2	10.5	10.8
4	Aquila Inc.	7.2	8.1	7.8	15.9	16.3
5	Avista Corp.	2.9	6.0	3.1	9.1	9.3
6	CH Energy Group	4.2	5.0	4.4	9.4	9.6
7	CMS Energy Corp.	7.2	6.4	7.7	14.1	14.6
8	Cinergy Corp.	5.1	5.7	5.4	11.1	11.4
9	Conectiv	3.5	5.0	3.7	8.7	8.9
10	Consol. Edison	5.0	3.8	5.1	9.0	9.2
11	Constellation Energy	3.1	6.5	3.3	9.8	10.0
12	DTE Energy	4.6	6.7	4.9	11.6	11.9
13	Dominion Resources	3.9	9.7	4.3	14.0	14.2
14	Duke Energy	3.0	11.4	3.4	14.7	14.9
15	Energy East Corp.	4.3	5.6	4.6	10.2	10.4
16	Entergy Corp.	3.0	8.4	3.2	11.6	11.7
17	Exelon Corp.	3.2	7.4	3.4	10.7	10.9
18	MDU Resources	3.2	10.3	3.6	13.9	14.0
19	NSTAR	4.7	7.3	5.0	12.3	12.6
20	NiSource Inc.	5.1	6.5	5.4	11.9	12.2
21	NorthWestern Corp.	6.2	6.5	6.6	13.1	13.5
22	Northeast Utilities	2.8	3.0	2.8	5.8	6.0
23	PPL Corp.	3.8	8.6	4.2	12.8	13.0
24	Progress Energy	4.2	6.7	4.5	11.2	11.5
25	Public Serv. Enterprise	4.7	6.3	5.0	11.3	11.5
26	Puget Energy Inc.	4.9	5.3	5.2	10.4	10.7
27	RGS Energy Group	4.5	1.5	4.6	6.1	6.3
28	Reliant Energy	6.0	6.9	6.4	13.3	13.6
29	SCANA Corp.	4.2	5.0	4.4	9.4	9.7
30	Sempra Energy	4.0	7.3	4.3	11.5	11.7
31	TECO Energy	5.2	7.0	5.5	12.6	12.9
32	TXU Corp.	4.4	8.3	4.8	13.1	13.3
33	Vectren Corp.	4.3	7.3	4.6	11.9	12.1
34	WPS Resources	5.0	4.0	5.2	9.2	9.5
35	Wisconsin Energy	3.1	5.2	3.3	8.5	8.6
36	Xcel Energy Inc.	5.8	7.2	6.2	13.4	13.7
	AVERAGE	**4.6**	**6.5**	**4.8**	**11.3**	**11.6**

Notes:
Column 1: Value Line Investment Survey for Windows, 05/2002
Column 2: Zacks long-term earnings growth forecast, 06/2002
Column 3 = Column 1 times (1 + Column 2/100)
Column 4 = Column 3 + Column 2
Column 5 = (Column 3 /0.95) + Column 2

INVESTMENT GRADE COMBINATION GAS & ELEC UTILITIES
DCF ANALYSIS:VALUE LINE GROWTH PROJECTIONS

Company	% Current Divid Yield (1)	Proj EPS Growth (2)	% Expected Divid Yield (3)	Cost of Equity (4)	ROE (5)
1 Allegheny Energy	4.7	11.0	5.2	16.2	16.5
2 Alliant Energy	7.1	6.0	7.6	13.6	14.0
3 Ameren Corp.	5.9	3.0	6.1	9.1	9.4
4 Aquila Inc.	7.2	9.5	7.9	17.4	17.8
5 Avista Corp.	2.9	6.5	3.1	9.6	9.8
6 CH Energy Group	4.2	1.5	4.2	5.7	5.9
7 CMS Energy Corp.	7.2	2.5	7.4	9.9	10.3
8 Cinergy Corp.	5.1	4.5	5.3	9.8	10.1
9 Conectiv	3.5	6.0	3.8	9.8	9.9
10 Consol. Edison	5.0	2.5	5.1	7.6	7.9
11 Constellation Energy	3.1	8.5	3.4	11.9	12.0
12 DTE Energy	4.6	8.5	5.0	13.5	13.7
13 Dominion Resources	3.9	16.0	4.5	20.5	20.8
14 Duke Energy	3.0	11.5	3.4	14.9	15.0
15 Energy East Corp.	4.3	3.0	4.5	7.5	7.7
16 Entergy Corp.	3.0	7.5	3.2	10.7	10.8
17 Exelon Corp.	3.2	7.4	3.4	10.7	10.9
18 MDU Resources	3.2	5.0	3.4	8.4	8.6
19 NSTAR	4.7	4.5	4.9	9.4	9.6
20 NiSource Inc.	5.1	14.0	5.8	19.8	20.1
21 NorthWestern Corp.	6.2	7.5	6.7	14.2	14.5
22 Northeast Utilities	2.8	3.0	2.8	5.8	6.0
23 PPL Corp.	3.8	7.0	4.1	11.1	11.3
24 Progress Energy	4.2	10.5	4.7	15.2	15.4
25 Public Serv. Enterprise	4.7	6.5	5.0	11.5	11.7
26 Puget Energy Inc.	4.9	2.0	5.0	7.0	7.3
27 RGS Energy Group	4.5	1.5	4.6	6.1	6.3
28 Reliant Energy	6.0	6.0	6.3	12.3	12.7
29 SCANA Corp.	4.2	7.0	4.5	11.5	11.8
30 Sempra Energy	4.0	7.5	4.3	11.8	12.0
31 TECO Energy	5.2	6.0	5.5	11.5	11.8
32 TXU Corp.	4.4	8.5	4.8	13.3	13.5
33 Vectren Corp.	4.3	11.0	4.8	15.8	16.0
34 WPS Resources	5.0	5.0	5.3	10.3	10.5
35 Wisconsin Energy	3.1	8.5	3.4	11.9	12.1
36 Xcel Energy Inc.	5.8	9.0	6.3	15.3	15.6
AVERAGE	**4.6**	**6.8**	**4.9**	**11.7**	**11.9**

Notes:
Column 1, 2: Value Line Investment Survey for Windows, 05/2002
Column 3 = Column 1 times (1 + Column 2/100)
Column 4 = Column 3 + Column 2
Column 5 = (Column 3 /0.95) + Column 2
Growth rate unavailable for Exelon, Northeast Util; used Value Line growth

PEOPLES GAS SYSTEM

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

Docket No. 020384-GU

In Re: Application for a rate increase by Tampa Electric Company d/b/a Peoples Gas System

Submitted for Filing: 6/27/2002

DIRECT TESTIMONY AND EXHIBIT OF:

WRAYE J. GRIMARD
On Behalf of Peoples Gas System

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Wraye J. Grimard. My business address is 702 North Franklin Street, Tampa, Florida 33602.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am Manager, Regulatory Planning, for Peoples Gas System ("Peoples" or the "Company").

Q. HOW LONG HAVE YOU BEEN EMPLOYED BY PEOPLES?

A. I have been employed by Peoples since May 1981. I have served in many areas of the Company including customer service and marketing. In 1988 I joined the Gas Transportation and Supply group where I was privileged to participate in the development of Peoples' philosophy and business strategies relating to the forthcoming restructuring of the natural gas industry in Florida. In June 1997, I was appointed Manager, Gas Acquisition and Supply, and in July 1999 I became the Manager of Industrial and Transportation Services. At that point, I was assigned the task of leading the effort to "unbundle" the gas supply and distribution functions, both of which had previously been performed by Peoples for its customers, and transition the Company, at least for its commercial customers, to a transportation provider rather than a seller of gas. In December 2000, I was appointed Manager, Regulatory Planning.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to sponsor the portions of the Minimum Filing Requirements ("MFRs") related to cost of service and rate design. These schedules of the MFRs are identified in Exhibit WJG-1 and were prepared by me or under my supervision.

I will provide an overview of the current market environment in which Peoples competes for business, and market risks currently affecting Peoples. I will also generally describe the components of the Cost of Service Study (MFR Schedules H-1 through H-3), how the study was developed, and the results.

Schedule E-9 of the MFRs consists of the Company's proposed new tariff sheets. I will describe the rate design philosophy used in designing the proposed rates and how the proposed rate changes differ from Peoples' present rate structure.

Finally, I will describe various other non-rate changes that Peoples proposes to make in its natural gas tariff.

Q. WHAT IS THE TOTAL AMOUNT OF REVENUE RELIEF THAT THE COMPANY IS SEEKING IN THIS PROCEEDING?

A. The Company is seeking to adjust its rates in order to recover an overall cost of service of $170.8 million. This, when compared to the projected test year cost of service at present rates of $148.2 million, results in a revenue increase of approximately $22.6 million.

Q. HAVE THERE BEEN SIGNIFICANT CHANGES IN THE BUSINESS ENVIRONMENT IN WHICH THE COMPANY COMPETES?

A. Yes. Since the Company's last rate case filing, which was over 10 years ago, the natural gas industry has become much more competitive, and there have been a plethora of dramatic changes in operating practices. Federal initiatives, including the Federal Energy Regulatory Commission's ("FERC") Order 636, have dramatically altered the traditional market and other relationships between producers, transporters, distributors, and end-users. Also ensuing from FERC Order 636 is an unpredictable and sometimes robust secondary capacity market. The industry has also evolved through the development and implementation of the NYMEX natural gas contract, various pricing indices, and access to risk-management tools. These are all relatively recent products that were not available to customers prior to FERC Order 636.

Q. PLEASE IDENTIFY HOW BUSINESS RISKS HAVE BEEN SHIFTED TO PEOPLES GAS AS A RESULT OF THESE CHANGES.

A. In the past, the interstate pipeline bore all risks associated with gas supply, transportation from production areas, marketability, contract failures, storage or inventory charges, take-or-pay liability, line loss, compressor fuel use and surcharges of almost every kind. During that time, the Company simply purchased, on a commodity basis, either firm or interruptible gas from interstate pipelines at their FERC-approved tariff rates, and then provided retail service to its end-use customers at its Florida Public Service Commission ("FPSC" or "Commission") approved tariff rates plus the commodity cost of the gas.

Since FERC Order 636 and the subsequent regulatory and market changes, these business risks of gas procurement and reliable supply, marketability of supply, transportation from production areas to the market, contract negotiations, take-or-pay liability, measurement, accounting, storage, line loss, compressor fuel, and FERC-imposed surcharges are risks that have been removed from the interstate pipelines or others and assumed by the Company.

Q. WHAT EFFECT HAVE THESE CHANGES HAD ON THE BUSINESS ENVIRONMENT IN WHICH PEOPLES OPERATES?

A. The federal regulatory policy of the past several years relative to natural gas has been clear. Aimed at introducing more competition into the marketplace, FERC orders have put market forces into play that have significantly changed the traditional relationships between the customer and the local distribution company ("LDC"), and also between the LDC and the traditional pipeline supplier. As an example, natural gas marketers are now a major component of the relationship between the interstate pipelines, LDCs and customers, when previously they had little influence.

The increase in gas-fired electric generation in the Florida market has further exacerbated operational complexities. The enormous amount of peak-hour demand required by these new gas-fired generators has a direct impact on the day-to-day market for natural gas supplies and capacity available to the Company and its transportation customers. These large "super-users" can swing a pipeline's line pack in a matter of hours, resulting in Alert Days or Operational Flow Orders for all interstate pipeline customers including the Company. The resulting financial and operational risks fall squarely on the Company as well.

Q. HOW HAVE RECENTLY ADOPTED COMMISSION RULES AND OTHER REGULATORY INITIATIVES AFFECTED PEOPLES' BUSINESS RISKS?

A. Since Peoples' last rate proceeding, both Peoples and the Commission have stayed in step with federal initiatives to provide an open and competitive natural gas marketplace in the State of Florida. Prior to Peoples' last rate proceeding in 1992, transportation service was available to no more than two dozen of the Company's large end-users. In its last rate case, Peoples lowered its minimum threshold for individual transportation customers from 1,000,000 therms to 500,000 therms annually. Thereafter, through a series of orders, Peoples has provided an aggregation program for customers owned by the same entity, and introduced two pilot aggregation programs to test the feasibility of providing transportation service to small commercial end-users, (Order Nos. PSC-95-1539-FOF-GU, PSC-96-1515-FOF-GU, PSC-98-0270-FOF-GU, PSC-99-0487-FOF-GU and PSC-00-0586-AS-GU). Peoples plans to continue those initiatives introduced by the Commission through its proposal in this filing to lower its Individual Transportation Service (ITS) threshold in its Non-West Florida service areas to match the former West Florida Natural Gas threshold of 182,500 therms annually.

In February 2000, the Commission adopted Rule 25-7.0335, Florida Administrative Code, which required all LDCs to offer transportation service to all non-residential customers. In November 2000, Peoples opened up its transportation service to all non-residential customers in accordance with the rule. As a result, Peoples now has over 8,000 transportation customers that transport approximately 75% of Peoples' total throughput on a daily basis.

As a result of these changes, Peoples has been required to assume significant additional administrative and operational responsibilities, such as becoming the "Delivery Point Operator" under Florida Gas

Transmission Company's ("FGT") FERC-approved interstate pipeline tariff. The Delivery Point Operator has sole responsibility for balancing scheduled quantities with actual customer demand on a daily basis. In order to maintain a balanced system, an LDC must perform daily activities that include demand forecasting, economic evaluation of the NYMEX and cash markets, dealing with individual customer outages or extraordinary demand needs, and reviewing and determining the effect on supply and demand of weather information, such as severe tropical weather affecting supply, or winter weather affecting demand in Florida as well as other areas of the country. Further, the LDC must maintain frequent contact with the interstate pipelines, customers, gas suppliers, and Pool Managers. To perform its Delivery Point Operator responsibilities, Peoples has updated its Supervisory Control and Data Acquisition ("SCADA") system and remote metering systems, as well as implemented its Gas Management System, Marketer Billing System, Volume Allocation System, and Individual Transportation Customer Tracking System.

Q. PLEASE DESCRIBE CURRENT COMPETITIVE MARKET RISKS FACED BY PEOPLES GAS.

A. A major portion of Peoples' competitive risk is attributable to the large industrial end-users on the Company's system. As a result of FERC Order 636, a number of these customers acquired the potential to bypass Peoples' system and connect directly to an interstate pipeline. These existing customers can connect directly to the FGT system and obtain direct transportation service from the pipeline, completely bypassing Peoples' distribution system. Courts in other states have ruled that the physical bypass of a LDC's system is not within the jurisdiction of the state public utility commission.

In addition to the on-going risk of physical bypass of the Peoples system, many customers operate internally on a facility-by-facility basis. In other words, a plant in Jacksonville may displace product produced in Georgia because the Jacksonville facility's production costs are lower. This is referred to as "economic bypass" and it is a tool used by many industrial-manufacturing customers to manage production costs. Thus, if a customer with multiple manufacturing facilities finds that its delivered cost of gas in Florida exceeds its delivered cost of gas for a facility in another state, it may shift the production of its product from the Florida facility to the one outside the state.

The Company also faces competition from alternative fuels, including diesel, #6 fuel oil, and waste oil. Peoples has lost several large asphalt plants over the past several years because these plants chose to burn waste oil, a product that comes from used vehicle motor oil that has been "cleaned." The waste oil is then sold to asphalt plants with cost savings that are not within reach of natural gas.

In addition, new interstate pipeline projects that will serve Central Florida have recently been completed. Although these pipelines are targeting electric generators as their primary customers, they are fully capable of providing direct service to existing and potential LDC customers whose plants are adjacent to the new pipeline routes. Gas-on-gas competition has become more evident over the past few years. For example, LDCs and municipalities are now actively competing against each other to provide natural gas in territories that have never before been served by natural gas.

Last, competition directed at Peoples' industrial customers and from other LDCs and municipalities is not the only competition facing the Company. Many of Peoples' small and mid-size commercial customers have a choice of using either natural gas, propane, electricity, or another fuel in their operations. Residential customers also can choose propane or electricity instead of natural gas. These on-going competition-driven business risks have created significant new challenges for Peoples. In particular, Peoples must maintain its rates at a competitive level in order to retain its large industrial customer base, as well as those commercial customers who have clear choices in the fuels they can use. These competitive forces have contributed to a shift in cost responsibility among the rate classes served by Peoples.

Q. WHAT TOTAL VOLUME OF NEW GAS LOAD DOES PEOPLES ADD TO ITS SYSTEM EACH YEAR?

A. The Company is currently adding high priority customers with requirements of approximately 75 million therms per year in the aggregate. However, these additional sales and transportation volumes continue to be partially offset by reductions in throughput resulting from conservation, continuing customer attrition, primarily in the inner city areas of our service areas, and warmer than normal weather for the past several years.

Q. HOW MANY AND WHAT TYPES OF CUSTOMERS WERE ADDED TO PEOPLES' SYSTEM DURING THE HISTORIC BASE

YEAR?

A. During that period Peoples added 20,107 new customers with a total anticipated annual consumption of 71.4 million therms. Of these customers, 18,207 were residential and 1,900 were commercial and industrial end users.

Q. PLEASE EXPLAIN HOW THE COST OF SERVICE STUDY WAS DEVELOPED.

A. The Cost of Service Study was segmented and developed in three stages. All costs were classified as being customer related, capacity related, commodity related or revenue related. Then customer classes were defined and the classified costs were allocated to the defined customer classes.

Q. PLEASE EXPLAIN HOW CUSTOMER COSTS WERE CLASSIFIED.

A. Costs that are affected directly by the number of customers served are classified as customer related. These are generally costs that are incurred to connect customers to the distribution system, meter their usage and maintain their accounts. Other costs such as meter reading, which is a function of the number of customers served, are also included in this category.

Capacity costs relate to the peak usage of gas by the utility's customers. Capacity costs are incurred to ensure that the system is ready to serve its customers at peak requirement levels. They reflect the theoretical distribution system that would be needed to serve high priority customers at peak load conditions. These costs are generally considered to be "fixed", and are incurred whether or not a customer uses any gas.

Commodity costs are costs that vary in direct proportion to the volume of gas consumed during a period of time.

Revenue related costs are assigned based on the percentage of total revenue received from each class of customer. These costs vary with the amount of sales revenue collected by the Company.

Q. PLEASE EXPLAIN HOW CUSTOMER CLASSES WERE DEFINED.

A. Customer classes were defined by identifying the natural breaks (minimum annual thresholds) that occur when examining various customer end uses. These customer classes typically have similar load profiles. They are also comparable in terms of the type and size of facilities Peoples needs to install in order to serve them. Therefore, they have similar costs associated with the service to each class.

Q. PLEASE EXPLAIN THE NEXT STEP IN THE PROCESS.

A. The next step was the allocation process. The allocation process involves the distribution or assignment of the classified costs to the individual customer classes.

Where it could be determined that a specific cost was caused by a certain rate class, that cost was assigned directly to that rate class. This is especially true in the case of the GS-5 through ISLV customers, where costs related to the investment in meters, regulators, and services is generally available from the Company's plant records.

The remaining costs were assigned by applying allocation factors that attempt to distribute the costs based on causal relationships between the customer classes and the classified costs. Customer related costs are allocated based on the weighted average number of customers in each rate class. Capacity costs are typically allocated based on each rate class's contribution to the total system throughput using an arithmetic average of the peak month therm sales and the average of the remaining eleven months (the "Peak and Average Method"). However, Peoples has allocated some capacity related costs by determining the miles of pipe (based on construction material and inside diameter) used by each rate class. Also, those capacity related costs for the GS-5 through the ISLV rate classes that were identified as specifically being caused by such customers were directly assigned to those classes. The balance of the capacity costs was allocated based on the Peak and Average Method.

Since Peoples' last rate proceeding, Peoples has curtailed its interruptible customers three times for periods of one to several days due to severe weather and force majeure events that occurred on the primary interstate pipeline in Florida. In addition, there have been instances where specific sections of Peoples' distribution system have reached peak capacity. When this has occurred, the Company has curtailed interruptible customers to preserve the system's integrity. In view of this, a weighting factor has been assigned to each firm customer class to give recognition to the theoretical burden that each class would impose on the system when peak conditions exist.

Commodity costs were allocated based on the total annual throughput by customer class. Revenue related costs were allocated on the basis of total revenue contribution by each rate class.

These allocations were used to arrive at an overall cost of service applicable to each rate class.

Finally, the cost of service for each class was divided by the total billing determinants in the projected test year for the class to derive unitized costs for the rate class. These were then used as guides in developing the proposed rate design.

Q. PLEASE DESCRIBE PEOPLES' DIAMETER OF PIPE ALLOCATION METHODOLOGY AND THE REASONS FOR ITS USE.

A. The diameter of pipe method of allocating capacity costs utilizes a breakdown of pipeline mains by construction material and inside diameter. This breakdown is shown on Exhibit WJG-2. This methodology has been used because Peoples' overall system investment is dominated by high priority related investments. Peoples' pipelines are by far its largest investment. In the case of allocating its rate base (Account 376 – Mains) that has been classified as capacity related, Peoples believes this allocation method is more appropriate because a relatively small part of Peoples' investment in this account is used to serve industrial customers. Further, if the total cost of the lines not assigned to industrial customers were allocated on the basis of volumetric consumption, the industrial customers would have to assume the cost of service associated with far more gas lines than they utilize. The use of volumetric consumption (i.e., the Peak and Average Method) alone for allocating capacity costs to interruptible customers is inappropriate because interruptible customers do not add to the peaking requirements of the LDC. FERC, Florida and other states have recognized this disparity and cross subsidization problem. In Peoples' last three rate cases, the Commission has taken corrective measures to more appropriately allocate costs.

Q. WHAT IS THE PHILOSOPHY OF PEOPLES WITH RESPECT TO RATE DESIGN?

A. Peoples proposes to continue using the cost of service basis for designing rates for its various classes of customers. As discussed previously, the Cost of Service Study is designed to produce unitized class costs based on causal relationships and utilizing various allocation factors. Some of these allocation factors have been employed to more accurately reflect the costs associated with serving specific rate classes. The result was a gradual shift in the cost of service away from interruptible and large commercial customers, which resulted in a lower, more equitable level of rate responsibility relative to that allocated to high priority customers. Because of the competitive nature of the energy industry in general, a cost study should not be simply a formula based accounting for costs by rate classes. A substantial amount of judgment is required to appropriately allocate and assign costs. The utility's business strategy, market area and competitive position must all be considered to develop the appropriate rate design. Within the Cost of Service Study, an understanding of the mechanical process used to allocate the costs is necessary, but consideration must also be given to economic, regulatory and competitive issues. In this proceeding, Peoples is requesting rates for each class of service commensurate with the cost to serve that class.

Relative to the Company's interruptible customers, over the past six years, Peoples has had three system-wide curtailment events plus several local curtailments that were required to maintain system integrity. While local curtailments are limited to specific geographic locations, system-wide curtailments affect all interruptible customers and are called in an effort to balance supply and demand at the system level. Peoples has curtailed twice (system-wide) as a result of force majeure events on the primary interstate pipeline feeding peninsular Florida. In February 1996, Peoples curtailed (system-wide) due to extremely cold weather. In addition, several times throughout the summer periods, many of our interruptible and transportation customers have been placed on a demand allocation that has required their consumption to equal their confirmed scheduled volumes. The continuation of the interruptible rates at or below their present level will better position the Company to compete against the on-going threat of bypass or alternate fuel use by large industrial customers.

Q. WHAT FACTORS DID YOU CONSIDER IN DESIGNING THE COMPANY'S PROPOSED RATE SCHEDULES?

A. Many factors were considered in an attempt to ensure that the rate design would be reasonable and fair to each customer class. While consideration was given to rate history, value of service, consumption and load profile, risk of alternate fuel competition and bypass potential. However, the factors considered most critical were the results of the Cost of Service Study and the competitive position of the Company in the marketplace. All natural gas customers have fuel alternatives, and most of them are becoming increasingly sophisticated in considering their energy sources.

An LDC's system is vulnerable to competition from alternative fuels in every class of customer it serves, with emphasis on the mid-level commercial classes through the largest industrial users. Likewise, within the residential service class, fuel price is only one factor that a homebuilder considers. There are numerous non-price issues in all customer classes that affect fuel selections, such as maintenance, fuel storage, emissions levels, appliance efficiency, comfort and aesthetics.

In its last three rate cases, Peoples has made efforts to more appropriately group similarly situated customers (those who enjoy similar load profiles and who place a similar value on their natural gas service) into the same rate class. In this proceeding Peoples has continued these efforts. The Company's proposed rate design utilizes a cost of service study as a starting point, but the final rate proposals have been developed with appropriate adjustments in consideration of the issues discussed above.

Finally, the rate structures were designed to make uniform the former West Florida and current Peoples' rates. The uniformity in rates and tariffs will help to simplify the administration of Peoples' rates and other tariff provisions as well as facilitate the development of future rate design and service offerings.

Q. HOW DOES THE PROPOSED RATE STRUCTURE DIFFER FROM THE PRESENT RATE STRUCTURE?

A. The proposed rate structure differs from the current rate structure in that Peoples has continued to expand the number of rate classes to result in a more equitable distribution of the costs involved in serving the various classes. The Company has also modified threshold levels in the Commercial and Small Interruptible rate classes to more accurately reflect similar end use patterns such as annual volume, load profile, and fixed and variable costs. The new rate classes and their minimum annual therm thresholds are as follows:

Rate Classification	**Therm Requirements**
RS	N/A
SGS	1 – 999 therms
GS-1	1,000 – 17,499 therms
GS-2	17,500–49,999 therms
GS-3	50,000–249,999 therms
GS-4	250,000 – 499,999 therms
GS-5	over 500,000 therms
SIS	1,000,000 – 3,999,999 therms
IS	4,000,000–49,999,999 therms
ISLV	50,000,000 therms and greater
WHS	N/A
CSLS	N/A
NGV	N/A

Analysis of these groups reveals that these threshold levels include those customers with similar end use patterns.

Within the Small Interruptible Service ("SIS") rate classification the minimum threshold has been increased from 500,000 to 1,000,000 therms annually. By re-opening this rate class and increasing its minimum threshold, Peoples will not compromise the operational integrity of the system. Customers who use greater than 1,000,000 therms annually can choose either firm or interruptible service.

The proposed changes to the SIS rate schedule will discourage those customers who meet the minimum threshold, but historically have had firm requirements, from stepping into an interruptible rate class simply to obtain the lower distribution rate. Based on the Cost of Service Study, as well as for competitive reasons, Peoples determined there should be no increase in rates for the interruptible classifications.

Q. **WHAT CHANGES, IF ANY, DOES PEOPLES PROPOSE TO MAKE IN ITS NATURAL GAS TARIFF, OTHER THAN CHANGES IN THE EXISTING RATES?**

A. Definitions of the terms "Customer Pool" and "Pool Manager" have been added to the technical terms and abbreviations in Section 4.

In Section 5, we have added charges to customers that include a temporary turn-off charge, a credit card use charge, and a failed trip charge. These are cost based charges that should be included in the tariff in order to assure that the costs of providing these services go to those customers that cause the expenses. Support for these charges is contained in MFR Schedule E-3. Also in Section 5, the "Meter Test by Request" language has been changed to reflect the actual language in paragraph 2 of the Commission's Rule 25-7.065. The "Service Extensions" provision has been changed to include the cost of service to the customer in the calculation of the Maximum Allowable Construction Cost. We have also updated the language in the "Indemnity" provision.

In Section 7, we have modified the Individual Transportation

Service Rider by lowering the threshold for this service to 182,500 therms per year. This modification will standardize the minimum threshold for individual transportation customers throughout the Peoples and former West Florida service areas as well as possibly provide access to natural gas supplies that better suit the load patterns of these high volume customers. To recover the cost of providing this service to a larger group of customers, Peoples seeks to collect the monthly ITS administration fee on a per-meter basis. In addition to the changes mentioned above, we have included an additional cash-out tolerance level for ITS customers, as well as new Alert Day notification language. Also in Section 7, we have updated our penalties for non-compliance during curtailments to make the penalty a floating indexed amount in order to deter non-compliance and avoid inadvertently setting an artificial market price during times when system integrity could be compromised. Last, in Section 7, we have deleted the language in the NCTS Rider referencing the agreement reached by Staff and Peoples in Docket No. 990935-GU concerning the minimum number of customers Peoples would transition to transportation service as of November 2000. The deleted language is no longer necessary due to the passage of time.

Q. IN YOUR OPINION, ARE THE COMPANY'S PROPOSED RATES AND CHARGES JUST AND REASONABLE?

A. Yes. The resulting rates from the Company's Cost of Service Study are contained in Schedule H-1 of the MFRs and the Company believes the proposed rates are fair and equitable and result in each customer moving toward a more uniform contribution to costs associated with providing their service.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

Exhibit No.__________
Docket No. 020384-GU
Peoples Gas System
(WJG-1)
Page 1 of 1

MFR SCHEDULES SPONSORED BY:

Wraye J. Grimard

Schedule	Title	Schedule Number
"E" Schedules	Cost of Service Schedules	E-1 through E-9
"H" Schedules	Cost of Service Schedules	H-1 through H-18

Pipe Size

Exhibit No ______________
Docket No 020384-GU
Peoples Gas System
(WJG-2)
Page 1 of 1

	Min Dia	0	2	4	8	12
Miles of Pipe	Max Dia	2	4	8	12	24
Steel	4,758	2279	1131	1171	103	74
Cast Iron	217	1	151	43	14	8
Plastic	3,853	2803	814	236	0	0
Cost Weighting	Cost / Inch					
Steel	2 50	2 50	7 50	15 00	25 00	45.00
Cast Iron	1 50	1 50	4 50	9 00	15 00	27 00
Plastic	2 00	2 00	6 00	12 00	20 00	36 00
Weighted Miles						
Steel	37,650	5,698	8,483	17,565	2,575	3,330
Cast Iron	1,494	2	680	387	210	216
Plastic	13,322	5,606	4,884	2,832	-	-
Total	52,466	11,305	14,046	20,784	2,785	3,546
Normalized	1 0000	0 2155	0 2677	0 3961	0 0531	0 0676

		Residential	SGS	GS 1	GS 2	GS 3	GS 4	GS 5	NGV	CSLS	WHS	SIS	IS	ISLV	SC
Peak	71,836,064	12,697,702	212,172	15,248,254	8,304,755	6,393,166	3,574,339	4,042,350	71,960	101,446	9,296	6,070,717	13,665,319	-	1,444,588
Average	92,801,467	4,811,901	107,793	8,938,437	5,799,780	5,837,180	3,262,342	3,898,115	73,684	109,176	8,147	5,503,238	12,761,223	19,059,490	22,630,962
	164,637,531	17,509,603	319,965	24,186,691	14,104,535	12,230,346	6,836,681	7,940,465	145,644	210,622	17,443	11,573,955	26,426,542	19,059,490	24,075,550
Std. Peak & Avg.	1 0000	0 1064	0 0019	0 1469	0 0857	0 0743	0 0415	0 0482	0 0009	0 0013	0 0001	0 0703	0 1605	0 1158	0 1462
0"-2"	75,544,088	17,509,603	319,965	24,186,691	14,104,535	12,230,346	6,836,681	-	145,644	210,622	-	-	-	-	-
	1 0000	0 2318	0 0042	0.3202	0 1867	0 1619	0 0905	-	0 0019	0 0028	-	-	-	-	-
	11,305	2,620	48	3,619	2,111	1,830	1,023	-	22	32	-	-	-	-	-
2"-4"	75,561,530	17,509,603	319,965	24,186,691	14,104,535	12,230,346	6,836,681	-	145,644	210,622	17,443	-	-	-	-
	1 0000	0 2317	0 0042	0 3201	0 1867	0 1619	0 0905	-	0 0019	0 0028	0 0002	-	-	-	-
	14,046	3,255	59	4,496	2,622	2,273	1,271	-	27	39	3	-	-	-	-
4" - 8"	121,502,491	17,509,603	319,965	24,186,691	14,104,535	12,230,346	6,836,681	7,940,465	145,644	210,622	17,443	11,573,955	26,426,542	-	-
	1 0000	0 0721	0 0007	0 0995	0.1161	0 1007	0 0563	0 0904	0.0012	0 0017	0 0001	0 0769	0 3844	-	-
	20,784	1,497	14	2,069	2,413	2,092	1,169	1,878	25	36	3	1,598	7,990	-	-
8" - 12"	164,637,531	17,509,603	319,965	24,186,691	14,104,535	12,230,346	6,836,681	7,940,465	145,644	210,622	17,443	11,573,955	26,426,542	19,059,490	24,075,550
	1 0000	0 0532	0 0010	0 1999	0 0857	0 0743	0 0415	0 0482	0.0009	0 0013	0 0001	0 0703	0 1617	0 1158	0 1462
	2,785	148	3	557	239	207	116	134	2	4	0	196	450	322	407
Over 12"	164,637,531	17,509,603	319,965	24,186,691	14,104,535	12,230,346	6,836,681	7,940,465	145,644	210,622	17,443	11,573,955	26,426,542	19,059,490	24,075,550
	1.0000	0 1062	0 0019	0.1682	0 0857	0 0743	0 0415	0 0482	0 0009	0 0013	0 0001	0 0492	0 1605	0 1158	0 1462
	3,546	376	7	596	304	263	147	171	3	5	0	174	569	411	519
Total	52,466	7,897	131	11,337	7,688	6,666	3,726	2,183	79	115	7	1,968	9,010	733	926
Capacity Alloc.	1 0000	0 1505	0 0025	0 2161	0 1465	0 1271	0 0710	0 0416	0 0015	0 0022	0 0001	0 0375	0 1717	0 0140	0 0176